

Biomass co-utilization with unconventional fossil fuels to advance
energy security and climate policy

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Chapter 1 Introduction

The energy supply chain that fuels our transportation system must be reengineered to reduce energy security risks caused by oil scarcity and climate risks caused by greenhouse gas (GHG) emissions. While some technologies, such as improvements in energy efficiency can address both risks at once, others, such as coal-to-liquids, would reduce oil consumption while increasing GHGs.

We can—and must—make rapid progress on the twin goals of energy and climate security. While there are many opportunities for synergy, it is naïve to imagine that hard trade-offs can be avoided. Wise policy must take these trade-offs seriously in order to find ways to advance both goals efficiently.

This report focuses on the opportunities to address climate and energy goals that arise from the development of unconventional fossil fuels, particularly liquid fuels from coal and from ultra-heavy petroleum, such as bitumen from Canadian oil sands. Specifically, we focus on how use of bio-energy might ease the trade-off between energy security and climate objectives in the development of unconventional fuels. Figure 1.1 provides a schematic illustration of these trade-offs.

The competitiveness of unconventional fossil fuels is increasing as a result of improvements in the technologies for producing gasoline and diesel from coal and ultra-heavy petroleum and from increasing long-run oil price expectations due to the growing scarcity of easily extracted conventional oil. While unconventional fossil fuels may be capable of increasing supply and shifting the geographical distribution of production away from politically unstable regions, advancing energy security objectives, they are also expected to substantially increase life cycle GHG emissions from liquid fuels¹.

Bio-energy development has been variously promoted as a petroleum substitute (via fuel switching or blending), a source of emissions offsets (if coupled with CO₂ capture and storage), and as a co-utilization option in unconventional liquid fuels production. Bio-energy development in any of these capacities could advance climate objectives. While there is a substantial body of research evaluating potential contributions from bio-energy development toward climate objectives, there is a lack of systems analysis required to understand the relative merits of alternate development pathways given the underlying uncertainties in factors such as feedstock supply chains, energy conversion systems, emissions accounting, land-use change, and infrastructure construction costs. Moreover, there is little systematic analysis of the potential for coupled development of bio-energy and unconventional fossil fuels or of the tradeoffs inherent to biomass' potential contributions to energy security and CO₂ mitigation.

¹ Life cycle accounting attempts to quantify emissions across all stages of the fuel's life cycle, which include in the case of conventional petroleum products, for example, extraction, crude transport, refining, fuels transport, and final combustion.

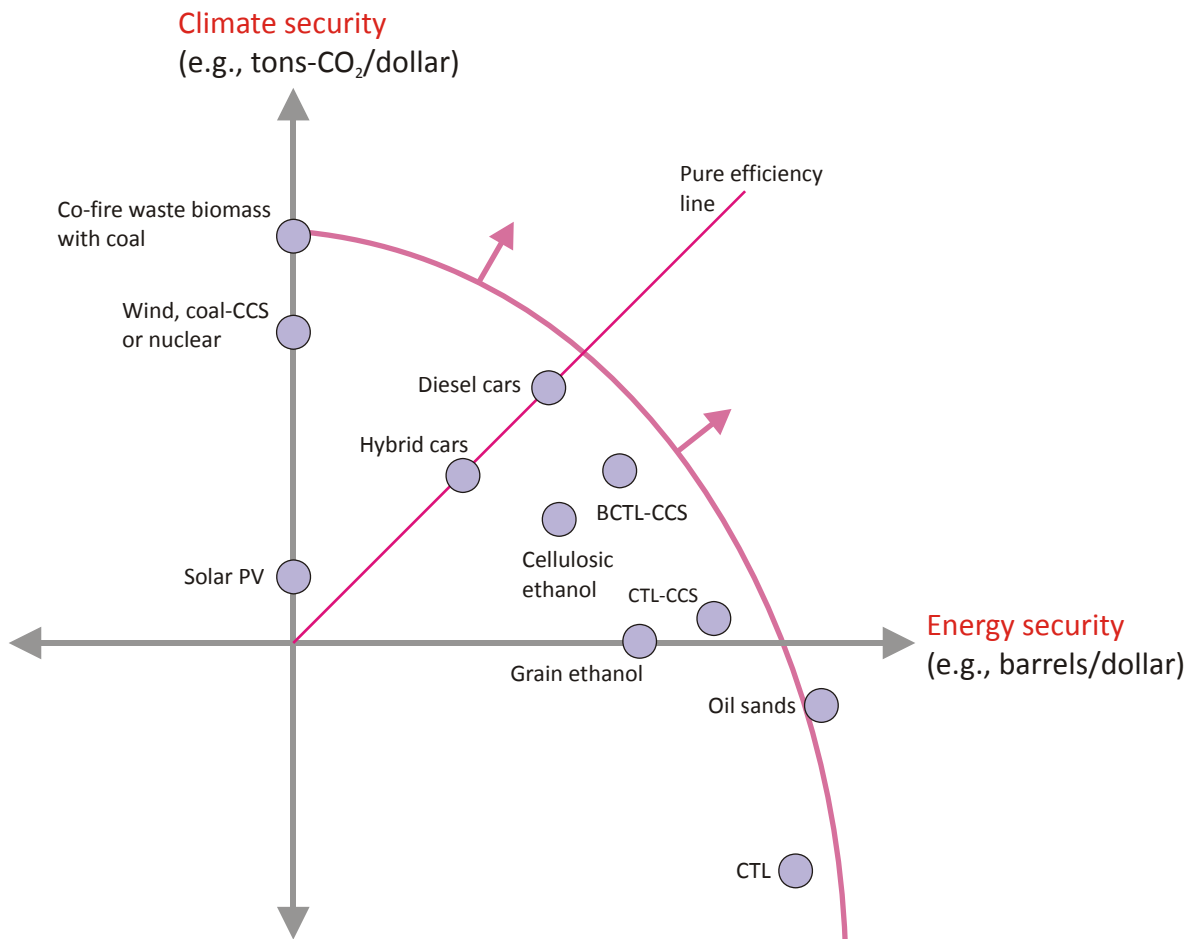


Figure 1.1. Schematic illustration of the trade-offs between climate and energy security. Points indicate our judgments of the relative performance of various energy technologies compared to the current energy-system average performance. The axes indicate the cost effectiveness with which a technology contributes to climate security (emissions reductions) or energy security (reduction in net imports to North America). Points represent the author's rough summary judgment of the comparisons between technologies given current prices, the individual placement of technologies is arguable, but the general fact of the security-climate tradeoff is robust. CTL is Coal-To-Liquids, BCTL is Biomass CTL co-production, and CCS is carbon capture. The most cost effective means of cutting emissions involve coal fired electricity and have no energy security benefit; conversely, unconventional fuels, among, the most cost effective ways to increase domestic fuel supplies increase carbon emissions. The central question addressed here is: where does biomass co-utilization in the production of unconventional fuels reduce the severity of these trade-offs, enabling us to push the curve outwards to the upper right?

In this context, we focus on two overarching questions that arise at the intersection of unconventional fuels and bio-energy. First, does the integration of bio-energy into unconventional fuel production represent a synergy that eases (though it cannot eliminate) the trade-offs between the energy security and climate risks of unconventional fuels? A closely related question is, does the co-utilization of bio-energy in unconventional fuel production represent an effective use of bio-energy resources? In this context, the effectiveness of bio-energy use is assessed in terms of its ability to reduce oil consumption and GHG emissions.

Second, does the integration of bio-energy into unconventional fuel production significantly increase the supply of unconventional fuels that might be available under emerging regulatory constraints on lifecycle GHG emissions?

The first question ignores the near-term realities of policy and asks how *can* unconventional fuels and bio-energy be efficiently deployed to address the twin challenges of energy and climate security, while the second question examines the emerging policy environment around unconventional fuels and asks, how *does* integration of bio-energy change the picture?

Of course where answers to the first and second questions diverge we suggest how policy might be adjusted to allow the transportation energy system to be more efficiently reshaped to meet the twin security and climate goals.

Chapter 2

Bio-energy systems

Summary

- Resource assessments indicate substantial quantities of biomass may be domestically available for energy applications, potentially as much as 20% of U.S. primary or 54% of U.S. petroleum energy consumption.
- The diffuse supply and low energy density of biomass make long-range transport difficult compared to fossil fuels. This implies that:
 - Feedstock markets will tend to be localized, decreasing market efficiency and so potentially raising costs; and
 - The ability to leverage economies of scale is feedstock limited in dedicated bio-energy facilities, decreasing conversion efficiencies and increasing costs relative to biomass co-utilization facilities.
- High variability in biomass fuel characteristics suggests that:
 - Feedstock markets may be further localized and fragmented; and
 - Technological constraints may limit usable biomass supplies to substantially lower quantities than current assessments indicate.
- Lifecycle emissions from bio-energy are variable, uncertain, and controversial.
 - Emissions from biomass supply appear to be lowest for waste streams and appear lower for cellulosic crops than for grain crops;
 - Clear accounting rules will help provide consistency across emissions estimates, but cannot resolve substantial underlying uncertainties.

Bio-energy may be used to advance public policy objectives associated with both energy security and climate change. The magnitude of potential contributions to each of these objectives and the performance relative to conventional fossil fuel alternatives varies dramatically across alternate bio-energy systems. Therefore, understanding the extent of bio-energy's potential role in advancing key policy objectives—in stand-alone applications, or via co-utilization with fossil fuels—demands systematic evaluation of the entire supply chain for each system contemplated.

These issues have been evaluated elsewhere for a wide set of potential system designs, results of which have been well summarized in several recent reviews [1-5]. The challenge for policymakers is that decisions driving bio-energy development are being made day-by-day, while many technologies have not yet been deployed at large scale and technological developments continue. As a result, substantial uncertainty exists in all evaluations of biofuel effectiveness in advancing energy security or climate objectives. Our aim is to present some simple underlying factors that transcend the specific cases analyzed and which ought to shape long-run policy decisions about bioenergy. In particular, our discussion highlights several key issues and provides representative estimates for system parameters that are believed to be most relevant for understanding opportunities for biomass co-utilization with unconventional fossil fuels in thermo-chemical energy conversion systems.

2.1. Feedstock supply

Biomass is variously defined in the literature, but all definitions reflect the notion that biomass resources embody stored solar energy and atmospheric carbon (recently) fixed via photosynthesis. As a result, “biomass” feedstock encompasses a broad range of organic materials including: woody, herbaceous, and algal energy crops; woody and herbaceous residues; food crops (e.g., starch, oil seed, and sugar crops); municipal solid wastes; oils and grease residues; and animal wastes (e.g., manure). Without prejudice to the relative merits of potential feedstock-specific market niches, this analysis is limited to woody and herbaceous energy crops and residues, as these are the sources that have the largest near-term availability, the lowest energy inputs to production, and are the most suitable for thermo-chemical transformations typically associated with unconventional fuels.

The cost, availability, and impacts of supplying biomass feedstocks are the subject of a large and rapidly growing body of research. Despite the rapid accumulation of knowledge, significant uncertainty remains and there are very widely divergent expert views about the feasibility and cost of large-scale use of biofuels as well as about the social and environmental consequences of substantial increases in biofuels production.

2.1.1. Feedstock distribution

Biomass production is necessarily limited by diffuse solar energy input. Production is further constrained by infrastructure availability and by competition for land, water, and other inputs to agricultural production, the direct and indirect consequences of which are only just beginning to be fully appreciated [6, 7].

On the one hand, the distributed nature of biomass resources provides an energy security benefit relative to the greatly unequal and geographically concentrated distribution of fossil fuels. On the other hand, the mismatch between the diffuse nature of biomass resources and the requirements of industrial energy systems presents unavoidable challenges, related both to the economics of concentrating diffuse biomass feedstock for industrial use and to the environmental and social consequences of the large land requirements for industrial scale biomass production.

The technical challenges posed by diffuse feedstock supplies are greatly magnified by the relatively low bulk and energy densities of biomass (see Figure 2.1), which limit the distance biomass can be economically transported for energy conversion. This limits the ability of bio-energy systems to leverage economies of scale achievable in industrial energy systems. This in turn has compounding effects on the cost effectiveness of bio-energy products, relative to fossil fueled alternatives, due to (i) high output-specific capital costs, as a direct result of economies of scale, and (ii) low conversion efficiencies as more efficient technologies are often only economical at larger scales.

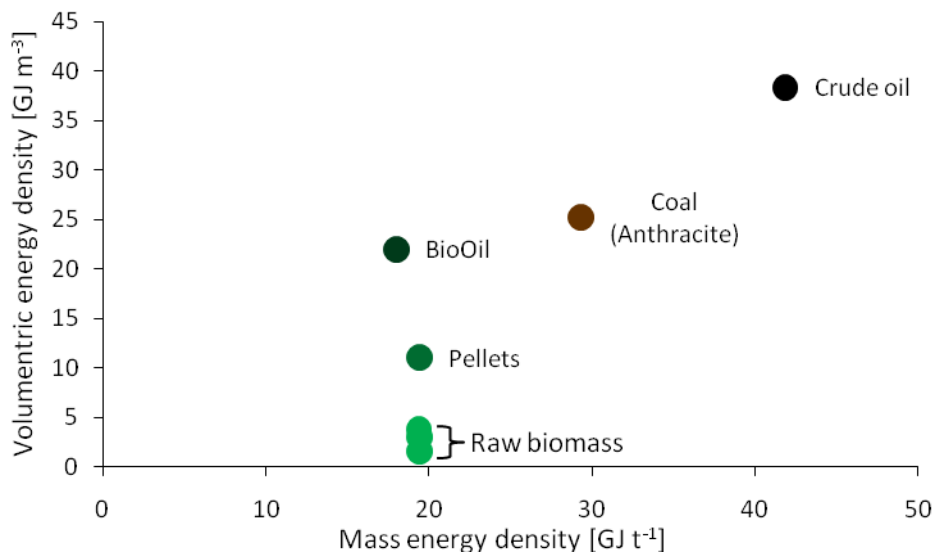


Figure 2.1. Volumetric versus mass energy densities of selected fuels and feedstock. Energy densities are plotted on a higher heating value, bone dry basis (except BioOil, which includes water in the non-aqueous phase); mass energy densities of raw biomass are 10 to 50% lower on a wet basis. Data are adapted from various sources including [8] and authors' judgment.

Another implication is that biomass supply chains will be more locally oriented than those of fossil fuels, compromising development of efficient markets. Demand will likely be monopolized, as conversion facilities are sited to minimize competition for available resources and associated feedstock prices, potentially increasing risks to feedstock suppliers. Localized supply may also magnify risks to conversion facility operators from weather, fire, or pest related supply shortfalls or disruptions. This may create attendant challenges for financing bio-energy

projects, which may require demonstrated available resources substantially in excess of facility design capacity.

At least three strategies exist for overcoming the challenges associated with feedstock distribution and energy density: waste utilization, densification and co-utilization. Waste utilization takes advantage of the biomass concentrated by other industrial processes, such as residues from milling activities. While such resources are attractive and potentially significant in quantity, their total supply is limited and subject to production constraints for associated primary industrial products. Additionally, such resources are often already utilized in process heat and power applications, albeit with relatively low efficiencies. Diverting these resources may induce fuel substitution effects, analogous to increasing natural gas demand with concomitant price increases. The implications of such effects have generally not been well resolved [1].

Feedstock densification, via pelletization or pyrolysis, represents a second strategy. Pelletization is a relatively mature technology, which has enabled international trade in biomass feedstock for industrial energy systems. For example, annual exports of biomass pellets from North America to the European Union are expected to exceed 1.5 Mt [9]. Pelletization is a relatively simple mechanical process, involving the extrusion of ground biomass under pressure. In contrast, pyrolysis (particularly “fast pyrolysis”) is a thermo-chemical process involving rapid heating and subsequent cooling of biomass to yield a mixture of light (gaseous) hydrocarbons, heavier (liquid) hydrocarbons, char, and water. Some combination of these products is typically burned to provide process heat and power. If it is not burned for this purpose, several potential applications exist for residual char, including as an energy feedstock, a source of activated carbon for industrial processes, or as a soil amendment with both productivity and soil carbon sequestration benefits (see Section 2.2).

These densification options substantially increase the energy density of biomass (see Figure 2.1) and may provide advantages for biomass handling and downstream use. For example, both of these methods appear to roughly double the effective energy capacity of truck-based transport. And pyrolysis oil handling infrastructure may be substantially simpler to install and operate than required for raw biomass [8]. They may also enable more cost effective modes of long-range transport, such as via dedicated pipelines, although additional analysis and subscale testing is required to resolve the feasibility of such options.

Biomass co-utilization in fossil fuel conversion facilities represents a third strategy for overcoming the challenges of feedstock distribution and energy density. In co-utilization systems, locally available biomass feedstock is substituted for fossil fuel inputs. Co-utilization enables bio-energy to achieve economies of scale and conversion efficiencies typical of fossil fuel applications at relatively low costs. In many cases, specific design decisions can enable increased fossil fuel utilization to offset any shortfalls or disruptions in biomass supply, minimizing risks from immature biomass feedstock markets and enabling efficient capital utilization. Moreover, retrofit applications can effectively leverage installed capital, dramatically reducing the marginal capital intensity of biomass co-utilization projects.

Each of these three strategies is capable of providing certain benefits, which can also be combined through their joint deployment. Nevertheless, they do not provide a general solution to the inherent challenges of biomass distribution and energy density.

2.1.2. Fuel characteristics

From a fuels perspective, woody and herbaceous feedstocks—the only biomass types considered here—share many similarities with low rank coals, enabling their use in many conversion technologies originally developed for coal. Two characteristics of biomass fuels, however, warrant some additional discussion here: their high moisture and mix of inorganic constituents.

Raw biomass typically contains up to 50% moisture by mass, compared with ~10% for many types of coal. High moisture content makes it harder to extract the fuel's energy in combustion applications, yielding energy losses proportional to moisture content. Fuel moisture's impact on gasification-based liquid fuels production systems is somewhat less clear, however, because steam is required for processing steps downstream from the gasifier. Elevated moisture content will lower the efficiency of gasification, but will also reduce steam production requirements. Therefore, the impact of biomass moisture may be low at the margin for gasification systems co-feeding biomass. Likewise, slurry-fed applications substituting pyrolysis oil for a fraction of slurry water should not experience significant efficiency reductions. The moisture content of raw biomass can often be substantially reduced by air drying; alternatively, feedstock drying can be incorporated as a pretreatment process in thermo-chemical applications, with additional costs and potential efficiency penalties.

Inorganic content of biomass feedstock, including ash, alkali, and chlorine, can be concerns in thermo-chemical applications due to potential slagging, fouling, corrosion, and bed agglomeration problems. Therefore, while biomass is a relatively “clean” fuel from the perspective of sulfur and mercury, which are of particular concern for coal, some of its inorganic constituents make biomass harder to use in thermo-chemical applications. These concerns may be particularly acute for feedstock with high or variable inorganic compositions, which is often typical for herbaceous feedstock, as illustrated in Figure 2.2. Long-term commercial scale tests of biomass co-fire in pulverized coal boilers and commercial co-gasification of biomass with coal suggest that these issues are generally manageable with judicious selection of feedstock and operating conditions [10, 11]; however, they may impose operational constraints and increase costs.

For example, while biomass can be utilized in a diverse set of energy conversion technologies, feedstock suitability to any particular conversion system configuration may vary dramatically by feedstock type. Moreover, certain system design decisions may anticipate feedstock parameters associated with particular feedstock supplies. As a result, capital investments in energy conversion systems may have some degree of feedstock specificity. Note that while the examples discussed above are specific to thermo-chemical applications, analogous issues (e.g.,

the variable recalcitrance of cellulose by feedstock type²) support similar conclusions for biological conversion systems.

For these reasons, biomass fuel characteristics and their variability tend to make biomass feedstock less attractive than it may appear based on energy content alone.

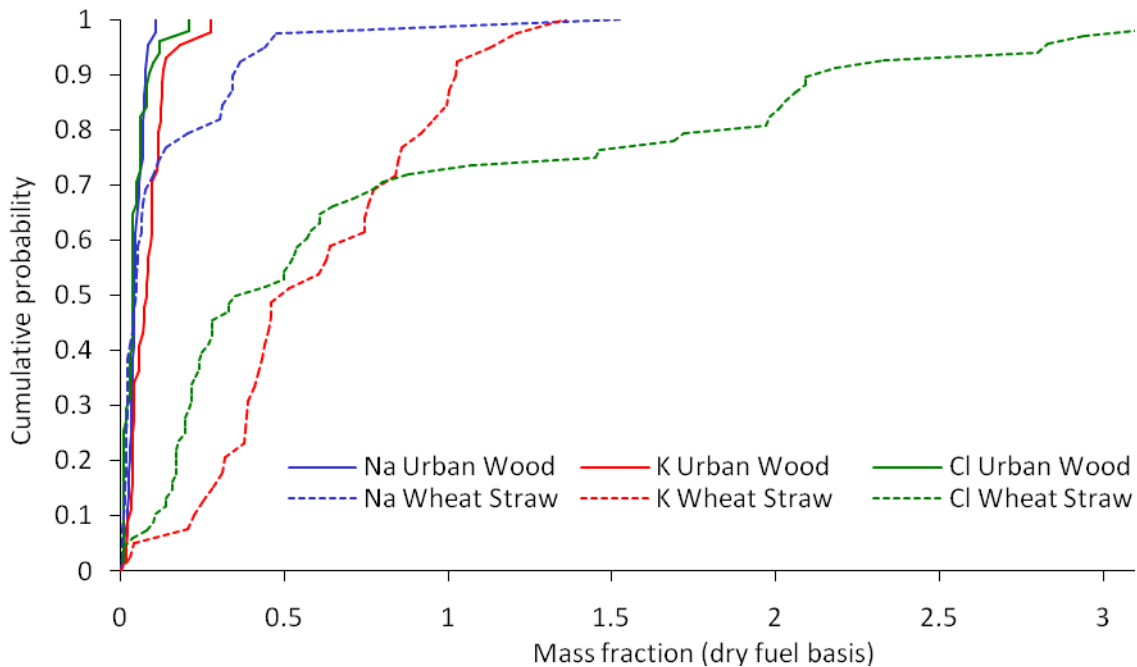


Figure 2.2. Empirical distributions of chlorine (“Cl”), sodium (“Na”), and potassium (“K”) contents in urban wood waste and wheat straw. Underlying data are adapted from an independently published database with a large number of feedstock samples [12].

2.1.3. Biomass feedstock supply estimates

Recent analyses have substantially advanced both the geographic scope and resolution of biomass supply estimates. Despite these advances, significant uncertainty remains regarding potential quantities, delivered costs, and broader social, economic, and environmental consequences of industrial biomass supply. Assessment of these issues is beyond the scope of this analysis. Instead, the focus here is on providing a sense of the potential quantities of biomass that could be available, so as to understand the relative scope of potential contributions from co-utilization. Within that context, it is relevant to consider biomass feedstock supplies that could be made available for co-utilization in CTL production in the contiguous U.S and synthetic crude oil (“SCO”) production from Canadian oil sands

² In this context, recalcitrance refers to the difficulty in making cellulosic constituents of biomass accessible to biological organisms, which is required for fermentation.

Biomass for co-utilization in CTL production. Absent a scale-up in biomass densification activities, feedstock supply chains for use in FT liquids production are expected to be locally oriented. Several analyses of biomass co-utilization in CTL have evaluated feedstock supply in detail for specific locations [13, 14]. Their results may be applicable on a broader regional basis. Similarly, analyses of potential feedstock supplies for large-scale bio-energy conversion facilities appear to be applicable for many potential CBTL facility locations.

In addition to these project-level assessments, several studies have developed biomass supply curves at various levels of geographic aggregation [15-18]. These assessments indicate potentially large resource bases and reveal certain patterns regarding biomass distribution by feedstock type—large endowments of woody biomass in the southeast and northwest, and large endowments of agricultural residues in the mid-western states and California, for example. These assessments are useful in understanding the ranges of potential feedstock supplies and prices, which are at least implicitly reflected in assumptions underlying the techno-economic analyses reported below. However, substantial uncertainty remains regarding both quantities and prices reflected in these supply curves. This uncertainty is partially due to the complex policy incentives affecting agricultural production and is unlikely to be resolved without deployment of large scale ligno-cellulosic bio-energy systems support competitive markets for biomass supply.

In a recent joint analysis, the U.S. Departments of Agriculture and Energy estimated that a total of approximately 1.1 Gt (dry) biomass could be made available annually in the contiguous United States for bio-energy purposes by 2050 without impacting agricultural production for food and fiber [19]. This is equivalent to roughly 20% of U.S. primary energy consumption or 54% of U.S. petroleum consumption, assuming a heating value of 18 MJ kg^{-1} [20]. This estimate is subject to significant uncertainty, reflected in ongoing debate regarding certain underlying assumptions (e.g., the fraction of agricultural residues that can be removed from the field without inducing increased erosion, soil degradation, or a need for increased chemical fertilization) [19, 21, 22]. That said, it appears to be the most widely endorsed estimate available for potential domestic biomass feedstock supply. Therefore, this value is used in estimating potential contributions from biomass co-utilization in CTL production. These results should be interpreted conservatively because the commercial viability and broader economic, social, and environmental implications of achieving this level of biomass resource utilization have not been evaluated.

Biomass for co-utilization in SCO production from oil sands. Canada generally has a large endowment of biomass resources. Some of this may be made available from land clearing activities associated with oil sands mining. Potential quantities of such overlying biomass remain to be evaluated, as does the proximity of bitumen extraction and upgrading facilities to more extensive biomass resources. In general, limited existing infrastructure combined with high labor and capital costs, which result from very large influxes of capital into oil sands producing regions, will likely provide significant challenges to the economic use of locally available biomass resources.

A 2003 Canadian biomass resource inventory provides some basis for developing a meaningful estimate of the biomass resource base that could be employed for co-utilization in SCO

production from Canadian oil sands [23]. Multiple Canadian government agencies have relied on this inventory as their primary source for biomass resource estimates in assessing the potential for bio-energy development in Canada [24, 25].

Based on the underlying data in the above mentioned inventory, we estimate that up to 58 dry Mt biomass could be available annually within the province of Alberta for co-utilization with SCO production³. Note that we focus on the province Alberta because this is where most of Canada's major oil sands deposits are located. This estimate is used to evaluate the magnitude of potential contributions from biomass co-utilization in SCO production in Section 3.3. However, this and all associated estimates should be interpreted very conservatively because (i) the value was developed using highly simplified assumptions (as discussed above), (ii) there remains substantial uncertainty regarding the quantity of residues that can be sustainably removed in agricultural and forestry activities (which affects all three resource categories above, as removal of forestry residues is included in the estimate of biomass potential from increased forestry activities), and (iii) this estimate ignores constraints from the commercial viability of supply as well as broader economic, social, and environmental implications of entraining these potential resources.

In addition, substantial wood could be made available from forestry activities aimed at improving forest health by removing timber damaged by pine beetle infestation. While this may prove to provide substantial quantities of biomass feedstock, it does not represent a sustainable resource base over the long term, so no characterization of its potential contributions to biomass co-utilization in SCO production are developed here. The potential also exists for biomass to be imported from other provinces (via feedstock densification) for co-utilization in SCO production. No attempt has been made to characterize this potential.

³ Up to 86 Mt per year of (dry) forestry residues are available across Canada for bio-energy utilization and approximately 12% of the annual allowable cut in the Province of Alberta. Assuming forest residue production is distributed in proportion with the annual allowable cut suggests that roughly 10 dry Mt per year of forestry residues could be available for bio-energy applications in the province.

Approximately 0.16% of Alberta's 25.7 Mha of Timber Productive Forest ("TPF") is harvested annually, compared with up to 2% in other provinces. Assuming (very simplistically) that (i) 1.5% of each province's total TPF can be harvested annually in a sustainable manner, and (ii) that the forest density of harvested and non-harvested TPF are similar, then Alberta's ~3.25 Gt (dry) biomass in its TPF could provide approximately 43 dry Mt biomass annually.

Approximately 17 Mt per year of (dry) crop residues are currently available for bio-energy applications across Canada, and approximately 27% of cropland is located in the Province of Alberta. Assuming crop residues are distributed in proportion to cropland implies that 4.6 Mt per year of (dry) crop residues are currently available in the province.

2.1.4. Greenhouse gas emissions from biomass feedstock supply

Bio-energy systems can reduce anthropogenic CO₂ emissions when the carbon released in energy conversion is balanced by the uptake of atmospheric CO₂ as the feedstock is grown. Biomass production and use can, however, produce GHG emissions from a variety of direct and indirect sources that will be supply chain specific. This variability will need to be addressed in relevant policy frameworks to facilitate efficient emissions reductions. While precise lifecycle estimates are—and will likely remain—uncertain and disputed, creating additional policy challenges, some general conclusions can be drawn. Biomass waste and residue streams with minimal sorting, cleaning, and drying requirements will generally have low embodied emissions. Emissions embodied in energy crops will be more supply chain dependent, as discussed above, and will hinge more crucially on policy decisions yet to be made. Emissions associated with production of trees and perennial crops are, however, likely to be far lower than those associated with production of grains such as corn or wheat.

Alternate feedstock types have dramatically different emissions profiles. Certain residues, for example, can be viewed as having negative net emissions when used in energy systems, if they would otherwise be degraded via methane-emitting bacteria. In contrast, energy crops typically induce direct emissions from fertilizer production, volatilization of applied fertilizers in the form of N₂O (a potent GHG), cultivation, harvest, and transport activities. The magnitude of these emissions is dependent on energy crop type and management practices, which generally depend on site-specific characteristics. This yields a large variance in potential lifecycle emissions profiles across alternate biomass supply chains, with attendant challenges for climate policy development and implementation.

Land use change induced by energy crop production can produce direct and indirect emissions. Direct emissions can arise from changes in above ground carbon stocks and soil carbon content resulting from energy crop introduction. This can yield emissions that are net positive or negative, depending on prior land uses, energy crop type, and associated management practices. Low intensity production of perennial crops on severely degraded lands can support soil carbon accumulation, whereas high intensity production of annual crops on previously unmanaged lands can yield substantial soil carbon depletion [7]. As a result, direct land use change emissions are both feedstock type and site specific.

Indirect land use change emissions arise from changes in soil carbon and standing biomass induced by market effects of biomass production. It has been effectively argued, for example, that: increasing diversion of U.S. corn production for biofuels applications puts upward pressure on world prices for agricultural commodities; resulting price increases drive conversion of pasture and unmanaged lands to agricultural production; and this market-induced, indirect land use change yields substantial net carbon emissions [6]. The manner and extent to which potential direct and indirect land use change emissions should be included in bio-energy GHG emissions accounting frameworks remains uncertain and highly controversial. Regulatory frameworks that account for potential emissions from indirect land use change will likely reduce the total quantities of economically viable biomass feedstock resources and shift the mix of feedstock away from energy crops on currently productive agricultural lands, where these effects are greatest.

2.2. Bio-energy conversion

Technologies for converting lignocellulosic feedstock into useful energy products have been the subject of substantial research and development, particularly since the energy shocks of the 1970's. More recently, a confluence of objectives—including energy security, rural economic development, environmental sustainability, and anthropogenic climate change—has motivated accelerated research and development. As a result of this and substantial international development activities, a relatively broad set of technologies is either commercially viable in niche applications or is expected to be ready for full scale deployment within the next ten years. These technologies will be briefly characterized below, along with several outstanding issues limiting widespread deployment.

2.2.1. Conversion technologies

A large and diverse set of lignocellulosic energy conversion technologies exist today at various stages of development. At the highest level, they can be organized according to their principle energy conversion process: combustion; pyrolysis; gasification; and fermentation. Technologies within each of these categories will be discussed here in terms of their final energy products, stage of development, co-utilization opportunities, and ability to integrate carbon capture and storage (“CCS”) technologies. The latter of these, CCS integration potential, is relevant in the context of this analysis for two reasons. First, CCS integration is frequently considered in the context of CTL production. Second, CCS integration with bio-energy systems can enable generation of negative net carbon emissions as atmospheric carbon, fixed via photosynthesis, is captured during energy conversion and sequestered away from the atmosphere for geological timescales. Resulting negative emissions can be used to offset, and thereby indirectly mitigate, fossil fuel CO₂ emissions from conventional or unconventional sources.

Combustion. Combustion is the most mature energy conversion process for ligno-cellulosic feedstock. A wide variety of technological alternatives exist for stand alone (i.e., dedicated biomass) applications as well as several options for fossil fuel co-utilization. These alternatives are generally differentiated by the physical means for moving reactants and combustion products through the system. Stand alone systems have generally been deployed in market niches with very low cost feedstock (e.g., mill residues). Combustion enables biomass utilization for heat and power generation, with typical conversion efficiencies of 16-25% (HHV) for electricity generation [26, 27]. These relatively low efficiencies, compared with fossil fuel combustion systems, result, in part, from the relatively small scales of deployment, which compromises the commercial viability of high efficiency technologies.

Co-combustion of biomass with fossil fuels has been demonstrated at commercial scales with generally positive results. Such applications enable capital cost and conversion efficiency advantages similar to large scale fossil fuel systems. They can also provide marginal environmental benefits for fossil fuel combustion (e.g., reduced sulfur emissions).

As with dedicated fossil fuel combustion systems, CCS integration with biomass combustion could be achieved via either oxyfuel (combustion in pure oxygen) or post combustion capture (with amine or methanol solvents) routes. However, very large scale deployments or co-utilization with fossil fuels (also at large scales) would generally be required for such applications to be economically viable.

Pyrolysis. Pyrolysis generally involves volatilization of organic compounds by heating biomass in the absence of oxygen. Primary pyrolysis products are light (non-condensing) hydrocarbons, residual char, liquid hydrocarbons (pyrolysis oil), which typically includes aqueous and non-aqueous hydrocarbons, and water. Yield distributions for these various products depend, among other things, on the rate of biomass heating, the maximum temperature, the reactor residence time, and the rate and timing of subsequent cooling. A variant of the process, termed “flash pyrolysis”, is of particular interest due to its ability to maximize yields of liquid phase hydrocarbons and is the primary subject of pyrolysis discussions throughout this report.

Flash pyrolysis is generally characterized by rapid heating with very short reactor residence times (~2 seconds or less) followed by rapid quenching to limit gaseous phase reactions. Biomass particles must be relatively small to enable rapid heating, which is generally provided by burning some combination of light hydrocarbon products, residual char, and (fossil) natural gas. Pyrolysis oils can be burned in modified gas turbines or other combustion systems, converted to syngas via gasification, or upgraded into products similar to petroleum-based liquid fuels. Two concerns specific to pyrolysis oil usage are its low pH (~2.5) and the presence of fine char particles, which have proven difficult to remove from liquid phase products [28]. Flash pyrolysis is currently in the early stages of commercialization.

As described above, flash pyrolysis can be viewed mainly as a densification process yielding feedstock for subsequent combustion or gasification processes. Collection of pyrolysis oil from a distributed network of relatively small scale facilities can plausibly enable utilization of widely distributed biomass resources in a centralized facility where economies of scale can be better leveraged [29]. Alternatively, it can be viewed as an energy conversion process yielding feedstock for refining and blending with conventional and unconventional liquid fuels [30].

Co-utilization of biomass and fossil fuels is impractical in the context of the pyrolysis process itself. However, pyrolysis products could readily support co-utilization in downstream processing. For example, pyrolysis oils and chars could be co-combusted or co-gasified with fossil fuels [29, 30]. It’s plausible that such processes could yield technical benefits, as well. For example mixing pyrolysis oils with coal slurries could increase thermal capacity with limited marginal costs. Alternatively, oxyfuel CCS applications involve combustion of primary feedstock in pure oxygen, often with some combination of water or recycled CO₂ for temperature control. Pyrolysis oils typically contain relatively large quantities of both oxygen and water, suggesting potential synergies for co-utilization in oxy-fuel systems. Alternatively, pyrolysis oil refining could enable co-utilization in conventional liquid fuel applications [30].

CCS integration can be achieved by minimizing char combustion for process heating and reserving it for non-energy uses. One option that appears compatible with climate and broader

sustainability objectives is pyrolysis char application as a soil amendment. This would directly increase soil carbon content in a way that is strongly resistant to subsequent decay and benefit soil fertility [31]. Alternatively, char could be used to produce activated carbon and used, for example in Hg removal applications [28]. CCS could also be integrated with the combustion section of pyrolysis systems, however, the feasibility of such options will likely be limited by scale and other practical constraints.

Gasification. Gasification includes a variety of technological pathways for the thermo-chemical transformation of solids to gases. Efforts to date have primarily focused on gasification with oxygen, air, or steam. Resulting syngas primarily consists of H₂, CO, and CO₂. This can be used in high efficiency gas turbines for power generation, or converted to a variety of gaseous or liquid fuel products.

Oxygen blown gasification is typically limited to large scale deployments by the economies of scale inherent to oxygen production (e.g., air separation units). As a result, such technologies are generally limited to coal gasification, for which a variety of oxygen-blown technological options have been developed. One of the primary distinctions between alternate technologies is associated with the gasifier feed system. Specifically, feedstock is delivered to oxygen-blown gasifiers via either dry feed (e.g., Shell gasifier) or water slurry (e.g., ConocoPhillips' E-GasTM gasifier) systems.

Slurry fed systems are generally not compatible with biomass co-utilization due to efficiency penalties from potential water absorption into biomass feedstock; however, substitution of pyrolysis oil for a portion of slurry water may be viable. Oxygen-blown coal gasification and co-gasification with biomass dry feed systems is practiced commercially [11]. It is anticipated that CCS can be integrated with either of these oxygen-blown gasification technologies with feedstock carbon capture rates of around 90%.

Research and development on stand alone biomass gasification has focused on air and steam blown options. In the U.S., attention has become focused on two basic systems: high pressure, directly heated, systems with potential for air or oxygen-blown operation (e.g., IGT gasifier); and low pressure, indirectly heated, steam blown systems (e.g., BCL / FERCO gasifier). The former system yields relatively high pressure syngas diluted with atmospheric nitrogen, substantially reducing efficiency advantages inherent to gasification-based routes to CCS. In contrast, the indirectly heated system yields concentrated syngas at relatively low pressure, potentially requiring additional compression for downstream processing. While avoiding syngas dilution with nitrogen, the systems indirect heating results in substantial carbon emissions associated with the gasification process itself. Such emissions may result from biomass char combustion, and therefore arguably have limited climate impacts; however, they substantially reduce carbon available for potential CCS. Both of these technologies are expected to be capable of commercial deployments within the next ten years, given sufficient interim research and development.

Fermentation. Fermentation of starch/sugar-based crops has been commercialized in a variety of regions and contexts. While not yet commercially deployed, fermentation of lignocellulosic

feedstock has been the subject of substantial research and development and is approaching commercial readiness. The primary focus to date for such systems has been ethanol, although other alcohols and hydrocarbons are possible (e.g., butanol). Fermentation-based options are generally beyond the scope of the current analysis; however, they are relevant because ethanol will likely be blended with unconventional liquid fuels, as it is currently with petroleum based fuels, and can support CCS integration. CO₂ is readily available for capture from fermentation off-gases, as it is a byproduct of fermentation, and could also be captured during combustion (or gasification and combustion) of residual biomass for process heat and power.

2.2.2. Key issues for development

While a diverse set of alternatives exist for converting ligno-cellulosic feedstock into useful energy products, industrial deployments to date have been generally limited to niche applications, for example where very low cost feedstock is readily available. This is due to a number of key issues that together make bio-energy systems generally more costly than fossil alternatives. Several of these are briefly outlined below, particularly in their relation to capital and feedstock costs, which are important drivers of bio-energy product costs.

Beyond limited market niches, delivered biomass feedstock costs are expected to be 3-5 dollars per gigajoule [\$/GJ], or twice the cost of coal. The impact of this feedstock cost premium is magnified in producer costs of energy products by the relative low efficiency of bio-energy conversion.

Additional feedstock-related costs arise from considerations unique to biomass feedstock supply. These include: temporal variability; risks from potential weather, pest, or fire related shortfalls or disruptions; risks stemming from immature feedstock market development and insufficient logistics infrastructure.

Bio-energy conversion technologies are expected to be highly capital intensive. For example, the National Energy Modeling System (“NEMS”) assumes 50% greater specific capital costs (e.g., dollars per kW capacity) for new biomass power plants than for comparable coal plants [32]. An important driver for this, as discussed above, is the relative scales of deployment, which NEMS assumes to be 80 and 550 MW for new biomass and coal power plants, respectively. Feedstock supply represents a principle constraint for the feasibility of bio-energy deployments at scales comparable with fossil energy systems. A central question of this report is: to what extent can co-utilization reduce these cost barriers?

Chapter 3

Biomass co-utilization in unconventional fossil fuels production systems

Summary

- The scale of potential contributions from biomass toward energy and climate security objectives is substantial via dedicated biomass and co-utilization pathways to liquid fuels. Similar progress on climate objectives can be achieved via biomass utilization for electricity generation.
- Performance metrics defined on a biomass specific basis (e.g., emissions benefit per ton of biomass) are better tools for policy decisions than end-product specific metrics (e.g., emissions benefit per unit of fuel energy) because:
 - Liquid fuels and their emissions intensities are naturally blended in the tank or more generally in the atmosphere;
 - Fundamental constraints on biomass supply imply that inefficient utilization limit potential benefits of available resources, raising the importance of biomass utilization efficiency in policy decision making;
 - Biomass-specific metrics enable meaningful comparisons across multiple end products, such as electricity and fuels, and limit the confounding effects of market-specific price uncertainty.
- Among options for co-utilization in coal-to-liquids production, there is no clear winner between co-gasification, co-synthesis, and co-refining.
- Opportunities for direct biomass co-utilization in synthetic crude oil production from ultra-heavy petroleum (e.g., bitumen in Canadian oil sands) are technically limited and may be impractical; however, biofuel co-refining or blending and emissions offsetting (via biomass-CCS) represent potentially important mitigation options for synthetic crude oil production systems.
- Electricity production in biomass co-utilization systems with CCS have high biomass specific mitigation potentials, high offset production potentials, and potentially low biomass specific marginal mitigation costs, suggesting that it may be an economically dominant pathway to mitigation in both transportation and power sectors.

Unconventional fuels production from coal or ultra-heavy crude, such as that present in Canadian oil sands, may advance energy security objectives by enabling substitution of locally plentiful resources for conventional crude oil. While the raw material and process technologies are different, coal-to-liquids and oil sands share a similar niche in the energy system. Both turn low-cost feedstock into high-value liquid transportation fuels, both require large inputs of capital and have high operating costs, and in both cases the cost of the raw material—coal or bitumen-rich sands—is a small component of the overall cost of producing the fuel. Finally, both take a high-carbon fuel as input and produce a lower-carbon fuel along with relatively large energy requirements and carbon dioxide emissions. This characteristic in particular creates tension between unconventional fuels production, and the energy security objectives they might advance, and climate policy objectives that require reductions in CO₂ emissions over time.

Unconventional fuels production from biomass can advance energy security objectives, by providing substitutes for petroleum-derived fuels, and advance climate objectives by reducing fossil fuel utilization. Biomass co-utilization can enable unconventional fossil fuels production to leverage these benefits, potentially easing the tension between these policy objectives.

Biomass co-utilization yields emissions reductions via two mechanisms: feedstock substitution and emissions offsets. Reductions from feedstock substitution result because a fraction of CO₂ emissions (from feedstock processing, combustion of finished energy products, or both) are derived from biomass rather than coal. Note that this effect exists generally for bio-energy systems that provide fossil fuel substitutes and thereby displace fossil fuel consumption. Co-utilization systems with CCS can yield additional reductions from emissions offsets by applying net negative atmospheric carbon emissions (that result when atmospheric carbon, fixed in biomass via photosynthesis, is captured during energy conversion and sequestered away from the atmosphere for geologic timescales) against net positive emissions from fossil fuel utilization. Potential contributions from this mechanism are particularly relevant in the context of biomass co-utilization in CTL applications because CCS is often assumed to be integrated with future CTL deployments.

3.1. Opportunities for biomass co-utilization in unconventional fossil fuel production

A variety of opportunities exist for co-utilization of biomass feedstock in unconventional fuels production, as illustrated in Figures 3.1 and 3.2. Summary descriptions of each opportunity and some of their basic merits are provided below.

3.1.1. Co-utilization options in CTL production

There are three broad routes to turning coal into synthetic liquid fuels. The first, and most important, is gasification followed by the production of Fisher Tropsch (FT) liquids. The second is gasification followed by methanol production and then by methanol-to-gasoline (MTG) processing. The third is direct liquefaction by hydrogenation of solid coal. We will ignore direct liquefaction in this report, as it seems unlikely to be relevant in US markets in the near term, although there are significant direct liquefaction projects in China. While FT processes are the

most important worldwide, MTG may be particularly important in the North American market where gasoline demand is relatively high compared to other liquid fuels such as diesel and kerosene.

As depicted in Figure 3.1, the fuel cycle for CTL can be divided into four basic processes: gasification, synthesis, refining, and combustion. Each of these processes can support biomass co-utilization.

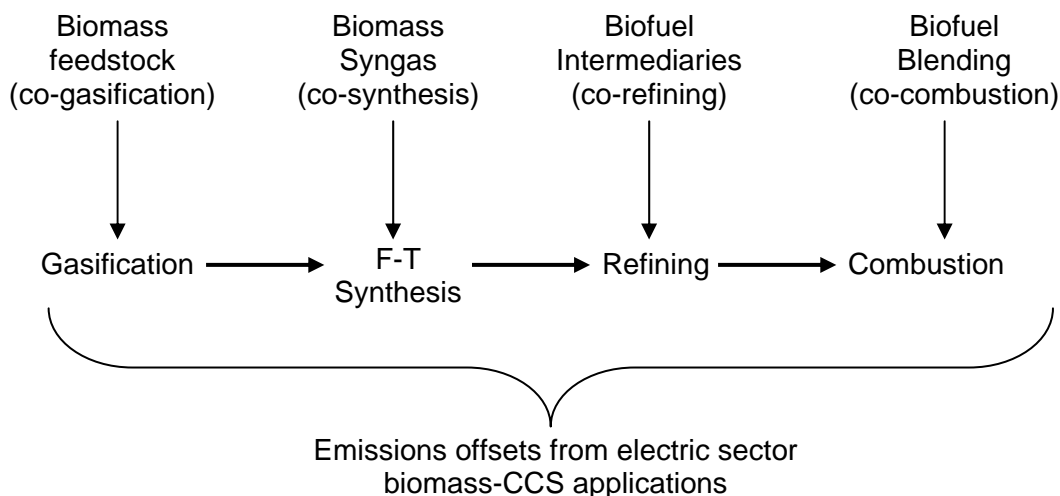


Figure 3.1. Biomass co-utilization opportunities in the CTL fuel cycle.

Co-gasification. Co-gasification is feasible using dry feed gasifiers (e.g., the Shell gasifier). It is currently practiced commercially at the Buggenum facility in the Netherlands, and resulting operational experience suggests that it is a feasible approach for a relatively wide variety of biomass feedstock types. This experience has been used, among other things, to justify assumptions in a number of published technical studies regarding this concept. Co-gasification may be achieved via biomass-coal co-feeding or via dedicated, feedstock-specific feed systems; however, a number of challenges with feeding biomass into pressurized gasifiers have been documented (principally as a result of its fibrous nature), and some additional research will likely be required to verify that these challenges can be overcome for specific system configurations. Alternatively, it may be possible to co-gasify pyrolysis oils or chars in slurry-fed gasifiers (e.g., the E-GasTM gasifier). There is, however, little or no operational experience or technical analysis of this approach.

The principle advantages and disadvantages of co-gasification both stem from its leverage of the installed capital of the coal gasifier. On the one hand, this leverage should provide substantial capital cost advantages relative to other co-utilization options by leveraging economies of scale inherent to coal gasifiers [33]. On the other hand, co-gasification may present certain challenges for feedstock-specific optimization of gasifier operations, and any operational problems resulting from biomass feedstock characteristics put the entire installed base—both capital and operational capacity—at risk. It has also been noted that co-gasification would remove the potential to utilize biomass char residues as a soil amendment for nutrient recycling [33].

Co-synthesis. A closely related alternative to co-gasification is co-synthesis of syngas derived from fossil and biomass feedstock. In such systems, syngas entering FT synthesis reactors, or methanation reactors in the case of MTG, would be blended from multiple feedstock-specific gasifiers. It is possible that co-synthesis might be particularly efficient for the MTG route in cases where biomass gasifiers produce methanol rich syngas. In the FT case blending would more likely be implemented upstream of any pre-synthesis syngas conditioning, including steam reforming and shift reactors, to ensure appropriate composition of the syngas entering the synthesis reactors. Some feedstock-specific cleanup or conditioning may still be required (e.g., tar removal from biomass derived syngas). However, a configuration in which feedstock specific gasification is accomplished in series with biomass-derived syngas flowing through the coal gasifiers, may remove the need for separate tar processing. Both of these configurations have been described and their relative merits evaluated in the technical literature [33].

Co-synthesis configurations would likely have high capital costs, relative to co-gasification configurations, but lower risks to operational capacity and installed capital from biomass-specific problems in gasification. Concern for these potential risks of co-gasification may tip the balance toward co-synthesis in the near to medium term.

Co-refining. Biomass integration by co-refining is most relevant for FT liquids where significant refining is required to convert FT liquids to final products and less relevant for the MTG route, where the analogue would be co-conversion of methanol derived from biomass and fossil feedstock. Co-refining could be practiced in new FT-dedicated refineries or in existing, petroleum based, refineries with minor modifications [30]. In either scenario, it seems reasonable to assume that biomass-derived FT liquids could be readily blended and refined with coal-derived FT liquids, as the compositions of these hydrocarbons should be principally determined by the FT synthesis process rather than by the original feedstock type.

The refining step offers the opportunity to introduce other biofuels. For example, hydrotreating with subsequent hydro-cracking has been proposed as a potentially efficient means for upgrading non-aqueous fractions of pyrolysis oils for use as gasoline blending stock [30]. Results from a recent analysis suggest this might be achieved in conventional refineries, with certain modifications, where aqueous fractions of pyrolysis oils could be used to provide process heat or hydrogen for hydrotreating [30].

Co-refining has potential advantages relative to co-gasification and co-synthesis from the flexibility inherent to decoupling biofuel and CTL production. Biofuels could therefore be produced where they are most cost effective and integrated into final energy products via refining processes. However, this decoupling also removes the potential for biomass to leverage the installed capacity of CTL facilities, raising producer costs as a function of economies of scale. As such, this approach is generally similar to pursuing biofuels development on a stand-alone basis.

Co-combustion. In this context, co-combustion is equivalent to fuel blending, which is currently the dominant means of biomass co-utilization (via ethanol blending). The concept is raised here

to highlight that this is likely the most straightforward approach to biomass co-utilization with unconventional fossil fuels. As with co-refining, this option is generally similar to biofuels development on a stand alone basis.

Emissions offsets. Emissions reductions from biomass co-utilization in systems without CCS evolve only from feedstock substitution. This can yield significant emissions reductions relative to coal-only FT liquids production, but because CTL products are expected to have carbon intensities⁴ roughly twice those of petroleum derived analogues, CTL production (without CCS) will necessarily increase fuel carbon intensities unless very high biomass co-utilization rates can be achieved. However, results from several published studies suggest that CCS integration with CTL production can reduce life-cycle emissions to levels comparable with petroleum derived fuels (see Section 3.2). In this context, biomass co-utilization could enable CTL production with emission intensities significantly below those of petroleum-derived analogues due to the joint effects of fuel substitution and emissions offsets. This “double benefit” provides a substantial increase in the amount of carbon mitigation achievable per unit biomass [$\text{kgC}_{\text{eq}} \text{GJ}_{\text{biomass}}^{-1}$].

Analyses of biomass co-utilization in CTL production with CCS generally apply internally-generated emissions offsets to the associated liquid fuel products. While this accounting is reasonable, it is also somewhat arbitrary, particularly when fuels are produced with electricity or other co-products in an integrated refinery. Notwithstanding the fact that a real and non-arbitrary amount of negative emissions are produced when the carbon content of sustainably harvested biomass is captured and stored underground, the allocation of these negative emissions to specific products is necessarily arbitrary. This distinction is crucial because it bears directly on two central questions addressed by this report, the effectiveness of co-utilization at (1) meeting the twin goals of energy and climate security; and, (2) at enabling greater use of unconventional fuels under lifecycle accounting frameworks, including those specified under the California Low Carbon Fuels Standard.

Allocation of negative emissions from biomass-CCS in CTL to resulting fuels raises the potential for the allocation of biomass-CCS emissions offsets generated elsewhere in the economy. For example, offsets from electric sector biomass applications with CCS could be used to mitigate emission from CTL production or combustion. Such co-utilization strategies effectively decouple biomass supply and conversion from CTL production, providing additional flexibility in deploying low carbon production systems. Moreover, because substitution effects of this strategy would occur in the electric sector, where GHG intensities are generally higher (from high coal utilization), this strategy may be capable of significantly increasing the mitigation potential of available biomass [$\text{kgC}_{\text{eq}} \text{GJ}_{\text{biomass}}^{-1}$].

3.1.2. Biomass co-utilization options in SCO production

As depicted in Figure 3.2, the fuel cycle for synthetic crude oil (SCO) from oil sands can be divided into four basic processes: extraction, upgrading, refining, and combustion. Each of these processes can support biomass co-utilization, as summarized below.

⁴ Carbon intensity here refers to life-cycle, energy specific GHG emissions [$\text{kgC}_{\text{eq}} \text{GJ}_{\text{fuel}}^{-1}$].

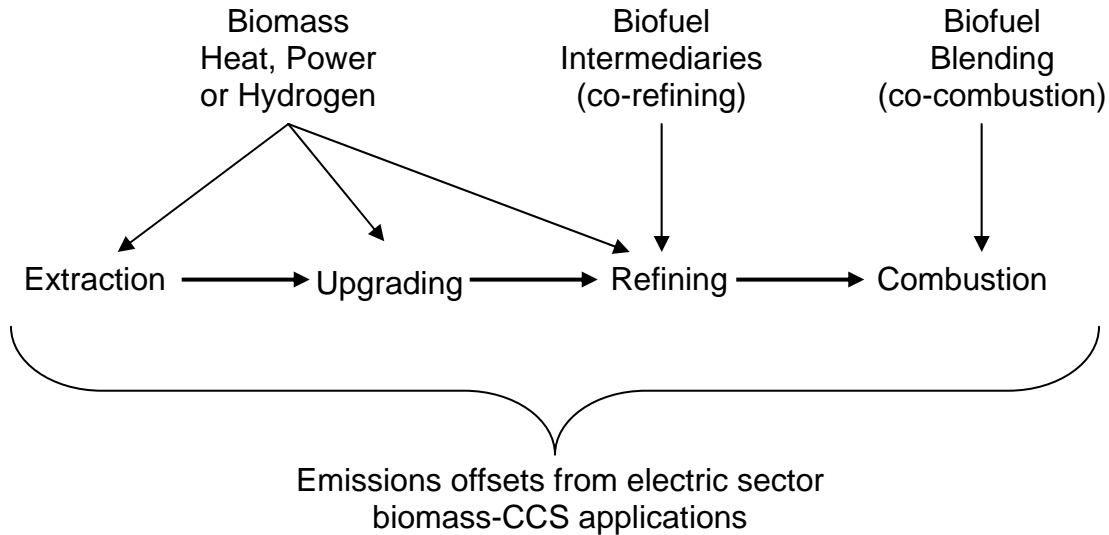


Figure 3.2. Biomass co-utilization opportunities in the fuel cycle of SCO from oil sands.

Extraction. SCO production starts with bitumen extraction either by surface mining with subsequent water-based processing; or by in situ extraction. Detailed explanation of these processes is available in the literature [34].

Extraction by surface mining starts with removal of bitumen-containing oil sands in large open-pit mines. The oil sand is then transported (generally via water slurry pumping) to a primary separation facility, the resulting bitumen is either upgraded on site in so called integrated mining operations or blended with a diluent to enable pipeline transport to offsite upgrading facilities. Large quantities of residual sand and waste water from the extraction process require subsequent disposal.

There are many in situ extraction technologies, all of which act to lower the bitumen viscosity enabling it to flow into production wells. Almost all current production uses steam injection to provide heat that enables extraction, and in almost all cases the steam comes from natural gas fired boilers or cogeneration facilities. Natural gas energy equivalent to approximately 16% of that in the product bitumen is typically burned for this purpose [35]. Other extraction technologies include in situ combustion of the bitumen to heat surrounding reserves and use of solvents such as butane in “vapor extraction” to lower viscosity without (or with less) external heat inputs. Bitumen extracted via in situ methods can be upgraded on site in integrated facilities, but is typically blended with a diluent to facilitate pipeline transport to offsite upgrading or refining facilities.

Both mining and in situ extraction options have significant heat and power requirements that are currently met with fossil fuels. These requirements might be met instead with biomass combustion systems, reducing CO₂ emissions. The magnitude of potential reductions from this mode of co-utilization is greatest for steam-based in situ options due to the large heat requirements of steam generation. Biomass combustion systems required for such applications are relatively mature technologies. Capital costs for such systems would generally be substantially higher than for the natural gas systems they would replace. Biomass feedstock

costs for such applications are highly uncertain, but could arguably be made relatively stable compared with natural gas.

Implementation of biomass co-utilization in extraction will likely be limited by feedstock availability and by the relatively high construction costs in the oil sands region which are driven by the rapid pace of growth. Some quantity of biomass feedstock may be available in close proximity to extraction facilities; however, supplemental feedstock will need to be imported to make a major impact, with all the logistical challenges that arise from long-distance biomass transport.

The effect of these challenges may be limited if pipeline transport of biomass pellet slurries or pyrolysis oils is feasible. This could spread investments in biomass production over a larger geographic area and enable biomass delivery by methods analogous to existing natural gas delivery systems. Use of pyrolysis oils could also enable onsite energy conversion in technologies similar to existing natural gas systems. In some cases, existing conversion systems could plausibly be adapted to burn pyrolysis oil with only minor modification. We judge that these advantages make pipeline transport of either pellet slurries or pyrolysis oils the most likely targets for biomass co-utilization in bitumen extraction. As such, co-utilization of pyrolysis oils is the focus of analysis in Section 3.2.

Upgrading. Bitumen can be sold in a raw form or upgraded to SCO for use as refinery feedstock. Upgrading generally consists of some combination of coking and hydrotreating, which both serve to increase hydrogen to carbon ratios. Coking removes carbon (via coke production), whereas hydrotreating adds hydrogen. Natural gas is typically used for generating both hydrogen and heat for upgrading processes.

Biomass co-utilization could be achieved in upgrading facilities by incorporating biomass derived heat and hydrogen. Commercially available biomass combustion technologies could be used to meet heat requirements, and several technologies have been considered for producing hydrogen from biomass. Alternatively, as oil sands operators move to gasify residual fuels (e.g., coke or asphaltenes) it may be feasible to co-feed biomass into the gasifiers allowing relatively low risk and efficient co-utilization. Nexen's Long-Lake project, the first large-scale project to use gasification (of asphaltenes) is just now (spring 2009) starting up production.

In addition to providing heat and hydrogen inputs, it may be possible to blend certain biofuel intermediaries with bitumen (or partially upgraded bitumen) for co-upgrading. Potential options for pyrolysis oil utilization in conventional refineries are discussed above. While the referenced study focused on integration with conventional refinery operations, it seems plausible to think that analogous approaches could enable pyrolysis oil use in bitumen upgrading, although substantial further analysis is required to understand the relative merits of this option. Unlike options for biomass utilization for heat and power discussed above, co-upgrading would enable biomass feedstock to displace emissions from the bitumen itself, rather than from natural gas, increasing the mitigation potential of available biomass [$\text{kgC}_{\text{eq}} \text{GJ}_{\text{biomass}}^{-1}$].

While the opportunities for biomass co-utilization in upgrading may be significant, their deployment may be frustrated by (legitimate) operator concerns that any benefits of co-utilization will be offset by risks of downtime imposed on the whole operation. Upgrading facilities are complex and highly integrated with very high capital costs demanding high utilization for effective amortization. In this respect, using biomass to provide heat for in situ extraction may be substantially less challenging.

Co-refining, co-combustion, & emissions offsets. Biomass co-utilization could reduce the carbon intensity of SCO production via co-refining, co-combustion (i.e., fuel blending), or emissions offsets. Assuming that refining and fuel blending activities are managed downstream from bitumen upgrading, these co-utilization options are expected to be similar to those discussed above in relation to CTL. On that basis, no additional discussion is provided here.

3.2. Potential performance

Rather than developing new engineering economic analyses of biomass co-utilization in unconventional fuels production, a task beyond the scope of this report, we have synthesized work from a variety of published analyses in order to calculate performance metrics that illuminate the two policy-driven questions about trade-offs between energy security and climate risk that shape this report. Given the substantial technical uncertainties and analytical inconsistencies in the underlying reports, results presented here are more robust as relative indicators of potential performance than as absolute performance metrics.

Performance expectations are defined here in terms of: (i) producer cost of liquid fuels [$\$ \text{GJ}_{\text{fuel}}^{-1}$]; (ii) GHG intensity of liquid fuels [$\text{kgC}_{\text{eq}} \text{GJ}_{\text{fuel}}^{-1}$]; (iii) mitigation costs [$\$ \text{tC}_{\text{eq}}^{-1}$]; (iv) biofuel yield [$\text{GJ}_{\text{biofuel}} \text{GJ}_{\text{biomass}}^{-1}$]; and (v) mitigation potential of biomass resources [$\text{kgC}_{\text{eq}} \text{GJ}_{\text{biomass}}^{-1}$]. The producer cost of liquid fuels represents the market price at the plant gate that the producer must receive to cover all costs of production and provide requisite returns to equity investors and lenders. Unless otherwise specified, producer costs are adapted from the original literature without normalizing financial parameters (e.g., costs of capital, debt to equity ratios, and amortization periods).

GHG intensity represents net GHG emissions per unit fuel energy computed on a life-cycle basis. It is computed as the sum of atmospheric fossil emissions minus sequestered biomass carbon (offsets). Emissions accounting assumptions have generally been retained from the original literature, but the methodology for emissions allocation across multiple product streams has not. Multiple accounting methodologies exist for such allocations ; the appropriateness of each depends on the context of the analysis.

Many techno-economic analyses of unconventional fuels production account for emissions effects of electricity co-production by defining an emissions credit equal to the product of electricity production [$\text{MWh} \text{GJ}_{\text{fuel}}^{-1}$] and an emissions factor equivalent to the emissions intensity of displaced electricity generation [$\text{kgC}_{\text{eq}} \text{MWh}^{-1}$]. This can be interpreted as a type of “system expansion”, in which the system boundaries for the LCA have been expanded to directly

account for electric sector emissions; however, it is problematic for two distinct reasons. First, the emissions factor is inherently arbitrary and sensitive to assumptions regarding displaced electricity production. Second, this method transfers electric sector mitigation (via substitution effects) to liquid fuel products, which is generally not appropriate in the context of LCA, is potentially inconsistent with future regulatory frameworks managing electric sector emissions (e.g., cap-and-trade), and could confound coherent climate policies, for example, by enabling arbitrarily low liquid fuels GHG intensities via increasing diversion of energy from fuels production to electricity generation.

An alternate approach is to explicitly allocate emissions (or lifecycle impacts, more generally) across product streams according to their relative energy content or financial value. We view the latter of these to be preferable because it is more closely aligned with investment (and technology deployment) decision variables. GHG intensity estimates presented here are therefore based on this methodology and are marked “-A” (for “allocation” method). We assume product values of \$65 per MWh and \$75 per barrel for electricity exports and liquid fuel products, respectively⁵.

Notwithstanding the foregoing, emissions offsets from negative emissions of biomass carbon [$\text{tC}_{\text{eq}} \text{GJ}_{\text{fuel}}^{-1}$] are subtracted from the GHG intensities of liquid fuels after positive emissions have been allocated across all product streams. This reflects that notions that emissions offsets in systems with biomass feedstock and CCS are measureable and non-arbitrary, and markets for GHG mitigation are arguably developing under the UN Framework Convention on Climate Change (e.g., via emissions trading, clean development mechanism, and joint implementation). As such, we assume that offsets can be allocated wherever they provide the largest financial benefit. The California Low Carbon Fuel Standard and similar policies under consideration appear likely to provide relatively large incentives for transportation sector mitigation, suggesting that offsets are likely to be allocated to liquid fuel products.

Mitigation costs represent the expected cost of GHG mitigation following a particular co-utilization strategy. Mitigation costs are calculated for each strategy relative to particular baseline technologies as the difference in producer costs divided by the difference in GHG intensity. GHG intensities for mitigation cost estimates are defined according to the “allocation” method and according to the “system expansion” accounting method to advance comparability of results with the published literature⁶. Note that these alternate estimates can also be interpreted as transportation-specific and economy-wide mitigation costs, respectively. The estimates are demarcated with “-A” and “-E” labels, respectively.

Mitigation cost estimates are sensitive to assumptions regarding the baseline technology. This is particularly confounding for analysis of liquid fuel production systems employing petroleum baseline technology assumptions, due to price uncertainty for petroleum-derived fuels. However, because the focus of this analysis is on biomass co-utilization to mitigate emissions from co-produced fuels, mitigation costs for biomass options are defined here relative to fossil-

⁵ Naphtha products are assigned a value equal to 70% of liquid fuel products on an energy basis [14].

⁶ An emissions factor of $48 \text{ kgC}_{\text{eq}} \text{GJ}_{\text{electricity}}^{-1}$ is used in the “system expansion” estimates, which represents the current grid average emissions intensity based on GREET model results, as described in the Princeton study discussed below [33].

derived fuels produced with analogous technologies. This answers the question: if unconventional fuels are commercially viable (due to market prices &/or policy incentives, which may be unrelated to climate policy), what is the carbon price required to motivate biomass co-utilization?

However, the interpretation of this mitigation cost is somewhat dependent on the GHG intensities of analogous fossil-derived unconventional fuels and on assumptions about why they might be competitive with petroleum analogues. For example, the commercial viability of fossil-derived unconventional fuels with relatively low GHG intensities (e.g., CTL systems with high CO₂ capture rates) may be enabled in part by a price on GHG emissions. In these cases, the mitigation cost defined above should be interpreted as the *additional* carbon price required to motivate biomass co-utilization; where the associated *market* carbon price would equal this price plus the minimum carbon price at which the analogous fossil-derived unconventional fuel is competitive.

Biofuel yield represents the liquid fuels production potential, or the potential contributions toward energy security objectives, of available biomass resources for each co-utilization strategy. It is equal to the conversion efficiency (HHV basis) of each system configuration. As this metric is not relevant for electric sector applications, bio-energy yield [$\text{GJ}_{\text{bio-electricity}} \text{GJ}_{\text{biomass}}^{-1}$] is reported, recognizing that this does not characterize potential energy security benefits.

The mitigation potential of biomass resources represents the potential contributions of available biomass toward climate objectives for each co-utilization strategy. Consistent with the computation of mitigation cost described above, biomass mitigation potentials are defined relative to fossil-derived fuels produced with analogous technologies rather than conventional petroleum fuels. As such, the mitigation potential of differential end use efficiencies (e.g., diesel vs. gasoline engines) is not considered here. Instead, mitigation potentials are computed as the difference in net emissions divided by the biomass feed rate. GHG intensities for estimates of mitigation potential are defined according to the “allocation” method and according to the “system expansion” accounting method to advance comparability of results with the published literature. Note that these alternate estimates can also be interpreted as total mitigation potential and transportation-specific mitigation potential, respectively. The estimates are demarcated with “-A” and “-E” labels, respectively.

3.2.1. Biomass co-utilization in CTL production

Co-gasification. As discussed above, several engineering-economic analyses exist of biomass co-utilization in CTL production. Unfortunately, the level of technical detail varies significantly by analysis, with some only implying co-gasification by the assumptions made in performance estimation. However, a relatively detailed study published by the National Energy Technology Laboratory in 2007 focuses specifically on biomass co-gasification, as a means for producing synthetic liquid fuels with a net GHG emissions intensity 20% below analogous petroleum derived fuels (FT diesel with the naphtha co-product utilized in ethylene production) [14]. This objective focused the study on configurations with (i) recycle of unconverted FT synthesis tailgas to maximize fuels production and (ii) CCS integration.

Five system options are evaluated in the study: CTL baseline; 7% biomass co-gasification (energy basis) using wood (i.e., poplar), switchgrass, and corn stover; and 10% woody biomass co-gasification (energy basis). All configurations assume high pressure, dry feed, entrained flow gasification (similar to the Shell gasifier). The study assumes that this level of co-gasification using a dedicated biomass feed system will not create unmanageable operational challenges. This assumption is based on a literature review and the operational experience at Buggenum (noted above); however, the authors note that additional research is necessary to validate this assumption.

Performance estimates from this analysis are presented in Table 3.1. They appear to be representative of undensified biomass co-gasification at relatively low co-feed rates in dry feed, entrained flow (Shell type) gasifiers. They may not be representative of other co-gasification options, such as pyrolysis oil & char blending with coal in slurry-fed gasifiers. The feasibility of this alternative may be limited by a variety of factors (e.g., pyrolysis oil pH), but if feasible, we would expect the performance of such systems could be significantly different from those for undensified biomass co-gasification.

To begin to understand the potential implications of FT liquids production via co-gasification of pyrolysis oil, (highly) simplified estimates of co-gasification performance metrics (other than costs) have been developed. Specifically, performance estimates for biomass co-gasification adapted from results published in the study described above have been modified to reflect: (i) a biomass to pyrolysis oil conversion efficiency of 0.71 (HHV) [29]; (ii) the potential for char sequestration as a soil amendment, with a char production rate equivalent to $0.14 \text{ kgC kg}_{\text{biomass}}^{-1}$ [28, 29]; and (iii) GHG emissions from pyrolysis oil transport equivalent to 1 kgC per GJ pyrolysis oil⁷. Resulting performance estimates, also presented in Table 3.1, are subject to substantially greater uncertainty than those adapted directly from the original analysis, due to the highly simplified methodology with which they are developed. Moreover, no attempt has been made to estimate the performance of pyrolysis oil co-gasification in slurry fed gasifiers, which are more appropriate for this application. As such, the relatively low precision of these performance estimates must be reflected in their interpretation.

Performance estimates adapted from the published results representing woody biomass and pyrolysis oil co-gasification are presented in Table 3.1. Because biomass is substituted for coal in co-gasification applications, emissions factors and producer costs published in the original study for CTL production without biomass co-utilization are defined as baselines of comparison in GHG mitigation calculations.

⁷ This estimate assumes 500 km transport in a dedicated pipeline with a capacity of 1000 m³ per day and power sourced from conventional coal fired power plants [Personal communications with Dr. Amit Kumar of the University of Alberta on 18 December 2008].

Table 3.1. Performance estimates for co-gasification

<i>Configuration</i>				
Biomass feed rate [% energy input]	7%	10%	14% ^a	14% ^a
Products	diesel, naphtha, & electricity	diesel, naphtha, & electricity	diesel, naphtha, & electricity	diesel, naphtha, & electricity
FT tailgas handling	Recycle	Recycle	Recycle	Recycle
CO ₂ handling	CCS	CCS	CCS	CCS + char sequestration
<i>Fuel production performance</i>				
Biofuel yield [GJ _{biofuel} GJ _{biomass} ⁻¹] ^b	0.50	0.50	0.36	0.36
<i>Lifecycle GHG emissions performance</i>				
GHG intensity-A ^c [kgC _{eq} GJ _{fuel} ⁻¹]	19	17	17	14
Mitigation-A ^c [kgC _{eq} GJ _{biomass} ⁻¹]	22	22	15	23
Mitigation-E ^c [kgC _{eq} GJ _{biomass} ⁻¹]	25	25	17	25
<i>Economic performance</i>				
Producer cost [\$ GJ _{fuel} ⁻¹]	13	14		
Mitigation cost-A ^c [\$ tC _{eq} ⁻¹]	170	150		
Mitigation cost-E ^c [\$ tC _{eq} ⁻¹]	210	190		

^a Reflects biomass pyrolysis with subsequent co-gasification of 10% energy input from pyrolysis oil. ^b Assumes uniform conversion efficiencies for all feedstock. This is a simplifying assumption that is contraindicated by slightly different conversion efficiencies across configurations with different biomass feed rates, but appears reasonable for performance estimation with the level precision of the current analysis. Also assumes naphtha co-product is used in fuel applications; however, it ignores energy requirements and emissions from naphtha conversion to fungible transportation fuels. ^c “-A” refers to emissions accounting with lifecycle GHG emissions allocated across product streams according to product financial values and offsets subtracted from liquid fuel emissions. “-E” refers to lifecycle emissions accounting with emissions credits for electricity exports and offsets both subtracted from system-wide lifecycle GHG emissions.

