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Nuclear Energy and Sustainability

Can a Nuclear-Assisted Biofuels System Enable Liquid Biofuels as the Economic Low-carbon Replacement for All Liquid Fossil Fuels and Hydrocarbon Feedstocks and Enable Negative Carbon Emissions?

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Abstract

Can a Nuclear-Assisted Biofuels System Enable Liquid Biofuels as the Economic Low-carbon Replacement for All Liquid Fossil Fuels and Hydrocarbon Feedstocks and Enable Negative Carbon Emissions?

This report integrates the results of a series of studies and workshops to address the question: *Can a nuclear-assisted biofuels system enable liquid biofuels as the economic low-carbon replacement for all liquid fossil fuels and hydrocarbon feedstocks and simultaneously enable negative carbon emissions?* "Economic" is defined as economically competitive relative to other low-carbon replacement options for crude oil. "All" refers to the capability to replace the 18 million barrels of oil per day used by the United States. "Nuclear-assisted" refers to the provision of massive quantities of low-carbon heat and hydrogen at the refinery to fully utilize the carbon content of the cellulosic biomass feedstocks for liquid hydrocarbon production.

A system is proposed that decarbonizes about half of the U.S. economy while improving long-term soil productivity and sequestering carbon from the atmosphere. In the U.S. almost half the energy consumed by the final customer is in the form of liquid hydrocarbons produced from crude oil. Liquid hydrocarbons are used as (1) an energy source, (2) a method for daily-to-seasonal energy storage, (3) a chemical feedstock, (4) a chemical reducing agent, (5) a method to enhance high-temperature heat transfer in many furnaces and industrial processes and (6) other purposes. As a consequence, the U.S. consumes ~18 million barrels of crude oil per day to produce liquid hydrocarbons. While there are substitutes for liquid hydrocarbons for some applications, our assessment is that the costs and difficulty will dramatically increase if liquid hydrocarbon use goes much below the equivalent of 10 million barrels per day of crude oil. New uses of liquid hydrocarbons to partly replace coal and natural gas could increase demand beyond the equivalent of 10 million barrels of oil per day.

One can produce and burn liquid hydrocarbons from biomass without any net addition of carbon dioxide to the atmosphere. Plants grow by removing carbon dioxide from the atmosphere; thus, burning biomass does not result in any net addition of carbon dioxide to the atmosphere. Biomass is typically 40% oxygen. To remove this oxygen to create hydrocarbon liquids, there are two options. The first option is to use biomass as (1) a feedstock, (2) an energy source to operate the process and (3) a supply of carbon to remove the biomass oxygen as carbon dioxide. The second option is to use external heat and hydrogen to remove the oxygen as water and produce liquid hydrocarbons. The use of massive quantities of external heat and hydrogen for hydrocarbon liquid fuels production reduces the biomass feedstock per unit of liquid hydrocarbon product by more than a factor of two reducing land use by more than a factor of two. Many cellulosic feedstocks unsuitable for liquid hydrocarbon production are viable feedstocks with external heat and hydrogen inputs. As a result, there is sufficient cellulosic feedstocks to meet U.S. and global liquid fuels hydrocarbon demand without significant impacts on food and fiber prices.

The heat and hydrogen (heat plus electricity) are produced using base-load nuclear power plants—the most economic form of nuclear energy. If low-price natural gas, there is also the option of producing hydrogen from natural gas with sequestration of the carbon dioxide. The biomass is locally processed in depots to produce commodity feedstocks that can be shipped long distances to large biorefineries (250,000 barrels per day, oil equivalent) similar to existing refineries except modifications of front-end processes. The depot system enables local recycle of nutrients back to the soil. The biorefinery can produce variable quantities of liquid hydrocarbon fuels and carbon dioxide for sequestration enabling removal of carbon dioxide from the atmosphere. Preliminary estimates are that the liquid hydrocarbon costs are equivalent to crude oil at between $60 and $70 per barrel. The largest cost is for hydrogen with biomass feedstocks and refinery costs a smaller fraction of the total cost.

Acknowledgement

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Table of Contents

Appendixes are in Volume II

Appendix A. Workshop Agenda and Organization
Appendix B. Participants
Appendix C. Presentations

List of Figures

List of Tables

Executive Summary

Can a Nuclear-Assisted Biofuels System Enable Liquid Biofuels as the Economic Low-carbon Replacement for All Liquid Fossil Fuels and Hydrocarbon Feedstocks and Enable Negative Carbon Emissions?

This report summarizes and integrates the results of a series of studies and three virtual workshops held in August 2021 to address the question: *Can a nuclear-assisted biofuels system enable liquid biofuels as the economic low-carbon replacement for all liquid fossil fuels and hydrocarbon feedstocks and simultaneously enable negative carbon emissions?* "Economic" is defined as economically competitive relative to other low-carbon replacement options for crude oil. "All" refers to the capability to replace the 18 million barrels of crude oil per day used by the United States. "Nuclear-assisted" refers to the provision of massive quantities of low-carbon heat and hydrogen at the refinery to fully utilize the carbon content of the biomass feedstocks.

The Challenge

A major challenge for the United States is the transition from fossil fuels to a low-carbon economy to minimize the risks of climate change. We focus here on oil: the most valuable and versatile of the fossil fuel resources. Since oil is a finite resource, a related challenge is to enable an eventual transition between oil and whatever energy sources will be available to humankind as oil availability decreases and its cost inevitably increases. However, the finite and decreasing nature of oil supplies is not the issue addressed here.

The primary fossil fuel used in the United States is oil. Oil provides about a third of the primary energy and almost half the energy input to the residential, commercial, industrial, and transportation sectors. Oil is the dominant energy source because of its relatively low cost, high energy density, ease of storage and ease of transport. Oil is also the major feedstock to the chemical industry for the production of everything from drugs to plastics.

Unless we find a drop-in replacement for oil, we must not only replace oil as an energy source but must also replace 150 years-worth of infrastructure that has been created to transport, store and use oil; pipelines, refineries, cars, aircraft, furnaces, chemical processes and a myriad of other systems. The development of these technologies took many decades and trillions of dollars of investment. The development and deployment of oil-replacement technologies will also take decades and trillions of dollars. *However, climate change (and probably the finite nature of oil supplies) must be effectively addressed on a significantly shorter timescale.*

Coupled with these considerations is that hydrocarbon liquids can substitute for natural gas and coal; oil can provide a near drop-in replacement for these fossil fuels in applications from gas turbines to produce peak electricity to expanding oil's use for heating in the residential and commercial sectors. In a low-carbon society, the demand for liquid hydrocarbon fuels is expected to decrease in the transport sector while increasing in other sectors depending upon the relative costs of providing low-carbon energy sources for these other sectors. In total, liquid hydrocarbons are used as (1) an energy source, (2) a method for daily-to-seasonal energy storage, (3) a chemical feedstock, (4) a chemical reducing agent, (5) a method to enhance high-temperature heat transfer in many furnaces and industrial processes and (6) other purposes. In high-temperature furnaces and other industrial processes the carbon in the burning fuel enables radiative heat transfer from the hot gases to surfaces. Non-fossil heating options such as electrically-heated hot air or burning of pure hydrogen do not radiate significant heat. In a low-carbon world some carbon fuel may be added to high-temperature processes to enable radiative heat transfer and the processes to operate. Our assessment is that the costs and difficulty will dramatically increase if liquid hydrocarbon use goes much below the equivalent of 10 million barrels per day of crude oil. The demand could be as high as the equivalent of 20 million barrels per day of crude oil depending upon finding substitutes for the energy and storage function of coal and natural gas. In this context, the likely competition is hydrogen replacing natural gas.

To reduce the overall costs of the transition away from oil and to thereby speed the transition, we ask a series of related questions: Can we economically: (1) replace crude oil with low-carbon biomass, (2) modify oil refineries to become biorefineries that produce drop-in hydrocarbon replacements for gasoline, diesel, jet fuel, and chemical feedstocks from renewable plant biomass and (3) keep everything else essentially unchanged?

Green plants remove carbon dioxide from the air and convert it into biomass. When the biomass is burned, carbon dioxide is released to the atmosphere with *no net change in the atmospheric carbon dioxide concentration*. We examine a nuclear-assisted biofuels system where biomass is the carbon source for the carbon in oil and nuclear energy is used to provide the heat and hydrogen to convert biomass into drop-in hydrocarbon biofuels. To our knowledge, this is the first time this option has been considered in any depth.

System Design

There are two strategies to convert biomass into liquid hydrocarbon fuels. The traditional process to provide hydrocarbon biofuels is shown in Equation 1 where biomass plus oxygen yields biofuels plus carbon dioxide. The carbon in the biomass serves three functions: (1) a source of carbon for the hydrocarbon fuel, (2) an energy source for the conversion process and (3) a method to remove the oxygen.

$$\text{Biomass} + \text{Oxygen} \rightarrow \text{Hydrocarbon Fuels} + \text{Carbon Dioxide} \qquad (1)$$

$$CH_{1.44}O_{0.66} + O_2 \rightarrow (CH_2)_xH_2 + CO_2$$

We are examining herein an alternative strategy: biomass plus massive quantities of external heat and hydrogen are converted into hydrocarbon fuels and water. The hydrogen is used to remove the oxygen found in biomass and to provide the added hydrogen to produce a hydrocarbon fuel. Biomass is the carbon source for producing gasoline, diesel and jet fuel. Nuclear energy provides the low-carbon external energy source to produce hydrogen and heat. If such a system is deployed, the nuclear energy inputs will be 10 to 20% of the total energy consumption of the U.S. and the world. For an economically viable system, massive steady-state heat and hydrogen inputs at large biorefineries are required that match the characteristics of nuclear systems.

$$\text{Biomass} + \text{Hydrogen} + \text{Nuclear Heat} \rightarrow \text{Hydrocarbon Fuels} + \text{Water} \qquad (2)$$

$$CH_{1.44}O_{0.66} + H_2 + \text{Heat} \rightarrow (CH_2)_xH_2 + H_2O$$

Using external heat and hydrogen inputs enables replacing all oil with biofuels using available biomass supplies. First, external heat and hydrogen more than doubles the quantities of hydrocarbon fuels per ton of biomass feedstock. *For a given amount of biofuels produced, this reduces the land requirements for biomass production by more than a factor of two*.

Second, external heat and hydrogen enables use of biomass feedstocks that are poor energy, food, and fiber sources but excellent sources of carbon for production of biofuels. The external heat and hydrogen provided by nuclear energy is the key enabling technology: there is sufficient biomass to provide the necessary carbon to replace oil without major increases in the costs of food and fiber—the other primary uses of biomass.

Assume, for example, that we wish to produce about 10 million barrels per day of diesel containing 85% carbon by mass, or roughly 460 million tons of carbon per year. Biomass contains approximately 50% carbon by mass (dry weight basis). Thus replacing 460 million tons of carbon in oil would require about 920 million tons of biomass per year. Our initial estimates are that the United States may be able to produce 4.2 to 5.7 billion tons of biomass annually on a sustainable basis when biomass is considered as a carbon source, not as an energy source. Less than 2 billion tons of biomass is required to replace U.S. oil consumption of about 18 million barrels per day.

The system is based on using cellulosic biomass, sometimes called lignocellulosic biomass, not starches, sugars, or vegetable oils which are the basis of today's biofuels industry. Cellulosic biomass is by far the most abundant source of biomass on earth. Other forms of biomass (starch, sugar and vegetable oils) do not exist in sufficient quantities to really address our need to replace petroleum, and they also represent significant potential conflicts with essential food and feed production.

The available cellulosic biomass resources may be much larger. The U.S. Department of Energy (DOE) estimates about a billion tons without significant impacts on food and fiber prices. However, that analysis did not consider major changes in the agricultural and forestry system. If change technology or assumptions, much more biomass may become available: (1) 1000 million tons/year if increase the price of biomass from \$40/ton to \$80/ton of biomass, (2) 300-1200 million tons/year from growing *Opuntia* on arid lands, (3) 120-170 million tons/year from double cropping in the Corn Belt, (4) 1230-1280 million tons/year from double cropping elsewhere with land-efficient animal feeds, and (5) 500-1000 million tons/year from increasing crop yields on pasture and range lands. This results in a total U.S. annual cellulosic feedstock supply between 4.2 and 5.7 billon tons per year and does not include any marine sources of biomass (kelp, algae, etc.)

The proposed system is shown in Fig. ES.1. Low-density cellulosic biomass is sent to local depots where it is converted into storable, stable, dense forms suitable for long-distance transport to the nuclear-enabled biorefinery. At the biorefinery the biomass is converted into hydrocarbon fuels and chemical feedstocks with massive inputs of nuclear heat and hydrogen. The liquid transport fuels are burnt releasing carbon dioxide to the atmosphere. The resulting carbon dioxide is available to produce new biomass—thus there is a circular carbon dioxide cycle.

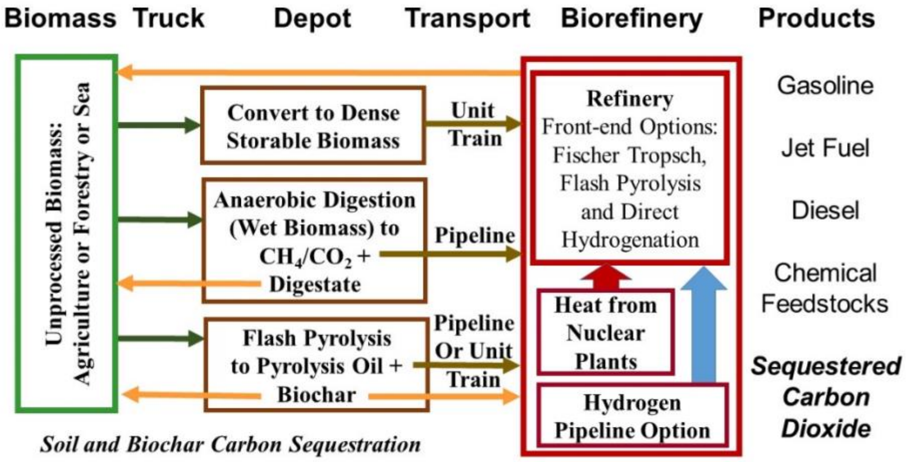

Fig. ES.1. Nuclear Biomass to Biofuels System

Large biorefineries, equivalent to a 250,000 barrel per day oil refinery, are required to minimize costs and enable variable production of gasoline, diesel, jet fuel and other products with time. *However, low-density cellulosic biomass cannot be economically shipped the long distances required to enable large biorefineries*. Therefore, local, near-farm, processing depots are essential to convert biomass into storable, economically-shippable intermediate commodities that will supply the large biorefineries.

This system design is driven by transportation and refinery economics. There are massive economics of scale associated with chemical plants and refineries. Truck transport costs increase rapidly with distance and thus limit economic shipping distances of unprocessed biomass to 50 to 80 kilometers in most cases. However, the cost of pipeline, rail, unit train and barge transport increases very slowly with distance. The economics are seen in the current systems used to move corn, soybeans and other agricultural commodities to market. These commodities are shipped by truck to local elevators and then shipped long distances by railroad and barge. Long-distance truck shipments are limited to more valuable cargo such as consumer goods and time-sensitive highly-perishable agricultural products such as lettuce and strawberries. The economics are also seen in the refinery industry with large refineries enabled by low-cost oil and natural gas transport via pipeline.

There are three depot options that produce different storable, economically-transportable intermediate commodities. The choice between depots depends upon the type of biomass available. First, biomass may be densified and shipped as dry pellets. This process is used to today to provide wood pellets to furnaces and boilers. Second, biomass may be fed to an anaerobic digester that produces a methane/carbon-dioxide gas mixture that is then shipped via pipeline to the refinery—plus a digestate that is returned to the soil. Anaerobic digestion is a commercial process and the source of renewable natural gas. Third and last, there is flash heating of biomass that produces pyrolysis oil and biochar. Thus we have three distinct intermediate commodities emanating from the depots to supply the biorefineries: 1) dry pelleted biomass, 2) biogas (methane and carbon dioxide) and 3) pyrolysis liquid.

For biofuel production we only want carbon and hydrogen—not the other elements in biomass including oxygen, nitrogen, potassium and phosphorus. The depots and the biorefinery enable recycle of nutrients in digestate and biochar back to farms and forests to improve long-term soil productivity. The sustainability/circularity of this approach contrasts sharply with the dominant current model of food and fiber production as well as the burning of biomass that does not recycle nutrients back to the soil. The nuclear-assisted biofuels system combined with depots may help enable long-term sustainable agriculture and forestry.

At the biorefinery the intermediate biomass commodities are processed into a “biocrude oil” by direct hydrogenation of biomass or by the Fischer-Tropsch process. This biocrude oil is then converted into hydrocarbon products by traditional, well-known refinery processes. These two processes are variants of existing, large-scale processes used to convert natural gas and coal into oil. These processes require massive quantities of hydrogen and concentrated heat sources (Equation 2) provided by low-carbon nuclear reactors.

The nuclear reactors providing the heat inputs to the biorefineries must be collocated with the biorefineries because heat can only be economically transported a few kilometers. Hydrogen can be produced on site or imported via pipelines. The heat inputs in traditional refineries are about 10% of the energy value of the liquid hydrocarbons that are produced. There are several options for hydrogen production.

First, hydrogen can be produced from natural gas with sequestration of the carbon dioxide byproduct. This may be the preferred option in locations with the combination of low-priced natural gas and good sequestration sites. Second, hydrogen can be produced by low-temperature (water) electrolysis and high-temperature (steam) electrolysis (HTE)—a more efficient process. Nuclear reactors produce heat that can be used to produce steam and electricity; thus, HTE is likely to be the most-favored nuclear hydrogen production process. All electrolysis processes are capital intensive, thereby creating incentives to operate hydrogen plants at high capacity factors.

There are two electrolysis process options that appear attractive to enable high capacity factors. The first option is that the reactor produce hydrogen for 85 to 95% of the time and peak electricity when high electricity prices exist. This strategy maximizes revenue while assuring high capacity factors for the hydrogen plant. It also addresses the challenge of meeting seasonal variations in electricity demand. The second option is a nuclear hydrogen gigafactory where the reactor factory, reactor site and hydrogen production facilities are collocated. Factory fabrication and deployment of reactors can dramatically lower reactor capital costs.

The system can sequester carbon dioxide from the atmosphere via two routes. The refinery can produce carbon dioxide for sequestration when excess low-priced biomass is available or during times of low liquid-fuel prices. This option provides variable negative carbon emissions while stabilizing the price of liquid fuels caused by variable production of biomass or changing markets for liquid fuels over time. This potential income stream assumes a market for negative carbon emissions; that is, removal of carbon dioxide from the atmosphere. Second, carbon is recycled from depots to the soil via the digestate from anaerobic digesters and biochar from flash pyrolysis. This carbon recycle to soils improves long-term soil productivity while providing long-term sequestering of carbon

Initial cost estimates for nuclear-assisted liquid hydrocarbon biofuels are equivalent to crude oil at between $60 and $70 per barrel. The largest cost component is for hydrogen. Hydrogen is produced using (1) nuclear energy and water or (2) steam methane reforming of natural gas with carbon capture and sequestration. The costs of the delivered biomass to the biorefinery and refining costs are similar. The cost of biomass as a fraction of the final cost of the liquid hydrocarbon is smaller than for traditional biofuel processes because in a nuclear-assisted biofuels system the biomass is primary a carbon source and secondarily a hydrogen source. In traditional biofuels systems, the biomass is (1) the carbon feedstock, (2) the source of carbon to remove oxygen from the biomass and (3) the energy source to operate the process.

Transition Strategy and Policy

The historical model for cellulosic liquid biofuels production has been dispersed biofuels plants where the size is limited to less than about 3,000 tons of biomass feedstock per day with outputs of a few thousand barrels per day. This size was largely determined by the maximum economic shipping distance of unprocessed biomass to the biorefinery. All of the first-generation cellulosic biorefineries failed, at least in part, because of the poor economics of small plants and the difficulties involved in handling unprocessed, raw biomass.

The biorefinery strategy proposed here is very different. We proposed to use crude oil refineries with modified front-end processing to receive cellulosic biomass and process it to supply a bio-oil to the rest of the refinery. Throughput rates are equivalent to an oil refinery processing 250,000 barrels per day of crude oil. Thus we propose to keep essentially unchanged the bulk of the refinery and thereby build upon 150 years of hydrocarbon liquid fuels processing. The strategy and system design are driven by the favorable economics of large-scale processes. The development of such a system requires favorable government policies of which several are identified.

- *Incentives to reduce fossil fuel consumption*. Fossil fuels are relatively inexpensive, easy to transport and easy to store. There will be little or no substitution to alternative fuels unless there are either incentives for alternative fuels or penalties for the use of fossil fuels. The crude oil market has the characteristic of extremely volatile prices over a period of a decade—prices far below and above the estimated cost of liquid hydrocarbon biofuels. This creates large financial risks for any capital-intensive technology to replace fossil fuels. One option to address this challenge is for assured prices for low-carbon liquid hydrocarbon fuels from cellulosic feedstocks where the government only provides support if the hydrocarbon liquid prices are below some set price.
- *Credit oil refineries for production of biofuels*. The evidence suggests that the fastest, lowest-cost transition away from fossil petroleum is to use existing oil refineries. Biofuel credits should apply to these refineries: if 10% of the carbon in the feedstock is from biomass, 10% of the hydrocarbon liquid fuel should be considered as low-carbon biofuels. Incentives should be based on the final product—not the route from field and forest to the consumer. This approach provides a transition pathway from crude oil to biomass.
- *Incentives for cellulosic biomass.* The technologically simple ways to make liquid biofuels are to produce ethanol from sugar or starch and biodiesel from vegetable oils or waste oils/greases. However, this resource base is insufficient to produce the required large quantities of liquid hydrocarbon fuels. Separate incentives for using cellulosic biomass are required to kick-start cellulosic liquid hydrocarbon fuels production

through the transition to commercial scale. Incentives should be structured to enable use by depots and existing refineries that are transitioning to biofuels incrementally. Cellulosic feedstocks are the lowest cost feedstocks; thus, the expectation would be that once at scale such incentives would no longer be required. Properly designed, incentives for increased cellulosic biomass production could also provide significant additional environmental services including increased biodiversity, reduced soil erosion, increased water supplies and improved water quality.

- *Carbon sequestration credits*. The U.S. government has a variety of incentives for sequestering carbon dioxide from the atmosphere. Such credits should apply to all strategies for carbon sequestration—from sequestration of carbon in soil to geological disposal of carbon dioxide.

What we have proposed here is a new option that is in the early stages of development where (1) most of the component technologies exist and (2) many of the technologies are deployed at a commercial scale. Further studies should identify what policies and strategies would enable the most rapid transition to low-carbon liquid fuels produced from cellulosic biomass feedstocks, centered on very large biorefineries collocated with nuclear reactor systems.

1. Introduction

This report summarizes and integrates the results of a series of studies [Forsberg et al., September 2021] and three virtual workshops held in August 2021 to address the question: *Can a nuclear-assisted biofuels system enable liquid biofuels as the economic low-carbon replacement for all liquid fossil fuels and hydrocarbon feedstocks and simultaneously enable negative carbon emissions?* “Economic” is defined as economically competitive relative to other low-carbon replacement options for crude oil. “All” refers to the capability to replace the 18 million barrels of oil per day used by the United States. “Nuclear-assisted” refers to the provision of massive quantities of heat and hydrogen at the refinery to fully utilize the carbon content of the biomass feedstocks. It is the first set of workshops and papers to address this question. The tentative answer to the question is “Yes”—but there are many questions and unknowns. Earlier studies [Forsberg, 2008] examined alternative uses of nuclear energy to assist production of liquid fuels from different fossil and biomass feedstocks but not the potential to replace all crude oil.

Appendix A provides the workshop agenda. Appendix B describes the participants that came from industry, national laboratories and universities. Appendix C has the viewgraph presentations from the workshops. The references in this report include references from the literature and references to specific talks in the workshop [Author, Appendix C]. The workshops were organized by a consortium including the Massachusetts Institute of Technology, (MIT), Michigan State University (MSU), North Carolina State University (NCSU) and Idaho National Laboratory (INL).

The question addressed by the workshop is based on two observations.

First, a major challenge for the United States is the transition from fossil fuels to a low-carbon economy to minimize the risks of climate change. We focus here on oil: the most valuable and versatile of the fossil fuel resources. Since oil is a finite resource, a related challenge is to enable an eventual transition between oil and whatever energy sources will be available to humankind as oil availability decreases and its cost inevitably increases. However, the finite and decreasing nature of oil supplies is not the issue addressed here.

The primary fossil fuel used in the United States is oil. Oil provides about a third of the primary energy and almost half the energy input to the residential, commercial, industrial, and transportation sectors. Oil is the dominant energy source because of its low cost, high energy density, ease of storage and ease of transport. Oil is also the major feedstock to the chemical industry for the production of everything from drugs to plastics.

Unless we find a drop-in replacement for oil, we must not only replace oil as an energy source but must also replace 150 years-worth of infrastructure that has been created to transport, store and use oil; pipelines, refineries, cars, aircraft, furnaces, chemical processes and a myriad of other systems. The development of these technologies took many decades and trillions of dollars of investment. The development and deployment of oil-replacement technologies will also take decades and trillions of dollars. *However, climate change (and probably the finite nature of oil supplies) must be effectively addressed on a significantly shorter timescale.*

The second observation is that the quantities of liquid biofuels that can be produced from existing biomass feedstocks without major impacts on food and fiber prices is strongly dependent upon process choices. The traditional process to provide biofuels is shown in Equation 1 where biomass plus oxygen yields biofuels plus carbon dioxide. The carbon in the biomass serves multiple functions: (1) a source of carbon for the hydrocarbon fuel, (2) an energy source to fuel the conversion process and (3) a method to remove the oxygen from the biomass.

$$\text{Biomass} + \text{Oxygen} \rightarrow \text{Hydrocarbon Fuels} + \text{Carbon Dioxide} \qquad (1)$$

$$CH_{1.44}O_{0.66} + O_2 \rightarrow (CH_2)_xH_2 + CO_2$$

There is an alternative strategy: biomass plus massive quantities of external heat and hydrogen are converted into hydrocarbon fuels and water. The hydrogen is used to remove the oxygen found in biomass and to provide the added hydrogen to produce a hydrocarbon fuel. Biomass is the carbon source in the production of gasoline, diesel and jet fuel. Nuclear energy provides the external energy source to produce hydrogen and heat.

$$\text{Biomass} + \text{Hydrogen} + \text{Nuclear Heat} \rightarrow \text{Hydrocarbon Fuels} + \text{Water} \qquad (2)$$

$$CH_{1.44}O_{0.66} + H_2 + \text{Heat} \rightarrow (CH_2)_xH_2 + H_2O$$

With external heat and hydrogen the quantities of liquid hydrocarbon fuels that can be produced increases by a factor of two or three per unit of biomass. Therefore the land required per unit of biofuel produced will drop correspondingly. Furthermore, many types of biomass that are unsuitable for biofuels production can be used.

As a consequence, there may be sufficient biomass resources to produce significantly more hydrocarbon liquid fuels than are currently produced from crude oil. However, massive inputs of heat and hydrogen will be required at a scale of 10 to 20% of the total primary energy production of the United States. The scale of input energy required, the need for concentrated heat sources and the need for constant energy inputs correspond well with the capabilities of nuclear energy systems. A simplified schematic is shown in Fig. 1.1.

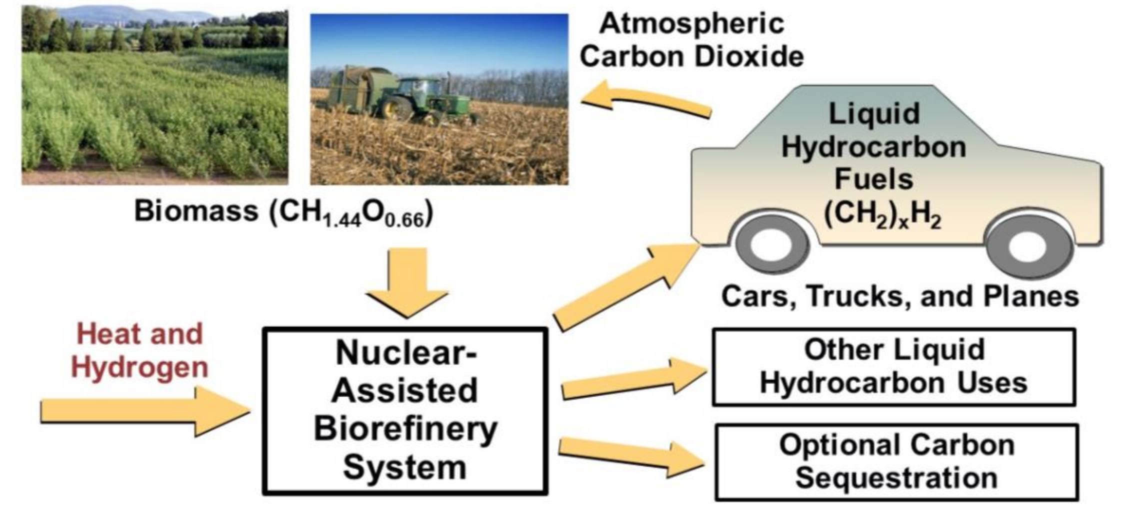

Fig. 1.1. Simplified Schematic of Nuclear-Assisted Liquid Hydrocarbon Biofuels System

The report is broken into six sections. Chapter 2 asks the question, what is the future demand for low-carbon liquid fuels? The current crude oil demand is about 18 million barrels per day. While the demand for transport fuels may decrease, other demands for liquid fuels may increase. We have found no credible estimates of future liquid hydrocarbon demand; but, our limited assessments suggest the demand will likely be about 10 million barrels per day oil equivalent assuming reasonable production costs for the biofuels. However, under some scenarios that demand could be much higher.

Chapter 3 describes the system where the design is controlled by (1) the economics of large-scale biorefineries, (2) the limited distances over which unprocessed biomass can be economically transported and (3) the relatively low-cost of long-distance transport of higher-density biomass commodities by train and barge.

Chapters 4 through 6 describe the agriculture/forest components of the system that deliver the biomass to the refinery gate. This includes estimates of available biomass resources (Chapter 4), the local depot system that converts local biomass into a storable, economically-transportable commodity to deliver biomass to the biorefinery gate (Chapter 5) and the transport system (Chapter 6). As will be discussed, we foresee three depot biomass processing options. Choices between these options are primarily determined by type of biomass available locally. Depot options for some biomass feedstocks may not be viable for other types of cellulosic biomass.

Chapters 7 and 8 describe the biorefinery system and associated heat and hydrogen production options. Central to this system is the use of world-scale refinery systems with throughputs equivalent to a 250,000 barrel per day crude-oil refinery with nuclear energy providing the required massive heat and hydrogen inputs.

Chapters 9 and 10 discuss economics, transition strategies to a biofuels system, policy considerations and conclusions. The transition strategy uses existing refinery assets that minimizes the cost and time for a transition.

1.1. References

Forsberg, C. W., B. E. Dale, D. S. Jones, T. Hossain, A.R.C. Morais and L. M. Wendt, 15 September 2021. "Replacing Liquid Fossil Fuels and Hydrocarbon Chemical Feedstocks with Liquid Biofuels from Large-Scale Nuclear Biorefineries", *Applied Energy*, 298, 117525. https://doi.org/10.1016/j.apenergy.2021.117225 [Accessed 5 March 2022]

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2. Future Demand for Liquid Hydrocarbons

The future demand for liquid hydrocarbons defines the scale of the challenge and viable options for meeting the challenge. If only small quantities of liquid hydrocarbons are required, there are many options including growing agricultural crops such as corn and soybeans that can be converted into hydrocarbon liquid fuels. If the demand is very large, then the only viable feedstock is cellulosic biomass—the primary form of plant biomass on earth. Furthermore, there are limited supplies of sustainable cellulosic biomass. If the demand is very large we must fully utilize most of the carbon in the cellulosic feedstock to minimize the potentially negative impacts of cellulosic feedstock provision. Reducing the demand for biomass in turn requires massive heat and hydrogen inputs at the biorefinery. The future demand for low-carbon liquid biofuels depends upon the cost of competing options; thus, we undertook a limited examination of future U.S. liquid hydrocarbon markets to develop some understanding of the competition.

2.1. Existing Oil (Liquid Hydrocarbon) Demand

Figure 2.1 shows energy consumption in the United States in 2019—just before the Covid-19 pandemic that reduced energy demand. Oil is 36.7% of the primary energy input but supplies 48% of the total energy input to the final customer. If one can replace crude oil with low-carbon, nuclear-assisted liquid biofuels, one decarbonizes about half of the overall the U.S. economy.

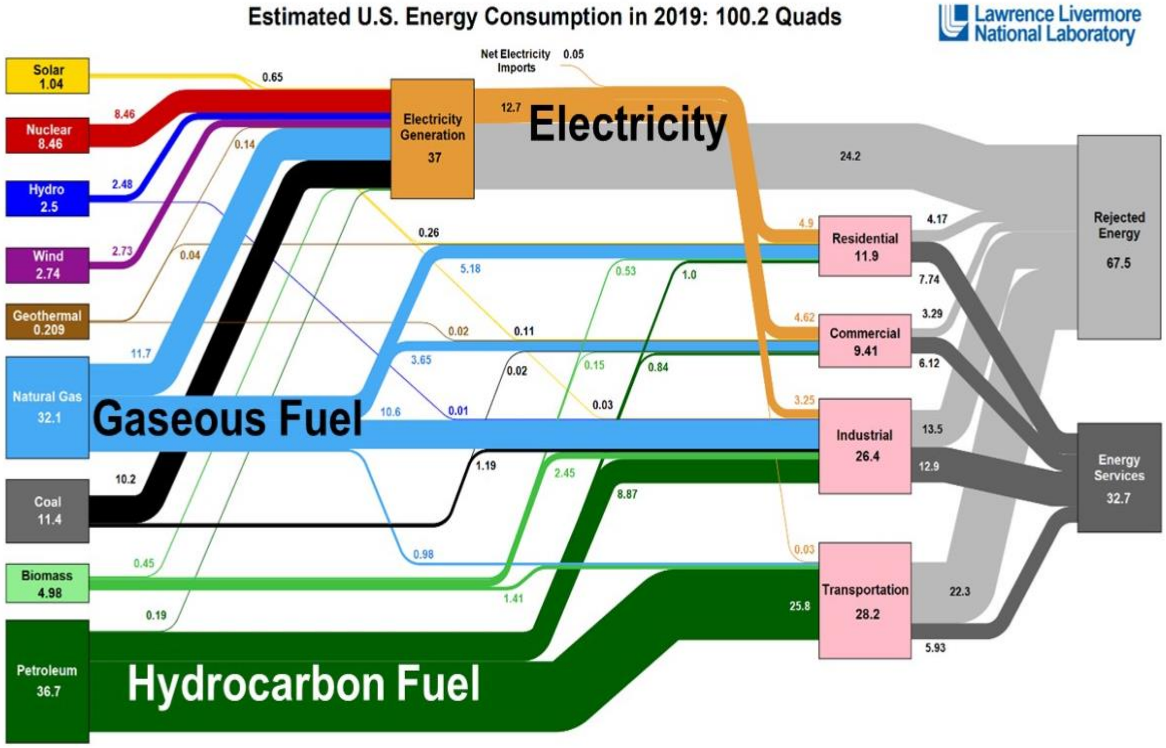

Fig. 2.1. Energy Flows in the U.S. Economy [Lawrence Livermore National Laboratory, 2020]

Fig. 2.1 is the traditional way energy markets are represented. However, liquid hydrocarbons are used for more than energy. The first use of fossil hydrocarbons is for energy production. The second use is as a feedstock for the production of various goods ranging from drugs to plastics. These products contain carbon and a carbon-containing feedstock (fossil fuels or biomass) is required. Today the primary chemical feedstocks are oil and natural gas. The third use is as a chemical reducing agent to convert materials such as iron ore into iron. Coal in the form of coke is the primary chemical reducing agent but natural gas and liquid hydrocarbons are used in some industries. Figure 2.2 shows the breakdown between the uses of fossil fuels in the U.S. industrial sector for energy versus these other uses of fossil fuels. About 6% of total fossil fuel consumption is, in fact, not for energy production at all, but rather for these non-energy uses of fossil fuels that depend upon the chemical characteristics of these fuels. When considering the future demand for liquid hydrocarbons, that demand could be from partly replacing coal and natural gas for these non-energy uses of fossil fuels.

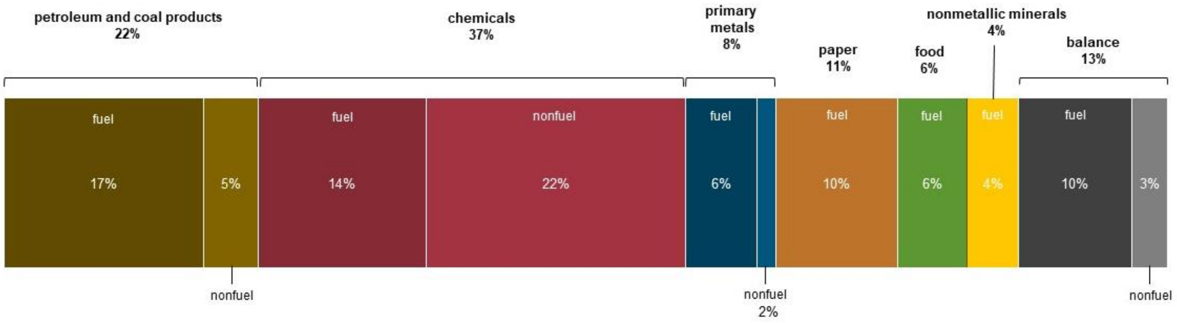

Fig. 2.2. Manufacturing energy fuel and nonfuel (feedstock) consumption by industry, 2018 (%) [EIA, December 2021]

Table 2.1 shows the products produced from crude oil in the United States. Total oil consumption is about 18 million barrels per day. The largest single use is gasoline for transport, representing a demand of about 8 million barrels of crude oil per day. However, many other products are also produced; thus, the challenge is replacing all the hydrocarbon products produced from crude oil.

Table 2.1. Products Produced from Crude Oil in the United States (EIA 2021a)

Products (U.S.)	**Annual Consumption (10^6 b/d)**
Finished motor gasoline	8.034
Distillate fuel oil (diesel fuel and heating oil)	3.776
Hydrocarbon gas liquids (HGLs)	3.197
Kerosene-type jet fuel	1.078
Still gas	0.611
Asphalt and road oil	0.342
Petrochemical feedstocks	0.286
Petroleum coke	0.260
Residual fuel oil (Shipping)	0.217
Miscellaneous products and other liquids	0.152
Lubricants	0.100
Special napthas	0.045

Aviation gasoline	0.011
Kerosene	0.008
Waxes	0.004
Total petroleum products	18.120

2.2. Liquid Transport Demand

Liquid hydrocarbon fuels are used in transportation because of their very high energy density per unit volume or mass compared to any other class of chemicals that exist as liquids at near atmospheric pressure and normal ambient pressure. The high energy density of liquid fuels is a result of two characteristics of this system. First, the H-C-H bond incorporates hydrogen in its high density chemical form. The average atomic weight of that three atom structure is 4.7 versus the next lightest element lithium with an atomic weight of 7. Second, the oxygen for combustion of hydrocarbon fuels comes from the atmosphere. It is not required to transport oxygen to the place where combustion occurs. In contrast, a lithium battery contains the lithium and oxygen—plus a massive amount of other materials to avoid having the fuel and oxidizer accidently combust inside a sealed package.

If fossil fuels did not exist, it may well be that diesel and jet fuel would have been discovered and manufactured for their remarkable properties including high energy density and safety in handling. There are severe economic penalties involved in transitioning from hydrocarbon fuels to batteries or other energy sources in aircraft or heavy trucks where an added kilogram of fuel necessarily requires one less kilogram of cargo.

The implication is that for these two markets (aircraft and heavy trucks) in a low-carbon world, the users will be willing to pay a large premium for liquid hydrocarbon fuels made from biomass rather than use alternative energy sources. That sets the minimum demand for hydrocarbon liquids as fuels at several million barrels per day over the next several decades given the growth of the heavy truck and aircraft industries. The extreme opposite in terms of transport fuel requirements are ships and railroads where weight is not a major constraint enabling the potential use of other energy sources.

The largest U.S. crude oil market is for light-weight cars and trucks—about 8 million barrels per day of oil equivalent in the form of gasoline. The expectation is that this demand will go down—partly because of continued improvement in the efficiency of light-weight cars and trucks [National Academies of Sciences, Engineering and Medicine, 2021]. The conventional wisdom is that this market sector will be electrified—but there are major questions on what fraction of this market will be electrified.

The light-duty vehicle fuel options [Green 2019] include (1) replacement of fossil-fuel gasoline with biofuels or hydrogen, (2) hybrid vehicles, (3) plug-in hybrid vehicles and (4) all-electric vehicles. Hybrid vehicles burn some type of fuel and have batteries on-board. When the vehicle slows down or goes down the hill, the battery is charged. When the vehicle goes a short distance, the vehicle accelerates or goes up the hill, the battery provides power. The battery enables the engine to operate in its most efficient modes most of the time. It has been estimated that an all-hybrid fleet could reduce gasoline consumption by up to 30%.

Plug-in hybrid vehicles have a heavier battery package that enables the vehicle to go on shorter trips without using the motor and to recharge by plugging into the electrical grid. A combustible fuel is used on longer trips. Because plug-in vehicles are duel-fuel vehicles, the owner can chose to operate using either fuel or electricity depending upon their relative prices. All-electric vehicles have larger battery packages to enable longer distances and significantly higher costs partly driven by the costs of raw materials in the batteries.

The choice of vehicle technology has massive economic and social implications. Traditional internal combustion engine (ICE) vehicles have the lowest initial costs while all-electric vehicles have the highest costs. Most of the ownership cost of cars is the initial cost of the vehicle—the fuel costs are a smaller fraction of lifetime ownership. This contrasts with aircraft and heavy trucks where fuel is the primary lifetime cost element. Thus economics drives users toward more efficient engines in aircraft and heavy trucks. Social decisions to electrify light vehicles significantly reduces the standard of living of the bottom 60% of society because the primary expenditure is in the vehicle, not the fuel.

Plug-in hybrid electric vehicles and all-electric vehicles obtain much of their energy from the electricity grid; thus, their economics must include the impacts on the grid where choices between the two types of vehicles may have radically different impacts on the cost of electricity delivered *to all customers*—not just vehicle owners [Anwar et al., 2022].

Figure 2.3 shows the cost breakdown for delivered electricity in the U.S. About 40% of the delivered cost of electricity is associated with transmission and distribution, the balance is in the cost of electricity production. If the additional or new electricity demand occurs at times of existing peak electricity demand, large expansions of the electricity grid are needed, with significant increases in electricity prices for *every customer*. In contrast, if there is added electricity demand at times of low total electricity demand, the average price of electricity may go down because the grid is delivering more electricity to the customer without grid expansion. The fraction of the cost of the electricity from building and maintaining the grid goes down.

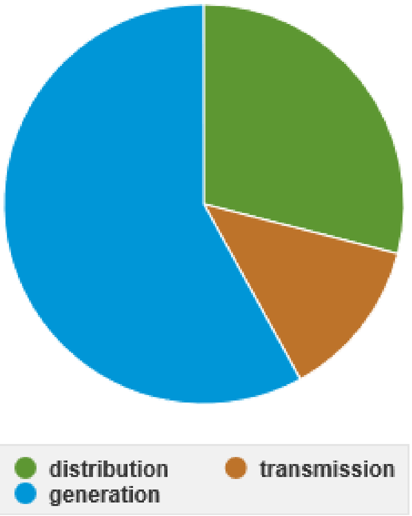

Fig. 2.3. Cost Breakdown of Delivered Electricity to the Customer in the United States in 2019 [EIA 2021b]

From the perspective of the electricity grid, there is a radical difference between all-electric vehicles and plug-in hybrid electric vehicles that have (1) batteries and (2) engines that could be fueled using biofuels, hydrogen and other storable fuels.

With a plug-in hybrid vehicle, there is still assured transportation for the vehicle owner if the battery is not charged by burning a combustible fuel. The owner of such a plug-in hybrid vehicle would prefer to recharge when electricity prices are at a minimum and is willing for the utility to control times of recharging. Plug-in hybrids have the potential to be recharged at times of lower electricity demand resulting in greater utilization of the transmission/distribution system and thus lowering the cost of electricity for all electricity customers. As a consequence, plug-in hybrids with hydrocarbon fuel storage can potentially reduce the average price of electricity, reduce investment in the electricity system, create a more robust electricity system where the vehicle load can be dropped if the grid requires it and thereby save the customer money. There is a secondary effect, plug-in hybrid vehicles support wind and solar by providing a demand when excess electricity is available—but not requiring expensive electricity storage for vehicle battery recharge at other times. A reasonable estimate is that plug-in hybrids have the potential to reduce gasoline consumption by two thirds—twice that of hybrid electric vehicles.

A recent review [Anwar et al., 2022] discussed the many studies on all-electric vehicles and concluded "Overall, a complete benefit-cost assessment, even at the regional scale, is still missing that considers the entire extent of values, enablement costs, and the perspectives of all stakeholders, including the utilities, EV owners, charging station owners and rate payers." There are several factors that make assessments of all-electric vehicles very challenging. A recent study [Bedir, 2018] examined likely times when these vehicles will be recharged in California (Fig. 2.4) and found that most recharging will be done in the early evening shortly after the sun sets—the time of peak daily electricity demand and also when no solar electricity is generated. This recharging pattern is caused by work schedules and single car families that want assured car availability. As discussed above, such charging has massive implications for the gird.

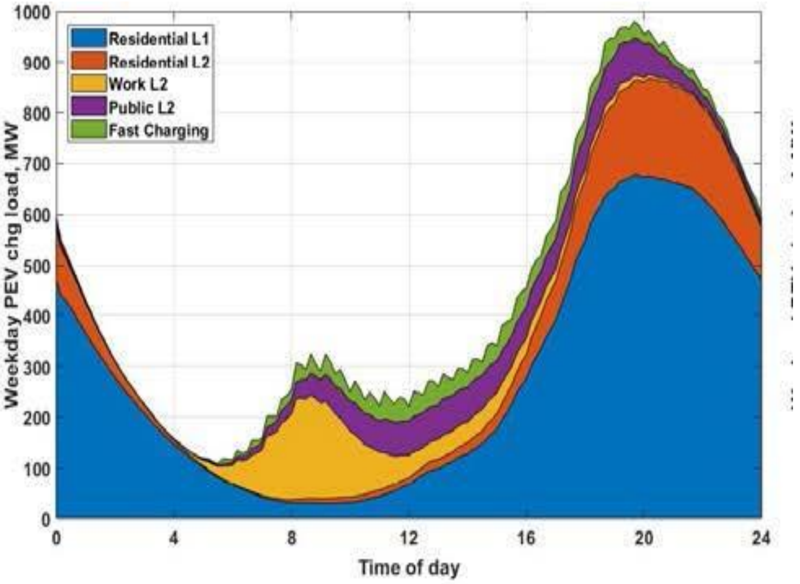

Fig. 2.4. Projected California plug-in electric vehicle electricity demand 2017-2025 vs time of day

There is a second effect of all-electric vehicles in northern climates. With internal combustion engines, heat for the passenger compartment is provided by the engine—waste heat to warm the passengers at no additional cost. With all-electric vehicles heat must be provided by batteries, thereby increasing peak vehicle electricity demand at times of peak winter electricity demand for other uses, combined with minimum solar electricity production. At the same time, there are efforts in parts of the United States to electrify heating and cooling. Any electrification of heating will show up on the coldest weeks of the year at the same time of peak demand for all-electric vehicles.

From the perspective of the electricity grid, an all-electric vehicle fleet implies massive grid and power plant capacity expansion to meet a peak demand and likely major increases in electricity prices. In this context, it is noteworthy that recent major studies of the future of the light-vehicle market [National Academies of Sciences, Engineering and Medicine, 2021] have not considered impacts on the electricity grid. This is not an issue if there are a few million all-electric vehicles; but, it may become the primary challenge if all-electric vehicles become the primary type of light-duty vehicle.

The above considerations suggest significant long-term decreases in the demand for liquid transport fuels; but, rapidly increasing costs to society if attempt to fully electrify the light-vehicle fleet or alternative fuels for aircraft and heavy trucks. In this context, the plug-in hybrid vehicles avoid most of these challenges because they combine the cheap storage capabilities of liquid hydrocarbon fuels on an hourly to seasonal basis with the capability to recharge batteries when low-cost electricity is available. That characteristic has the potential to lower average electricity prices to all customers. While one can make a reasonable case to reduce combustion fuel demand by two thirds for light-vehicle transportation via electrification, complete electrification becomes very expensive because one must replace the hourly to seasonal transportation storage function of liquid fuels.

2.3. Energy Storage Demand

Fossil fuels provide two critical functions: (1) an energy source and (2) an energy storage system that enables energy production to better match energy demand. The storage challenge is a large part of what makes transitioning away from fossil fuels so difficult. The storage challenge may create a major long-term demand for cheap-to-store liquid hydrocarbons.

Figure 2.1 shows energy flows in the United States, We use about 100 quads of energy per year in the U.S. with about 6 weeks of stored energy required for the system to operate effectively—more energy storage in the winter and less in this summer. U.S. energy storage includes a 90-day supply of oil, a 30-day supply of natural gas, over a 100-day supply of coal and 6 to 9 months of nuclear fuel in reactors. The large oil inventory includes the Strategic Petroleum Storage reserve operated by the U.S. government to minimize economic damage in the case of an oil supply disruption. Our energy storage system addresses daily to seasonal changes in energy demand while providing assured energy in the face of hurricanes, earthquakes, and multi-week weather events. Six weeks of storage is 3.4 million GWhs; that is, the U.S. storage requirements are measured in millions of gigawatt-hours [Forsberg, December 2021]. A million gigawatt hours requires about 1.8 million barrels of oil equivalent per day for a year.

To understand the scale of the energy storage problem, consider options to provide a million gigawatt hours of storage for the electric sector. The U.S. Energy Information Agency [EIA. August, 2021] reports installed costs of utility-scale battery systems at $589/kWh. Equally important, the decelerating cost trends with time (Fig. 2.5) suggest that battery system costs will level off near $500/kWh. Many battery advocates project large cost reductions in battery costs but *that is not the same as system costs*. System costs include batteries, land, power connections, AC/DC power conversion equipment, engineering, insurance and all the other costs to the utility. Except for the batteries, there is no basis to expect reductions in these other costs that are dominating total costs.

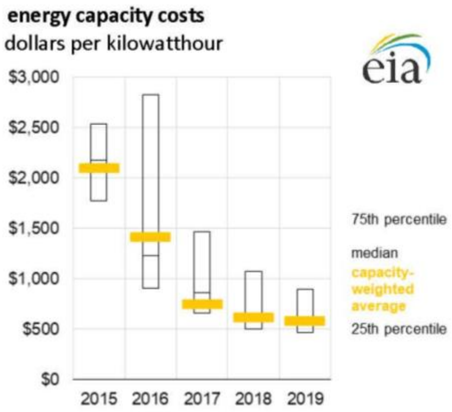

Fig. 2.5 Total Installed Battery Costs for Large-scale Systems in the United States [EIA, August 2021]

While large-scale battery installations have been growing rapidly, the scale is small—about 0.5 GWh of added storage capacity per year. To provide a million gigawatt hours of electricity storage in batteries at $500 per kWhr, would require a capital investment of about $USD 500 trillion…roughly 20 times the U.S. gross national product.

Today 99% of U.S. electricity storage is hydroelectric pumped storage—553 GWh (DOE 2021). The estimated costs are near $150/MWh (Akhil, 2013) but these costs are highly site dependent and limited in number—unlike manufactured storage systems such as batteries. If we use hydro pumped storage, we would need to expand the total U.S. pumped storage capacity by a factor of 1800 for a million gigawatt hours of electricity storage. Pumped hydro systems do have very long lifetimes relative to batteries

The addition of non-dispatchable wind and solar may dramatically increase storage requirements in the electric sector. In systems with large wind or solar input, the costs of storage drives the cost of electricity. The U.S. Energy Information Agency [February, 2021] has estimated the levelized cost of electricity for solar ($31.30/MWh), on-shore wind ($31.45/MWh) and offshore wind ($115.04/MWh) in good locations. The levelized cost of storage using batteries is $121.86/MWh—about four times higher than the cost of making electricity. Because of the night-day cycle and cloud cover, solar systems operate only about 25% of the time. In any system with significant solar or wind this implies that most of the electricity will go through storage before going to the customer. Therefore, the cost of storage in systems with large wind or solar, not the cost of electricity production from wind and solar, is the primary cost of electricity to the customer.

Separately there is the seasonal storage challenge. An example can demonstrate the challenge. In the United States the added peak demand for natural gas in January over the base-load demand for natural gas is about equal to the total electricity production [AGA, 2021]. Peak energy demand is in the winter because of peak heating load. In addition, there is about a factor of two difference in the seasonal output of solar at the mid-latitudes [Mulder, 2014] implying a massive seasonal impact on storage requirements if any significant amount of electricity is provided by solar energy sources that peak in the summer. Electricity storage technologies are too expensive and or geographically limited to meet the storage challenge. As energy sources migrate away from fossil fuels, the requirements for and costs of energy storage drive the energy system design.

The challenge of daily to seasonal energy storage until recently has not received much attention because energy storage is very cheap and mostly invisible in fossil systems. It is becoming visible as society attempts to transition off fossil fuels. In the member states of the European Union, Germany has the highest penetration of renewable electricity (installed capacity of roughly 2.2 kWs per capita) [Per Capita, 2020]. Germany also has the highest residential energy prices [Strom Report, 2022] in the EU (€30cent per kWhr), roughly 50% higher than the EU average. Germany has chosen to keep open its lignite-fired power stations—reflecting the reality today that there is no economically affordable option to address the energy storage challenge in countries without massive hydro-electric capacities except burning fossil fuels. The same rapid price increases in electricity have been seen in California with the move to renewables and the recent decision to build added natural-gas-fired power stations to address the energy storage challenge using stored natural gas to assure reliable supplies of electricity. The actions of Germany and California are leading indicators that the low-carbon energy storage challenge has arrived with no clear solutions even in parts of the world willing to accept much higher energy prices. In the United States the economic large-scale use of wind depends upon natural-gas-fired turbines using the low-cost storability of natural gas to enable electricity production at times of low wind and solar output. Battery storage is only used for very short duration storage. The functioning of the system is dependent upon the storability of fossil fuels. The countries that have very low carbon emissions use some combination of nuclear and massive hydro facilities but only a few countries have massive hydro reserves (Norway, Iceland, etc.)

A second indicator of the storage challenge is the growth rate of renewables versus oil and gas as shown in Figure 2.6. From 2000 to 2019 solar and wind grew from about 22 TWh to 2,000 TWh. In 2019, renewable electricity represented a little more than 1% of global direct primary energy consumption. In contrast, gas and oil consumption grew from 65,400 TWh in 2000 to 97,200 TWh in 2019, a total increase of about 32,000 TWh, or *16 times as much* as renewable electricity increased over that time period. While the rate of growth of solar and wind was impressive, the absolute amount of energy generated from solar and wind is dwarfed by the growth in the absolute amount of gas and oil consumed with very low energy storage costs that enable dispatchable energy when needed.

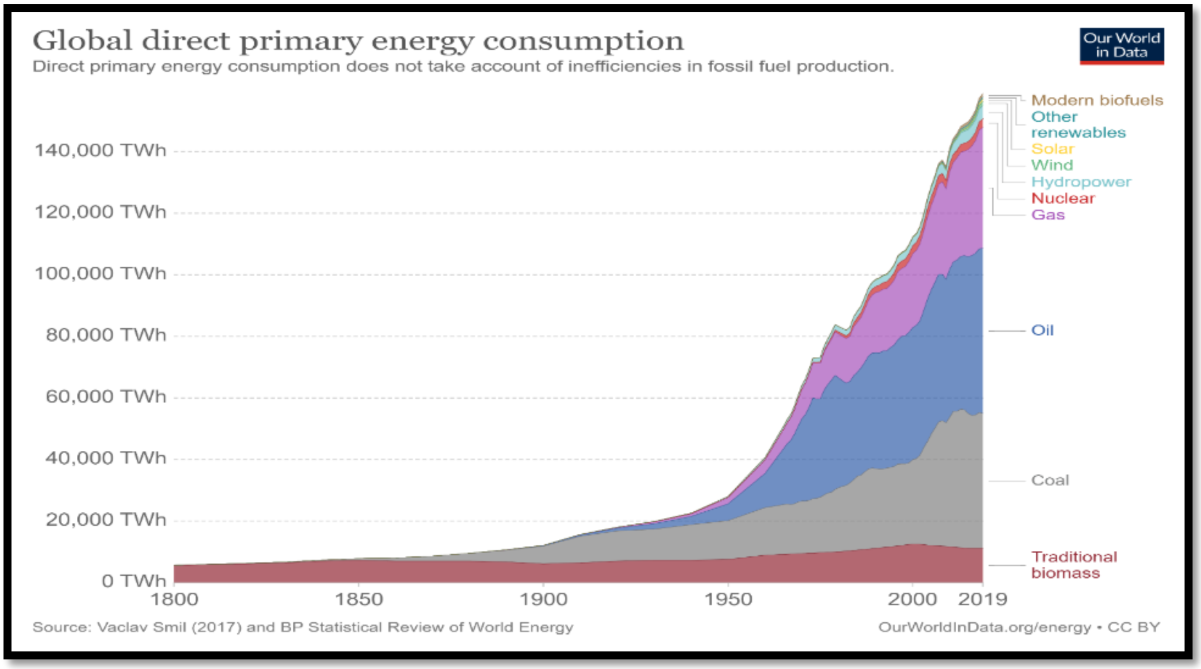

Fig. 2.6 Global Direct Primary Energy Consumption (Ritchie and Roser 2022)

Recent studies [Sepulveda, 2021; Dowling 2020] have evaluated what is required of storage to have a major beneficial economic effect on the price of electricity in a low-carbon electricity system. Electricity storage capital capacity costs must be <$20/kWh to reduce electricity costs by more the 10%--expensive storage is of little value to the electrical customer and hence such storage will not be built. The cost of storing fossil fuels is far below that number. In the United States, about 59% of the electricity is from burning fossil fuels (Fig. 2.1)—primarily coal and natural gas. To maintain the long-term storage function in the electricity systems with high renewables, would require about 20% of the electricity from combustible fuels. The high cost of low-carbon energy storage systems is why today most energy storage is in the form of natural gas, oil and coal in the residential, commercial, industrial, and transportation sectors. In a low-carbon world, there are only four affordable energy storage options at the million gigawatt hour scale [Forsberg, December 2021].

- *Nuclear fuel*. Most nuclear reactors are refueled every 18 to 24 months in the United States. As a consequence, they have massive quantities of energy storage in the form of nuclear fuel.
- *Gaseous fuels*. The first well-documented use of gaseous fuel was for town lighting that occurred in 1807 in London and rapidly expanded to major cities around the world. This gas was “town gas”—a mixture of hydrogen and carbon monoxide made from gasification of coal with gas storage facilities built into these systems. Town gas was soon used for cooking in homes and other purposes. Natural gas did not fully replace town gas until the 1950s in the United States and the 1970s in Great Britain. The natural gas system relies

on massive underground storage facilities that decouple steady-state production from highly variable demand. The projected path forward is a second conversion of gaseous fuels to hydrogen that can use the same underground storage system [AGA 2021, GPI 2022].

- *Liquid hydrocarbon fuels*. The current source of liquid hydrocarbon fuel is crude oil. As discussed herein the replacement is nuclear-assisted liquid biofuels. These liquid biofuels could play a much larger role in energy storage.
- *Heat storage*. Heat storage has not been historically used on a large scale because of the availability of storable fossil fuels, but heat storage may become important in a low-carbon economy. The heat source for storage might be nuclear, concentrated solar power or electricity converted to heat.

Systems [Forsberg, 2021] have been developed (Fig. 2.7) that integrate heat storage, liquid biofuels, and hydrogen with electricity generation. Such systems are used in some existing concentrating solar power (CSP) plants and are being planned for advanced nuclear plants. Cold fluid from heat storage is heated by a nuclear reactor or CSP facility with hot fluid sent to a hot storage tank. Hot fluid from the storage tank is sent to the power block to produce electricity and/or to supply industrial heat users. The peak power block output may be several times the peak output from the nuclear or CSP facility. Heat storage capacity may enable energy storage for up to a week. If very low-price electricity is available, it can be converted into stored heat for later use. Seasonal peak demands can be met by using energy sources such as liquid hydrocarbon fuels and hydrogen to heat the storage fluid. Heat storage is the low-cost energy storage for periods up to a week with hydrogen or liquid hydrocarbons the low-cost longer-duration storage option.

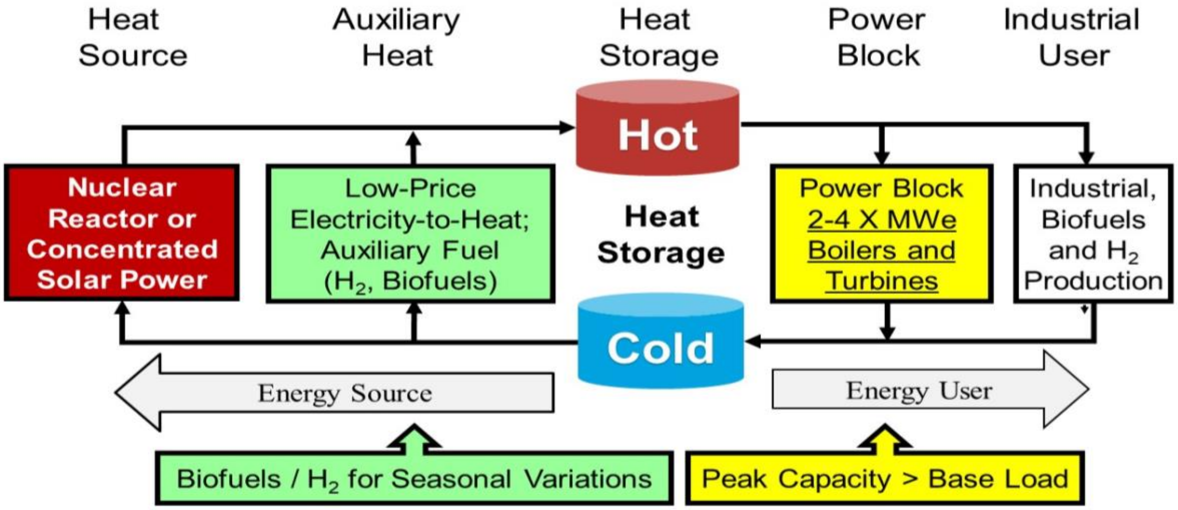

Fig. 2.7. Variable Heat and Electricity with Heat Storage to Match Production with Demand

The question is what replaces the several million gigawatt-hours of very-low-cost energy storage provided by fossil fuels? Batteries are too expensive and pumped hydro sites are too limited for this scale of energy storage. Will storable biofuels be required for providing peak electricity [NEA, 2019] or to meet seasonal energy demands that are now provided primarily by natural gas and coal? *Transfer of any significant fraction of the energy storage currently in the natural gas or coal systems results in millions of barrels per day of liquid hydrocarbon fuel demand*.

2.4. New Markets

Fossil fuels are deeply embedded into all aspects of our current industrial economy to meet requirements that exit for society to function but are not generally recognized. Transitioning to a low-carbon economy may require significant quantities of liquid hydrocarbons for these “new” applications. We have identified one such market but there may be other markets that have not been recognized and that represent a hidden demand for liquid hydrocarbons.

Many industrial processes require high-temperature heat (>500ºC) that is currently provided by burning fossil fuels. Most energy studies assume that future high-temperature heat needs will be provided by electrical heating or burning of hydrogen. However, in most high temperature processes heat is partly or primarily transferred from the burning fuel to the colder object via radiative heat transfer. Large furnaces have high-temperature radiative heat transfer sections followed by lower-temperature convective heat transfer sections. Radiative heat transfer makes a campfire feel warm and is enabled by carbon particles in the flame which convert energy into a form that can be radiated to the person.

In contrast, if hydrogen is burned or air is electrically heated, there is almost nothing in the hot gases to convert that heat into radiant heat. In hydrogen facilities this can create a safety challenge [Eck and Snyder, December 2021] where burning hydrogen is not visible nor is radiating large quantities of heat. Special sensors are used to detect such burning hydrogen to prevent people from walking into super-hot invisible flames. This problem also exists with very high-temperature, invisible steam leaks.

What this fact implies is that some carbon may be needed to be added to hydrogen [Hutny and Lee, 1991] or electrically-heated hot air in many applications to transfer high-temperature heat from non-fossil energy sources to whatever is being heated. The unanswered questions are (1) how many of our uses for fossil fuels require radiative heat transfer that is an intrinsic characteristic of burning carbon-based fuels but not an intrinsic characteristic of alternative energy sources such as hydrogen and electrically-heated hot air and (2) what is the future demand for carbon-based fuels co-fired with other energy sources to provide radiative heat transfer? There has been very little work in this area because it is academic until one wants to stop using carbon-based fuels.

2.5. Conclusions

We did not find credible assessments of the long-term demand for hydrocarbon liquids for a low-carbon world. That result was not unexpected because that demand will depend upon the relative costs of alternative technologies. That knowledge in turn requires predicting technological advances and economics in multiple areas including the electricity grid. The U.S. Energy Information Agency (2022) has projected a business-as-usual case for the United States as shown in Fig. 2.8 that shows small changes in total liquid hydrocarbon demand between now and 2050. It reflects the reality that liquid hydrocarbons are remarkable materials where finding substitutes will be difficult. Electric vehicles may reduce gasoline demand but increases in areas such as air travel increase the demand of other liquid transport fuels.

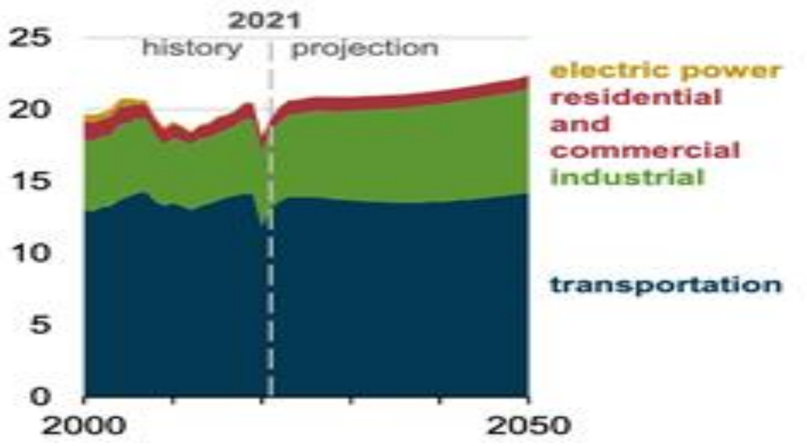

Fig. 2.8. Petroleum Consumption AEO2022 Reference Case, Millions of Barrels

The largest uncertainties for low-carbon liquid biofuels demand are (1) the demand for stored energy to replace the stored energy function of fossil fuels and the added demand for long-duration energy storage imposed by expansion of wind and solar, (2) the requirement for hydrocarbons or some other particulate to be added in systems using hydrogen or electricity to produce radiative heat transfer and (3) future trajectories of the transport sector. Based on the above considerations, our engineering judgement is that the likely liquid hydrocarbon demand for the United States in a low-carbon world is near 10 million barrels of oil equivalent per day but under some circumstances could be as high as 20 million barriers of oil equivalent per day. The higher estimates of liquid hydrocarbon demand occur if constraints on (1) vehicle electrification such as high prices for battery materials such as lithium as demand increases and (2) replacing some of the energy and energy storage functions of natural gas and coal. Today (Fig. 2.1) in the United States crude oil provides 36.7 quads of the energy while natural gas provides 32.1 quads and coal provides 11.4 quads. *If any significant fraction of the storage function of natural gas or coal is moved to biofuels, it results in much larger demands for liquid hydrocarbon biofuels*. The likely competition in these markets for liquid hydrocarbons is hydrogen as a replacement for natural gas and coal.

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3. System Design

In this section we describe the top-level system design and the basis for that design [Forsberg, 2020; Forsberg, Appendix C]. The design is based on three factors.

- *Demand for hydrocarbon liquids*. The likely demand for liquid biofuels exceeds the equivalent of 10 million barrels of oil per day (Chapter 2). Conventional biofuels can't meet this demand. Only cellulosic feedstocks can meet this demand.
- *Refinery economics*. The economics strongly favors very large biorefineries.
- *Economics of biomass transport*. The economic shipping distance of unprocessed cellulosic biomass is 30 to 50 miles. There is insufficient biomass within this distance to support a large biorefinery. Long-distance shipments of dense forms of biomass commodities is relatively inexpensive.

The desired levels of liquid hydrocarbon fuels production may not be achievable with conventional biofuels strategies that use biomass as a carbon source and energy source for the conversion process, at least not without devoting at least twice as much land to biomass production as would otherwise be required (Equation 3.1).

$$\text{Biomass} + \text{Oxygen} \rightarrow \text{Hydrocarbon Fuels} + \text{Carbon Dioxide} \qquad \text{(Equation 3.1)}$$

$$CH_{1.44}O_{0.66} + O_2 \rightarrow (CH_2)_xH_2 + CO_2$$

The system design herein uses biomass as a carbon source with external heat and hydrogen to convert all biomass carbon to hydrocarbon liquids (Equation 3.2). The hydrogen removes the oxygen found in biomass and provides the added hydrogen to produce a hydrocarbon fuel. Nuclear energy provides the external energy source to produce hydrogen and heat. External heat and hydrogen more than doubles liquid hydrocarbon production per unit of biomass (and hence per unit of land devoted to biomass production) and also enables use of low-grade biomass resources not normally considered suitable for biofuels production. Chapter 4 estimates the U.S. sustainable liquid hydrocarbons biofuels production capability that substantially exceeds current demands for liquid hydrocarbons.

$$\text{Biomass} + \text{Hydrogen} + \text{Nuclear Heat} \rightarrow \text{Hydrocarbon Fuels} + \text{Water} \qquad \text{(Equation 3.2)}$$

$$CH_{1.44}O_{0.66} + H_2 + \text{Heat} \rightarrow (CH_2)_xH_2 + H_2O$$

The biomass to biofuels conversion processes are variants of existing refinery processes as described in Chapter 7. Refining experience shows massive economics of scale resulting in a minimum biorefinery size near 250,000 barrels of oil equivalent, or biomass refinery feedstock requirements of about 60,000 tons per day. However, the bulk density of raw biomass is low (<< 100 kg/cubic meter) and it is therefore uneconomic to ship raw biomass more than about 30 to 50 miles. All first-generation cellulosic biorefineries used local biomass that limited the feed input to about 3,000 tons per day and all failed, partly because of the poor economics of small chemical plants. There is insufficient biomass to feed a very large integrated refinery within this economic transport distance. To address this crucial logistics cost challenge, low-density biomass is sent to local depots where it is converted into storable, stable, energy-dense forms suitable for economic long-distance transport to large biorefineries. The result is the system as shown in Fig. 3.1.

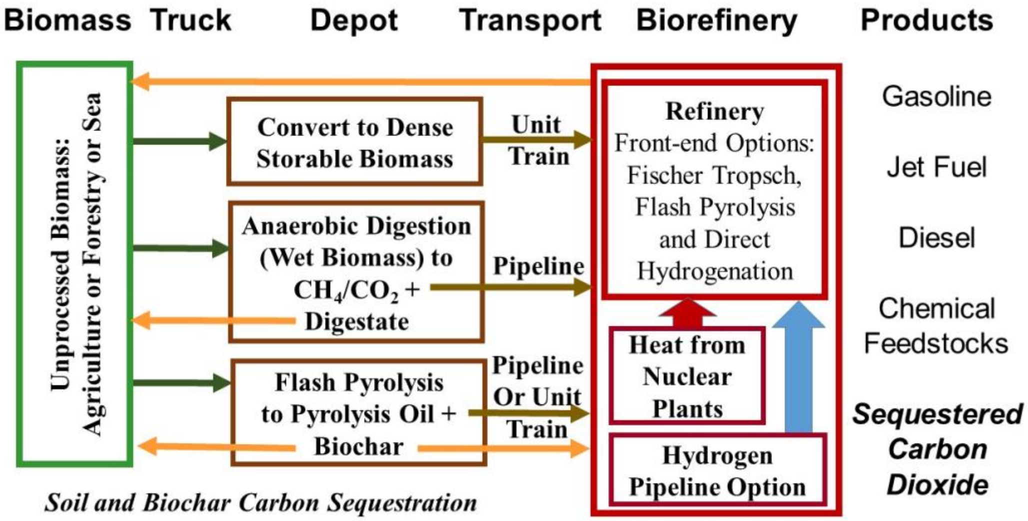

Fig. 3.1. Nuclear-Assisted Liquid Biofuels System

In this context, today’s biofuels industry is based on sugar, starch and other forms of biomass. Many of these forms of biomass are dense and shippable long distances but are in limited supply and have important competing uses as food and animal feed. Most of the world’s biomass is in the form of cellulosic biomass. Cellulosic biomass is the only low-carbon feedstock available at the required scale but, as noted, raw biomass has low density. Thus its energy content must be densified for shipment.

Chapter 5 describes the three basic depot options while Chapter 6 describes the transportation logistics and economics the drives the need for local depots. The choice of depot option depends upon the properties of the biomass available within the depot collection radius and transportation constraints. First, biomass may be densified and shipped as dry pellets. Second, biomass may be fed to an anaerobic digester that produces a methane/carbon-dioxide gas mixture that is then shipped via pipeline to the refinery—plus a digestate that is returned to the soil. Third and last, there is flash heating of biomass that produces pyrolysis oil and biochar. Depots producing pyrolysis liquids or pelleted solids might in turn ship to larger facilities that would blend materials to achieve a uniform feedstock for ultimate shipment to the biorefinery. Each depot option produces different storable, economically-transportable intermediate commodities.

The depot designs (Chapter 5) include other important functions that enable long-term sustainable biofuels production. For biofuel production we only want carbon and hydrogen in the feedstock—not the other elements in biomass including nitrogen, potassium and phosphorus, etc. The depots based on anaerobic digestion largely achieve this objective without further processing and enable recycle of nutrients in digestate to improve long-term soil productivity. Recycle of some nutrients in biochar will occur, but the pyrolysis liquids will probably require additional processing to remove, recover and recycle some mineral elements. For pelleted solids, essentially no nutrient recovery is likely to be practiced at the depot; nutrient recovery and recycle will have to be achieved at the biorefinery or at potential intermediate processing locations. This recycle of nutrients includes recycle of refractory carbon to the soil that improves long-term soil productivity while sequestering carbon in the soil. The approach outlined here contrasts sharply with the dominant current model of food and fiber production as well as the burning of biomass that does not recycle nutrients back to the soil. The nuclear-assisted biofuels system combined with depots can help enable long-term sustainable agriculture and forestry with the potential for significant improvements in soil productivity—making the design of the depot system as important as the refinery.

The system design requires massive heat and hydrogen input to minimize feedstock requirements that (1) enable large-scale liquid hydrocarbons production and (2) minimize volatility in liquid hydrocarbon prices. The nuclear reactors providing the heat inputs to the biorefineries must be collocated with the biorefineries because heat can only be economically transported a few kilometers. Hydrogen can be produced on site or imported via pipelines. There are several options for hydrogen production (Chapter 8). First, hydrogen can be produced from natural gas with sequestration of the carbon dioxide byproduct. This may be the economic option in locations with the combination of low-priced natural gas and good sequestration sites. Second, hydrogen can be produced by low-temperature (water) electrolysis and high-temperature (steam) electrolysis (HTE)—a more efficient process. Nuclear reactors produce heat that can be used to produce steam and electricity; thus, HTE is likely to be the most-favored nuclear hydrogen production process. All electrolysis processes are capital intensive, thereby creating incentives to operate hydrogen plants at high capacity factors.

The last component of the system design is sequestration of carbon from the atmosphere. This enables the entire system to be carbon negative even if components of the system (such as steam methane reforming of natural gas with CCS) release small quantities of carbon dioxide from fossil fuels. It also enables large-scale negative emissions. Negative carbon emissions occur in two locations.

- *Refinery*. The refinery can produce carbon dioxide for sequestration (Chapter 7) when excess low-priced biomass is available or during times of low liquid-fuel prices. This option provides variable negative carbon emissions while stabilizing the price of liquid fuels caused by variable production of biomass or changing markets for liquid fuels over time. This potential income stream assumes a market for negative carbon emissions; that is, removal of carbon dioxide from the atmosphere.
- *Depots*. The depots can provide variable quantities of refractory carbon (Chapter 5) for sequestration of carbon in the soil. The anaerobic digesters produce a digestate for recycle to the land with refractory carbon. Fast pyrolysis produces a char that can be recycled to the land for carbon sequestration, burnt as a fuel or sent to the biorefinery for conversion into liquid fuels.

The system design allows for wide flexibility in biomass feedstocks, hydrocarbon products and sequestered carbon depending upon market and societal demands. That flexibility is a requirement for an energy system that is undergoing rapid change with the transition off of fossil fuels.

3.1. References

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4. Potential Size of the Cellulosic Biomass Resource

The potential size of the U.S. cellulosic biomass resource is necessarily imprecise and depends on many assumptions including: public policy, land use decisions, advances in technology, prices paid to farmers and many other imponderables.

Among these many imponderables perhaps the most important is the eventual yields (mass of dry material per hectare) of cellulosic biomass. We have spent many tens of billions of dollars to increase the yield of grains and oilseeds. For example, the average yields [Nielsen, August 2021] of corn grain went from about 20 bushels per acre in 1920 to nearly 180 bushels per acre in 2020, a nine fold increase. No such emphasis has been placed on increasing the yields of cellulosic biomass; large yield improvements can therefore be expected with a high degree of confidence.

Fortunately, we have a somewhat well-defined target: approximately one billion tons of cellulosic biomass per year can potentially supply enough carbon to replace the carbon in 10 million barrels per day of petroleum, if the needs for heat and hydrogen are met by nuclear energy in large, integrated biorefineries. Roughly 10 million barrels per day of oil equivalents is approximately what is required to maintain current living standards in the U.S. Therefore the question: *is one billion tons of biomass per year a reasonable target for the US?*

Yes, it certainly is. As shown below, one billion tons per year is actually something of a floor on the potential supply of cellulosic biomass in this country. Several times as much cellulosic biomass might reasonably be produced, perhaps as much as 4.2 to 5.7 billion tons per year over the next few decades [Appendix C, Dale].

4.1. Cellulosic Biomass Resource Estimates: The Effect of Price

The U.S. Department of Energy has published a series of reports on the potential domestic biomass resource, appropriately entitled the Billion Ton Report. The most recent of these reports was published in 2016 [DOE, 2016]. From the introduction to this 2016 report, we quote the following:

“The report concludes that the United States has the future potential to produce *at least* one billion dry tons of biomass resources (composed of agricultural, forestry, waste, and algal materials) on an annual basis without adversely affecting the environment.” (emphasis added)

Two figures from the Executive Summary of this report are particularly relevant to address the question of how much cellulosic biomass the U.S. might ultimately produce.

First is Figure 4.1 at the left, (Figure ES.5 in the 2016 DOE report). At a price of $40 per ton of harvested biomass, this figure shows that a total of 1000 million dry tons (one billion tons) of biomass can be expected from all sources (forestry, agriculture and wastes).

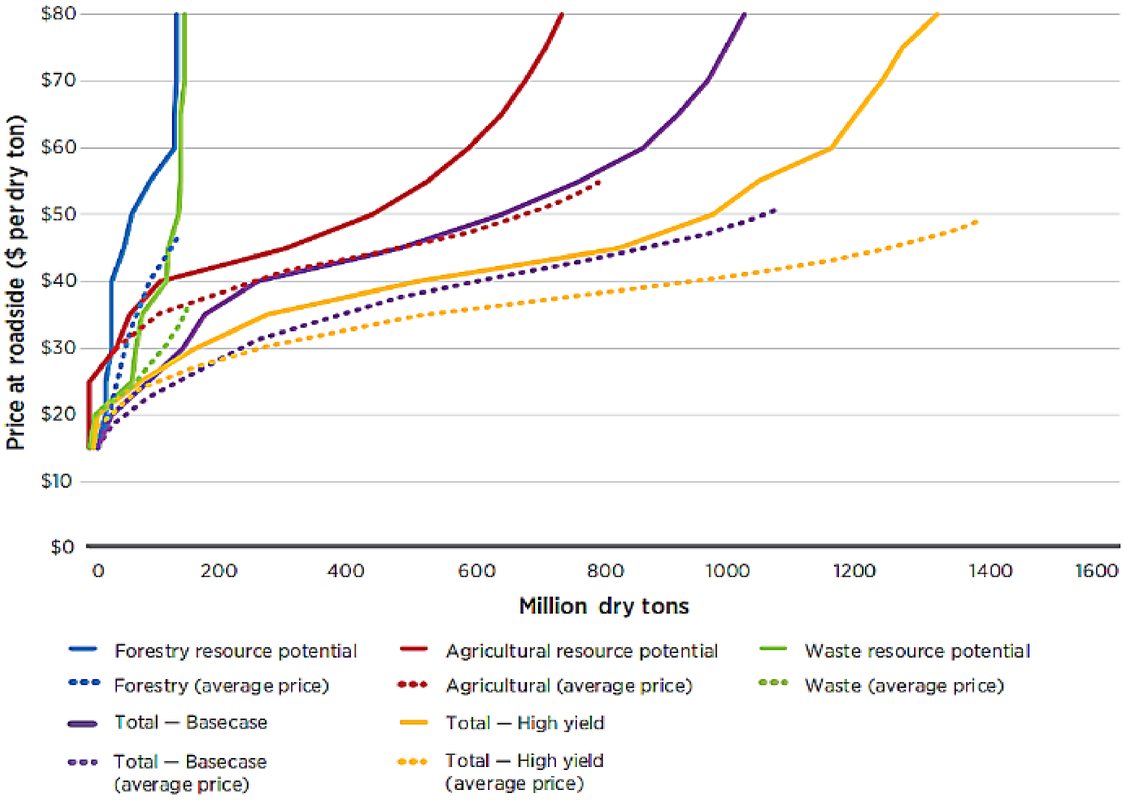


Fig. 4.1 Biomass Resources from Billion-ton Report

The assumed price of $40 per ton biomass *paid to the farmers* is a critical parameter here. In preparing the report, the DOE and its associated researchers set this low biomass price to meet DOE cost targets for the final selling price of biofuels produced. Furthermore, the report assumed that biomass would be converted to biofuels in *relatively small biorefineries (<3,000 tons biomass per day) receiving essentially unprocessed biomass.*

We do not assume small biorefineries, nor do we assume that biorefineries will receive unprocessed biomass. Instead we assume that biomass will be transported from the farms to intermediate preprocessing facilities called depots (Chapter 5). In these depots, biomass will be converted into energy-dense, uniform format materials (solids, liquids and gases) which are transported to the biorefineries. The economies of scale of very large, nuclear-assisted biorefineries, plus the improved economics of handing and transporting densified, uniform-format biomass will reduce the final biofuel selling price compared to small biorefineries receiving unprocessed biomass, the DOE's constraining assumption.

In previous work [Kim and Dale, 2015], we used the basic DOE biomass supply modeling structure described in the 2016 Billion Ton study, but relaxed the assumption of small biorefineries and assumed that biomass pelleting depots (see Chapter 5) provided densified biomass to large (>10,000 tons/day) "conventional" biorefineries in which the energy required for biorefinery operations was supplied by biomass. We further assumed that instead of paying the farmers $40 per ton for their biomass, we would pay them up to $80 per ton.

The results were surprising. The amount of biomass delivered to the biorefinery) did not merely double: it increased by almost nine fold. Apparently, if you reward farmers and foresters by paying them more for their biomass, they will produce more…a lot more. These general trends are borne out by Figure 4.1. If we extrapolate the price paid for biomass, to $80 per ton, we can very conservatively assume that the amount of biomass available will at least double, from one billion tons to about two billion tons per year.

While the assumed price paid to farmers doubled in our study, the estimated selling price of the ethanol biofuel did not double. On average, the assumed biofuel price increase due to doubling the feedstock cost was about 12%, less than the fuel taxes in many locations [Robertson, et al., 2017]. This is a consequence of having much larger biorefineries with the attendant economies of scale, and reduced transportation costs due to moving energy-dense, uniform format products from the depot to the biorefinery.

The DOE Idaho National Laboratory [Lamers, et al., 2015] makes a compelling case that depot-level processing can reduce the costs of biofuel production by as much as $2.00 per gallon of gasoline equivalent compared to systems not using depots, i.e. compared to the model long assumed by the US DOE. Key factors driving the cost reduction include interest rate reduction on loaned capital, economic of scale, conversion yield improvements, and reduced equipment requirements at the biorefinery.

4.2. Using Semi-Arid Lands

A second highly relevant figure from the 2016 Billion Ton Report is Figure ES.4, shown here as Figure 4.2. This figure makes it clear that the more arid part of the U.S. (the west and southwest in particular) does not really participate in cellulosic biomass supply. While it is probably true that conventional crops cannot be produced in significant quantities in these areas of the country, there may be unconventional, and highly relevant, crops that can be produced.

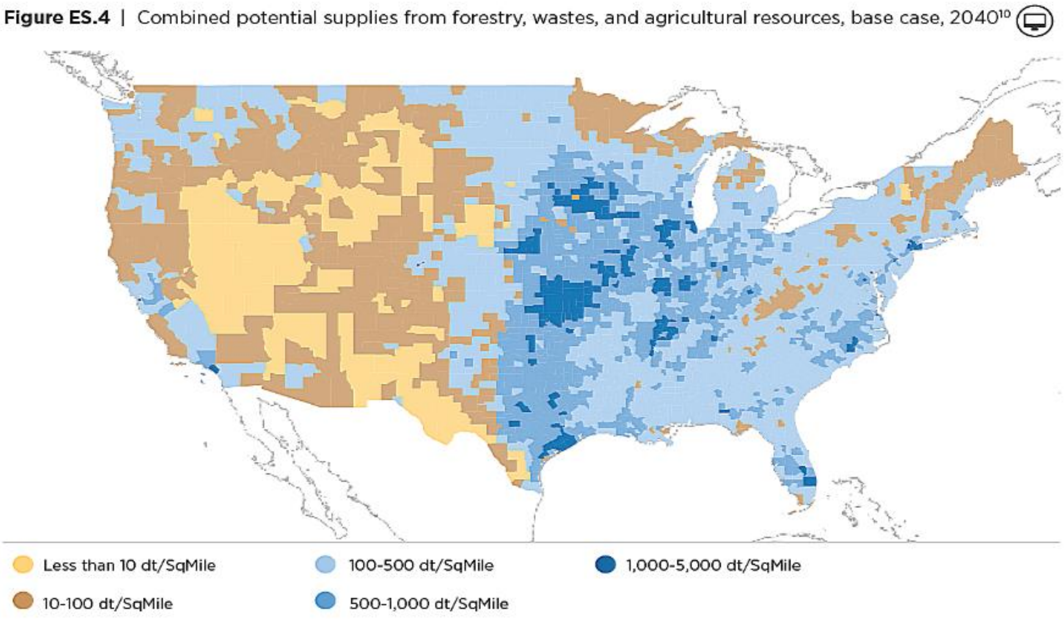


Figure ES.4 | Combined potential supplies from forestry, wastes, and agricultural resources, base case, 2040[10]

Fig. 4.2. Distribution of Cellulosic Biomass Resources

Perhaps the most promising of these unconventional biomass crops for biofuel production from semi-arid lands is *Opuntia* (prickly pear). *Opuntia* is a highly water-efficient plant with relatively stable yields, even during drought conditions. Under large scale cultivation in semi-arid regions of Brazil, unirrigated *Opuntia* averaged annual yields of 11 MT of dry weight per ha. Under favorable conditions of irrigation, prickly pear can produce 45-50 MT dry weight per ha per year [Santos, et al., 2016].

There are roughly 240 million ha of semi-arid lands in the US, versus only about 120 million ha total harvested cropland [Merrill and Leatherby, 2018]. Some of these semi-arid lands are public lands, national forests, parks and monuments, probably unavailable for cultivation with prickly pear. Other semi-arid lands are currently cropped for winter wheat, sunflower, canola, etc., or irrigated for food or animal feed (eg, alfalfa) production and still other semi-arid lands are grazed by animals. But if we assume that only 10% of US semi-arid lands could be cultivated in *Opuntia* then between about 300 and 1300 million tons per year of dry biomass might be produced. Even at the lower estimated yield, this is more biomass than any other single source in the entire Billion Ton Study.

Importantly, the high water content (about 85%) of prickly pear probably rules out depot level processing by pelleting or pyrolysis, both of which require relatively dry biomass. However, 85% moisture content is an ideal moisture level for anaerobic digestion to produce methane and carbon dioxide. Furthermore, the anaerobic digestion process conserves water already in the biomass, therefore the water accumulated by prickly pear could become available to irrigate itself…thereby increasing yields versus unirrigated cultivation, while simultaneously recycling mineral nutrients and stabilized carbon to the soil.

In short, there is immense potential for semi-arid lands to contribute biomass.

4.3. Double Cropping

Double cropping (also called sequential or winter cropping) refers to the practice of growing a primary or cash crop (often corn, wheat or soybeans) during the summer and then, after harvesting the primary crop in the early fall, planting a second crop, often an annual grass plant such as winter rye. This double crop is harvested the following spring prior to planting the next cash crop.

Double cropping was the standard farming practice prior to the advent of large scale farm mechanization in the 1950s. The double crop was used primarily to feed working farm animals and to supply local markets for food and feed. With increased farm mechanization, good cropland was increasingly left bare (fallow), and largely unprotected from erosion during the late fall, winter and early spring, leading to a very strange farm ecology in which nothing was growing for months on end.

As the tide of globalization crests and eventually recedes due to increasing costs and decreasing supplies of petroleum, and as more scrutiny is given to the reliability of supply chains, more food and feed production is likely to be consumed locally. All this means that double cropping is likely to grow in importance, particularly since double cropping also offers numerous environmental benefits including increased biodiversity, increased soil carbon levels, improved crop yields, reduced erosion and better water quality, among others [Schulte, et al., 2021].

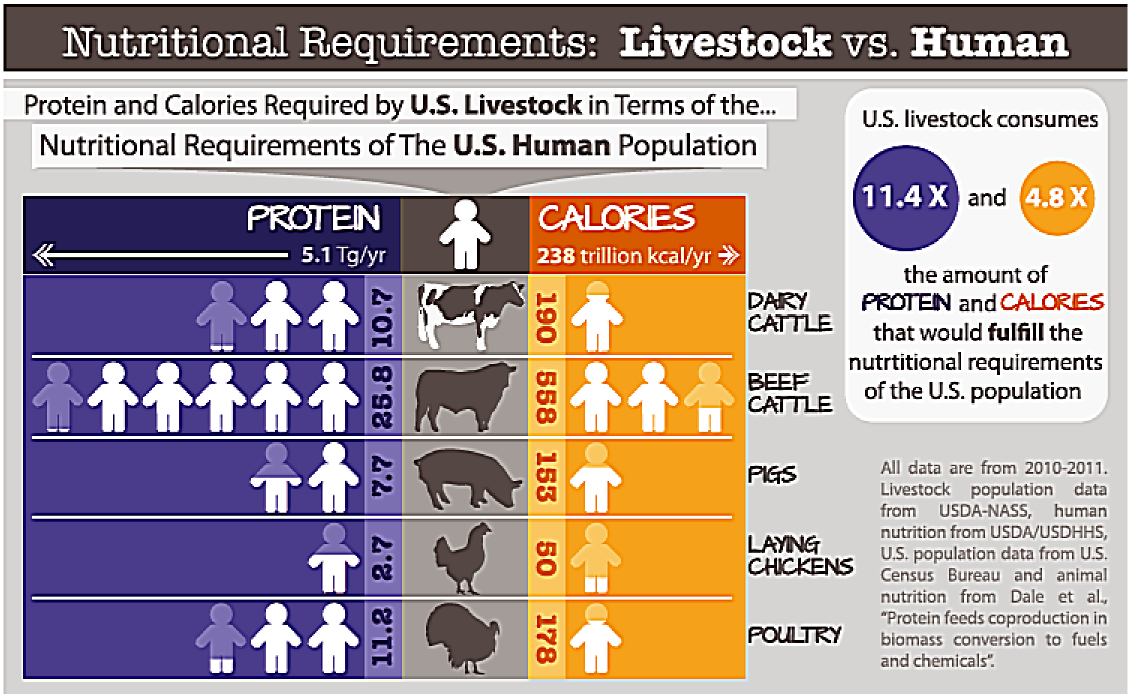
For our purposes, we are interested in the potential of double cropping to provide additional biomass for bioenergy production. Fortunately, Feyereisen, et al. [2013] performed precisely this analysis for double cropping by growing winter rye on corn-soybeans cropland. They estimated that about 120-170 million tons of additional rye biomass can be harvested from this cropland without redirecting the primary food crop to fuel. Double cropping can also be performed on croplands other than corn-soybean lands, so this figure should be regarded as a lower limit on the amount of additional biomass potentially available from double cropping. We further discuss double-cropping on existing croplands in Chap. 5 as it is likely one of the principal and most rapidly implemented means of producing biomass for on-farm (depot level) production of biogas.

4.4. Redesigning/Rethinking Food and Feed Systems

Contrary to popular opinion, we do not use land to “grow food”. Instead, about 80% of land in agriculture or grazing is actually used to grow feed for animals. We then consume the meat, milk, eggs, cheese and so forth provided by these animals. Thus we believe that food and fuel production do not inherently conflict. Instead, what we have is an opportunity to integrate food/feed/bioenergy production to their mutual benefit [Schulte, et al., 2021]

What if we were to redesign-rethink how we use land to provide animal feeds and bioenergy? In one such "what if" analysis [Dale, et al., 2010], we explored using three land-efficient technologies for producing animal feeds (leaf protein concentrates, pretreated forages and double crops) and found that using less than 30% of total U.S. cropland we could produce approximately 1400 million tons of additional biomass for cellulosic biofuel production. Some of this is from double-cropping, already considered above, but most of it is from simply using land more efficiently to produce feeds for animals and by treating biomass to make it more digestible to ruminant animals [Blummel, Steele and Dale, 2014].

Ruminant animals (principally dairy and beef cattle plus sheep and goats) are central to any discussion of integrating food, feed and bioenergy production. In 2010, U.S. dairy and beef cattle herd consumed approximately three times as many calories (food energy) and over seven times as much protein as the entire human population [Dale and Ong, 2014]. Overall, our livestock consumes about five times as much protein and over eleven times as many calories as the human population (Fig. 4.3).



All data are from 2010-2011. Livestock population data from USDA-NASS, human nutrition from USDA/USDHHS, U.S. population data from U.S. Census Bureau and animal nutrition from Dale et al., "Protein feeds coproduction in biomass conversion to fuels and chemicals".

Fig. 4.3. Nutritional Requirements of the U.S. Human Population vs. Major Livestock Classes

But ruminants are nutritionally flexible, and they can use a much wider variety of feeds, especially cellulosic materials, than can human beings. Thus, if we chose, we could sustain the human population on a simpler and probably healthier diet using less grain-fed and more grass-fed meat, less processed foods and more whole grains and legumes. The land made available by this simpler diet could be devoted to bioenergy production, environmental services and to nature.

4.5. Increasing Cellulosic Biomass Yields: Emphasizing Pasture/Rangeland Yields

It may seem strange to city dwellers or those who have been fed a steady diet of "the world is running out of food" to realize that for many decades, U.S. agricultural productivity has far outstripped domestic demands for food and feed. Nonetheless, such is the case, particularly on cropland where, for example, corn yields are roughly nine times higher than they were a century ago.

The potential of increasing the productivity of pasture and grazing lands is particularly relevant. Of the total U.S. agricultural land (about 470 million hectares), almost 80% or 370 million ha is devoted to animal feed production [Dale and Ong, 2014]. Of this 370 million ha land area, about 262 million ha or 71% is range and pasture land. Cropland pasture, about 25 million ha [Sanderson, Jolley and Dobrowolski], receives some management to increase biomass yields, but much pasture receives little or no management, and rangeland receives essentially no management.

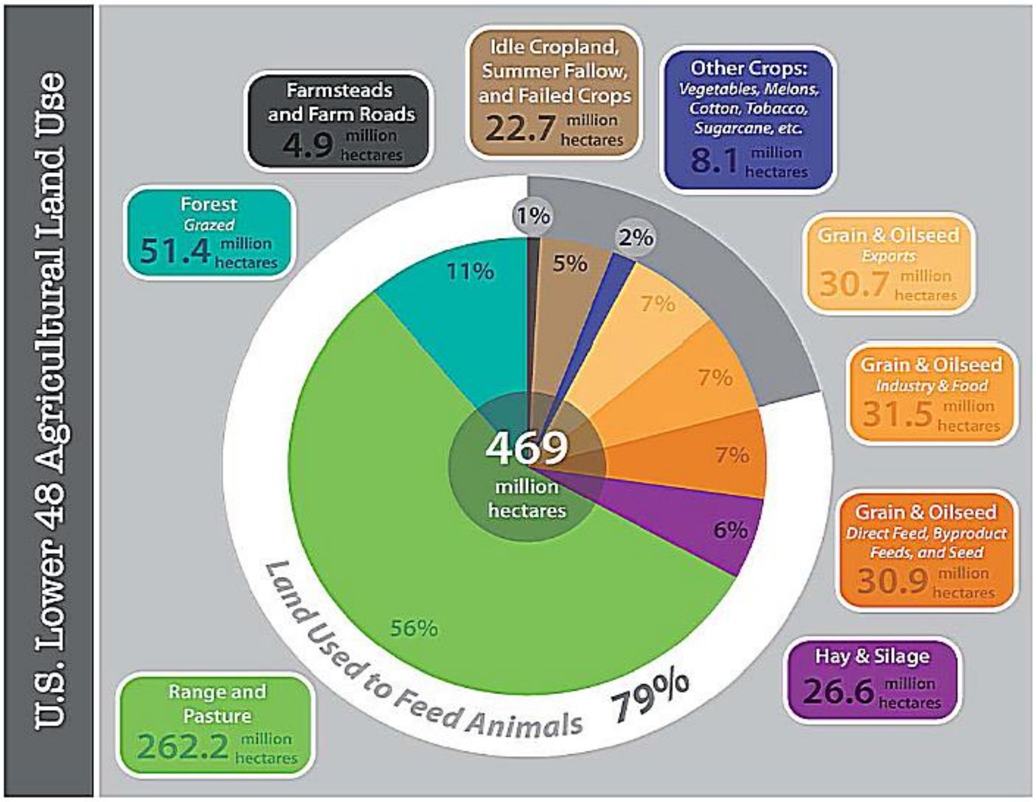


Fig. 4.4. Land Use Patterns in the Lower 48 U.S. States

Thus approximately 230 million ha of U.S. pasture/rangeland is unmanaged for increased biomass production. Increasing the average yield by just one ton per acre per year would increase overall amount of biomass produced by over 500 million tons per year. If over a period of two decades, the average annual yield was increased by two tons per acre, then about a billion tons per year of additional cellulosic biomass might be produced.

As noted above, it will take decades to roll out a large scale cellulosic biofuels industry. Development of the necessary crop science, agronomy and agricultural engineering required to support this industry will also take decades, plenty of time to increase sustainable crop yields.

4.6. Future Cellulosic Biomass Yields: A Rough and Very Preliminary Estimate

In the previous sections of this chapter we have briefly explored several different approaches to increasing cellulosic biomass supplies in the U.S. Here we will combine these different approaches to see what total amount of biomass we might be able to supply, say by 2040, a couple of decades from now.

We start with the amount of cellulosic biomass the DOE indicates can be supplied at $40 per ton: or about 1000 million tons/year then add:

- 1000 million tons/yr from paying a higher price for the biomass
- 300-1200 million tons/yr from growing *Opuntia* on arid lands
- 120-170 million tons/yr from double cropping in the Corn Belt
- 1230-1280 million tons/yr from double cropping elsewhere, land efficient animal feeds
- 500-1000 million tons/yr from increasing crop yields on pasture and range lands

For a total of between about 4.2 and 5.7 billon tons per year of cellulosic biomass.

4.7. Paper, Pulp and Other Sources of Biomass

There are other significant sources of biomass for liquid fuel production that are poorly understood. The existing paper and pulp industry converts pulpwood into paper products and burns the residual biomass to provide energy for the process. Figure 4.5 shows average energy use in paper and pulp plants with almost 50% of the energy from spend liquor solids and 15% from hogged fuel and bark. These fuels have a very high water content and thus a low energy value per ton. The total energy produced from these fuels is about 0.88 quads, about 1% of total U.S. energy consumption. If alternative heat sources are available such as fission batteries (Forsberg et. al., 2021), this biomass that is now burnt could be used for hydrocarbon liquid fuels production.

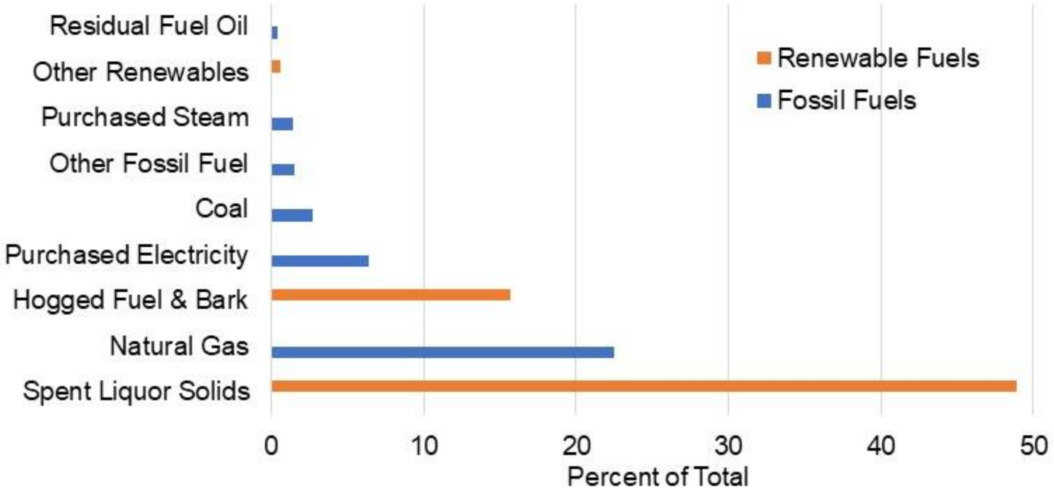


Fig. 4.5. Energy Consumption by Source in Paper and Pulp Mills

The size of this biomass resource is potentially measured in hundreds of millions of tons but is not well defined. The U.S. produces over 250 million tons of pulp wood that yields about 75 million tons of paper. However, the paper includes significant quantities of clay and other fillers; thus there is not a simple method to estimate potential hydrocarbon liquid fuels feedstock potential. Furthermore, the paper and pulp industry has the option to recover other wood wastes from the harvesting process (tree stumps, branches) if there is an economic incentive. They have the logistics system in place and the mills (depots) are set up to accept massive quantities of biomass.

The other major biomass source are marine sources such as kelp and other types of seaweeds. There have been studies back to the 1980s looking at the large-scale harvesting and conversion of kelp into natural gas or other biofuels [Brehany, J. J. et al., 1982; Roesijadi, G. et al., 2008]. Kelp is harvested commercially for a variety of purposes; thus, there is an experience base. Today there are studies on how to remove various types of seaweeds that cover beaches that damage the tourist trade of many islands and coastal areas [Gray et al., 2021]. There is also the possibility of algae [Xu, H. et al., January 2019] as a source of biofuels. Total resource estimates of these various marine biomass resources are measured in billions of tons. We did not identify any recent systematic studies on large-scale harvesting of these different biomass resources.

The paper/pulp and marine biomass resources are potentially very large; but, these feedstocks have different characteristics than traditional cellulosic feedstocks. That implies that different depot options may be required to integrate into a large-scale biomass hydrocarbon liquids production system.

4.8. Direct Burning of Biomass for Energy and Carbon Dioxide Sequestration

In parallel, there have been a series of studies [Fajardy et al., 2021; Kasturi et al., 2021] examining collection of biomass to be burnt in power plants to produce electricity with the carbon dioxide removed from the stack gas for sequestration underground. The results indicate that (1) this strategy is one of the less expensive ways to remove carbon dioxide from the atmosphere, (2) there are massive resources of biomass that can be used and (3) it does not have a major impact on food and fiber prices if properly managed. The definitions of biomass are different because burning the biomass for energy is a goal rather than biomass as a carbon feedstock—wet biomass is not a viable feedstock if the goal is lighting a fire. It is a different but relevant perspective when considering nuclear-assisted liquid hydrocarbon fuels production and provides another set of estimates on available biomass.

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5. Depots to Prepare Biomass for Transportation and Biorefining at Very Large Scale

Depots process local biomass to produce multiple products and enable economic long-distance shipment of those products. They exist in many forms today such as grain elevators that receive grain from farms by truck and ship by rail and barge. Grain elevators also dry grains to enable long-term storage and separate weed seeds from grains. Other types of depots process wood into pellets for long-distance shipments to furnaces and boilers. The concept is not new and many variants for different types of biomass exist. The specific application herein is new as is the proposed scale.

5.1. Why Depots are Essential

Decades of research and development effort and billions of dollars of investment have not yet catalyzed the formation of a viable industry producing cellulosic biofuels. We believe that the current model of small scale cellulosic biorefineries processing essentially raw biomass received directly from the farm/forest is not viable. A different model is required. In our view, intermediate biomass processing depots are an essential component of scalable, practical cellulosic biofuel systems. Probably the most important functional feature of depots are that they provide a transition point for shifting between supply chain segments of very different scales, in this case between the farm/forest scale and the biorefinery scale.

Grain elevators serve the same function in the grain industry. A grain elevator can accept grain from the farmer by any means of transport. It is at the grain elevator that the supply chain transitions to the high-capacity handling systems used by feed terminals, wet mills, and other very large facilities. Such facilities generally accept only rail or barge deliveries. Oil and gas "mid-stream" systems perform the same function in the petroleum/natural gas supply chains as do grain elevators but are more sophisticated in their fractionation and merchandizing capabilities.

The biomass supply chain for biorefineries will operate at multiple scales at different points in the system. Therefore the biomass supply chain also requires transition points between supply scales. Every biorefinery that has tried to directly connect to field level biomass supply chains (i.e., bales or something similar) has failed. The farm and biorefinery supply systems work at two different scales and these scales are simply incompatible. At a small scale, field-run supply systems and small refining systems can work together because the small size of the biorefinery matches the farm scale systems, but this pairing will not work when the biorefinery moves to the larger scale. The larger scale is essential if cellulosic biofuels are to make a real contribution to national fuel needs. A supply system transition point is needed to make the overall system work. Our perspective is that the diversity and variability of raw biomass is so significant that processing and fractionation depots, like the oil and gas midstream systems, are absolutely essential to create truly efficient and effective biomass supply systems that deliver conversion-ready feedstocks [Langholtz, et al., 2022; Williams, et al., 2016].

Accordingly, the required thinking, research and development around these depots must now also advance. To move forward from this point, depots must become more than supply chain scale transition points. They must also manage biorefinery feedstock quality and merchandize their products as conversion-ready biorefinery feedstocks or as feedstocks for other, related markets. In summary, here are seven inter-related reasons why we believe depots are essential parts of the supply for large scale biorefineries.

First, depot-level processing can reduce the costs of biofuel production by up to $2.00 per gallon of gasoline equivalent [Lamers, et al., 2015] compared to systems not using depots, i.e., compared to the model that has dominated thinking in this area for the past 40+ years. According to this study, the key factors driving the cost reduction include interest rate reduction on loaned capital, improved economies of scale, conversion yield improvements, and reduced equipment requirements at the biorefinery.

Second, without an intermediate processing step to densify, homogenize and stabilize the biomass for low-cost shipping and further processing at the biorefinery, cellulosic biomass refineries producing hydrocarbon drop in fuels will never be large enough to compete economically with oil refineries because they will never achieve the required economies of scale [Kim and Dale, 2015]. It is unrealistic to expect these small biorefineries (<3,000 tons per day) to compete with oil refineries which operate at an average scale of about 250,000 barrels per day, or about 38,000 tons per day. Newer oil refineries, with which biorefineries will have to compete, are even larger, processing up to a million barrels of oil per day, or well over 100,000 tons per day of oil processed.

Third, the processed biomass materials coming from the depots can become uniform, tradeable commodities with multiple markets beyond the biorefinery, just as corn grain is a feedstock today for biofuels as well as animal feeds and many other products. Commodification is required so that multiple, stable markets will emerge to contract for and consume these biomass commodities. If depots sell into a single market, namely the biofuel market, then such depots are at great risk of being captured by the biofuel market to their great financial detriment.

As mentioned, the depots we propose here are similar to other intermediate processing facilities currently found in agriculture. The same logic and economic forces that have led to the formation of the other intermediate processing facilities in agriculture and forestry will also dictate the formation of depots to supply a successful cellulosic biofuel industry.

Fourth, several organizations in different countries have attempted to build large "pilot scale" cellulosic biorefineries at roughly the 700 ton per day scale. All of these attempts have failed, at least in large part because they were unable to solve the problem of feeding raw, unprocessed biomass into the upstream portion of their biorefining systems [Rivers, 2018; DOE, 2016]. The processed biomass commodities produced by depots will be much more physically and chemically consistent than unprocessed biomass and therefore will be much easier to feed into the upstream processing equipment at the large biorefinery.

Fifth, depots represent the most promising means by which farmers can benefit from participating in the cellulosic biofuel industry. Without full participation and "buy in" from farmers, the cellulosic biofuel industry will never achieve the size required to really address our need for domestic hydrocarbon fuels: at least 10 million barrels per day of hydrocarbon fuels. Depots represent a potential focal point for farmer investment to produce and sell these value-added biomass commodities [Dale and Ong, 2014].

Sixth, depots may also serve to verify, aggregate and monetize the potential environmental services that can result from environmentally-improved farm operations supplying the depots. If we wish to catalyze the environmental services that could result from depots supplied with biomass from regenerative agriculture/forestry, then we must also catalyze the formation of such depots [Schulte, et al., 2021].

Seventh, value-added products are probably needed to help jump start the biorefining industry [Huang, et al., 2021]. Depots are able to produce a wide variety of value-added products and services including essential oils, aromatics, animal feed proteins [Dale, et al., 2009], drying services, high value foods (from greenhouses using the waste heat and carbon dioxide from the digester—see below) and many more.

5.2. Potential Depot Configurations

Multiple depot configurations are potentially suitable for biomass energy densification and commodification (Figure 5.1). The three primary types of depots we envision would produce, respectively, solids, liquids and gases as their primary products.

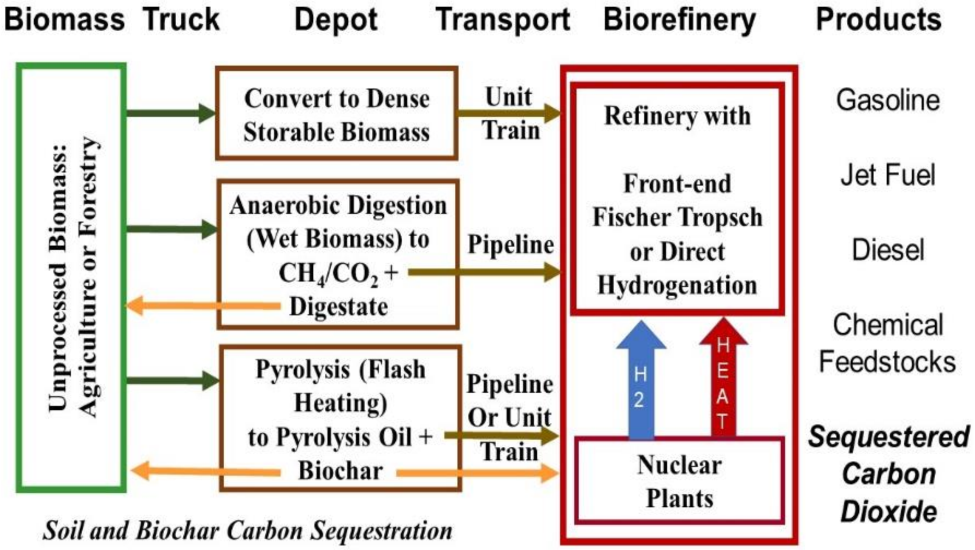

Fig. 5.1 Three different depot configurations in the biomass to hydrocarbon fuels system

The first type of depot would employ grinding, separation, blending and pelletization of densified, flowable solids and/or pelletization combined with biomass pretreatment to produce enhanced-quality pellets suitable for fermentation, refinery feedstock or as more digestible animal feeds. Pellets would be shipped by unit train to the biorefinery or to other, much larger facilities where they might be blended and further processed into salable commodities. As mentioned above, such larger facilities are similar to the large terminals that currently process, store and distribute cereal grains.

The second type of depot would produce a low-grade liquid hydrocarbon feedstock for the biorefinery and a solid carbonaceous biochar for use as: 1) a soil additive, 2) a solid fuel to replace coal or 3) a potential biorefinery feedstock. The liquid feedstock would be shipped to the biorefinery either by pipeline or unit train while the biochar could be used locally as a solid fuel, or as a soil amendment. Densified biochar might also be shipped by unit train to the biorefinery as a solid feedstock for conversion to liquid hydrocarbon fuels or for large scale combustion as a solid fuel.

Finally, a third depot configuration would use anaerobic digestion to produce biogas (a mixture of methane and carbon dioxide) to be shipped by pipeline to the biorefinery. The digestate slurry resulting from anaerobic digestion contains stabilized carbon and most of the mineral nutrients in the original biomass. Digestate is recycled to the farmer’s fields as a soil improver and liquid fertilizer. This digestate is a source of long-term soil carbon that will increase soil fertility while also drawing down atmospheric carbon dioxide levels, a potentially marketable environmental service. The residual water in the anaerobic digestion tanks can irrigate farmers’ fields during dry periods.

The specific depot configuration chosen will vary significantly depending on the biomass feedstock, including its moisture content, composition and probably other factors—factors that are as yet only partly understood.

Following a brief discussion of the different types of depots, their estimated capital costs and technology readiness levels (TRLs), we will provide some preliminary suggestions about what types of depots seem most appropriate for different feedstock types. We will also estimate the likely costs involved in transporting the depot products to the biorefinery.

Finally, we will address an essential issue that must govern our societal choices between all such cellulosic biofuel systems, namely the net energy for these systems. We are entering a new age of relative energy scarcity, particularly with regards to petroleum, and we must choose wisely among our energy options from this point on.

5.3. Depots Based on Grinding and Densification With/Without Chemical Processing

Rural America, where the biomass feedstocks are produced, is already accustomed to handling solid feedstocks. Much of this solids-handling expertise and capacity is available to support the proposed depots that will process the various raw biomass materials into solid, liquid or gaseous streams.

Grinding, Pelleting and Mechanical Processing

Researchers at the Idaho National Laboratory have proposed and are developing the Conversion-ready Feedstock platform [Roni et al., 2019; Hossain et al., 2021]. The goal of this platform is to manage feedstock properties for subsequent processing to fuels and at the same time to fractionate feedstocks into different value-added streams, a critical aspect of maximizing revenue. This platform builds on the Uniform Format Designs to supply the nation's feedstock needs to end users [Hess et al., 2009].

As more diverse resources are used to support a circular carbon economy, more emphasis is required to reduce variability in feedstock flowability, handling, fractionation and stability. Feedstock management is critical to biorefinery performance and therefore feedstock quality is a key issue for all biomass resources. A better understanding of particle processes, linked to solving practical problems, is particularly important [Chen, et al., 2022]. Systems of solid particles have sometimes been called a fourth state of matter, highlighting how aggregates of solid particles are so very different from liquids, gases and non-particle solids [Xia, et al., 2020]. The feedstock quality required to meet specific feedstock properties at the biorefinery must be designed into that feedstock during prior processing, including processing at the depot.

Hossain et al. [2021] presented a nationwide supply chain analysis that delivers herbaceous biomass with a desired quantity and quality at the biorefinery gate for less than $80 per ton. The capital costs of a 100 ton per day depot based on drying, grinding, shredding/shearing and densifying the biomass and operating 250 days per year would be about $300,000. The technology readiness level (TRL) is expected to be about 7; commercial examples of the integrated system do not exist but the necessary equipment is available and has been tested at scale in a linked system.

One example of depot level processing is the fractionation of loblolly pine. Chips would be temporarily stored in piles at the depot, followed by air classification to reduce ash content and then drying to <10% moisture prior to grinding [Emerson, et al., 2018]. Grinding affects different wood tissue fractions differently, and these different fractions (bark, needles, etc.) are separated using various technologies, depending on the specific tissue and target market for that fraction.

Tissue fractions are then recombined by pelleting or other densification processes to meet the quality specifications [Tumuluru, et al., 2011]. A critical objective is minimize the overall amount of material processed to achieve the required design quality. Excessive processing is expensive and will usually detract from the desired feedstock design quality.

The fact that different plant tissue fractions have different compositions and properties and therefore potentially different markets deserves much more exploration. For example, alfalfa is composed primarily of protein-rich leaves and cellulose-rich stems. Dry alfalfa can be coarsely ground and then air-classified to separate the stem and leaf fractions. The alfalfa leaf fractions have significant potential value in animal feeds, including fresh and salt water fish and shrimp diets. The stems are suitable for conversion to hydrocarbon biofuels.

A second example, out of many possible examples, is the potential separation of plant oils, aromatics and similar valuable compounds from plant species such as mint. The fiber resulting from separation would be processed as a biofuel feedstock while the high value product would help jump start the supply of cellulosic biomass for biofuel uses. Importantly, depot level processing of higher value products will help avoid saturation of the markets of such products if they were produced at the biorefinery scale.

Grinding and Pelleting Combined with Chemical Treatment to Add Value: the Case of AFEX™

Biological conversion of biomass (via microbes and/or enzymes) to hydrocarbon fuels requires pretreatment of biomass to reduce its "recalcitrance" or its resistance to conversion. Many pretreatments exist, but one particular pretreatment called Ammonia Fiber Expansion (AFEX™) has several unique features that may make it especially suited to depot-level processing [Balan, et al., 2012]. These include the facts that: 1) AFEX™ is a dry-to-dry process using very little water, 2) AFEX™ yields a material that is easily pelleted, and 3) the AFEX™-treated biomass is also a useful ruminant animal feed.

The AFEX™ depot is designed to have a 110 U.S. dry ton biomass/day capacity, running 24 hours per day and 350 days per year with a combined total capital cost of about $5.0 million. In the AFEX™ system design, biomass is collected throughout the surrounding area and brought to the depot in bales. Storage is assumed to be offsite with only temporary storage at the depot.

Bales are shredded and milled to 1" particle size prior to entering the AFEX™ process. The milled biomass is packed into AFEX™ reactors at a bulk density of 100 kg dry weight per m^3 and a moisture content of ~20%. AFEX™ is performed in stainless steel vertical pressure vessels that are 5 feet in diameter and 35 feet tall with a single quick-opening hatch at the top of the reactor.

After treatment, the biomass exits at ~40% moisture. It is then dried to <20% in a triple pass rotary drum dryer, which also removes any residual ammonia. The dried, treated biomass is milled further to 1/4 inch particle size before being pelletized and cooled. The heat of pelletization brings the final moisture to 15%, which is low enough to be safely stored. The pellets can then be stored, metered out, and shipped in a manner similar to corn grain. This system has been developed and tested at about one tenth of commercial scale, so the TRL is estimated at about 7.

Following AFEX™, the sugars in the biomass are much more available for biological conversion (~ 5x more available). Biological conversion includes conversion by enzymes and microbes in, for example, an ethanol fermentation, by mixed microbes in anaerobic digesters or by the microbial population of ruminant animals.

Ruminant animals are nutritionally flexible. They can use a much wider variety of feeds, especially cellulosic materials, than can monogastric animal such as swine and poultry. And ruminant animals can use even more cellulosic biomass if these materials are previously AFEX™-treated [Blummel, et al. 2014]. Thus, if we chose, we could sustain the human population on a simpler (and probably healthier diet) using less grain-fed and more grass-fed meat, less processed foods and more whole grains and legumes. The land made available by this simpler diet could be devoted to bioenergy production, environmental services and to nature.

At the depot level, AFEX™ can produce easily-fermented biomass pellets that can then be shipped to the biorefinery. Such pellets can also be used as enhanced animal feeds, either locally or nationally, thus providing additional markets that would make the depots more economically robust and independent of the biorefinery, as mentioned in the introduction to this chapter.

5.4. Depots based on Pyrolysis to Produce a Liquid "Bio-oil" plus Biochar

Pyrolysis involves rapidly heating solid biomass under oxygen-limited conditions. The pyrolysis process has low energy requirements. It is very nearly neutral with regard to endo/exothermicity. The temperatures are modest, about 500 ^{0}C and there is a very short (<1 sec) vapor residence time in the reactor. Pyrolysis is also carbon-retentive; approximately 63% of the inlet carbon (mostly cellulose, hemicellulose and lignin) is ultimately liquefied in the bio-oil (specific gravity 1.1-1.2) while approximately 25% of the carbon becomes biochar (a potentially valuable soil amendment) [Lam, et al., 2015]. The resulting gaseous products from pyrolysis can be combusted to provide the necessary energy for the depot.

Pyrolysis is most suited for low moisture feedstocks (<10 wt %) Fresh cut biomass can serve as a feedstock source, provided that some form of drying is employed. Solar drying at the roadside of logging systems or during storage of agriculture resources offers inexpensive moisture removal. Pyrolysis may even be used for wet feeds if thermal energy is available from nearby power plants or if co-product biochar is burned for process heat.

Pyrolysis "bio-oil" is not truly an oil, rather it is a complex mixture of reactive, corrosive and unstable compounds including aldehydes, ketones, phenols and carboxylic acids that require upgrading. Bio-oil also has a relatively low specific energy content (HHV between 15-19 MJ/kg) owing to high oxygen content. Electro-catalysis (ECH) at 50% overall energy efficiency using non-fossil electricity (i.e., electricity from wind, solar or nuclear power) is proposed to upgrade the HHV and to stabilize pyrolysis bio-oil for storage, transport and processing at the biorefinery to make liquid hydrocarbon fuels.

As mentioned, the biochar could be pelletized and shipped to the biorefinery as a solid feedstock for direct conversion to hydrocarbon fuels. Biochar could also be used locally or nationally as a solid fuel, or incorporated as a soil conditioner that would fix carbon in a stable form, of which 65-100% is considered stable [Crombie and Masek, 2014; Crombie, et al., 2015] thereby potentially reducing atmospheric carbon dioxide levels.

Pyrolysis-based depot capital costs are expected to be in the range of $20 million for a 100 ton of biomass per day pyrolysis depot. Fast pyrolysis depots, without downstream stabilization by ECH, are operating in The Netherlands, Finland, and Sweden using BTG Bioliquids technology [BTG Liquids, 2015]. Although fast pyrolysis is already commercialized (TRL=9), the TRL for ECH stabilization of bio-oil is low as this technology remains under development. Even so, pathways to liquid fuels prices under $3/GGE are achievable with low cost electricity, decentralized biomass processing in depots, high electrocatalysis energy efficiencies, and low cost catalysts.

5.5. Depots Based on Anaerobic Digestion (AD)

During anaerobic (i.e., oxygen-free) digestion, mixed populations of micro-organisms, primarily bacteria, convert diverse carbon-containing materials (simple and complex carbohydrates, lipids and proteins) into a mixture consisting mostly of methane and carbon dioxide in approximately a 60:40 volume ratio, with trace amounts of water and hydrogen sulfide.

These product gases can be burned on site in combined heat and power (CHP) systems and the resulting electricity exported to the grid. The byproduct heat can be used in several applications, including the drying of hay for local or regional animal feeding operations. The gases can also be further processed to remove trace contaminants and then compressed to be shipped via pipeline or truck to a central, larger-scale processing facility located at a natural gas pipeline hub.

At this hub facility the gas mixture is further processed to remove carbon dioxide and the resulting renewable natural gas (RNG) is injected into the pipeline. RNG is functionally equivalent to fossil natural gas and is therefore suitable for all the current uses of natural gas, including heating, electricity generation, fertilizer production and chemical manufacturing. Under some potential nuclear-assisted biorefinery configurations, it may be possible to convert methane/carbon dioxide mixtures directly into liquid hydrocarbon fuels. In such cases, it is likely that these mixtures would be shipped by pipeline to the nuclear-assisted biorefinery.

So-called "wet" AD systems operate at mesophilic conditions (105-115 ^{0}F) with incoming solids usually at 15% solids (85% water content) and a residence time of 60-95 days. Dry systems are often thermophilic (125-140 ^{0}F) and use incoming solids at water contents between 55 and 80%. Residence times are typically 9-45 days.

Commercial scale AD systems can be large, occupying 3-6 acres, and can have digesters up to 100 feet in diameter and 110 feet high. Capital costs for the AD system for the equivalent input of 100 ton dry matter/day of feedstock can vary between $USD 20-30 million [Bortoluzzi, et al., 2014]. About half of this cost is for the CHP unit. Thus if the biogas is exported rather than burned on site, the capital investment is significantly reduced.

Anaerobic digestion (AD) is suitable for a wide variety of organic materials including manure, food scraps, food processing wastes, yard and landscape by-products, algae, grasses, wood wastes and woody materials (in limited amounts). Supplies of biomass feedstocks adequate for days or weeks of operation can be stored on site and fed as needed to the digesters

In the context of this article, AD is highly suitable for purpose-grown energy crops such as grasses and immature grains. Such materials are typically ensiled on site to stabilize and prepare them for feeding to the digester. Fine grinding is not required to prepare most AD feedstocks, although some size reduction or shredding may be necessary. This is an important feature of AD systems since fine grinding is both expensive and energy consuming.

A further significant feature of AD, especially AD performed on or near the farm, is that the liquid/solid slurry remaining after digestion can be recycled to the land, providing both significant fertilizer values (phosphorus, potassium and nitrogen) and recalcitrant carbon that will improve soil quality, including increased fertility and water holding capacity.

Critically, all the individual system components that make up the overall farm-based anaerobic digestion system (double cropping, ensiling and anaerobic digestion) are already practiced at large scale. In addition, the entire system is practiced at scale in Italy and Germany, and now increasingly in France. Therefore this system is already at TRL=9.

5.6. Feedstock Considerations in Depot Selection

Centuries of experience with large-scale processing industries demonstrate that it is that the properties of the feedstocks that largely dictate the choice of processing technologies.

For example, petroleum consists of a mixture of hydrocarbons with different boiling points, hence distillation became the processing technology to generate useful products from petroleum. In comparison, sugar cane juice is a solution of sucrose and other components in water. Sucrose is not volatile, so distillation cannot separate sucrose from water. However, the sucrose solubility in water is limited. Removal of sufficient water such that sucrose crystallizes out of solution and can be removed by filtration of the solid sugars is the dominant processing technology in the sugar industry.

In the same way, biomass feedstock properties are likely to strongly influence or even dictate the selection of processing technologies. For example, pyrolysis requires a mostly dry feedstock (< about 10% moisture). Industrial drying, rather than natural drying, will increase the capital and operating cost of the depot and reduce the overall net energy of the system. Therefore drying and other energy-intensive steps should be avoided as much as possible.

Likewise, the biological conversion of biomass (eg, by fermentation in the biorefinery or by anaerobic digestion in the depot) is strongly limited by feedstock lignin content. Therefore, woody feedstocks are much less amenable to anaerobic digestion in the depot. Some of these limitations of different processing approaches can be addressed by blending feedstocks, mentioned above, but as general guidelines we think that the most appropriate feedstocks for the three different depots are as follows:

1) Pelleting/densification-based depots: Woody biomass or grasses and residues that are mostly dry. For depots producing products for eventual fermentation at the biorefinery, feedstocks are probably limited to low-lignin, mostly dry biomass.
2) Pyrolysis-based depots: Clean woody biomass, low ash content.
3) Anaerobic digestion-based depots: Low lignin wet biomass such as *Opuntia* or ensiled grasses and straws, crop residues and food processing wastes, manure, kelp.

5.7. Net Energy: A Key Criterion to Guide Our Energy Choices

All activities require energy. Of the total energy consumed by society, some fraction must be used to operate the energy production system itself. When the energy required to operate the energy production system is subtracted from the total energy used by society, what is left (the net energy) is the energy required to operate everything else in our culture: food production, health care, education, national defense, culture…literally everything else we do besides producing energy. A simple equation representing this basic fact is:

Net energy available to society = Total energy consumed – Energy consumed to produce energy

As the energy required to produce and make available that same energy increases, the net energy decreases; thus less and less energy is available to operate the rest of society. Our focus here is on replacing the energy services provided by liquid hydrocarbon fuels from petroleum with liquid hydrocarbon fuels from biomass. Thus the relevant net energy comparison for biomass fuels is with the net energy of petroleum-derived liquid fuels.

In the early years of petroleum production, the net energy levels were very high. Approximately one barrel of oil energy equivalent was required to find, produce, refine and deliver 100 barrels of liquid hydrocarbons used by society. Thus the energy "profit" was 99 barrels of oil per barrel of oil "invested", or an energy return on energy invested (EROEI) of 99 to 1. Now the situation is much different. We have largely depleted the high EROEI oil resources. They are gone; and we are busy burning up what oil is left at ever-increasing rates and ever decreasing EROEI values [Moerschbaecher and Day, 2011]. The sobering "take away" from these considerations is that declining oil availability will serve to shrink the oil available to operate every other aspect of society: food production, education, health care, cultural activities—everything else.

A pioneer in the field of net energy is Dr. Charles Hall, formerly professor at the State University of New York-Buffalo. Among his many other contributions to this area, Dr. Hall and coworkers estimate that an EROEI of about 10:1 is the minimum required to support the other functions (education, health care, culture, etc.) that we associate with an advanced society [Hall, et al., 2009].

Thus we should rigorously evaluate the energy inputs required to produce liquid fuels from biomass, and minimize these wherever possible. In the future, we are likely to be much more energy-constrained than we have been in the last century or so. It may well be that some potential pathways to produce liquid hydrocarbon fuels are simply "non-starters" if our goal is an overall EROEI of 10:1. Such pathways should be rejected as alternatives. Our efforts must focus on potentially promising pathways and we must have the discipline to prune our potential energy pathways and follow only the most promising ones.

5.8. References

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6. Depot to Refinery Transportation

Transport logistics determines the overall system design in which multiple depots receive and process raw biomass into feedstock commodities. The processed biomass commodities are then shipped to biorefineries (Fig. 6.1). This logistics system enables (1) large-scale biorefineries, (2) creates competitive commodity markets and (3) assures sufficient biomass feedstock even if low biomass yields occur in one part of the United States in a particular year.

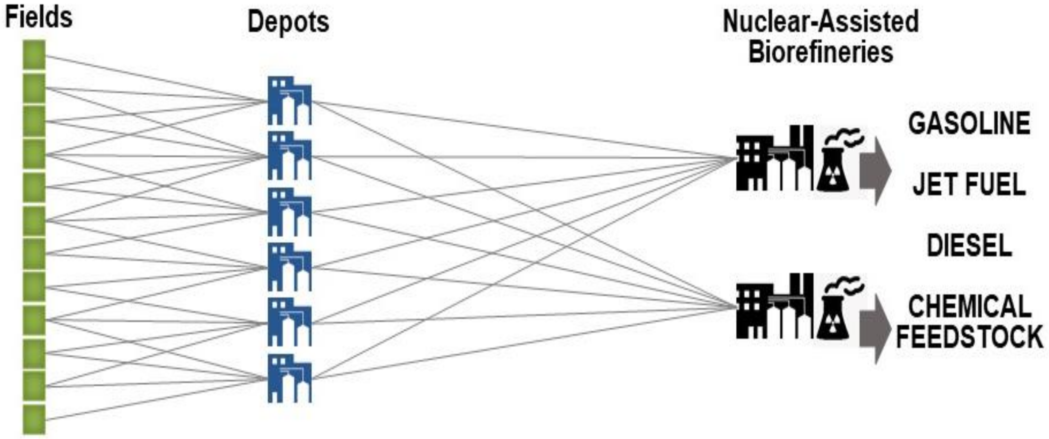

Fig. 6.1. Farms and Forests Ship to Local Depots, Depots Ship to Multiple Biorefineries [modified from Hossain et al., 2021]

The preferred transport option depends upon the shipping distance and the nature of the biomass commodities. Figure 6.2 shows the relative capacity of truck, a single rail car and a unit train. Trucks are used for local shipments to the depots. For unprocessed biomass, capacity is always limited by volume given the low density of unprocessed biomass.

Fig. 6.2. Relative Capacity of Different Modes of Shipping Bulk Commodities [Iowa Department of Transportation 2019]

The proposed depot logistics system for nuclear-assisted biofuels is similar to the existing system for moving corn, other grains and soybeans to markets. Depending upon local conditions, when corn is harvested it is stored on the farm or hauled directly from the field to the local grain elevator. Corn may be locally processed to remove weed seeds and other impurities. If the moisture content is high, it is dried so it can be stored for long periods of time.

Corn is then shipped by truck or rail to export terminals or corn processing plants that produce ethanol fuel and other products. In 2020 the U.S. produced 14.2 billion bushels of corn; that is, about 360 million tons of corn. Currently, the world's largest corn wet mill operated by Archer Daniels Midland (ADM) in Decatur, IL processes approximately 15,000 tons of corn grain per day [Archer Daniels Midland, 2021; Town and Nature, 2021]. A nuclear-assisted biofuels system would be integrated into the existing system using larger biorefineries, but not a fundamental departure from current practice.

Figure 6.3 shows shipping costs for truck, individual rail cars, small unit trains, large unit train and barge for shipments from the Midwest going east or southeast (CSXT railroad) and going from the Midwest to the west (BNSF railroad) [Jones, Appendix C; Gonzales et al., 2013]. Trucks are the lowest cost method to ship short distances but become much more expensive at longer distances. Barges have extremely low shipping costs. These costs are for shipping non-time-sensitive bulk commodities in large quantities.

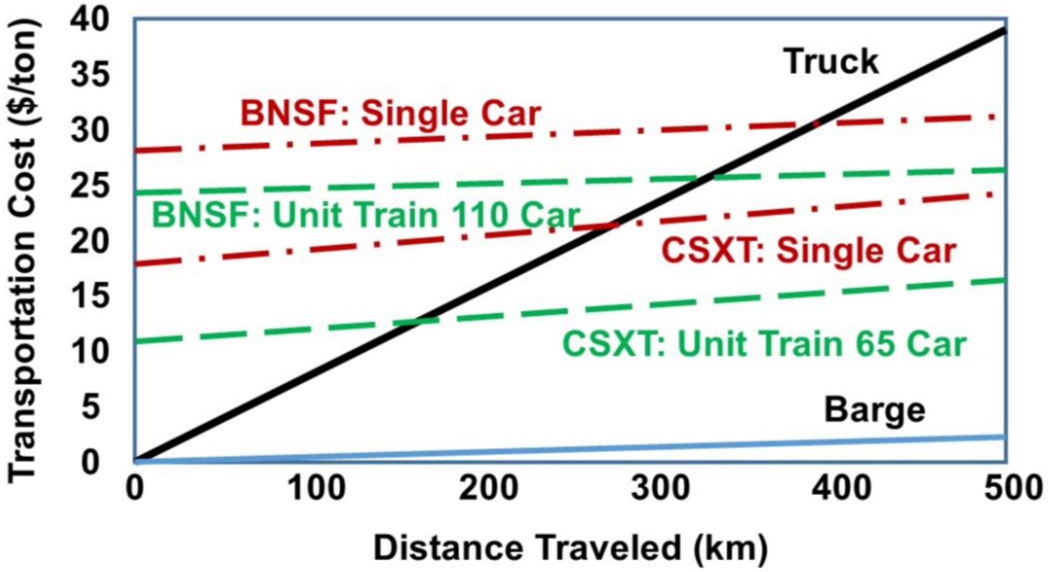

Fig. 6.3. Shipping Cost versus Distance for Different Modes of Transportation [Based on data from Gonzales et al., 2013].

Some shipping options, such as barges on the northern half of the Mississippi River, are not open in winter. Restricted shipping times are acceptable if a storable commodity is shipped. The shipping costs are a fundamental factor driving the need for depots. The U.S. does ship large amounts of freight by long-haul truck but that is for time-sensitive, higher-value cargoes. With commodities, one is willing to accept (1) week to month-long shipping times for very low-cost transport and (2) bulk handling.

The defining feature of bulk commodity transportation by train, unit train and barge is the shallow slope of costs with distance if the commodity transported is consistent. The money is in the loading, assembling the train cars or barges, disassembling the train cars or barges and unloading---the cost of an incremental kilometer of transport is cheap. In contrast, there are massive economics of scale associated with chemical plants and refineries. It is this difference in the cost structure of transportation systems with distance versus chemical plants with size that creates the massive incentives for a depot system to ship biomass to very-large central refineries the size of large-scale oil refineries. There are many papers [Kim and Dale, 2015; Jack 2009; Zetterholm et al., 2018; Hossain et al., 2021] that have documented this in various environments.

Pelleted biomass and pelleted biochar are assumed to be transported by unit train. Pyrolysis oil, if sufficiently stable, might be shipped by either tank car in unit trains or by pipeline. Biogas, either as purified renewable methane (natural gas), or as a mixture of methane and carbon dioxide, is assumed to be transported by pipeline to the biorefinery. The cost to ship biomass pellets within the contiguous U.S. by unit train varies with the distance traveled and the direction of travel, but an average value is roughly $22 per ton of biomass delivered.

While we were unable to find corresponding information about the cost of gas and liquid transport by pipeline, we anticipate that it would be similar to or less than the cost of liquid transport by rail because liquids handling is less complex than solids handling. Roni et al. (2014) estimated transportation costs using liquid commodities such as crude petroleum, and natural gas or gasoline (Figure 6.4) based on rates from multiple U.S. railroads. Comparing gas versus liquid transport by pipeline, we expect that gases would be less expensive to transport because of their lower viscosity. However, gas would need to be compressed prior to shipping and the cost of compression might tend to offset the lower viscosity of gases relative to liquids.

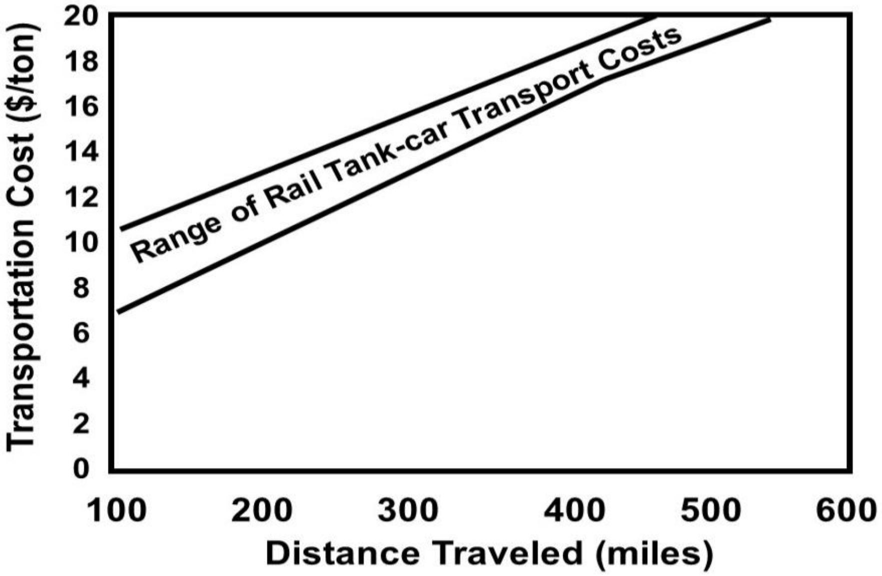

Fig. 6.4 Cost of liquids transport by rail [Based on data from Roni et al., 2014].

Oil refineries, which we propose to use as platforms for the integrated nuclear biorefineries, are already set up to receive large shipments of liquids and gases, but not solids. Therefore, shipping gases or liquids by pipeline to these biorefineries would appear to be advantageous versus supplying them by rail.

Last, the energy costs of transport can become important [Vanek, 2019]. Energy costs are measured in units of energy (BTU, kWh, etc.) per ton mile traveled. Rail achieves the lowest energy intensity of any large scale means of transport. The energy cost of rail transport is about half that of pipeline transport and about one fourth that of truck.

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7. Large-scale Biorefineries

There has been a massive amount of work over many decades on how to convert biomass into different types of liquid fuels [Davis, et al., 2018; Wang et al., 2016; Hannula and Melin, 2021; Nag, A., 2008]. The historical operating assumption has been a local processing plant converting local biomass into liquid fuels. Because of the cost of transport of unprocessed biomass, economic transport distances are 30 to 50 miles limiting biomass input rates into the biorefinery of ~3,000 tons per day and outputs of a few thousand barrels per day [Schultz et al., 2021; Wang et al., 2016; Hannula and Melin, 2021]. In the United States, there have been several attempts to commercialize conversion of cellulose feedstocks into biofuels. All failed, partly because of the poor economics of small biofuels plants and partly because of the difficulties feeding unprocessed, raw biomass into the reaction systems. The plants were also exposed to the risks of local crop failures implying limited locally available feedstocks.

A radically different model is proposed herein [Forsberg and Dale, 2020]—the integrated refinery (250,000 barrels per day oil equivalent) with biomass input rates of 60,000 tons per day. This is the same scale as large integrated oil refineries. This scale of operation creates massive, enabling economics of scale [Birkler et al., 1986]. It enables more complex flowsheets that can (1) produce a wider set of products and (2) vary the product slate to match demand over time—such as more gasoline in summer and more heating oil in winter. Very large biorefineries enable wider variations in the feedstock—be it crude oil or biomass. Last, the logistics model of a commodity input that can be economically shipped long distances eliminates the risks of local weather conditions causing local shortages of biomass feedstocks.

7.1. Large-scale Refineries for Crude Oil or Biomass

A large-scale biorefinery producing liquid hydrocarbons is a variant of existing crude oil refineries. There are significant changes in some of the front-end operations to handle incoming feedstocks but much of the refinery remains unchanged. The major difference is the massive quantities of hydrogen required to remove the oxygen. In many refineries the primary use of hydrogen is removal of sulfur; some crude oils have up to 6% sulfur by weight. Raw biomass may be 40% oxygen by weight. Fortunately, the element with the chemical characteristics closest to oxygen is sulfur. In a refinery the sulfur leaves as hydrogen sulfide (H_2S) while any oxygen in crude oil leaves as water (H_2O). Desulfurization processes tend to remove oxygen whether desired or not.

Figure 7.1 shows a simplified integrated refinery flowsheet. The most important observation is that these are highly complex chemical plants that convert crude oil into multiple hydrocarbon liquids. Crude oil has highly variable composition—varying from liquids with viscosities similar to alcohol to other feedstocks having the consistency of peanut butter at low temperatures. Some heavy crude oils must be heated before they can be pumped. For example, in the recovery of oil from tar sands in Canada, steam is injected into the deposits to raise the temperatures so the oil can flow. Major refinery processes include [Self, Ekholm, and Bowers, 2007; Gary Handwerk and Kaiser, 2007]:

- *Distillation*. Distillation is the primary method of separating oil into different fractions based on boiling point. There are many distillation columns in a refinery. The most important distillation column is the font-end or atmospheric column that separates the crude oil into different fractions. Crude oil is heated to about 400`C and fed into the lower half of the atmospheric column. The more volatile components of the crude oil are vaporized going up the column through a series of trays while less volatile components go down the column. At the top of the column, a fraction of the vapor is condensed and flows downward counter-current to the up-flowing vapor. Each tray is at a different temperature with different crude oil fractions condensing at different temperatures and exiting different trays. Raw gasoline with a low boiling point exits from a tray near the top of the atmospheric column. The heavy oil mixture leaves the bottom of the atmospheric column and enters the vacuum column that separates the heavier components of in the crude oil. Different crude oils may be mixed or recycle streams from the refinery may be added to the crude oil to create a crude oil feed going into the atmospheric column that can be processed—enabling the refinery to accept crude oils with widely varying properties. Any single refinery will have an atmospheric column designed for a set of similar crude oils but can accept a much larger range of crude oils with some loss in efficiency as recycle oil streams from inside the refinery are added to the crude oil to produce the feed to the atmospheric column.

- *Hydrotreating*. These processes [Ortega, October 2021] use hydrogen to (1) to remove sulfur in oil fractions by conversion to hydrogen sulfide (a gas) and (2) convert double bonds in oil molecules into single bonds (including breaking up ring (cyclic) compounds). The same process removes oxygen that is chemically similar to sulfur with the oxygen exiting the process as water.
- *Hydrocracking*. These processes add hydrogen to remove sulfur and break big molecules into smaller molecules. A major goal in most refineries is to convert low-value heavy oils into higher-value gasoline and jet fuel.
- *Recombining*. There several processes that convert light molecules into heavier molecules—higher value gasoline, diesel and jet fuel.
- *Molecular rearrangement*. There are also several processes that rearrange molecules to increase the octane number of gasoline and the centime number for diesel fuels.
- *Feedstock and product blending*. There are blending operations at the front end and back end of the refinery. Front end blending operations mix different crude oils and refinery recycle streams to provide a feedstock that the refinery can process. Backend blending operations are used to meet product specifications. For example, jet fuel has specification on the vapor pressure; that is, how volatile the jet fuel is. That specification exists because at high elevation the atmospheric pressure is lower and one does not want the jet fuel to boil out of the fuel tanks.
- *Special separations systems*. Many large refineries have special separation units to separate out chemical feedstocks from one or more of the intermediate or final product streams. The crude oil inputs partly determine which integrated refineries produce specific chemical feedstocks.

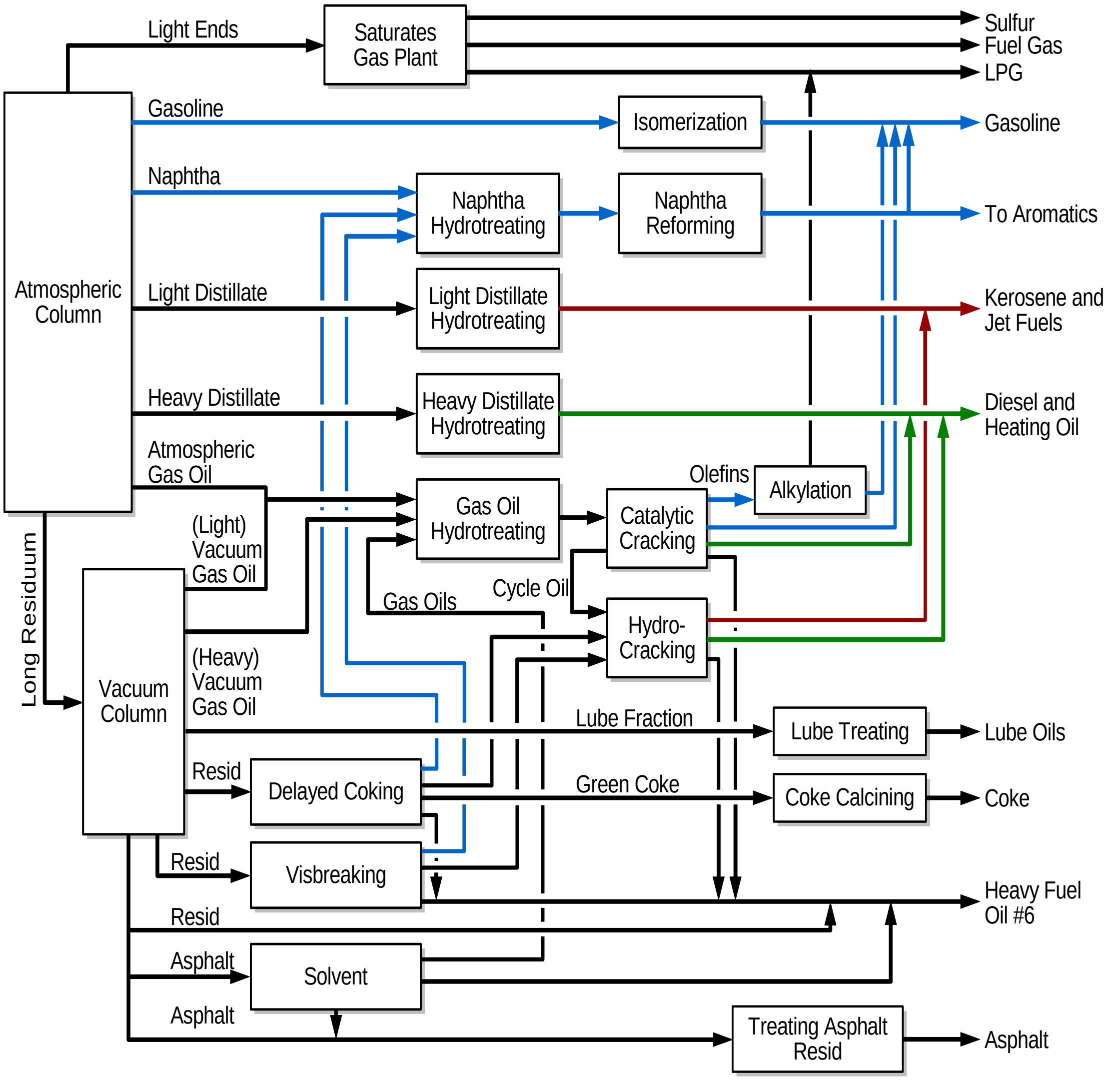

Fig. 7.1. Simplified Integrated Refinery Flowsheet

The complexity of integrated refineries enables those refineries to accept variable crude oils and produce variable products that match changing demand—including different blends of gasoline in summer and winter to meet regulatory requirements. Summer gasoline has fewer low-boiling components to reduce gasoline vapor release to the atmosphere causing air pollution. Winter gasoline has more low-boiling components to enable the engine to start on a cold day.

Almost all crude oil is refined in very large refineries (greater than 250,000 barrels per day) for multiple reasons. First, these complex chemical plants enable conversion of all crude oil into useful products. Early refineries in the 1800's only had the front-end distillation columns—most of the oil barrel was thrown away. Kerosene was the primary product. Over time processes were developed to use the entire oil barrel. In that context, moving to biomass feedstocks is a small step compared to the evolution of refineries over the last century [Nichols, January 2022; Nichols, February 2022; Nichols, March 2022]. Second, the refinery can change the product slate depending on market demand. Last, there are massive economics of scale. The economics of scale in refineries is shown in Equation 7.1 where the exponent α varies between 0.6 and 0.7 for different refinery processes [Birkler et al., 1986].

$$\text{Cost Refinery A / Cost Refinery B} = [\text{Refinery Capacity A / Refinery Capacity B}]^{\alpha} \quad \text{Equation 7.1}$$

Small refineries have much simpler flowsheets that can only accept some types of crude oil. They generally produce a few products and large quantities of lower-value heating oil or bunker oil because they have limited capability to rearrange molecules into high-value products such as gasoline. Most small refineries exist in isolated locations with locally available crude oils where it is expensive to ship crude oil to larger refineries and/or expensive to ship in gasoline and diesel fuel. Many of the same factors that rule out or greatly limit small oil refineries will limit the emergence of small biorefineries. Table 7.1 shows the existing capacities of all 126 refineries in the United States where economics has driven refinery sizes. The bottom 32 refineries in size have a total capacity of the single largest refinery. As a point of comparison, traditional biorefineries have had capacities of a few thousand barrels per day. Table 7.1 is also a list of potential future nuclear-assisted biorefineries.

Table 7.1. U.S. Refineries, Operable Capacity as of January 1, 2021 (EIA, June 2021)

Corporation	**State**	**Site**	**Barrels/day**
Saudi Aramco	Texas	Port Arthur	607,000
Marathon Petroleum Corp	Texas	Galveston Bay	593,000
Marathon Petroleum Corp	Louisiana	Garyville	578,000
ExxonMobil Corp	Texas	Baytown	560,500
ExxonMobil Corp	Louisiana	Baton Rouge	520,000
BP PLC	Indiana	Whiting	435,000
PDV America Inc	Louisiana	Lake Charles	418,000
ExxonMobil Corp	Texas	Beaumont	369,024
Marathon Petroleum Corp	California	Carson	363,000
Chevron Corp	Mississippi	Pascagoula	356,440
WRB Refining LP	Illinois	Wood River	356,000
Koch Industries Inc	Minnesota	Saint Paul	335,000
Valero Energy Corp	Texas	Port Arthur	335,000
Deer Park Refining Ltd Partnership	Texas	Deer Park	302,800
Marathon Petroleum Corp	Kentucky	Catlettsburg	291,000
Valero Energy Corp	Texas	Corpus Christi	290,000
Chevron Corp	California	El Segundo	269,000
Koch Industries Inc	Texas	Corpus Christi, West	265,000
Phillips 66 Company	Texas	Sweeny	265,000

Phillips 66 Company	Louisiana	Westlake	264,000
Access Industries	Texas	Houston	263,776
Phillips 66 Company	New Jersey	Linden	258,500
Phillips 66 Company	Louisiana	Belle Chasse	255,600
Marathon Petroleum Corp	Illinois	Robinson	253,000
ExxonMobil Corp	Illinois	Joliet	251,800
Chevron Corp	California	Richmond	245,271
BP PLC	Washington	Ferndale	242,000
Royal Dutch/Shell Group	Louisiana	Norco	230,611
Total SA	Texas	Port Arthur	225,500
Valero Energy Corp	Texas	Texas City	225,000
Valero Energy Corp	Louisiana	Norco	215,000
Phillips 66 Company	Oklahoma	Ponca City	206,000
Valero Energy Corp	Texas	Houston	205,000
Valero Energy Corp	Texas	Sunray	195,000
Delta Air Lines Inc	Pennsylvania	Trainer	190,000
PBF Energy Co LLC	Louisiana	Chalmette	190,000
Valero Energy Corp	Tennessee	Memphis	180,000
PDV America Inc	Illinois	Lemont	179,265
Husky Energy Inc	Ohio	Lima	179,000
PBF Energy Co LLC	Ohio	Toledo	172,800
PBF Energy Co LLC	Delaware	Delaware City	171,000
PDV America Inc	Texas	Corpus Christi	167,500
HollyFrontier Corp	Kansas	El Dorado	162,000
PBF Energy Co LLC	California	Torrance	160,000
PBF Energy Co LLC	California	Martinez	156,400
BP Husky Refining LLC	Ohio	Toledo	152,000
WRB Refining LP	Texas	Borger	149,000
PAR Pacific Holdings	Hawaii	Ewa Beach	147,500

Royal Dutch/Shell Group	Washington	Anacortes	145,000
Valero Energy Corp	California	Benicia	145,000
Marathon Petroleum Corp	Michigan	Detroit	140,000
Phillips 66 Company	California	Wilmington	139,000
Transworld Oil USA Inc	Louisiana	Lake Charles	135,500
CVR Energy	Kansas	Coffeyville	132,000
Marathon Petroleum Corp	Texas	El Paso	131,000
Valero Energy Corp	Louisiana	Meraux	125,000
Phillips 66 Company	California	Rodeo	120,200
Marathon Petroleum Corp	Washington	Anacortes	119,000
Chevron Corp	Texas	Pasadena	112,229
HollyFrontier Corp	New Mexico	Artesia	110,000
CHS Inc	Kansas	Mcpherson	109,800
Phillips 66 Company	Washington	Ferndale	105,000
Marathon Petroleum Corp	Minnesota	Saint Paul	103,000
PBF Energy Co LLC	New Jersey	Paulsboro	100,000
Marathon Petroleum Corp	Ohio	Canton	97,000
Valero Energy Corp	Texas	Three Rivers	89,000
Royal Dutch/Shell Group	Alabama	Saraland	87,500
Valero Energy Corp	Oklahoma	Ardmore	86,000
HollyFrontier Corp	Oklahoma	Tulsa West	85,000
Valero Energy Corp	California	Wilmington Refinery	85,000
Kinder Morgan Energy Partners LP	Texas	Galena Park	84,000
Delek Group Ltd	Arkansas	El Dorado	83,000
Delek Group Ltd	Louisiana	Krotz Springs	80,000
Delek Group Ltd	Texas	Tyler	75,000
Placid Oil Co	Louisiana	Port Allen	75,000
Sinclair Oil Corp	Wyoming	Sinclair	75,000
CVR Energy	Oklahoma	Wynnewood	74,500

Koch Industries Inc	Texas	Corpus Christi, East	73,500
Delek Group Ltd	Texas	Big Spring	73,000
Marathon Petroleum Corp	N. Dakota	Mandan	71,000
HollyFrontier Corp	Oklahoma	Tulsa East	70,300
Marathon Petroleum Corp	Alaska	Kenai	68,000
Suncor Energy Inc	Colorado	Commerce City West	67,000
Phillips 66 Company	Montana	Billings	66,000
Red Apple Group Inc	Pennsylvania	Warren	65,000
Marathon Petroleum Corp	Utah	Salt Lake City	63,000
CHS Inc	Montana	Laurel	62,000
ExxonMobil Corp	Montana	Billings	61,500
Buckeye Partners LP	Texas	Corpus Christi	60,000
Calumet Specialty Products Partners, LP	Louisiana	Shreveport	57,000
Arctic Slope Regional Corp	Alaska	Valdez	55,000
Chevron Corp	Utah	Salt Lake City	54,720
Hunt Consolidated Inc	Alabama	Tuscaloosa	48,000
Magellan Midstream Partners LP	Texas	Corpus Christi	42,500
PAR Pacific Holdings	Washington	Tacoma	40,700
HollyFrontier Corp	Utah	Woods Cross	39,330
Husky Energy Inc	Wisconsin	Superior	38,000
Suncor Energy Inc	Colorado	Commerce City East	36,000
Hartree Partners LP	Texas	Channelview	35,000
Calumet Specialty Products Partners, LP	Montana	Great Falls	34,600
FJ Management Inc	Utah	North Salt Lake	31,664
Sinclair Oil Corp	Wyoming	Evansville	29,850
Countrymark Coop Inc	Indiana	Mount Vernon	28,800
Ergon Inc	Mississippi	Vicksburg	26,500
Kern Oil & Refining Co	California	Bakersfield	26,000
Petromax Refining Co LLC	Texas	Houston	25,000

Ergon Inc	W. Virginia	Newell	22,300
Starlight Relativity Acquisition Co	Texas	San Antonio	20,000
Arctic Slope Regional Corp	Alaska	North Pole	19,700
PAR Pacific Holdings	Wyoming	New Castle	18,000
ConocoPhillips	Alaska	Prudhoe Bay	15,000
San Joaquin Refining Co Inc	California	Bakersfield	15,000
Silver Eagle Refining Inc	Utah	Woods Cross	15,000
Blue Dolphin Energy Co	Texas	Nixon	14,000
Calumet Specialty Products Partners, LP	Louisiana	Cotton Valley	13,020
American Refining Group Inc	Pennsylvania	Bradford	11,000
Hunt Consolidated Inc	Mississippi	Sandersville	11,000
Greka Energy	California	Santa Maria	9,500
World Oil Co	California	South Gate	8,500
Calumet Specialty Products Partners, LP	Louisiana	Princeton	8,300
Martin Resource Management Grp	Arkansas	Smackover	7,500
Hilcorp Energy Co	Alaska	Prudhoe Bay	6,500
Valero Energy Corp	California	Wilmington Asphalt Plant	6,300
Goodway Refining LLC	Alabama	Atmore	4,100
Silver Eagle Refining Inc	Wyoming	Evanston	3,000
Foreland Refining Corp	Nevada	Ely	2,000

For a nuclear-assisted biofuels system, three commodity products would be produced by the depot systems for shipment to large biorefineries: (1) pelletized biomass, (2) a mixture of carbon dioxide, methane and other gases from bio-digesters and (3) pyrolysis oil. From a refinery perspective, pyrolysis oil is similar to some low-grade crude oil feedstocks. That implies relatively small changes in the refinery—(1) potentially blending with other crude oils or recycle streams inside the refinery and sending it to hydro-treating for removal of oxygen or (2) hydro-pretreating for oxygen removal to minimize recycle within the refinery. The specific pathway will depend upon the refinery and pyrolysis oil characteristics.

Anaerobic digestion produces a mixture of methane and carbon dioxide with small quantities of other hydrocarbons. At the refinery this would mixture would be converted into crude oil by gasification followed by Fischer-Tropsch synthesis. This process is commercially used to convert natural gas and coal into liquid hydrocarbon fuels. The Sasol coal-to-liquids plant in South Africa produces 150,000 barrels per day of liquid fuels using gasification followed by Fischer-Tropsch synthesis. The newer Shell natural gas-to-liquids plant in Qatar produces 260,000 barrels per day of liquid fuels [Shell, 2021; von Bavel, Appendix C]. It is a three step process.

$$H_2O + CH_4 \rightarrow CO + 3\ H_2 \text{ (Gasification)} \qquad \text{Equation 7.1}$$

$$H_2O + CO \rightarrow H_2 + CO_2 \text{ (Water shift)} \qquad \text{Equation 7.2}$$

$$(2n + 1)\ H_2 + n\ CO \rightarrow C_nH_{2n+2} + n\ H_2O \text{ (Fischer Tropsch)} \qquad \text{Equation 7.3}$$

The gasification process (Equation 7.1) can be used to produce syngas from any carbon-containing material: natural gas, coal, oil or biomass. Natural gas is used in the example above. One can add air or oxygen to combust part of the feedstock to provide the energy for gasification. The second step (Equation 7.2), the water shift reaction, involves gas cleanup and the conversion of the syngas to the proper ratio of carbon monoxide and hydrogen by separating out CO_2 or adding hydrogen. It is an equilibrium process that can go in either direction. Heat, if needed, can be added by the nuclear reactor or chemical reactions.

The CO_2 from the gasification process or anaerobic digesters can be (1) recycled with the addition of hydrogen to produce a carbon-monoxide hydrogen mixture through the water-shift reaction to produce liquid hydrocarbons, (2) combined with water in a co-electrolysis cell to produce syngas [Knighton et al., 2020], (3) electrolyzed to produce carbon monoxide and oxygen [van Bavel et al., 2020] or (4) sequestered underground. Unlike fossil fuel electric power plants with CCS, the Fischer Tropsch process produces pure CO_2. As a result the cost of CCS is drastically lowered. In the broader context, there is a large effort on power (electricity)-to-liquid fuels where most but not all of the options start with carbon dioxide and hydrogen from various sources [Dieterich et al., 2020].

Gasification is a widely used industrial process to produce syngas—the mixture of carbon monoxide and hydrogen. Syngas is the starting material for the production of a wide variety of chemical products. There are many different types of gasifiers designed for a wide variety of carbon-containing feedstocks including coal, oil, natural gas and biomass. The third step is the Fischer Tropsch process where the choice of catalyst and operating conditions determines what hydrocarbon liquids are produced.

The third depot feedstock is pelletized biomass. This can be converted by either hydrogenation or by Fischer Tropsch to liquid hydrocarbons. In this context, there has been significant work on direct liquefaction of coal and biomass by hydrogenation—but these processes have not been commercialized. A simplified refinery front-end modification for direct liquefaction [Morais, Appendix C] is shown in Figure 7.2. The ground biomass is mixed with an oil fraction, fed into a biomass conversion hydrotreating process, converted to bio-oil and sent to the atmospheric column that separates oil into the various fractions. In this specific example, the oil fraction that carries the biomass is mixture of naphthas that are recycled.

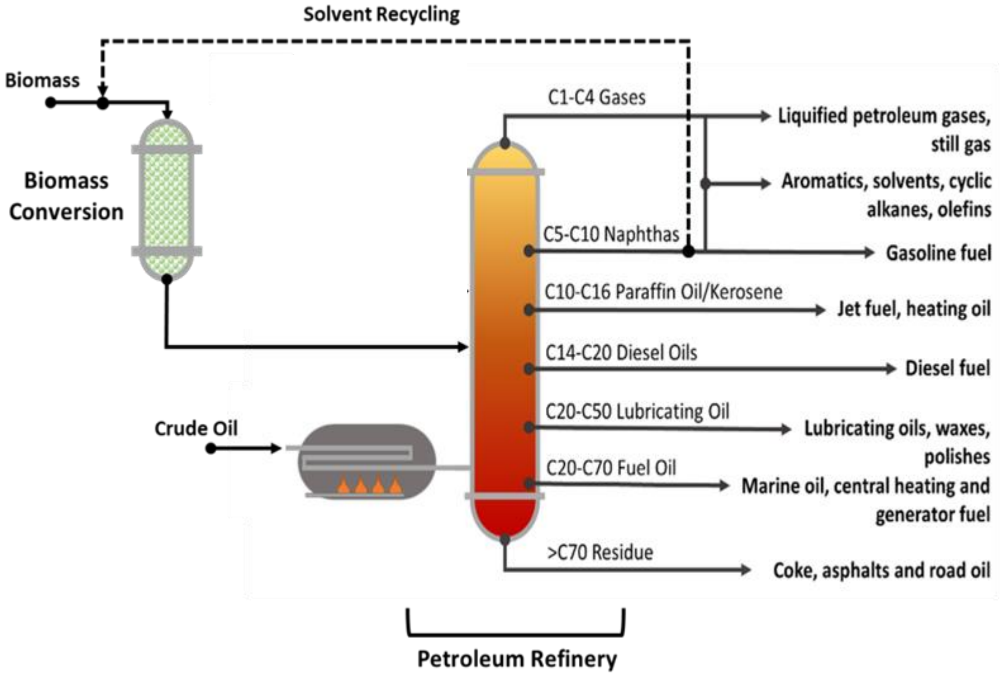

Fig. 7.2. Biomass Front-End Conversion into Liquid Hydrocarbons by Hydrotreating

Alternatively, the ground biomass can be mixed with incoming crude oil and hydrotreated [Morais, Appendix C]. The bio-oil is separated into different fractions and is then further treated, including by additional hydro processing, as shown in Fig. 7.1. This approach is similar to direct hydrogenation processes that have been developed to liquefy coal, except that coal is a much more refractory organic than is biomass.

Commercially [Le Grange et al., January 2022] many refineries are beginning to process various biomass feedstocks into hydrocarbon biofuels. Most of the feedstocks are bio-oils; an option that does not scale globally due to limited feedstocks. Small amounts of cellulosic and other feedstocks are beginning to be fed into refineries on a trial basis and blended with other feedstocks or refinery recycle streams. There has been one announcement [Hydrocarbon Processing, February 2022] to build a biorefinery using gasification of wood wastes and the Fischer-Tropsch process to produce primary jet fuel and sequestered carbon dioxide. Most of the ongoing work to integrate biomass feedstocks into refineries is associated with feeding vegetable oils and similar biomass feedstocks into hydrocracking and fluid catalytic cracker (FCC) units rather than the Fischer-Tropsch process because this minimizes changes in existing refineries. Hydrotreating processes require massive hydrogen inputs and can convert most of the carbon into hydrocarbons while FCC units use less hydrogen but produce more carbon dioxide. The pathway for conversion of refineries from crude oil feedstocks to biomass feedstocks has started.

7.2. Ethanol to Liquid Hydrocarbons

Today many forms of biomass are converted to ethanol for industrial and fuel uses. Catalytic processes using the Guerbet reaction can catalytically oligomerize ethanol to produce the entire range of transportation fuels [Hannon, Appendix C; Hannon et al., 2020; Dowson et al., 2013; Kulkarni, Brennessel and Jones, 2018]. The ethanol is converted into a mixture of aromatic and aliphatic hydrocarbons typical of blend stock constituents (C_4-C_{12}) used in refineries as part of the gasoline and diesel fuel pool. The Guerbet reaction is an alternative pathway to producing liquid hydrocarbons and is currently being commercialized at some ethanol plants.

7.3. Separation and Sequestration of Carbon Dioxide

If there is a market for removal and sequestration of carbon dioxide from the atmosphere, there will be incentives to vary the amount of liquid fuels produced versus the amount of carbon dioxide sequestered depending upon the relative prices of biomass, liquid hydrocarbons and sequestered carbon. In the nuclear-assisted biorefinery there are multiple high-pressure gas streams with high concentrations of carbon dioxide where the cost to extract a pure stream of carbon dioxide for sequestration is low. The economic tradeoffs are shown in Fig. 7.3. A market for sequestered carbon will dampen price volatility of biomass feedstocks and liquid fuels. In years of low biomass and liquid fuel prices, there will be large-scale sequestration of carbon dioxide. In years of high biomass prices and liquid fuel prices, less carbon dioxide will be sequestered.

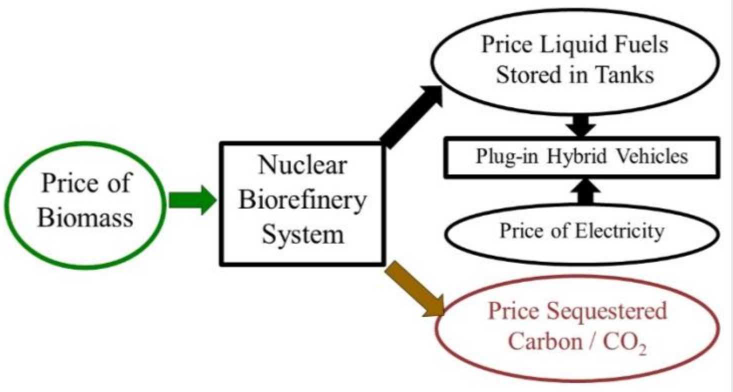

Fig. 7.3. Major Factors in Determining Hydrocarbon Biofuels Prices

The cost of sequestered carbon dioxide from the atmosphere will be significantly lower in this system than via most other routes. Studies of carbon capture and sequestration [Smith et al., 2021; Herzog, Appendix C] show (1) large economics of scale and (2) most of the cost of CCS is associated with carbon capture. The refinery has large economics of scale and gas streams with high concentrations of carbon dioxide for low-cost capture and sequestration of carbon dioxide. These include the feedstock from anaerobic digesters that is a mixture of methane and carbon dioxide—as well as several internal gas streams within the refinery.

Separate from sequestration of carbon dioxide from the refinery, there is the option to sequester carbon from depots in soil as discussed earlier in Chapter 5. Adding carbon improves soil productivity. The refractory carbon is in the digestate from anaerobic digesters and char from flash pyrolysis. The current carbon inventory in the soil is about three times the inventory in the atmosphere and four times the carbon in all biomass. The soil is potentially a massive sink for carbon sequestration [Ussiri and Lal, 2017]

An alternative strategy [Kim et al., 2020; NAS, 2019] to reduce carbon dioxide concentrations in the atmosphere is to collect biomass, burn it in power plants and use CCS. However, the carbon dioxide concentration in the flue gas is near 10% and such systems operate at atmospheric pressure making CCS expensive. Current cost estimates [Herzog, Appendix C] for carbon dioxide capture and sequestration are (1) less than $50/ton if there is access to a high purity or high pressure source of carbon dioxide [such as in refineries], (2) $50 to 100/ton if there is a dilute source of carbon dioxide such as stack gas, (3) approximately $240/ton if biomass is burned to produce electricity generation and recover the carbon dioxide from the stack gas and (4) approaching a $1000/ton if carbon dioxide is directly captured from the atmosphere. We have over a century of experience removing carbon dioxide from various gas steams in the chemical industry to validate these large increases in the cost of carbon dioxide sequestration as the concentrations of carbon dioxide and gas pressures decrease.

There is a second factor to consider in terms of long-term sustainability. The depot systems based on anaerobic digestion, and pyrolysis, enable local recycle of nutrients to the soil. At the biorefinery, the ash and other wastes with trace nutrients such as potassium and phosphorous are in chemical forms that enable recycle back to soils. In contrast, burning biomass in high-temperature furnaces with CCS under highly oxidizing conditions results in much more refractory ash that may severely limit options to recycle nutrients. We are not aware of any studies that have addressed long-term sustainability of burning biomass with sequestration of the carbon dioxide.

As described in Section 7.2, ethanol can be converted into liquid hydrocarbons. Ethanol is made from starch (corn) by a fermentation process that produces pure carbon dioxide. Work is underway (Summit Carbon Solutions, 2022) to permit pipelines to move carbon dioxide from multiple ethanol plants to sequestration sites. This results in negative carbon emissions provided low-carbon heat sources provide the heat to the ethanol plants (Section 8).

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8. Heat and Hydrogen Production

The nuclear-assisted liquid biofuels system design enables replacement of crude oil. Crude oil provides almost half the energy to the final customer in the U.S. Converting biomass into a direct replacement for crude oil requires massive amounts of hydrogen and heat. The hydrogen energy input alone would represent 10 to 20% of the total primary energy input into the U.S. economy. We describe herein the sources of that heat and hydrogen. There are many internal tradeoffs between quantities of biomass, heat and hydrogen per unit of hydrocarbon liquid product. The relative prices of biomass, heat and hydrogen will drive choices and will change with time.

8.1. Hydrogen Production

A nuclear-assisted liquid-hydrocarbon biorefinery requires massive quantities of hydrogen [Forsberg et al., September 2021; Forsberg, Appendix C]. To replace U.S. crude oil, these biorefineries may consume a 100 million tons per year of hydrogen. Current U.S. hydrogen production is about 11 million tons per year where the primary markets are crude-oil refineries and the production of fertilizer. Today large quantities of hydrogen are shipped by pipelines that connect most of the major refineries in Texas and Louisiana. On any particular day, a refinery may need more hydrogen that it can produce or might have excess hydrogen production capacity. Refinery demand depends upon the specific crude oil that is being refined. The pipeline enables individual refineries to buy and sell hydrogen as needed. The pipelines have merchant hydrogen production plants that sell hydrogen and hydrogen storage facilities. A similar system would be used if refineries transition to biomass feedstocks with hydrogen production facilities located at the refinery, offsite or some combination of the two.

While the hydrogen demand can be estimated, there are several uncertainties. The refinery can use (1) carbon to remove oxygen from biomass as carbon dioxide and produce smaller amounts of liquid hydrocarbons per unit of feedstock or (2) hydrogen to remove oxygen from biomass as water to maximize liquid hydrocarbon production. Consequently, there is an economic tradeoff between using hydrogen or biomass carbon for removing the oxygen.

Second, liquid hydrocarbon fuels are mixtures of hydrocarbons defined by their performance—not by a specific chemical formula. The typical composition of gasoline by volume percent is 4-8% alkanes; 2-5% alkenes; 25-40% isoalkanes; 3-7% cycloalkanes; l-4% cycloalkenes; and 20-50% total aromatics. The alkanes have two or more hydrogen atoms per carbon atom whereas the aromatics may have as low as one hydrogen atom per carbon atom. The refineries have some control over the composition of liquid hydrocarbon fuels; thus, the hydrogen content of the liquid hydrocarbon fuels will change with the price of hydrogen.

Recent reviews [van der Spek et al., 2022; Somtochukwu, 2022] examined hydrogen production methods and applications. The near-term low-carbon lowest-cost hydrogen production option is steam methane reforming of natural gas followed by CCS [Muradov, 2017; Shell, 2021; Carter and Hickman, June 2021; Cruz, Appendix C; Hydrogen Council, 2021; MacDowell et al., 2021; Somtochukwu, 2022]. The cost of hydrogen with sequestration of 90 to 98% of the carbon dioxide is about 30% higher than the conventional methods to produce hydrogen. There are many variants of this process. For areas with low-cost natural gas and good sequestration sites, hydrogen from natural gas with CCS is estimated to cost between $1.50 and $2.00 per kilogram. Multiple companies have announced building such facilities to meet existing hydrogen demand. The relatively low cost is because of process chemistry where the two-step gasification reactions (Equations 7.1 and 7.2) of natural gas with oxygen and steam yields hydrogen and concentrated carbon dioxide. A fossil power plant with CCS is expensive because of the high cost of separating the carbon dioxide from the stack gas. Carbon dioxide is typically about 10% of the stack gas. In steam methane reforming most of the carbon dioxide exits the process as nearly pure carbon dioxide—reducing the cost of carbon capture. Carbon dioxide sequestration underground is inexpensive [Smith, 2021]. Heat is also required in the process and the combustion of natural gas does produce a dilute carbon dioxide stream. However, there are variants of the process where the carbon dioxide released to the atmosphere is below 1%. If the heat is provided by nuclear reactors, there are no carbon dioxide releases [Yan and Hino, 2011]. There is a rapidly expanding effort [Great Plains Institute 2022] to develop hydrogen hubs that are primarily based on natural gas with carbon dioxide sequestration because the chemical and refinery industry recognizes that this is one of the lowest-cost ways to reduce carbon dioxide emissions.

As discussed in Section 7.3, the nuclear-assisted biorefinery can produce variable liquid hydrocarbons and sequestered carbon dioxide. Any releases of carbon dioxide from steam methane reforming with CCS can be compensated for by sequestering carbon dioxide that originated from the biomass. Economic tradeoffs will determine allowable releases from hydrogen production via natural gas with CCS.

The second set of options uses low-temperature electrolysis or high temperature electrolysis (HTE). Low-temperature electrolysis is electrolysis of water—a process that has been commercial for over a century. High-temperature electrolysis is steam electrolysis that requires electricity and steam. It is significantly more efficient [van der Spek et al., 2022, James et. al. 2016; O'Brien et al., 2010; O'Brien, 2012; Hauch, 2020], is expected to have lower capital costs and couples well to nuclear plants that can produce steam and electricity. Efficient is defined as the amount of hydrogen produced divided by heat input to the process and heat used to produce the electricity. HTE is in the early stage of commercial deployment with the expectaation that the capital costs will also be lower—partly because of the higher efficiency and partly because no noble metal catalyst is required.

A defining characteristic of all electrolysis processes is the high capital costs—both for the electrolytic cells and associated power supply systems and hydrogen handling systems (compressors, etc.). Low-cost hydrogen is only possible with high capacity factors as shown in Fig. 8.1. One consequence is that today solar hydrogen is very expensive because of the low capacity factors of solar systems that provide the electricity. The other consequence [Palmer et al., 2021] is that the greenhouse gas emissions from solar hydrogen are about a quarter of conventional steam methane reforming of natural gas and above many options to produce hydrogen from natural gas with carbon sequestrion. That reflects the high energy input for the large quantities of materials required to build such plants with low capacity factors. Nuclear plants have capacity factors of about 90% versus wind with a capacity factor near 41% and large-scale solar with a 24% median capacity factor [Bolinger, 2021].

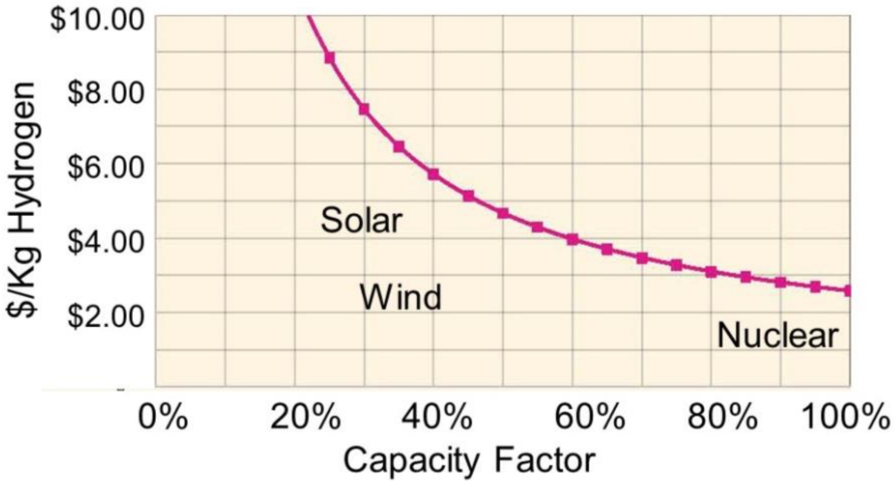

Fig. 8.1. Illustrative Cost of Hydrogen Vs Capacity Factor (Courtesy of LucidCatalyst [2020])

The U.S. Department of Energy has a major program to lower the cost of hydrogen to $1.00 per kilogram. For electrolyzers, that requires higher efficiency and lower capital costs. The near-term nuclear hydrogen production option with HTE is co-production of hydrogen and peak electricity (Fig. 8.2). Hydrogen is produced most of the year to minimize hydrogen production cost. To maximize revenue, electricity rather than hydrogen is produced 5 to 15% of the year when electricity prices are high. The economic penalty incurred by lower hydrogen plant capacity factors is relatively small if electricity is diverted to the grid for a limited number of hours per year. This feature can help meet the occasional peak summer or winter electricity loads. The nuclear plant replaces the gas turbine for peak electricity production. The first demonstration of this system is planned for the Prairie Island nuclear plant in Minnesota.

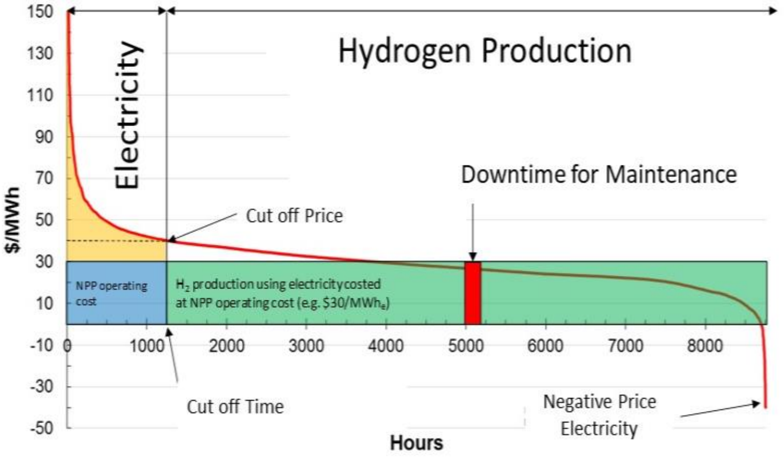

Fig. 8.2. Coproduction of Nuclear Hydrogen and Electricity [Boardman, August 2019]

The second nuclear hydrogen production option is the nuclear hydrogen gigafactory (Fig. 8.3). A modular nuclear reactor fabrication plant produces reactors that are sited next to the hydrogen gigafactory. Shipyard cranes that can lift several thousand tons move reactors from factory to the nuclear plant site by crane. If a reactor needs refurbishing these cranes transport it back into the factory.

This approach changes building nuclear reactors from a construction-site-based model into a manufacturing-based model in which the hydrogen production capacity at the site grows over 10 years and thereafter the factriory produces replacement reactors. Factory fabrication, rather than on-site construction, [LucidCatalyst, 2020; EPRI 2021; Appendix C Ingersoll] can dramatically lower the capital cost of nuclear power plants—in addition to improved economics of operation of multiple nuclear reactors at a single site and economics of scale for the hydrogen production plant. A single site might have 36 nuclear reactors with an energy output of 600 MWt each for a total site production rate of 2 million tons of hydrogen per year. Studies [Gandrik, 2012] on operating high-temperature gas-cooled reactors show staffing levels of 382 people for one reactor but only an additional 71 people for a two unit site. Much larger sites with many reactors results in added savings. For example, when a reactor shuts down for maintenance and refueling, the number of workers on site may triple—including many expensive high-skilled temporary workers. With a large number of reactors, one has lower-cost permanent refueling / outage staff. Nuclear fuel is typically 5% of the cost of nuclear energy and thus not a major cost driver.

Fig. 8.3. Hydrogen Gigafactory with Factory in Back, Reactor Field in the Middle and Hydrogen Plant in the Front (Courtesy of LucidCatalyst [2020])

The gigafactory is economically attractive because of the cost difference between transporting and storing energy as hydrogen versus electricity. A very large power line can transmit a few gigawatts of energy with significant (about 7%) energy losses in transmission. A single hydrogen pipeline can transport many tens of gigawatts with lower loses and can be coupled to low-cost underground hydrogen storage facilities to match steady-state production with variable demand on an hourly to seasonal basis. The same combination of low-cost oil pipelines for inexpensive energy transport and oil storage made possible today's large integrated oil refineries that are similar in the scale of energy output to proposed hydrogen gigafactories. The levelized cost [EPRI, 2021] of hydrogen is estimated at $0.91/kg for a gigafactory producing two million tons per year of hydrogen.

Normally transportation is a significant cost as natural gas and hydrogen are distributed to large numbers of customers. If producing ten million barrels per day of biofuels with each refinery having a capacity of 250,000 barrels per day, there are 40 bio-refineries that may be consuming in total over a 100 million tons of hydrogen. This implies large pipelines with few customers resulting in very low transport costs.

There are three longer-term hydrogen production options. The first is direct pyrolysis of natural gas into hydrogen and solid carbon that is buried. The energy cost of this process is about one seventh that of electrolysis—however the process is early in the development cycle [Upham et al., 2017]. The second set of options are nuclear thermochemical processes that convert heat and water into hydrogen and oxygen [Yan and Hino, 2011]. This process potentially has significantly lower costs than electrolysis and is at the early pilot plant stage of development. The third option [Forsberg, September 2021] is coupling solar to very large-scale heat storage to enable economic large-scale hydrogen plants that operate at high capacity factors. This option couples efficiently to high-temperature electrolysis that requires heat and electricity. There are multiple hydrogen production options [MacDowell, 2021] where rapid changes are occurring and where the preferred option will vary with location.

8.2. Heat Production

The largest industrial users of heat are the large integrated oil refineries with heat demand measured in gigawatts [Forsberg and Foss, March 2021]. The heat input is 9 to 10% of the energy content of the products [Elgowainy et. al, 2014]. The heat demand of nuclear-assisted biorefineries will be greater—in part to remove the water associated with biomass feedstocks. Heat in the form of high-temperature steam or molten salts can only be economically transported a few kilometers; thus the nuclear reactors must be co-located with the refinery. High-temperature heat (500-600 ºC range) is required for some refinery operations. There is only limited demand for higher-temperature heat because oils decompose at higher temperatures.

This steady state heat demand matches the capabilities of nuclear reactors to produce cheap heat. Nuclear energy has the lowest lifecycle greenhouse gas emissions per unit of heat [United Nations, 2021]. Nuclear reactors produce cheap heat but more expensive electricity because it takes several units of heat to produce a unit of electricity (work). In contrast, one unit of electricity can be converted into one unit of heat with a conversion efficiency exceeding 95%. The characteristics and size of the heat demand match high-temperature nuclear reactors including (1) high-temperature gas-cooled reactors (HTGRs), (2) molten salt reactors (MSRs) with fuel dissolved in the salt and (3) Fluoride-salt-cooled high-temperature reactors with solid fuel and liquid salt coolant.

About 15 years ago, a major U.S. Department of Energy program called the Next Generation Nuclear Plant designed and tested fuel for a HTGR specifically designed for industrial heat applications. The demonstration plant was cancelled because of the fracking revolution that dramatically decreased the price of natural gas. With restrictions on natural gas, nuclear energy becomes the low-cost option to provide steady-state heat. Wind and solar are more expensive because they produce electricity that must be converted to heat and also require expensive storage to provide steady-state heat.

The depot heat demand depends upon the type of depot. Depots using pelletization or anaerobic digester systems have relatively low energy requirements. Pyrolysis processes have higher heat demands to break down the organics. Ethanol and paper mills have the highest heat demands. Pyrolysis requires high-temperature heat whereas the other facilities require lower temperature (<300ºC) heat. However, total heat demands do not exceed 100 to 200 MWt per site versus multi-gigawatt heat demands of refineries. This is because there is an economic limit to the shipping distance of raw biomass—be it corn stover or pulpwood.

There are several candidate low-carbon heat sources for pyrolysis depots, ethanol plants and paper mills. There is the option to burn biomass—but in a low-carbon world this is a valuable resource. Typical nuclear power plants are much larger in size. There is the option to co-locate such depot facilities with power reactors and buy heat from those facilities. In Russia, China and Europe there are nuclear co-generation plants that do sell steam to industrial customers. This is likely to be attractive for some new depot facilities.

The last option for heat at the depot level are fission batteries—also called nuclear batteries [Agarwal, Gehin, and Ballout, January 2021; Forsberg and Foss, March 2021; Buongiorno et al., June 2021; Buongioro et al., 2021]. These are small nuclear reactors specifically designed to replace natural gas, oil and coal in industrial facilities with total heat demands up to 200 MWt. Fission batteries would be mass produced and leased to industrial customers. For technical reasons, the size of fission batteries would be between 5 and 30 MWT. Multiple units would be used to meet specific site energy requirements. These systems are currently under development.

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9. Economics and Transition Strategies to Nuclear Biofuels

There are two questions for commercialization of any product or process. The first is economics relative to the competition. That is a market question. The second question is the development strategy. If the time or resources to implement the new system are too large, it will not occur even though the economics are favorable.

9.1. Estimated Costs of Nuclear-Assisted Liquid-Hydrocarbon Biofuels

Based on the workshop and other assessments, cost estimates for liquid hydrocarbon liquids using a nuclear-assisted cellulosic biomass refining system can be developed. This process starts by estimating the cellulosic liquid-hydrocarbon biofuels costs based on raw materials costs—the equivalent of dollars per barrel of crude oil. We start by assuming that gasoline is octane (C_8H_{18}). By weight, gasoline is 84.2 % carbon and 15.7 % hydrogen. A gallon of gasoline weighs 6.3 pounds (1 pound hydrogen and 5.3 pounds carbon) with 42 gallons in an oil barrel.

Hydrogen is the principal costs and is estimated to cost \$2/kg from steam methane reforming of natural gas (near term) or from a nuclear hydrogen gigafactory. At \$2/kg of hydrogen, the hydrogen cost is \$0.91/gallon or \$38/barrel. As discussed earlier, estimated prices for hydrogen from natural gas with CCS are between \$1.50 and \$2.00 per kilogram. The U.S. Department of Energy goal for hydrogen is to reduce the cost to \$1/kg. The EPRI [2021] cost estimate for hydrogen from the gigafactory is \$0.91/kg. With the accelerated work on low-carbon hydrogen production, we will have within a few years commercial experience with hydrogen production using natural gas and CCS. We will also have within a decade a much better understanding the cost of low-carbon hydrogen via other routes. Actual hydrogen demand is expected to be lower. Biomass contains some hydrogen that will reduce the actual hydrogen demand at the biorefineries.

The second most expensive component is the biomass. We estimate the dry biomass cost delivered at the refinery gate at \$125/ton with a 40% oxygen content and the remainder as carbon, This estimate assumes pelletized biomass at \$80/ton for the raw biomass, \$20/ton added costs at the depot and \$25/ton for unit train transport to the biorefinery. The estimated carbon cost is therefore \$0.10/pound or \$0.55/gallon or \$23/barrel of oil. This cost is substantially less than for other biofuel/biorefining systems because biomass in those systems can serve as many as three functions when producing biofuels, namely as a source of: (1) carbon, (2) hydrogen and (3) energy to operate the process. In the nuclear-assisted biofuels case, we assume the biomass is only a source of carbon—which is the minimum amount of carbon needed for the final product.

The above analysis results in a biocrude oil (feedstock) price of \$61/barrel (\$1.46/gallon) for the biomass and hydrogen delivered to the refinery. The other important cost is refining. Typical refining cost are near \$0.37/gallon [EIA, 2017]. We assume a 50% increase in refinery costs to account for the additional steps required to refine biomass, thus bringing the total processing costs to about \$0.50/gallon or \$21/barrel. EIA analysis of refinery costs include heat input and hydrogen addition to the crude oil that we have not separated out. The extra refining cost is equivalent to adding \$7.00 per barrel bringing the equivalent oil price up to \$68.000 per barrel.

There have been assessments [Hannula and Reiner, 2019] that have done comparisons of biofuels, electrofuels and batteries for light-duty vehicles. Those studies indicate biofuels at the above prices would be competitive with batteries assuming batteries meet the DOE cost goal (\$125/kWh) in electric vehicles with relatively short range (135 km). Battery costs go up with longer-range vehicles with 500 km range equivalent to \$243/barrel oil, Plug-in hybrid vehicles have relatively short ranges when operating only on batteries

Crude oil prices are highly volatile (Table 9.1). Since 2010 the average yearly prices [Amadeo, 2021] have varied from a low of \$38.70/barrel in 2016 to a high of \$102.58/barrel in 2011. One can see the effect of the fracking revolution on oil prices as well as the effects of the pandemic. That volatility also reflects the structure of the oil industry that has the big national oil companies with massive oil reserves (Saudi Arabia, 307 million barrels; Iran, 315 million barrels; Venezuela, 241 million barrels; etc.) and the much smaller western oil companies with limited oil reserves (British Petroleum, 18 million barrels; Exxon-Mobil, 17 million barrels; Total, 12 million barrels; etc.). Political decisions by national governments often determine oil prices. Recent crude oil prices have been $75-80/barrel ($1.78-1.90/gallon). Our simplified analysis implies biofuels hydrocarbon fuel costs equivalent to oil at $60 to $70 per barrel. The cost is most sensitive to the cost of hydrogen where most predictions are for lower cost hydrogen. About half the time in the last decade crude oil prices have been higher.

Table 9.1. U.S. Crude Oil Prices Since 2010

Year	Price per Barrel
2010	$75.83
2011	$102.58
2012	$101.09
2013	$98.12
2014	$89.63
2015	$46.34
2016	$38.70
2017	$48.98
2018	$61.34
2019	$57.95
2020	$37.22
2021	$66.18

Several observations follow from this simplified analysis. First, nuclear-assisted liquid hydrocarbon costs will be in the same range as the costs of crude oil-derived liquid hydrocarbon fuels we have experienced roughly half the time since 2010. Liquid hydrocarbon biofuels will not go down to the very low oil prices seen in the middle of the fracking revolution. The expected cost of nuclear-assisted liquid hydrocarbon biofuels will be somewhat less than recent prices of liquid fossil fuels. The largest costs are for hydrogen with similar costs for the refinery and biomass. In an optimized system, there will be tradeoffs between biomass inputs, hydrogen inputs and refining. There will probably not be a single lowest-cost route but rather the most economic option will depend upon local feedstocks, availability of cheap natural gas with good sequestration sites and other factors.

9.2. Transition Strategies

The historical model for cellulosic liquid biofuels production has been dispersed biofuels plants in which the size is limited to less than about 3,000 tons per day of biomass. This size was determined by the maximum economic shipping distance of unprocessed biomass to the biorefinery. All of the first-generation cellulosic biorefineries failed, at least in large part, because of the poor economics of small plants and the difficulties involved in handling unprocessed, raw biomass.

The biorefinery strategy proposed here is very different. We propose to use crude oil refineries with modified front-end processing to receive cellulosic biomass and process it to supply the rest of the refinery. Thus we propose to keep the bulk of the refinery essentially unchanged and thereby build upon 150 years of hydrocarbon liquid fuels processing. The strategy and system design are driven by the favorable economics of large-scale processes. The development of such a system requires favorable government policies of which several are identified here.

- *Incentives to reduce fossil fuel consumption*. Fossil fuels are relatively inexpensive, easy to transport and easy to store. There will be little or no substitution to alternative fuels unless there are either incentives for alternative fuels or penalties for the use of fossil fuels. There is a second deployment challenge: enabling the required massive financial investments in an existing market with (1) existing capabilities to produce hydrocarbon products from crude oil and (2) high volatility of oil prices. The combination of these two characteristics makes investments in any replacement technology very risky and strongly discourages deployment of nuclear-assisted biofuels or, for that matter, *any alternative system* [Reicher, 2017].
- *Credit oil refineries for production of biofuels*. The evidence suggests that the fastest, lowest-cost transition away from fossil petroleum is to use existing oil refineries. Biofuel credits should apply to these refineries: if 10% of the carbon in the feedstock is from biomass, 10% of the hydrocarbon liquid fuel should be considered as low-carbon biofuels. Incentives should be based on the final product—not the route from field and forest to the consumer. This approach provides a transition pathway from crude oil to biomass feedstocks.
- *Incentives for cellulosic biomass.* The technologically simplest ways to make liquid biofuels are to produce ethanol from sugar or starch and biodiesel from vegetable oils or waste oils/greases. However, that resource base is completely insufficient to produce the required massive quantities of liquid hydrocarbon fuels. Separate incentives for using cellulosic biomass are required to kick-start cellulosic liquid hydrocarbon fuels production through the ultimate transition to commercial scale. Incentives should be structured to enable their use by depots and existing oil refineries that are transitioning to biofuels in an incremental fashion. Cellulosic feedstocks are the lowest cost feedstocks; thus, at scale such incentives should no longer be available. Properly designed, incentives for increased cellulosic biomass production could also provide significant additional environmental services including increased biodiversity, reduced soil erosion, increased water supplies and improved water quality.

  Incentives can be in many forms. For liquid fuels, one option from the electric sector is "Contracts for the Difference". In its simplest form, the government guarantees a minimum price for cellulosic biofuels to any biofuels producer for X years. If the sales price of biofuels when produced is below the guaranteed fuel price, the government makes up the difference. If the sales price of biofuels when produced is above the guarantee price, no payment is made. More complicated variants have the producer split the difference in added revenue when prices are above the guaranteed prices.
- *Carbon sequestration credits*. The U.S. government has a variety of incentives for sequestering carbon dioxide from the atmosphere. Such credits should apply to all strategies for carbon sequestration—from sequestration of carbon in soil to geological disposal. It should make no difference if one is growing trees to sequester carbon dioxide or sequestering refractory carbon from an anaerobic digester into agricultural or forestry soil that improves long-term soil productivity.

There are other challenges. The largest such challenge is the belief that biofuels are in direct competition with food production, even though national biomass resource assessments take into account future demands for food, feed and fiber [U.S. Department of Energy, 2016]. Moreover, cellulosic biofuel production would use nonfood-based sources such as grasses and crop residues. The reality is that the primary challenge for Western agriculture for more than 50 years has been finding markets for surpluses—not dealing with shortages. A related important fact is that there are numerous ways in which the production of energy, food and environmental services can be combined to their mutual benefit [Schulte *et al.*, 2021].

The proposed nuclear-enabled biorefining system could be rapidly deployed. American agriculture for several decades had productivity growth rates about twice that of American manufacturing. A fleet of ethanol plants were deployed in less than a decade; this is an existing industry that has the capability for large-scale deployment of depots in a similar time frame. The oil industry scaled up gas fracking in about a decade. In the near-term the fracking industry could be converted to a hydrogen production system based on steam methane reforming of natural gas with sequestration of the carbon dioxide. In the 1960s and 1970s, the nuclear industry deployed many reactors in about 15 years. The oil and nuclear industries have traditionally had the highest paying blue color jobs, an important social consideration.

9.3. References

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10. Conclusions

In the United States almost half the energy consumed by the final customer is in the form of liquid hydrocarbons. The feedstock used to produce these liquid hydrocarbons is primarily crude oil—but a small fraction of liquid hydrocarbons are produced from coal, natural gas and biomass. Because of concerns about climate change, two important policy goals are to stop carbon dioxide emissions from fossil fuels in the next several decades and reduce atmospheric emissions of carbon dioxide.

Liquid hydrocarbons are used as (1) an energy source, (2) a means of daily-to-seasonal energy storage, (3) a chemical feedstock, (4) a chemical reducing agent, (5) a method to enhance high-temperature heat transfer in many furnaces and industrial processes and (6) for many other purposes. As a consequence, the U.S. consumes ~18 million barrels of crude oil per day. Because the use of hydrocarbon liquids is so deeply embedded into society, it will take many decades and trillions of dollars to find replacements. While there are substitutes for liquid hydrocarbons for some applications, our assessment is that the costs to and negative impacts on American society will dramatically increase if liquid hydrocarbon use goes much below the equivalent of 10 million barrels per day of crude oil. Expanded uses of liquid hydrocarbons to partly replace coal and natural gas could increase demand to 20 million barrels per day of oil. The high-end demand occurs if we do not find economic replacements for the combined energy and storage functions of natural gas and coal.

We propose a nuclear-assisted liquid-hydrocarbon biofuels option to fully replace crude oil with drop-in replacements for gasoline, diesel, jet fuel, chemical feedstocks and other oil products. Plants grow by removing carbon dioxide from the atmosphere; thus liquid hydrocarbons from biomass can be burned without any net addition of carbon dioxide to the atmosphere Under this option, the feedstocks to refineries and some front-end refinery processes are changed—but everything else remains the same. Agriculture also changes significantly and for the better. This strategy may enable a more rapid conversion of the oil/chemical sector to a low-carbon economy because it minimizes required changes to the U.S. infrastructure. It includes the option of sequestering carbon dioxide from biomass to reduce atmospheric carbon dioxide levels as well as sequestering carbon in soils within some of the agricultural scenarios.

Today’s biofuels industry is based on converting starches, sugars or vegetable oils into liquid fuels; but these forms of biomass do not exist in sufficient quantities to replace petroleum, and they also represent significant potential conflicts with essential food and feed production. To meet global liquid hydrocarbon demand, the proposed system uses cellulosic biomass, sometimes called lignocellulosic biomass, as the feedstock for liquid hydrocarbon fuels production. Cellulosic biomass is by far the most abundant source of biomass on earth and sufficient sustainable resources exist to replace oil consumption.

Biomass is typically is 40% oxygen. To remove this oxygen to create hydrocarbon liquids, there are two options: oxygen can be removed by reacting (1) with carbon to produce carbon dioxide or (2) with hydrogen to produce water. In addition, hydrogen must be added to the biomass to produce liquid hydrocarbons. There are two processing options. The first option is to use biomass as (1) a feedstock, (2) an energy source to operate the process and (3) supply the carbon to remove the oxygen from the biomass. The second option proposed herein is to use external heat and hydrogen to remove the oxygen as water and produce liquid hydrocarbons.

The use of massive quantities of external heat and hydrogen for hydrocarbon liquid fuels production has important implications; the required amount of biomass per unit of liquid hydrocarbons produced is reduced by more than a factor of two thereby also reducing land use by more than a factor of two. Many cellulosic feedstocks unsuitable for liquid hydrocarbon production are viable feedstocks with external heat and hydrogen inputs. As a result, there is sufficient cellulosic feedstocks to meet U.S. and global liquid fuels hydrocarbon demand without significant impacts on food and fiber prices. We propose massive heat and hydrogen inputs at the refinery to fully convert all carbon in biomass into liquid hydrocarbon fuels—biomass only as a carbon feedstock to the refinery.

Over half the processes in a biorefinery producing drop-in liquid hydrocarbons are identical to those of a crude-oil refinery. Most of the other processes are variants of existing refinery processes. This enables the incremental conversion of many oil refineries into biorefineries and can accelerate a transition to biofuels by leveraging over a century of experience in the design and operation of oil refineries. There are massive economics of scale that result in refinery capacities of 250,000 barrels of oil per day or larger. This defines the size of the nuclear-assisted biorefinery.

The economic shipping distance of unprocessed biomass is 30 to 50 miles; thus, insufficient biomass is available to support a large biorefinery. To support large biorefineries, local depots near the farm or forest are required to convert biomass into energy-dense, economically-shippable commodities where depots can ship to multiple biorefineries. There are three depot options. The first option is pelletization of biomass to produce a high-density storable shippable commodity. The second option is anaerobic digestion that converts biomass into (1) a methane / carbon dioxide gas that is shipped via pipeline to the refinery and (2) a residue containing most of the nutrients and refractory carbon that is recycled to the soil to improve long-term soil productivity. The third option is pyrolysis (fast heating of biomass) that produces (1) a bio-oil that is shipped to the biorefinery and (2) a carbon residue that can be recycled to the land to improve soil productivity or sent to the biorefinery to be converted into liquid hydrocarbons. Depots may also separate biomass into high-value animal food or other products with the remainder shipped to the biorefinery. For example, most of the nutrition in plants such as alfalfa is in the leaves (proteins for animals) creating incentives to use the leaves as animal food and the steams converted into biofuels.

At the refinery the depot feedstocks are converted into a bio-crude oil. The pyrolysis oil is similar to some crude oils. The methane / carbon dioxide feedstock from anaerobic digesters is converted into a bio-oil using the Fischer-Tropsch process, the same process used commercially to convert natural gas and coal into liquid fuels. The pelletized biomass can be converted into a bio-oil by the Fischer-Tropsch process or direct hydrogenation. Massive quantities of hydrogen will required. Individual refinery heat demands are measured in gigawatts. Heat is provided by high-temperature reactors co-located at the refinery.

Hydrogen can be produced on-site or transported by pipeline. In locations with low-cost natural gas and good sequestration sites, the likely low-cost hydrogen production route is conversion of natural gas into hydrogen and carbon dioxide with sequestration of the carbon dioxide. The other option are large-scale nuclear hydrogen production facilities. The most efficient hydrogen production processes, high-temperature electrolysis of steam, require heat and electricity. Hydrogen production facilities have high capital costs. These factors favor nuclear hydrogen production systems where the reactor operates at full capacity providing heat and electricity. Nuclear plants have capacity factors (fraction of time producing maximum output) of over 90% versus 24% for solar and 41% for wind. It is unclear at this time if technology developments will enable low-cost hydrogen from wind or solar because of the high costs of the hydrogen production facilities.

The system can remove and sequester carbon from atmospheric carbon dioxide via two routes. The depot system enables soil sequestering of carbon via recycle of digestate and bio-char to the land. Second, there is also the option to reduce atmospheric carbon dioxide by separating out carbon dioxide from the anaerobic digesters or in various refinery streams. Because these streams contain high concentrations of carbon dioxide at pressure, the cost of carbon removal from the atmosphere and its subsequent sequestration is significantly less than other routes. If there is a market for sequestered carbon dioxide, this option could be chosen when low biomass feedstock or liquid hydrocarbon prices occur. This second class of products would reduce price volatility of biomass and liquid hydrocarbons.

The majority of the required technologies are either commercial or at the demonstration stage of development. Replacing liquid fossil fuels and chemical feedstocks with drop-in nuclear-assisted biofuels avoids developing and commercialization of dozens of technologies to decarbonize an economy built on fossil fuels. In that context, large-scale nuclear bio-refineries have the potential to be the fastest route to decarbonize a large fraction of the U.S. economy.