American Forest & Paper Association

AMERICAN WOOD COUNCIL

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Attn: Docket ID No. EPA-HQ-OAR-2015-0199

Re: Federal Plan Requirements for Greenhouse Gas Emission From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations, Proposed Rule, FRL–9930-67-OAR, 80 Fed. Reg. 64,966 (October 23, 2015)

Dear Sir or Madam:

The American Forest & Paper Association (AF&PA) and the American Wood Council (AWC) appreciate the opportunity to provide written comments to the U.S. Environmental Protection Agency (EPA) regarding the above-referenced proposed *Federal Plan Requirements for Greenhouse Gas Emissions From Electric Generating Units Constructed on or Before January 8, 2014, Model Trading Rules; Amendments to Framework Regulations; Proposed Rule* (the Proposal). AF&PA and AWC also are joining the comments filed today by the National Association of Manufacturers (NAM) and several other associations raising important concerns of the broader manufacturing community (NAM Comments), as well as comments of the National Association of State Energy Officials (NASEO) Industrial Energy Innovation Working Group (NASEO Group). We support those comments in their entirety. Finally, AF&PA and AWC are incorporating by reference several portions of the comment filed today by the Alliance for Industrial Efficiency (see Section VIII of our comments below).

AF&PA and AWC and other Energy Intensive/Trade Exposed sectors (EITEs) contracted with NERA Economic Consulting to perform a number of analyses and make recommendations on the Proposal. That report (NERA Report) supports our comments today and also is attached and incorporated by reference.

These comments discuss issues that are particularly important to AF&PA and AWC members because of their concern over the negative competitiveness impacts of the Proposal, the unique use of biomass for energy, and their extensive use of Combined Heat and Power (CHP) technology. We already have addressed many of these issues in our previous comments on EPA's proposals to regulate greenhouse gas (GHG)

emissions from new and modified and reconstructed Electric Generating Units (EGUs) and existing EGUs. Those comments also are incorporated herein by reference.[1]

EPA must ensure that federal plans and model rules are consistent with the requirements of the Clean Air Act (CAA). Like the Clean Power Plan (CPP) itself, AF&PA and AWC believe that EPA in imposing the federal plan or the States in adopting the model rules will exceed their authority under the CAA by imposing emission reduction obligations beyond the regulated source category. Any such obligations on companies beyond the regulated source are unlawful. See Section III for further discussion. To the extent the courts uphold the legality of any aspect of the CPP, we have a strong interest in any proposals to implement the CPP, including EPA's proposed federal plan and model trading rules.

EPA should take a flexible and open-minded approach that ensures that any impacts on the electricity generators and companies dependent on affordable and reliable electricity are minimized. In particular, it is critical that EPA incorporate all of the flexibility options included in the final CPP into any federal plan. By excluding certain emission reduction options from mass-based and rate-based plans as well as other flexibility tools such as a reliability safety valve, the proposed federal plan and model trading rules are unduly restrictive and will ultimately frustrate the CPP's emission reduction goals. For the same reason, EPA must adjust its treatment of CHP units to more fully recognize their emission reduction benefits.

Also, EPA must refrain from prejudging components of a federal plan and should instead defer final decisions until a federal plan is necessary. This would enable EPA to first gather as much information as possible before making a state-specific decision and result in a better outcome. In the interim, EPA should issue guidance to the States to clarify that it will approve and endorse state plans that include broader flexibility options that go beyond what is included in the narrowly construed proposed federal plan and model rules.

I. Introduction to AF&PA and AWC

AF&PA serves to advance a sustainable U.S. pulp, paper, packaging, and wood products manufacturing industry through fact-based public policy and marketplace advocacy. AF&PA member companies make products essential for everyday life from renewable and recyclable resources and are committed to continuous improvement through the industry's sustainability initiative - *Better Practices, Better Planet 2020*. The forest products industry accounts for approximately 4 percent of the total U.S.

[1] AF&PA and AWC, Comments on Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Docket Id. EPA-HQ-OAR-2013-0495-9733 (May 9, 2014); AF&PA and AWC, Comments on Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units, Docket Id. EPA-HQ-OAR-2013-0603-0247 (Oct. 16, 2014); AF&PA and AWC, Comments on Carbon Pollution Standards for Existing Stationary Sources: Electric Utility Generation Units, Proposed Rule, Docket Id. EPA-HQ-OAR-2013-0602-23012 (Dec. 1, 2014).

manufacturing GDP, manufactures approximately $210 billion in products annually, and employs nearly 900,000 men and women. The industry meets a payroll of approximately $50 billion annually and is among the top 10 manufacturing sector employers in 47 states.

AWC is the voice of North American traditional and engineered wood products, representing over 75 percent of the industry. From a renewable resource that absorbs and sequesters carbon, the wood products industry makes products that are essential to everyday life and employs more than 360,000 men and women in family-wage jobs. AWC's engineers, technologists, scientists, and building code experts develop state-of-the-art engineering data, technology, and standards on structural wood products for use by design professionals, building officials, and wood products manufacturers to assure the safe and efficient design and use of wood structural components. AWC also provides technical, legal, and economic information on wood design, green building, and manufacturing environmental regulations advocating for balanced government policies that sustain the wood products industry.

A. Use of CHP and/or Renewable Energy Have Improved Our Members' Energy Efficiency and Reduced GHG Emissions.

The forest products industry produces and uses renewable energy for manufacturing operations and is a significant contributor to our country's existing base of renewable energy. In fact, paper and wood products facilities account for 62 percent of the renewable biomass energy produced by the total U.S. manufacturing sector.[2] On average, approximately 66 percent of the energy used at AF&PA member pulp and paper mills, and over 75 percent of the energy from our wood products facilities are generated from carbon-neutral biomass.

The industry also strives to use all types of energy as efficiently as possible. The industry is a leader in the use of CHP technology, which is extremely efficient because it uses the same fuel to produce both thermal energy used in the manufacturing process and electricity, some used on-site and some sold to the grid. In 2012, pulp, paper, packaging, and wood products mills produced 30 percent of the CHP electricity generated by manufacturing facilities. In fact, over 96 percent of electricity produced by our members' pulp and paper mills was CHP-generated.

The use of CHP provides energy efficiencies in the range of 50 to 80 percent at forest products mills, far beyond non-CHP electrical stations such as utilities, which are only about 33 percent energy efficient. Unlike the CHP commonly used by utilities and other manufacturers, most of the CHP processes used in the pulp and paper and wood products industry are highly integrated into the manufacturing process. The biomass residuals from the manufacturing process – e.g., bark, spent pulping liquor, sawdust, shavings, and paper residuals that cannot be used for products – are used as the primary fuel to power the mills and to provide electricity for the grid.

[2] The U.S. manufacturing sectors that use renewable biomass energy includes the paper and wood products industry, as well as the chemicals and bio-refineries manufacturing industries.

Our commitments to renewable biomass energy and energy efficiency, including our extensive use of CHP, have led to a dramatic decrease in the sector's use of fossil fuel and GHG emissions. Energy purchased by member pulp and paper mills -- most of which is fossil fuel-based -- has decreased 25.4 percent since 1990, 14.6 percent since 2000, and almost 9 percent since 2005 (making significant progress toward achieving AF&PA's *Better Practices, Better Planet 2020* goal of at least a 10 percent reduction in purchased energy). This has helped reduce GHG emissions intensity by over 23 percent since 2000. Beyond what the industry has already achieved, we have committed to reducing GHG emissions by at least 15 percent by 2020, from a 2005 baseline. Since 2005, AF&PA members' GHG emissions have been reduced by 14.5 percent — nearly reaching their 2020 goal of 15 percent five years early.

Moreover, the forest products industry is the largest producer and user of bioenergy of any industrial sector and has long-standing operations in the U.S. The creation and use of biomass energy in forest products mills is integral and incidental to the manufacture of products such as pulp, paper, packaging and wood products. Pulp mills, integrated pulp and paper mills, and wood products mills convert biomass residuals to energy while manufacturing biobased products that are useful to society. There are substantial GHG reduction benefits from using manufacturing residuals for biomass energy in the forest products industry. According to a study by the National Council for Air and Stream Improvement (NCASI), the use of biomass residuals each year avoids the emission of approximately 181 million metric tons of CO_2e.[3] (This is equivalent to removing about 35 million cars from the road.)

AWC member companies met almost 75 percent of their energy needs from renewable, carbon neutral biomass energy in 2012. The GHG reduction benefits of using biomass manufacturing residuals for energy by the wood products industry are equivalent to about 24 million tons of carbon dioxide. This is equivalent to removing the emissions of approximately 4.6 million cars from the road each year. The current inventory of wood structures in the U.S. is estimated to store 1.5 billion metric tons of carbon, which is equivalent to 5.4 billion tons of CO_2. Using wood as a substitute product in construction could save 14 to 31 percent of global CO_2 emissions and 12 percent to 19 percent of global fossil fuel consumption.

B. AF&PA and AWC Members Operate in Global Markets and Energy is a Significant Cost That Impacts Competitiveness.

AF&PA and AWC member facilities are fundamentally different than the affected EGUs regulated under the Proposal. AF&PA and AWC members manufacture a wide variety of value-added forest products, such as paper, packaging, wood products, wood-based

[3] *See* NCASI, *Greenhouse Gas And Fossil Fuel Reduction Benefits of Using Biomass Manufacturing Residuals for Energy Production in Forest Products Facilities*, Technical Bulletin No. 1016 (Rev. Aug. 2014), *available at* http://www.ncasi.org/Downloads/Download.ashx?id=9603 (attached); Gaudreault, C. and Miner, R., *Temporal Aspects in Evaluating the Greenhouse Gas Mitigation Benefits of Using Residues from Forest Products Manufacturing Facilities for Energy Production*. *J. of Industrial Ecology* 19(6):994-1007 (2015), at 1,004.

chemicals, and other innovative wood-based products. Because they operate in a highly competitive global market and face fierce international competition, they cannot automatically pass on higher raw material and energy costs to their customers and still remain competitive. Further, many AF&PA and AWC members' facilities are located in rural areas, and provide high-paying jobs for those communities. Those jobs are a critical driver of the overall economic health of those oftentimes vulnerable communities.

The paper and wood products manufacturing sector spent over $7 billion on net purchased electricity and natural gas in 2013. As large consumers and ratepayers, AF&PA and AWC members will face base rate and fuel electricity cost increases as utilities seek cost recovery of their fixed and variable compliance costs for numerous environmental requirements, including: 1) CAA programs (e.g Mercury and Air Toxics Standards (MATS) and ozone National Ambient Air Quality Standards (NAAQS)); 2) Clean Water Act Section 316(b) cooling water intake structures regulations; and 3) revised Resource Conservation and Recovery Act regulations pertaining to coal combustion residuals. These compliance costs passed along from utilities are in addition to the cumulative burden of regulations under the CAA, such as Boiler Maximum Achievable Control Technology standards and ozone and particulate matter NAAQS, along with several major pending regulations that could directly cost the forest products industry more than $10 billion over the next eight years.

II. The Final Clean Power Plan Would Significantly Raise Electricity Prices and Federal Plan Implementation Could Further Raise Costs.

In addition to the compliance costs utilities will pass on to our members discussed above, the final CPP would further increase energy costs, harming our competitiveness in global markets. According to a previous NERA report,[4] average annual U.S. retail electricity rate increases range from 11 percent per year to 14 percent per year (relative to the baseline) from 2022 through 2033 under the CPP. This report also demonstrates that states with significant forest products industry presence will face major cost increases for electricity. For example, some of the states in the southeast region modeled in the NERA report include Florida, Georgia, North Carolina, South Carolina, Alabama, and Mississippi, all states with significant industry presence, and that region faces average annual U.S. retail electricity rate increases from 2022 to 2033 similar to the national increases.[5]

According to the NERA Report, the choices made in federal plan implementation could further raise energy prices and create energy cost tradeoffs in a particular state. Under numerous scenarios examined (which include rate- and mass-based approaches and differing trading and allocations to Electricity Distribution Companies (EDCs)) in most cases a rate-based approach led to lower delivered electricity prices than a mass-based

[4] NERA Economic Consulting, 2015. Energy and Consumer Impacts of EPA's Clean Power Plan, report prepared for American Coalition for Clean Coal Electricity, November 7.
[5] NERA modeling run in support of NERA Economic Consulting, 2015.

approach. However, that relative advantage is offset by the disadvantage of higher natural gas prices under a rate-based implementation.

EPA should carefully consider the impacts to the economy (including on overall economic growth, jobs, and trade in manufactured goods) as it seeks to implement GHG reductions from EGUs. This is particularly important for EITE[6] sectors such as the forest products industry. As discussed below, we are suggesting ways to ameliorate the negative economic effects on EITE sectors of the final CPP and any final federal plan by allowing non-affected entities to voluntarily participate in both rate- and mass-based trading markets. EPA should ensure that the regulatory structure for the trading of credits and allowances allows for and promotes voluntary industrial energy efficiency, including CHP, as an avenue for GHG reduction, while at the same time maintaining the provisions that correctly exempted most of our members' CHP from regulation as affected EGUs.

Further, the cumulative impact to affected EGUs and the CPP's effect on the forest products industry discussed above should be considered when developing GHG reduction regulations and policies that affect our industry and other EITE sectors. Failure to consider the impact of current and future GHG reduction regulations and policies on EITE manufacturing sectors, such as the forest products industry, could result in the export of manufacturing and jobs to foreign suppliers not subject to restrictive GHG mitigation requirements.

As mentioned above, our industry has strived to reduce voluntarily its GHG emissions and to use all types of energy as efficiently as possible. If our facilities participate voluntary as eligible energy efficiency and renewable energy resources to help states achieve their GHG reductions goals, EPA and states must recognize in subsequent regulations those GHG emission reduction efforts. Electricity consumers engaging in these activities in association with the Section 111(d) rules for EGUs that result in verified GHG emission reductions should be exempted from, or given credit towards, compliance with any subsequent future Section 111 standards of performance for GHGs or other GHG regulations and policies. Failure to provide this exemption or credit could result in a source being subject to regulation under GHG standards of performance for multiple source categories. To be clear, we are not inviting EPA to set additional Section 111(d) standards for other sectors or sources, especially EITE sectors that are already reducing GHG emissions. In fact, affected EGUs are unique as EPA acknowledges and may be the only source category appropriate for this type of a national program, assuming it is found lawful.

[6] Under the Waxman-Markey legislative proposal, qualifying sectors that meet an average energy or GHG intensity of 5% and a trade intensity of 15%, or a very high (20%) GHG intensity were considered EITEs.

Finally, the increased direct and indirect costs to U.S. paper and wood products manufacturers discussed above, and continued uncertainty around the treatment of their biogenic emissions (see Section VII, below) will further adversely affect their global competitiveness, jobs, and other economic and social benefits they provide for their communities. Competitor nations in Europe and elsewhere fully recognize bioenergy as carbon neutral in their GHG reduction policies, leaving U.S. manufacturers at a competitive disadvantage. EPA's analysis also did not consider the "leakage" that could occur if increased energy-related costs force the closure of mills in the U.S., shifting production and emissions to other countries with less stringent requirements.

III. EPA Cannot Mandate Beyond-the-Source Compliance Options.

As mentioned above, the forest products industry has committed voluntarily to reducing GHG emissions from their operations. Our voluntary commitments to renewable biomass energy and energy efficiency, including our extensive use of CHP, have led to a dramatic decrease in the sector's use of fossil fuel and GHG emissions. However, AF&PA and AWC reiterate that EPA has exceeded its legal authority under the Clean Air Act by imposing CO_2 emission targets that are based on beyond-the-source emissions reductions that cannot be achieved by the fossil fuel-fired EGUs that are the subject of regulation under the CAA and the CPP. Nothing in these comments is intended to waive any legal argument that we and other petitioners have made or may make in litigation regarding the legality of the CPP and hereby incorporate by reference all arguments made in our and their comments on the proposed CPP and in our and their briefs in litigation over the CPP. In particular, EPA has exceeded its authority by looking beyond the emissions controls that can be implemented at the source and instead evaluated the entire electricity system as a whole when determining the potential for emissions reductions from existing sources. This is inconsistent with both the plain meaning of the CAA and with existing case law interpreting Section 111. See NAM Comments for additional comments on the legality of the CPP.

Prior to the resolution of the legal challenge, EPA should maximize flexibility options in developing a federal plan and in the model trading rules to ensure that states and affected EGUs can meet EPA's emissions reduction goals in the least cost manner.

IV. The Final Federal Plan and Model Rules for Both Rate- and Mass-Based Approaches Should Be Based on a Principle of Least-Cost Compliance for the Ratepayer.

A. Consideration of "Least Cost" Should Transparently Consider All the Direct and Indirect Costs Imposed by the Adoption of a Federal Plan and Application of the Model Rules.

If the CPP survives legal challenge, EPA should consider the least cost approach when imposing a federal plan and finalizing the model trading rules. The term "least cost"

compliance should be broadly defined to include both the short- and long-term costs of electric power and natural gas to customers (including costs to maintain reliability and to build necessary infrastructure) as well as the broad impact of compliance-related decisions on the state's economy including job- and income-related impacts. Costs that should be minimized include the displacement of existing industries and the jobs they provide (such as those provided by EITE sectors), as well as GHG leakage caused by the relocation of domestic EITE sectors' production to other countries that may use less energy-efficient processes with resultant higher GHG emissions. It is important to note that the utility costs incurred for compliance will be paid by all consumers, including EITE sectors.

As noted in the previous NERA report, states with significant forest products industry presence will face major electricity cost increases under the CPP. These increased costs (both direct and indirect) will adversely affect U.S. manufacturers of paper and wood products' global competitiveness thereby affecting jobs, and the other economic and societal benefits these facilities provide to the rural communities where they are located. EPA needs to focus on least cost compliance mechanisms to minimize cost increases with the implementation of the federal plan and model trading rules. As also noted in the NERA Report, cost impacts can vary significantly from state to state potentially setting up situations of creating "winners and losers" amongst the states. As costs for manufacturers increase, leakage of jobs, leakage of capital investment, and leakage of GHG emissions will occur as manufacturers look to relocate to other states or international jurisdictions with lower manufacturing costs. Therefore, the final federal plan and the model rules should establish a mechanism to assess employment and other economic impacts on potentially affected industries that will pay the increased bills for power and natural gas before final plans are adopted. See Section VI.B, below for further discussion on mitigating impacts on EITE sectors.

The states also should select specific electricity generating resources including energy efficiency as an option based on a principle of least-cost compliance when adopting the model rules. States should develop their compliance plans and choose specific resources only after undertaking a detailed analysis of current baseline energy demand, future projected demand, and the least-cost methods for achieving their reduction targets. This should include a careful consideration of displacing existing businesses and the jobs and value they provide to the state's economy.

B. The Federal Plan and Model Rules Should Include as Many Potential Resources as Possible, Including all the Available Resources in the CPP.

As discussed more fully in the NAM and NASEO Group comments, EPA should adopt broadly inclusive implementation plans that incorporate all CO_2 reducing technologies and sources of energy that can cost-effectively contribute to achievement of the CPP's emission reduction goals. The Proposal fails to meet this requirement because it limits the types of CO_2 reducing technologies and energy sources that are eligible for

Emission Rate Credits ("ERCs") under a rate-based plan and set-aside allowances under a mass-based plan.

While various parts of the CPP rule and its associated materials (rule preamble and technical support documents) favorably note energy efficiency as an often most cost-effective and beneficial emission mitigation approach, there remains uncertainty and confusion among some state officials and other stakeholders as to the standing and "creditability" of energy efficiency. This is prompted in part by EPA's exclusion of end-use energy efficiency as a "building block" for the Best System of Emission Reduction (BSER) determination, despite the building blocks being irrelevant to compliance approaches (i.e., states may use all, some, or none of the building blocks in any proportion to achieve compliance). Specifically, under the proposed federal plan rate-based approach, EPA excluded energy efficiency as an eligible resource for ERCs.[7] Not only would energy efficiency be excluded as an eligible emission reduction approach in states under the federal plan, but some states looking to the federal plan as a model may then exclude energy efficiency from their state compliance plans. This may not be the intent but could very well be the effect of omitting energy efficiency from the federal plan, and could result in states forsaking least-cost, beneficial energy efficiency opportunities based on the impression that EPA may have less confidence in energy efficiency as a viable compliance resource for states and affected EGUs.

As indicated in the NERA Report, removing energy efficiency from the federal rate-based plan significantly increases natural gas prices. Indeed, every one of the mass-based scenarios analyzed (which include energy efficiency) has lower natural gas prices than every one of the rate-based options. Further, varying the allocations or trading options in the scenarios has minimal impact on natural gas prices. For example, in 2031, the rate-based scenarios (with either national or intra-state trading) projected Henry Hub prices are approximately $6.75 ($2015/MMBtu), while all the mass-based scenarios (with differing trading and allocation approaches) are all approximately $6.00 ($2015/MMBtu). This is because with end-use energy efficiency available and adopted by states (as assumed in the mass-based scenarios), there is less need for fuel switching to natural gas and thus less pressure on wholesale and delivered natural gas prices. In contrast, if end-use energy efficiency is not adopted as in the proposed rate-based federal plan, there is a much larger shift towards natural gas-fired generation, increasing demand for natural gas and putting upward pressure on wholesale and delivered natural gas prices throughout the country.

In addition to making clear that energy efficiency broadly is included under the rate- and mass-based federal plans and model rules, EPA also should make clear that a broad category of industrial energy efficiency, including CHP, waste heat to power, and non-utility industrial efficiency programs, are available to states as voluntary compliance options by including them in the final federal plan and in both the rate- and mass-based final model trading rules. Moreover, many CHP units operate "Behind the Meter" and self-supply power to their host facilities without selling excess power to the grid.

[7] 80 Fed. Reg. at 64,990-91.

Similarly, industrial facilities take steps that reduce their purchased power requirements for their facilities such as undertaking voluntary energy efficiency measures pursuant to non-utility energy efficiency programs. In both cases, the facility meets the requirement of Section 62.16434(b)(2) that the resource is "connected to, and delivers energy to or *saves electricity*, on the electric grid in the contiguous United States." (emphasis added). This is because the self-generated electricity and energy efficiency obviates the need to purchase additional power from the grid. Regardless of whether a facility is party to a "buy all – sell all" arrangement with its utility provider or if the facility sells self-generated electricity to one party while buying back the facility's power requirements from another party, the facility's self-generation is, on net, reducing the amount of power purchased and therefore "*saves electricity"* on the grid.

Along with a broad category of energy efficiency, EPA should include biomass as an eligible renewable energy resource in the federal plan and both model trading rules. Including all these options would provide as many compliance options as possible to affected EGUs and states, providing them greater opportunities to adopt least-cost options. (See additional discussion in Section VI on rate- and mass-based plans and Sections VII and VIII on biomass energy and CHP, both of which are important components of our members' energy profiles.)

C. There Should be a Level Playing Field Between Energy Efficiency and Renewable Energy.

As discussed in the NASEO Group comments, the federal plan and model trading rules should provide a level playing field in EPA's (and states') treatment and consideration of energy efficiency projects and renewable energy in the federal plan and model rules as well as under the Clean Energy Incentive Program (CEIP) to ensure least cost options are chosen. We recognize that some renewable power generation options are easier to measure directly (e.g., metering solar, hydroelectric, and wind power generation) than other renewable energy generation technologies and end-use efficiency. However, there are established EM&V methodologies that permit adequate quantification of energy savings projects or alternative generation. These should help address concerns with energy efficiency projects that at first blush might seem to present an additional challenge for including energy efficiency in a federal plan or model trading rules, even though energy efficiency projects may be the least cost option and, therefore, should be included in those plans.

V. EPA Should Finalize Both Rate- and Mass-Based Federal Plans.

EPA indicates that once it finalizes a federal plan by applying it in one state, it will use the approach in that state (i.e., either a rate or mass-based approach) in all future states in which it adopts a federal plan. EPA is under no obligation to make final decisions with respect to the federal plans until after a state fails to meet a state plan submission deadline or submits an unacceptable plan. Thus, there is no reason for EPA to reduce its own regulatory flexibility by locking itself into a certain regulatory approach before the need for a federal plan arises in another state, and the agency certainly can apply

different approaches in subsequent states. Accordingly, EPA should finalize both rate- and mass-based final federal plans so both are available for use in any future state in which a federal plan is imposed. Further, the agency should tailor any federal plan it adopts to the particular circumstances of the state in order to achieve the least cost compliance for all ratepayers, including AF&PA and AWC members, in that state. While, as the agency has noted, that may provide additional challenges if EPA adopts a federal plan in more than one state, it is incumbent upon the agency to manage those challenges to achieve least cost compliance.

The importance of maintaining the flexibility to adopt either a rate- or mass-based federal plan is highlighted in the NERA Report, which demonstrates that with limited exceptions, a rate-based implementation of the federal plan results in lower delivered electricity rates at the state level compared to a mass-based implementation of the federal plan considering intra- and interstate trading scenarios. However, this relative advantage of a rate-based implementation may be offset by the disadvantage of higher natural gas prices under a rate-based implementation in many states because EPA does not allow for energy efficiency as a compliance measure in the rate-based federal plan. Thus, in states that rely on larger percentages of natural gas to supply their energy needs, it may be that, overall, mass-based federal implementation is the better way to achieve least cost compliance. The NERA Report illustrates that cost impacts on states depend on the fuel mix within the state and emphasize the need for greater flexibility in implementing the federal plan. EPA, therefore, needs to have the flexibility to adopt whichever approach leads to least cost compliance and should ensure it has that flexibility by promulgating both federal plans.

In addition, EPA should develop and adopt a trading mechanism that allows ERCs and allowances to be used in either mass- or rate-based trading programs. In the Proposal, EPA seeks to finalize a federal plan that "enhances the consistency of the federal trading program [and] achieve economies of scale through a single broad trading program."[8] Providing mechanisms to convert ERCs to allowances and allowances to ERCs will allow for a broader and robust trading system with the least cost among states where the federal plan is imposed or where states adopt the model trading rules.

VI. EPA Should Include Design Features In Rate- and Mass-Based Federal Plans and Model Rules that Promote Flexibility and Least-Cost Compliance.

As discussed above, EPA should finalize both rate- and mass-based federal plans with conversion mechanisms for ERCs and allowances, so that the most appropriate and least cost choice can be applied to a state where a federal plan is imposed or model rules are adopted. Below we discuss several issues that EPA should consider as it finalizes the federal plan and model rules under both rate- and mass-based approaches.

[8] 80 Fed. Reg. at 64,970.

A. Rate-Based Approach

1. EPA Should Include All Available Resources in the Federal Plan and Model Rules

In order to facilitate a least-cost compliance approach, EPA should include all resources available under the CPP in both the federal plan and model rules. EPA, however, significantly limited the resources that can generate ERCs in the federal rate-based plan, as compared to the model rule and CPP. The proposed federal rate-based plan allows ERCs for certain eligible resources (on-shore utility-scale wind, utility-scale solar photovoltaics, concentrated solar power, geothermal power, new nuclear units and capacity uprates at existing nuclear units, and utility-scale hydropower) as long as the resource provides generation data from a revenue quality meter. The proposed model rule expands this list of eligible resources to include post-January 1, 2013 installed qualified biomass, waste-to-energy (biogenic portion), non-affected CHP, and demand-side energy efficiency and demand-side management measures that can be quantified on the basis of ex-post savings. EPA should include in the federal plan all the eligible resources that are included in the rate-based model rule.

2. EPA Should Adopt "Subcategorized" Emission Rates Under the Rate-Based Approach

EPA proposes to use "subcategorized" emission rates; that is, separate CO_2 emission performance rates for affected EGUs in two subcategories: "natural gas-fired stationary combustion turbines (i.e., natural gas combined cycle units, or NGCC units) and fossil fuel-fired EGUs (i.e., utility boilers and integrated gasification combined cycle (IGCC))".[9] EPA says this provides greater flexibility and more fungible ERCs[10] than a single rate-based approach, which is the weighted average of the two subcategory targets based on the percentage of each type of facility in the state's mix in the 2012 baseline year. This approach also will be more transparent given that some of the newer NGCC units can also produce gas-shifting ERCs. We support the subcategorized approach for the reasons EPA provided.

3. Banking, Borrowing, and Trading ERCs

EPA proposes to allow banking, but not borrowing of ERCs, but does not provide any basis for excluding borrowing. We support including both banking and borrowing, as they will provide more flexibility and allow EGUs to more cost effectively comply.

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[9] 80 Fed. Reg. at 64,990.

[10] "The EPA is using the subcategorized rates in the rate-based trading approach because it allows ERCs to be fungible across jurisdictional borders and provides an incentive structure, as compared to other rate-based approaches, that facilitates implementation of measures identified as part of the BSER. Using subcategorized rates allows for: (1) Consistently applied emission rates for power plants of different types; and (2) free trading of fungible ERCs among all affected EGUs subject to the federal plan and within the federal trading program." 80 Fed. Reg. at 64,990.

In addition, as discussed above in Section V, EPA should develop and adopt a trading mechanism that allows ERCs to be used in mass-based trading programs. Providing conversion mechanisms for ERCs to be used in mass-based programs will allow for a broader and robust trading system among states where the federal plan is imposed or where states adopt the model trading rules.

B. Mass-Based Approach

The agency's mass-based approach has several primary components on which AF&PA and AWC are commenting: set-asides to renewable energy, allowances for certain categories of facilities, and several other issues.

1. Allowance Set-Asides for Renewable Energy to Address Leakage to New Sources

EPA proposes three set-asides for both the mass-based federal plan and the model rule to address leakage, one of which is a set-aside for renewable energy. Specifically, EPA proposes that 5 percent of allowances will be reserved from the allocation for each state for renewable energy projects that meet the requirements for rate-based ERCs under the federal plan and model rule (i.e., on-shore wind, solar, geothermal power, and hydropower that have come on line after January 1, 2013). As discussed in Sections VII below, we believe that biomass should be included as an eligible resource under the federal plan and model trading rules, and we do not support the post-2012 date cutoff for renewable energy projects, including biomass energy, as well as other requirements for biomass to be included in the final CPP.[11] Indeed, AF&PA and AWC have filed a petition for review challenging many of those requirements.[12]

2. Mechanisms to Evaluate and Address Impacts to EITE Sectors

As discussed above, AF&PA and AWC members operate in global markets, and must remain as competitive as possible to compete successfully in those markets. Energy also is a significant manufacturing cost and unlike affected EGUs, our members to a large extent cannot pass those costs on to our customers. Affected EGUs, especially those that are part of vertically integrated public utilities in regulated states, can pass through compliance costs to their customers. Implementation of the CPP's emission reduction goals threatens to have a significant impact on EITE sectors that face stiff overseas competition if energy prices rise, service reliability lessens, and other cumulative burden impacts increase. Federal and model plans that place an undue burden on such industries through increased energy prices or other direct or indirect effects could thwart global GHG emission reduction goals by shifting production and emissions to overseas competitors. As a result, such plans would not produce a net

[11] This argument will be raised as part of our petition for review in the D.C. Circuit. *American Forest & Paper Association and American Wood Council v. EPA*, No. 15-1485 (D.C. Cir. 2015).
[12] *American Forest & Paper Association and American Wood Council v. EPA*, No. 15-1485 (D.C. Cir. 2015).

global reduction in emissions due to international leakage of emissions on an international level. Thus, EPA should develop safeguards to ensure that any adverse effects on EITE sectors are mitigated by maximizing options and flexibility to ensure that the least cost solutions are available and that the impacts to EITE manufacturers are addressed.

EPA should make it clear that the Agency (when imposing the federal plan) and the states (when adopting the model rules) have the flexibility to mitigate impacts to EITE sectors. EPA and states should evaluate the types and extent of direct and indirect impacts on EITE sectors in that state. EPA and states then should determine what type of mechanism can be implemented to reduce impacts to EITE sectors. For example, EPA and states should have the flexibility to consider alternatives to EPA's proposal to distribute allowances to affected EGUs based on historical emissions (e.g., allocate to EITE sectors, or to EDCs, or a combination thereof).

3. Allowances for Industrial Energy Efficiency, Including CHP

To remain economically sustainable, socially responsible, and sensitive to the U.S. GHG mitigation objectives, industrial facilities already have and continue to prioritize investment in energy efficiency in their manufacturing operations. They also have set energy efficiency as a high priority for capital investment. For example, AF&PA has set a goal to improve purchased energy efficiency by 10 percent by 2020 as compared to a 2005 baseline, and it had improved by 8.8 percent by 2012. These improvements translate to decreased purchases of power from utilities with affected EGUs, and therefore help those utilities meet their compliance obligations. Accordingly, the mass-based federal plan and model rule should include allowances for a broad category of new voluntary industrial energy efficiency projects, including CHP and non-utility led voluntary projects that result in reduced power purchases from the grid.

To fully credit these resources under a mass-based approach, EPA has at least four options: it could auction allowances and direct some of the proceeds toward this purpose (with the remaining revenue going to either load serving entities or to affected EGUs); directly allocate allowances to new, incremental use of these resources; create a special set-aside for these resources; and/or expand the proposed set aside for leakage to include these resources. We recommend that the Agency choose one or more of these options to fully credit voluntary industrial energy efficiency projects.

Direct allocation has several advantages compared to set-asides or obtaining allocations of auction revenues. It treats eligible projects the same as affected units for purposes of receiving allocations and does not require periodic project-based applications to secure allowances. A set-aside is comprised of a reserved pool of allowances established at the beginning of a compliance period. Owners of eligible resources or projects must then apply for allowances typically on an annual basis, subject to a limit on the size of the set-aside. To institute a set-aside, EPA must determine up-front the size of the set-aside pool and will likely be unable to award set-aside allowances to all eligible activities. A direct allocation does not require the same

up-front determination. As a consequence, it is administratively simpler for both state agencies and for potential allowance recipients.

Please see additional comments related to CHP in Section VIII.

4. Banking, Borrowing, and Trading Allowances

Similar to the proposed rate-based approach, EPA proposes to allow banking, but not borrowing of allowances, but does not provide any basis for excluding borrowing. As stated above, we support including both banking and borrowing, as they will provide more flexibility and allow EGUs to more cost effectively comply.

In addition, as discussed above in Section V, EPA should develop and adopt a trading mechanism that allows allowances to be used in rate-based trading programs. Providing conversion mechanisms for allowances to be used in rate-based programs will allow for a broader and robust trading system among states where the federal plan is imposed or where states adopt the model trading rules.

5. State-Determined Allowance Distribution

EPA proposes to allow a state to replace the EPA-determined allowance distribution provisions with a state-developed allowance distribution provision. EPA believes that this would provide states with greater flexibility and allow them to consider distributions that work better for a state and allow a state to consider allowance distribution approaches EPA may not have included in the Proposal.[13]

We support this proposal for the reasons EPA has provided. States likely will be in a better position than EPA to know which allowance distribution provisions would work the best. For example, a state likely would be more familiar with the EITE sectors located within its borders and may want to provide allowances or other mitigating measures to those industries, an option not available under the EPA proposed federal and model rules.

VII. Biomass Energy Should Be an Eligible Measure in the Federal Plan and Rate- and Mass-based Model Plans.

EPA is seeking comment on the inclusion of other emission reduction measures such as use of biomass energy to be eligible for ERC issuance under the rate-based federal plan. EPA should not limit biomass energy as an eligible measure to the rate-based Federal Plan. Biomass energy should be included as an eligible measure in both mass- and rate-based federal plans and model trading rules.

[13] 80 Fed. Reg. at 65,027.

A. Biomass Energy Should Be Included in the Final Federal Plan as an Eligible Emission Reduction Measure.

In the proposed rate- and mass-based federal plans, EPA is only considering wind, solar, geothermal power, hydropower, and new nuclear units and capacity uprates as eligible measures because they (1) were a part of the renewable energy generation potential quantified for the BSER; (2) are able to be deployed on an economic basis during the compliance period; and (3) provide the "simplest and most timely path" for EM&V implementation of the federal plan because they use existing metering infrastructure to quantify generation. 80 Fed. Reg. at 64,994.

It would be arbitrary and capricious for EPA to exclude biomass energy as an eligible measure under the federal plan based on these justifications. In *Motor Vehicle Manufacturers Ass'n v. State Farm Mutual Automobile Insurance* Co., 463 U.S. 29 (1983), the Supreme Court held that an agency must satisfy two basic requirements to avoid violating the arbitrary and capricious standard. Initially, the agency must engage in "reasoned decision making." *Id.* at 52. Then, ''the agency must . . . articulate a satisfactory explanation for its action." *Id*. EPA has failed to justify excluding biomass and limiting emission reduction resources to only wind, solar, geothermal power, hydropower, and new nuclear units and capacity uprates.

First, EPA has acknowledged that other emission reduction measures that were not included in the BSER determination would be available to states to meet emission reductions goals under the CPP. EPA states that the "availability of these measures [such as biomass energy and CHP] further assures that the appropriate level of emission reductions can be achieved."[14]

Similarly, the federal plan should allow for a broad range of eligible measures for compliance to minimize cost and energy impacts for the state where a federal plan is imposed. When implementing a federal plan, EPA "stands in the shoes of the defaulting State, and all of the rights and duties that would otherwise fall to the State accrue instead to EPA" to develop a Clean Air Act plan. *Central Az. Water Conservation Dist. v. EPA*, 990 F.2d 1531, at 1541 (9th Cir. 1993) (citation omitted). In assuming the state's role in implementing the federal plan, EPA must establish a standard of performance that includes consideration of the costs of achieving emission reductions and energy requirements of the state where the federal plan is implemented. 42 U.S.C. §§ 7411(d)(2); 7411(a)(1). EPA is limiting its implementation options and potentially creating negative cost and energy impacts by excluding biomass energy, CHP, energy efficiency, and other cost-effective measures from the federal plan.

Second, EPA has not evaluated whether biomass energy can be deployed on an economic basis when implementing a federal plan. The preamble to the Proposal references the discussion in the CPP (Section V.E.6) in determining that wind, solar,

[14] EPA, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 Fed. Reg. 64,662, 64,735 (Oct. 23, 2015).

geothermal power, and hydropower resources can be economically deployed during the compliance period.[15] For the BSER analysis in the CPP, EPA used historical deployment patterns for wind, solar, geothermal power, and hydropower sources and modeled economic potential for those sources to demonstrate the successful levels of renewable energy that have been incorporated into the power system.[16] EPA should conduct a similar analysis to determine whether biomass energy can be economically deployed before deciding whether to eliminate it from consideration as an eligible least-cost resource for the federal plan.

Lastly, EPA claims that there is no "simple" or "timely" EM&V process to quantify biomass energy. However, in the preamble, EPA set forth a clear and simple EM&V path for renewable energy such as biomass. "[Q]uantification of RE generation can leverage the infrastructure and documentation associated with the establishment of renewable energy certificates (RECs) and registration of such certificates in REC registries. These registries typically include well established safeguards, documentation requirements, and procedures for registry operations intended to support the demonstration of compliance with state RPS policies."[17] As explained below in Section VII.E, there are other options to fulfill EM&V requirements for biomass energy when implementing the federal plan. These contradictory statements should be reconciled in favor of including biomass energy given the outlined EM&V procedures adopted in state RPS programs.

The list of eligible measures in the federal plan should include biomass energy, CHP, and any other measures that meet the requirements for eligible resources in the CPP.

B. Biomass Energy Should Be an Eligible Emission Reduction Measure in Both the Rate- and Mass-based Final Model Trading Rules.

It is arbitrary and capricious to include biomass energy as an eligible measure in the rate-based model trading rule but to exclude it in the model mass-based trading rule. The proposed rate-based model trading rules list "qualified" biomass as an eligible resource category for a state adopting the rate-based model rule (but not when applied as a federal plan).[18] In contrast, the mass-based model rule limits eligible resources to "onshore utility scale wind, solar, geothermal power, or utility scale hydropower" and excludes biomass or other resource categories allowed in the rate-based model rules.[19] See Table 1 below for difference in proposed rule language:

[15] 80 Fed. Reg. at 64,994.
[16] CPP, 80 Fed. Reg. at 64,807.
[17] 80 Fed. Reg. at 65,003.
[18] 40 C.F.R. § 62.16435(a)(4), 80 Fed. Reg. at 65,093 – 094.
[19] 40 C.F.R. § 62.16245(a)(2), 80 Fed. Reg. at 65,068.

Table 1: Proposed Model Rule Language for Eligible Resources

Model Rate-Based Rule	Model Mass-Based Rule
§ 62.16435 What eligible resources qualify for generation of ERCs in addition to affected EGUs? (a) ERCs may only be issued to an eligible resource that meet each of the requirements in paragraphs (a)(1) through (4) of this section. All categories of resources other than on-shore utility scale wind, utility scale solar photovoltaics, concentrated solar power, geothermal power, nuclear energy, or utility scale hydropower, and all provisions of this subpart relating to such resources, are not available or applicable in States where this subpart has been promulgated as a federal plan pursuant to section 111(d)(2) of the Act. . . . (4) The resource falls into one of the following categories of resources: (i) Renewable electric generating technologies using one of the following renewable energy resources: wind, solar, geothermal, hydro, wave, tidal; (ii) Qualified biomass; (iii) Waste-to-energy (biogenic portion); (iv) Nuclear energy; (v) A non-affected combined heat and power unit, including waste heat power; or (vi) A demand-side EE or demand-side management measure that saves electricity and is calculated on the basis of quantified ex poste savings, not ‘‘projected’’ or ‘‘claimed’’ savings.	**§ 62.16245 How are set-aside allowances allocated?** (a)(1) *Renewable energy set-aside*. The Administrator will establish a renewable energy set-aside as set forth in § 62.16235(c), and allocate CO_2 allowances from the set-aside for each year of a compliance period as outlined in this section. (2) *Eligible renewable energy capacity*. To be eligible to receive renewable energy set-aside allowances, an eligible resource must meet each of the requirements in paragraphs (a)(2)(i) through (v) of this section. Any resource that does not meet the requirements of paragraphs (a)(2)(i) through (v) of this section cannot receive set-aside allowances. (i) The resource must be a renewable energy resource that falls into one of the following categories of resources: onshore utility scale wind, solar, geothermal power, or utility scale hydropower.

EPA fails to justify why biomass energy is an eligible resource under the model rate-based rule but not in the model mass-based rule. EPA’s exclusion of biomass energy in the model mass-based rules seems contrary to the preamble language that states that “We are proposing, as part of the ***mass-based*** federal plan and ***model rule***, that a project is eligible to receive set-aside allowances if it is RE that meets the eligibility requirements for rate-based ERC issuance as specified in section IV.C of this preamble

and section VIII.K of the final EGs."[20] EPA does not provide any further explanation of this arbitrary and segregated treatment. Since biomass energy is an eligible resource under the rate-based model rule, EPA should include it in the mass-based model rule.

Moreover, as discussed in Section IV.B, as with many CHP units, many biomass-based renewable energy sources operate "Behind the Meter" and self-supply power without selling excess power to the grid. Some also may have "buy-sell" arrangements with their electricity provider. In both cases, as with CHP, the facility meets the requirement of Section 62.16434(b)(2) that the resource is "connected to, and delivers energy to or *saves electricity*, on the electric grid in the contiguous United States" (emphasis added). This is because the self-generated electricity reduces the amount of power that needs to be purchased on net from the grid.

C. EPA Should Include a List of Pre-approved Biomass Fuels in the Federal Plan and Both Model Trading Rules.

Assuming EPA's final federal plan includes biomass energy as an eligible compliance measure, AF&PA and AWC support the approach in the proposed Federal Plan to specify a list of pre-approved qualified biomass fuels. The list should include the following biomass fuels:

1. <u>Forest-derived industrial byproducts</u> (known also as forest products manufacturing residuals). These by-products/residuals should be defined as forest-derived biomass from pulp and paper mills, wood products manufacturing facilities, and downstream manufacturing facilities including, but not limited to:
   - spent pulping liquors (e.g., black liquor, red liquor, liquor solids) and pulping by-products and substances (e.g., rectified methanol, black liquor soap, red oil, lignin);
   - woody manufacturing residuals, such as:
     - pulping, paper, and converting process residuals (e.g., knots, shives, non-recoverable trim and broke);
     - bark;
     - wood product process residuals (e.g., residual sawmill chips, sawdust, shavings, sander dust, resinated wood residuals, veneer residuals, slabs, cutoffs, knots, woody residuals from air emission control systems), manufactured wood residuals (e.g., furniture, crate and pallet plant residuals);
     - off-specification materials; reinjection char (partially burnt biomass); paper machine cleaner, screening and other rejects; and
     - similar manufacturing residuals;
   - paper recycling residuals (e.g., materials removed from recovered paper and paperboard during the recycling process, such as non-recyclable fiber or old corrugated containers rejects);

[20] 80 Fed. Reg. at 65,023 (emphasis added).

- wastewater and process water treatment plant residuals; and
- "Grandfathered" biomass energy from residuals. Post-2012 eligible sources have already been providing biomass energy from residual byproducts to affected EGUs (see Section VII.C.b, below for further explanation)

Although burning forest products manufacturing residuals releases CO_2 into the atmosphere from the oxidation of the biomass, it both avoids GHG emission that would occur anyway if these residuals were not used for energy recovery. It also displaces the use of fossil fuels.

A critical fact is that forest products manufacturing residuals arise from the harvesting and processing of biomass for the purpose of manufacturing products to meet societal needs, and of necessity, the vast majority of this very large continuously produced volume of residuals would have to be disposed of – through landfilling, incinerating, wastewater treatment and discharge, or biodegrading in place – if they were not used as an energy source. Because biodegradation of woody forest products manufacturing residuals can release methane, and methane has a much greater impact on global warming than CO_2,[21] disposal of these residuals (i.e., not using them for fuel) in those cases can in fact result in significantly higher addition of GHGs to the atmosphere, in terms of global warming potential, than from their combustion for energy. In addition, EPA has recognized in other contexts that burning biomass to generate thermal energy and/or electricity means that fossil fuel will not be burned to meet that same energy demand, thus reducing the build-up of anthropogenic CO_2 in the global atmosphere.

A study by the NCASI[22] finds substantial GHG reduction benefits from using manufacturing residuals for biomass manufacturing residuals for energy in the forest products industry.[23] See attachment. The study examined the life cycle GHG and fossil fuel reduction benefits of using biomass residuals for energy production in the U.S. forest products industry. Wood processing activities at pulp, paper and wood products mills continuously produce a significant volume of biomass residuals, and they are the primary source of energy to run these mills. On average, about two-thirds of the energy powering forest products mills is derived from biomass. Accounting for fossil fuel displacement and avoided emissions associated with disposal, the use of biomass residuals each year avoids the emission of approximately 181 million metric tons of

[21] Viewed over a 100-year time frame, EPA believes that methane has 25 times greater impact on global warming per ton emitted than CO_2. *See* Table A-1 to 40 C.F.R. part 98 subpart A. Over a 20-year timeframe, the greater impact of methane emissions on the potential for global warming is even higher: According to Table 8.7 of the IPCC's *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, the 20-year global warming potential of methane is 86 times that of CO_2.

[22] The National Council for Air and Stream Improvement (NCASI) is an independent, non-profit research institute that focuses on environmental and sustainability topics relevant to forest management and the manufacture of forest products.

[23] *See* NCASI, *Greenhouse Gas And Fossil Fuel Reduction Benefits of Using Biomass Manufacturing Residuals for Energy Production in Forest Products Facilities*, Technical Bulletin No. 1016 (Rev. Aug. 2014), *available at* http://www.ncasi.org/Downloads/Download.ashx?id=9603 (attached).

CO_2e.[24] (This is equivalent to removing about 35 million cars from the road.) Based on this analysis, energy produced from manufacturing residuals has been demonstrated to control increases in CO_2 levels in the atmosphere.

In addition, the benefits of using biomass residuals for energy are rapidly realized. The GHG reduction benefits are realized in 1.2 years or less.[25] Even if the benefits of displacing fossil fuels are ignored, the use of manufacturing residuals for energy produces lower cumulative GHG emissions in 0 to 19.5 years, depending on the type of residual, with a weighted average break-even time of 7.6 years. When considering the historical and ongoing production and use of biomass energy over many decades, the U.S. forest products industry already is producing net GHG benefits by using biomass as its major energy source. For all of these reasons, forest products manufacturing residuals should be listed as a pre-approved biomass feedstock in the federal plan and model rules.

EPA has recognized that certain types of biomass feedstocks and post-life products are unlikely to contribute to atmospheric carbon. In a November 19, 2014 memorandum and in the revised draft *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* ("Revised Framework"), EPA states that certain forest-derived industrial byproducts such as black liquor, and waste-derived feedstocks such as municipal solid waste (e.g. urban wood waste, yard trimmings) and wastewater, have minimal or **no** net atmospheric concentrations of biogenic CO_2 emissions.[26] Further, EPA determined in a Prevention of Significant Deterioration (PSD) final permit that use of certain "feedstocks [mill residuals, untreated wood debris from urban areas, agricultural crops and residues, forest residues, and non-merchantable forest biomass] are unlikely to result in a significant increase in atmospheric CO_2 loading. . . . EPA believes that these revisions to Permit Condition X.G. will limit the facility to the types of biomass fuels that are generally considered to have lower net atmospheric contributions when combusted."[27]

For spent pulping liquor (e.g. black liquor), EPA conducted a careful consideration of black liquor in an addendum to Appendix D of the Revised Framework,[28] and concluded that the use of black liquor for energy at pulp and paper mills is carbon neutral. EPA

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[24] Gaudreault, C. and Miner, R., *Temporal Aspects in Evaluating the Greenhouse Gas Mitigation Benefits of Using Residues from Forest Products Manufacturing Facilities for Energy Production*. *J. of Industrial Ecology* 19(6):994-1007 (2015), at 1,004.

[25] Gaudreault, C. and Miner, R., *Temporal Aspects in Evaluating the Greenhouse Gas Mitigation Benefits of Using Residues from Forest Products Manufacturing Facilities for Energy Production*. *J. of Industrial Ecology* 19(6):994-1007 (2015), at 1,002.

[26] Memorandum from Janet McCabe, EPA Acting Assistant Administrator, to Air Division Directors, Regions 1-10 (Nov. 19, 2014) at 2 (emphasis added) ("McCabe Memo"); EPA, Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources, Draft (2014) (emphasis added) ("Revised Framework").

[27] EPA Region 9, Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit Major Modification for Sierra Pacific Industries - Anderson Division (Apr. 2014), at 10-12, *available at* http://www.epa.gov/region09/air/permit/pdf/spi-anderson/spi-anderson-final-permit-public-comment-response-2014-04-25.pdf.

[28] Revised Framework, at App. D-21 – D-32.

states that "an estimated BAF [biogenic assessment factor] of 0 can be considered for black liquor," and under two theoretical alternative fates, EPA actually calculates a negative BAF for black liquor, which indicates that using black liquor for energy could be better than carbon neutral.[29]

Based on the weight of this scientific evidence and data, EPA can conclude that the use of forest-derived industrial byproducts/residuals for energy has been demonstrated to control increases in CO_2 levels in the atmosphere and should be placed on a pre-approved list as qualified biomass feedstocks qualified according to the CPP rule.

a. An alternative markets test for forest products manufacturing residuals raises significant and complex issues and concerns.

In the proposed Federal Plan, EPA seeks comment on the option of specifying a list of "pre-approved biomass fuels" such as certain industrial byproducts feedstocks (e.g. "black liquor or other forestry or agricultural industrial by-products with no alternative markets"). In the Revised Framework, EPA raised the issue of "market leakage" where "[d]eviating by-products that do have current market uses to additional energy production instead of their traditional use could have potential impacts on those traditional markets."[30] EPA suggests in the Framework that an assessment of biogenic CO_2 emissions from forest-derived industrial processing products and byproducts should assess whether or not these materials have current alternative market uses to bioenergy.[31]

The concept of an alternative markets test for manufacturing residuals resulting from the manufacture of value-added forest products raises highly complex issues, and it is not clear how it could be practically and accurately implemented. EPA has not provided any guidance on how to make this demonstration.[32] Despite EPA's attempt to mitigate the potential biomass market distortions created by the CPP, AF&PA and AWC believe that whether there are alternative markets for forest products manufacturing residuals is an issue that is best left to the market (not the government) to determine, given the

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[29] *See, e.g.,* Revised Framework, at App. D, D-21 – D-32 ("The information in this appendix, including example calculations of alternative fate-related biogenic emissions, supports that a 0 or *negative [biogenic] assessment factor* for black liquor may be reasonable.") (emphasis added); *id.*, at D-31 (calculating negative biogenic assessment factors for black liquor and stating that "avoided emissions associated with disposal of black liquor as compared with the current management practice (burning for energy and chemical recovery in a recovery furnace) resulted in hypothetical example BAFs ranging from different negative values to 0, depending on the treatment method."). The three alternative fate scenarios considered by EPA include: (1) incineration without energy recovery (BAF = 0); (2) disposal in an aerobic wastewater treatment system (BAF = -0.09); and (3) disposal in an anaerobic wastewater treatment system (BAF = -1.2). *Id*. at D-29 – D-31.

[30] Revised Framework, App. D, at D-8.

[31] Revised Framework, App. D, at D-7 and D-8.

[32] *See* Revised Framework, at 19 ("The framework includes an equation term for leakage; however, the illustrative calculations presented in the appendices do not explicitly quantify leakage or provide a method to do so."); *see also id.*, at App. E, at E-10 (". . . the development and implementation of a land use analysis that adequately reflects leakage is a very complex endeavor . . . .).

complexities and dynamic nature of biomass markets. For example, except under sales contract, biomass manufacturing residuals and byproducts may swing from market to market depending on supply and demand which include external sales for product use or bioenergy markets to on-site bioenergy use. Fungibility of the manufacturing residuals markets results in frequent price fluctuations. Fiber market prices can change daily based on numerous factors. The mix of factors that makes an alternative market viable one day may not be viable on the next day. An alternative markets analysis process will not be able to preserve the nimbleness required to optimize buying and selling of manufacturing residuals. These practical real-world situations make binding alternative market analyses impractical from a business perspective.

Further it would be a costly, complex, resource-intensive process that could result in unintended consequences such as revealing confidential business information, and do little to address market leakage, which is the concern driving inclusion of the requirement. To determine whether there is an alternative market for a biomass manufacturing residual or byproduct, a renewable generator would likely need to demonstrate that viable markets for the residuals used do not exist. A viable market could mean the generating facility could benefit more by providing the residuals to a third party for use in manufacturing products than providing them to a power plant. How much benefit constitutes an alternative market will vary widely by entity. This may require extensive market and economic analyses and the disclosure of pricing information to EPA or affected EGUs wishing to purchase these manufacturing residuals for energy use, resulting in the loss of the pricing privacy normally associated with commercial transactions. In addition, the forest product manufacturer that is generating the residuals would have to expend significant time and resources to conduct an alternative markets analysis every time the supply or demand changes. Furthermore, once leakage is established, an LCA assessment would need to be conducted to determine whether it contributes materially to atmospheric CO_2 levels, adding further complexity and expense to this approach.

b. EPA must provide for public notice-and-comment before any type of alterative markets/leakage test is required.

If EPA requires an alternative markets analysis for manufacturing residuals/byproducts to be deemed qualified, EPA should first determine if market leakage is likely to occur. EPA should identify when factors exist that empirically relate to the probability of leakage and only require analysis at that point in time. For instance, distance from the alternate use is a key factor as the cost of transport will influence the economic viability of either the primary use or its alternate use. Significant distance between primary and secondary users makes market leakage highly unlikely.

As highlighted above, it is not practical for alternative markets determinations to be conducted in real time on a transaction by transaction basis. These determinations, once established, should remain valid for a set period of time and/or until a significant change in residual flows and markets occur.

Given the huge potential variability in what constitutes an alternative market, and the absence of a proposed methodology in this rule and other EPA guidance documents, it is imperative that EPA provide for public notice-and-comment before any type of alterative markets/market leakage test is required.

In addition, if post-2012 eligible sources have already been providing biomass energy from residual byproducts to affected EGUs, it is likely that the practice was driven by market forces or other considerations not directly related to the CPP. It would, therefore, be misguided to assume leakage as the result of the CPP. These facilities should be "grandfathered" and their biomass energy should be included on the list of qualified biomass without requiring an alternative markets test.

Finally, self-generated residuals combusted on site should always be carbon neutral. An entity should not be subject to an alternative markets test and forced to sell residuals it generates into other markets when the owner chooses to combust these residuals on site. For example, self-generation onsite includes situations where the same entity owns the saw or chip mill that will generate the residuals and the site that will combust the residuals for self-generated on-site energy, or owns the logs that are being processed at the saw or chip mill.

2. Waste-derived feedstocks, such as landfill gas and post-life wood products (e.g., used crates, pallets, construction and demolition wood, biomass materials listed under 40 C.F.R. Part 241, etc.).

EPA has recognized that waste-derived feedstocks that include landfill gas and post-life products are unlikely to contribute to atmospheric carbon. Similar to forest products manufacturing residuals, while burning of waste-derived feedstocks release CO_2 into the atmosphere from the oxidation of the biomass, it both avoids emission of GHGs that would occur anyway if these residuals were not used for energy recovery and displaces the use of fossil fuels. In EPA's November 19, 2014 memorandum and Revised Framework, EPA states that waste-derived feedstocks have minimal or **no** net atmospheric concentrations of biogenic CO_2 emissions.[33]

In Appendix N in the Revised Framework, EPA concludes that "the biologically based material in waste-derived feedstocks was removed from the land base for economic and production purposes outside of generating materials for the waste stream (e.g., for manufacture of consumer and industrial products, such as newspaper, food, and construction materials), [and] if waste-derived feedstocks had not been processed or used by a stationary source, the material would have been managed through an alternative strategy with an alternative emissions pathway. Whatever the waste management strategy, it would result in biogenic CO_2 emissions and likely some amount of CO_2e GHG emissions (e.g., CH_4 emissions as a result of anaerobic decomposition)."[34] The Revised Framework calculates a zero to negative biogenic

[33] McCabe Memo at 2 (emphasis added).
[34] Revised Framework, at N-7

assessment factor (BAF) for municipal solid waste (i.e., biogenic resources including food, paper and wood products such as wood pallets) that is burned for energy as opposed to landfilled.[35]

Also, EPA determined in a PSD final permit mentioned above that use of certain waste-derived woody feedstocks such as wood pallets, crates, dunnage, manufacturing and construction wood debris from urban areas are "unlikely to result in a significant increase in atmospheric CO_2 loading. . . . EPA believes that [these] types of biomass fuels that are generally considered to have lower net atmospheric contributions when combusted."[36] Further, EPA plans to revise the PSD rules "to include an exemption from the Best Available Control technology (BACT) requirement for GHGs from waste-derived feedstocks."[37]

Based on the weight of EPA's own analysis and data, waste-derived feedstocks have been demonstrated as a method to control increases in CO_2 levels in the atmosphere and should be placed on a pre-approved list as qualified biomass energy feedstocks for use as a compliance option under the CPP.

3. <u>Certain forest-derived biomass feedstocks from timberlands</u>.

Other types of forest-derived biomass feedstocks such as roundwood from timberlands should be considered qualified biomass where the growth rate of timberlands is greater than or equal to harvest levels on a broad regional scale, based on data produced by the Forest Inventory and Analysis (FIA) program administered by the U.S. Forest Service. Change in above-ground wood inventories on timberlands should be used to assess the status of FIA regions.

Given the continuous cycle of biogenic emissions (through combustion or decay), regrowth and sequestration (via photosynthesis), EPA should assess whether growth exceeds harvest on a broad regional scale consistent with four FIA regions as discussed below, rather than assessing individual sources and sinks in isolation. Roger Sedjo addresses this issue in his study, "Carbon Neutrality and Bioenergy":

> *A forest system also behaves differently from a site. In the United States, for example, large landscapes are managed as forest systems. Management activities in one place are related to activities elsewhere in the system, beyond the specific site. For example, a steady flow of wood may not be possible in sufficient volumes from an individual site but can*

[35] Revised Framework, at N-29 – N-37.
[36] EPA Region 9, Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit Major Modification for Sierra Pacific Industries - Anderson Division (Apr. 2014), at 10-12, *available at* http://www.epa.gov/region09/air/permit/pdf/spi-anderson/spi-anderson-final-permit-public-comment-response-2014-04-25.pdf
[37] McCabe Memo at 3.

> *be achieved from a system. The same could be true for carbon emissions, where sequestration on one site offsets emissions from another.*[38]

Assessing biogenic emissions on a small scale only measures a portion of the carbon cycle and will result in misleading conclusions regarding the benefits of biomass for GHG mitigation over the long-term. Because trees require a long-term investment before harvest, forests are managed for long-term productivity on a landscape scale. Each individual tree or stand is part of a larger forest management plan that includes multiple stands at different stages of development. At any given period in time, a few stands will be subject to harvest or other stand improvement projects while the vast majority will continue to grow and sequester more carbon. Thus, it makes little sense to evaluate the effects of biomass energy in a stand-by-stand manner because it fails to give a full picture of the effects taking place on other stands that are part of the same management regime. Also, procurement areas for timberlands more often than not encompass more than one state.[39] In addition, this regional approach provides the ability to assess emissions and sinks from natural and manmade occurrences such as forest fires and land use changes or conversions that affect multiple states.

Regions should consist of states that are related ecologically and where similar levels of forest management are taking place. For example, the following four regions in the contiguous United States result in reasonable state groupings for analysis purposes:

- North: CT, DL, IL, IN, IA, KS, MA, ME, MD, MI, MN, MO, NE, NH, NJ, NY, ND, OH, PA, RI, SD, VT, WV, WI
- South: AL, AR, FL, GA, KY, LA, NC, OK, SC, MS, TN, TX, VA
- SouthWest: AZ, CO, NV, NM, UT
- Pacific Coast NW: CA, OR, WA, ID, MT

FIA does not yet have sufficient annual inventory data for Wyoming for that state to be included in the analysis. FIA data for Alaska is generally limited to coastal areas and was not included. Montana and Idaho are somewhat different from surrounding states, but resemble Pacific Coast states with regard to industrial forest activity and ecological characteristics. See attached NCASI paper*, Grouping Montana and Idaho with Surrounding States for Biogenic Accounting* (May 2014), for detailed explanation for this regional grouping.

EPA should also assess the net growth for timberlands based on long temporal horizons. A 100-year time horizon should be used for assessing the net benefits of

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[38] Sedjo, Roger. *Carbon Neutrality and Bioenergy: A Zero Sum Game*. Resources for the Future (Apr. 2011).

[39] *See* Abt, Robert, Galik, Christopher, and Henderson, Jesse, *The Near-Term Market and Greenhouse Gas Implications of Forest Biomass Utilization on the Southeastern United States*, Duke University (Aug. 2010), at 7, Fig. 3 (showing that about two-thirds of coal fired power plants in the south have a 50-mile procurement radius that encompasses more than one state. In a number of cases, the procurement would be from more than two states).

using biomass as well as the net biogenic CO_2 emissions. The carbon footprint of burning biomass to generate energy should be calculated over a sufficiently long timeframe to allow the major transfers of GHGs to and from the atmosphere to play out. Given that the global warming (GW) impacts of fossil-fuel-derived GHGs are typically judged using 100-year GW potentials as per Intergovernmental Panel on Climate Change (IPCC) guidance,[40] the net warming impacts of biogenic CO_2 should also be assessed using a similarly long timeframe. To use a temporal scale other than 100-years would assess the atmospheric impacts of biogenic CO_2 in a way that is inconsistent with how the impacts of fossil-fuel derived GHGs are assessed in the CPP.[41]

Also, when it comes to roundwood that is sourced directly from timberlands, it is important to use a timeframe that captures the investment response – i.e., market forces that increase forest productivity and keep forestlands from being diverted to development or other low-carbon storage uses.[42] Because of the global warming dynamics of CO_2 and the timing of benefits from biomass energy systems, EPA should consider a longer temporal scale or risk implementing polices that would result in more net GHG emissions.

Further, EPA should use a reference point baseline to assess the growth of timberlands. A reference baseline approach that uses current and historical data provides a more straightforward and transparent way to assess whether there are any atmospheric impacts from the use of biomass for energy. While a reference point baseline approach may have limitations, it is much more objective than a future anticipated baseline approach. In fact, a commentary published in Nature Climate Change, "Uncertainty in Projecting GHG Emissions From Bioenergy," demonstrates that reference point baselines have actually been more accurate predictors of future forest inventories than future anticipated baselines.[43] The article concluded that "[g]iven the challenges in predicting the future status of forest resources, anticipated future baselines might be best suited for planning and policy development, while constant reference baselines might be more appropriate for monitoring and regulatory frameworks."[44] Moreover, a future anticipated baseline likely will involve greater complexity and cost to the regulatory system, which could reduce incentives to keep lands forested, particularly for smaller entities.

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[40] Gaudreault, C. and Miner, R., *Temporal Aspects in Evaluating the Greenhouse Gas Mitigation Benefits of Using Residues from Forest Products Manufacturing Facilities for Energy Production*. *J. of Industrial Ecology* 19(6):994-1007, at 998 (2015).

[41] *See* EPA, Regulatory Impact Analysis for the Clean Power Plan Final Rule (Oct. 2015 revision), at 2-24 n.33 ("CO_2 equivalent data in this section are calculated with the IPCC SAR (Second Assessment Report) GWP potential factors.").

[42] EPA, *SAB Review of EPA's Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources* (September 2011), at 6 (Sept. 28, 2012).

[43] Buchholz, T., S. Prisley, G. Marland, C. Canham and N. Sampson, *Uncertainty in Projecting GHG Emissions from Bioenergy*, Nature Climate Change, Vol 4., at 1045-1047 (Dec. 2014).

[44] Buchholz, T., S. Prisley, G. Marland, C. Canham and N. Sampson, *Uncertainty in Projecting GHG Emissions from Bioenergy*, Nature Climate Change, Vol 4., at 1047 (Dec. 2014).

If the growth of timberlands is greater than or equal to harvest levels in the FIA regions as defined above, the use of forest-derived biomass feedstock from those timberland regions should be considered fully carbon neutral, a method to control increases in CO_2 levels in the atmosphere, and should be listed as pre-approved qualified biomass.

D. Under the Federal Plan and Both Model Trading Rules, EPA Should Allow Sources to Seek Approval for Other Types of Biomass to Add to the Pre-approved List.

Given the changing dynamics of the energy market and other policy factors, EPA should allow affected EGUs and other sources to petition EPA to add additional biomass feedstocks to the pre-approved list. If a source can demonstrate that the use of a biomass feedstock not on the pre-approved list can be used as a method to control increases in CO_2 levels in the atmosphere in its petition, EPA should add that biomass feedstock to the list after appropriate public notice-and-comment. States which adopt the model trading rules should be allowed to amend their state plans to update their pre-approved qualified biomass list.[45]

E. Qualified Biomass Feedstocks on the Pre-approved List Should Be Measured as Carbon Neutral and Have Limited EM&V Requirements.

EPA is seeking comment on what types of EM&V requirements should be imposed for eligible measures such as biomass energy for the federal plan and model trading rules. We support EPA's recommendation that the monitoring and reporting requirements for biogenic CO_2 emissions in 40 C.F.R. part 98 (40 C.F.R. §§ 98.3(c), 98.36(b)-(d), 98.43(b), and 98.46) are sufficient to monitor and report biogenic CO_2 emissions from eligible sources and affected EGUs.[46] Eligible resources and affected EGUs that use qualified biomass feedstocks from the pre-approved list should count the biogenic CO_2 emissions from these feedstocks as zero/carbon neutral. Therefore, under a mass-based federal plan, an affected EGU would need to hold allowances equal to its CO_2 emissions less the biogenic CO_2 emissions attributed to the co-firing of biomass. Under a rate-based plan, an affected EGU would count the biogenic CO_2 emissions attributed to the co-firing of biomass as zero emissions when calculating its emission rate to demonstrate compliance.

In addition, we believe that complicated verification or tracking of qualified biomass on the pre-approved list is unnecessary. Other renewable energy sources such as wind and solar do not require additional tracking or verification beyond verifying the total MWh output. Once these biomass feedstocks are listed as pre-approved, an eligible source or affected EGU should only need to specify that the biomass used is included on the pre-approved list and verify the total MWh generated from the biomass

[45] This proposed petition process is in addition to and separate from a state's action to include a biomass feedstock in its development of a CPP state compliance plan.
[46] 80 Fed. Reg. at 65,005.

feedstock. One method that could be used to verify MWh output can be modeled after the documentation requirements for renewable energy credits under state Renewable Portfolio Standards.

F. Sustainable Forest Management or Certification Programs Are Not Carbon Standards.

EPA proposes that third-party sustainable forest management or certification programs may be used to demonstrate that biomass feedstocks from these programs help control increases of CO_2 in the atmosphere.[47] AF&PA and AWC support state and third-party sustainable forest management and certification programs as effective tools to improve the health and productivity of forests.

We recognize that key aspects of these programs and certification standards seek to maintain stable forest carbon stocks in the long term. For example, the Sustainable Forestry Initiative (SFI) requires program participants to "ensure that forest management plans include long-term harvest levels that are sustainable and consistent with appropriate growth-and-yield models" and "measures to avoid forest conversion."[48] Also, a key principle of the Forest Stewardship Council (FSC) standard is that the "rate of harvest of forest products shall not exceed levels which can be permanently sustained."[49] These programs help to maintain a balance between harvesting and regrowth which result in stable long-term carbon stocks in managed forests.

However, these sustainable forestry management and certification programs do not specifically address carbon sequestration and encompass a wide range of practices not related to the control of carbon emissions from biomass used for energy. While these certification standards may indicate that certified biomass originates from well-managed forests, EPA should assess biomass feedstocks using carbon-based standards and assessment tools.

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[47] 80 Fed. Reg. at 64,995.

[48] Sustainable Forest Initiative (SFI), *SFI 2015-2019 Forest Management Standard*, 1.6 SFI 2015-2019 Forest Management Standard Requirements (Jan. 2015), at 4, *available at* http://www.sfiprogram.org/files/pdf/2015-2019-standardsandrules-section-2-pdf/. *See also*, Programme for the Endorsement of Forest Certification (PEFC), *Sustainable Forest Management – Requirements*, at 8 -10 ("5.1 Criterion 1: Maintenance and appropriate enhancement of forest resources and their contribution to the global carbon cycle. 5.1.9 Forest management practices shall safeguard the quantity and quality of the forest resources in the medium and long term by balancing harvesting and growth rates . . . .") (Nov. 2010), *available at* http://www.pefc.org/standards/technical-documentation/pefc-international-standards-2010/676-sustainable-forest-management-pefc-st-10032010.

[49] Forest Stewardship Council, *FSC-US Forest Management Standard (v1.0), Principle 5, Benefits from the Forest*, C5.6, at 22 (approved Jul. 8, 2010), *available at* file:///C:/Users/LTsang/Downloads/FSC-US%20Forest%20Management%20Standard%20v1.0.pdf.

VIII. The Proposed Accounting Approach for Non-Affected CHP Undervalues Its Emissions Benefits and Should Be Modified.

EPA appropriately recognized in the final CPP that non-affected new CHP units can generate and receive ERCs.[50] The agency also acknowledges the need to provide technical assistance to help states include CHP in their plans and the rule seeks to provide some of this initial guidance. The proposed model rule for a rate-based emission-trading program includes an accounting method for determining the ERCs from non-affected CHP units that could be a "presumptively approvable accounting approach."[51] We believe that the proposed approach significantly undervalues CHP's emission benefits.

The Alliance for Industrial Efficiency (Alliance) today is filing comments on numerous CHP issues and includes a discussion of the environmental, economic, and reliability benefits of CHP.[52] We support that discussion, as well as the comments' detailed proposed modification on how to properly account for CHP's benefits. As EPA recognizes in the final CPP, for fossil fuel-fired CHP the accounting approach must both "take into account the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low."[53] We concur with EPA that it is appropriate to net out (i.e., account for the fossil fuel-fired emissions) the incremental emissions associated with CHP units before ascribing ERCs to the output. This approach to calculating CHP benefits is an example of the avoided emissions approach. Of course, if the CHP unit is fired by qualified biomass, then the amount of CO_2 emissions that should be attributed to the CHP unit should be zero.

The proposed methodology, however, is flawed because of two mistakes in the way it compares emissions from generation at non-affected CHP systems to emissions from generation at affected EGUs (and therefore, what emissions will be "avoided"):

1. It compares the CHP output to natural gas generation, rather than the generation that is most likely to be avoided due to CHP deployment; and

[50] As discussed in previous AF&PA and AWC comments, while non-affected CHP units can generate ERCs, our members' CHP units should be excluded as affected EGUs. This apparently was EPA's intent in the final CPP, but it was unclear in the pre-publication version that this was the case due to an omission of the definition of "net sales." EPA rectified this error in the CPP published in the Federal Register. See 40 C.F.R. § 60.5880, 80 Fed. Reg. 64,959. See also the NSPS definition, at 40 C.F.R. § 60.5580, 80 Fed. Reg. at 64,656. Any final plan or model trading rules should ensure that the "net-electric sales" definition is included or otherwise incorporated into those measures. *See* 40 C.F.R. § 60.5880, 80 Fed. Reg. 64,959.
[51] 80 Fed. Reg. at 64,902.
[52] Comments on Model Trading Rules: Federal Plan Requirements for Greenhouse Gas Emissions From Electric Generating Units Constructed on or Before January 8, 2014, Alliance for Industrial Efficiency (Jan. 21, 2016), at Sec. II.1.
[53] *Id.*

2. It compares the CHP output to future emission target rates, rather than real-time emissions rates.

We do not believe it is appropriate to base the netting of the electrical output from a biomass or natural gas CHP system on the compliance goals for stationary combustion turbines. Instead, EPA should compare the emissions from the non-affected EGUs to actual emissions data from actual affected EGUs from the previous calendar year. We propose three alternative approaches, all of which would more accurately account for the actual emission reductions from CHP and increase the value of ERCs for CHP over EPA's proposed approach:

1. The average affected EGU emission rate for the eGRID subregion in which the CHP project is located;
2. The average affected EGU emission rate for each state; or
3. A single national average affected EGU emission rate.

The Alliance comments discuss these options in detail and some of the benefits and disadvantages of each of them. Based on that discussion, we recommend that EPA defer to the states in determining which option to implement to ensure that CHP technology is appropriated credited for emissions avoided.

C. The Proposal's Discussion of Line Losses for CHP Should be Modified.

We also support EPA's recognition that distributed generation such as CHP has value in reducing line losses. As the Alliance comments point out,[54] however, EPA's language implies that only CHP units smaller than 1 megawatt (MW) can include transmission and distribution (T&D) losses in the calculation of ERCs. We do not believe that was EPA's intent, and we support the Alliance's proposed language to clarify the point.

IX. The Final Federal Plan and Model Rules Should Expand the Clean Energy Incentive Program (CEIP) to Allow for all Eligible Renewable Resources.

We oppose government mandates and incentives that distort the market. If the government does impose incentives or mandates for renewable energy, those policies must treat industry energy generation from biomass equally with newly created renewable energy generation.

We do not support the CEIP as currently drafted because it does not necessarily lead to least-cost compliance nor does it treat all renewable resources equally. Nonetheless, the CEIP is included in the final CPP and it is clear that EPA intends to implement it as part of any federal plan. As proposed, renewable energy in the CEIP only includes "metered MWh from any type of wind or solar resources" as eligible to participate in the CEIP. Although we oppose incentive programs such as the CEIP, we believe that all eligible renewable energy resources, including biomass, that are included in the final

[54] Alliance Comments, Sec. II.3.

CPP should be eligible to participate in the CEIP for the final Federal Plan and both model trading rules. We do not agree that renewable energy resources other than wind and solar are incapable of accurately measuring their electrical output, as EPA proclaims in the Proposal. EPA has picked winners (and losers) by selecting only wind, solar and low-income energy efficiency as eligible resources. Moreover, contrary to the requirements for establishing the BSER, EPA has failed to conduct any cost-benefit analysis whatsoever to show that these CEIP-eligible options would be the least costly among all technologies. As discussed elsewhere in these comments, this would provide additional flexibility and help achieve least-cost compliance for all ratepayers. Accordingly, if a renewable energy project, such as a biomass-fired CHP unit, can meet criteria similar to the criteria in the final CPP and can adequately account for and verify MWh generated, those projects should be allowed to participate in the CEIP under the Federal Plan and model trading rules.

X. The Federal Plan Should Include a Reliability Safety Valve (RSV) and Include Other Provisions to Address Reliability.

In our comments on the proposed CPP, we highlighted the importance of a reliable supply of energy for manufacturers such as our members. Many other commenters also discussed in detail their reliability concerns with the proposed CPP and made a number of recommendations to improve reliability, including the suggestion that EPA include an RSV in the final rule.

EPA did include an RSV and took a number of other steps to address reliability concerns, including delaying the start of the initial compliance period by two years to 2022. Nonetheless, those steps have not completely addressed all reliability concerns. For example, Federal Energy Regulatory Commissioner (FERC) Tony Clark pointed out in recent congressional testimony[55] that it can take from 3 to 12 years to site the infrastructure, such as new transmission facilities and natural gas pipelines that will be required for CPP compliance. EPA provides the option for states to seek extensions only until September 2018 for submitting state compliance plans, and most states are expected to use that full extension. In this case, there will be only four years between the date of the submittals to the first compliance period, yet as Commissioner Clark noted, it can take many more years for the needed infrastructure to be completed.

EPA's proposed federal plan did not include an RSV. In light of the unresolved reliability concerns just stated, AF&PA and AWC support including an RSV in the final federal plan and in both model rules. We also support including in the federal plan and model mass-based rules an allowance set-aside available in emergency circumstances in which an affected EGU was compelled to provide reliability critical generation, and

[55] Written Testimony of Tony Clark, Commissioner, Federal Energy Regulatory Commission, Before the Committee on Energy and Commerce, Subcommittee on Energy and Power, United States House of Representatives, Hearing on Oversight of the Federal Energy Regulatory Commission (FERC), December 1, 2015.

demonstrates that a supply of allowances needed to offset emissions was not available. We also support similar mechanisms for rate-based plans.

* * * *

Thank you for the opportunity to comment on the Proposal. If you have any questions about these comments, please contact Jerry Schwartz, AF&PA and AWC Senior Director, Energy and Environmental Policy at (202) 463-2581 or Jerry_Schwartz@afandpa.org or Linda Tsang, AF&PA and AWC Director, Climate and Air Quality at (202) 463-2752 or Linda_Tsang@afandpa.org.

Sincerely,

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Robert Glowinski
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Attachments

- NERA, *Potential Electricity and Energy Price Outcomes Under EPA's Federal Plan Alternatives for the Clean Power Plan* (Jan. 2016).
- NCASI, *Greenhouse Gas And Fossil Fuel Reduction Benefits of Using Biomass Manufacturing Residuals for Energy Production in Forest Products Facilities*, Technical Bulletin No. 1016 (rev. Aug. 2014)
- NCASI, *Grouping Montana and Idaho with Surrounding States for Biogenic Accounting* (May 2014)

Potential Electricity and Energy Price Outcomes under EPA's Federal Plan Alternatives for the Clean Power Plan

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American Wood Council
American Chemistry Council
American Iron & Steel Institute
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Executive Summary

On October 23, 2015, EPA promulgated the Final Clean Power Plan ("CPP") rule to reduce CO_2 emissions from existing fossil fuel-fired power plants and simultaneously published a proposed rule for a Federal Plan ("FP") in the Federal Register (EPA, 2015a and 2015b). Comments on the proposed FP are due January 21, 2016. In this report, NERA presents modeling results for alternative FP implementations to support comments on the FP. The report focuses primarily on the implications for state-level retail electricity rates and national natural gas prices of alternative FP options. The report also provides some insights about a proposed option to prevent leakage.

A. Overview of Proposed Federal Plan

The CPP is a nationwide regulation under Section 111(d) of the Clean Air Act that regulates existing electricity generating units, specifically fossil fuel-fired steam units and combined-cycle combustion turbines. The rule provides two compliance structures, one based on meeting state-specific emission rate targets in pounds of CO_2 per megawatt-hour (lb/MWh) and the other based on a CO_2 cap for total emissions from the regulated generators in each state ("mass cap"). Each state's mass cap is based on EPA's assessment of the emissions that would be equivalent to complying with the state's rate-based limit. The limits, whether rate- or mass-based, are phased in from 2022 through 2030. The rule also allows states to trade with other states that elect the same generic regulatory option. According to EPA's estimates, the CPP will result in U.S. power sector CO_2 emissions in 2030 that will be 32% below their level in 2005.

EPA is authorized to implement a FP if a state fails to submit a compliance plan or if the state's compliance plan is considered inadequate. The proposed FP features both a rate-based and mass-based plan, but EPA has proposed that only one option become the final FP approach.

- *Rate-based approach.* The rate-based proposed FP would require a state to meet a given average emission rate, in lb/MWh, equal to the state's rate-based limit in the CPP. The proposed rate-based FP specifies the covered emissions and covered generation that would be used to determine compliance. Because the FP can include only measures that are federally-enforceable, end-use efficiency is presumed to be precluded from rate-based plans. Trading among units within the affected state would be allowed, as well as trading with other states under a rate-based FP or with states whose plans meet the conditions for linkage to the federal plan.

- *Mass-based approach*. The mass-based proposed FP would require aggregate emissions from affected sources within a state—consisting of fossil-fuel steam units, existing natural gas combined cycle units, and combined heat and power facilities—to be less than or equal to a state cap equal to the state's mass-based limit in the CPP. The proposed FP identifies how EPA would set initial allocations of allowances, *i.e.*, the right to emit a ton of CO_2, but states would be allowed to make their own alternative allocation decisions. Affected generating units would be able to buy and sell emission allowances from other affected generating units within the state as well as potentially from affected generating

units in other states covered by their own mass-based FP. If a mass-based approach is applied, the state must demonstrate that leakage to non-covered NGCC plants will be prevented.

B. NERA Objectives and Methodology

NERA's principal objective was to evaluate key energy price outcomes under FP alternatives. We focused on the major choice involved—which is whether to adopt a rate-based or mass-based FP—but we consider several important implementation uncertainties that may affect that choice. In particular, we consider the level of trading (*i.e.*, state vs. regional vs. national trading) and, for mass-based programs, the nature of initial allowance allocation. We compare these alternatives in terms of their implications for projected state-specific retail electricity rates and for national natural gas prices.[1] We also have considered alternative mechanisms proposed for preventing leakage under a mass-based cap (i.e., increased emissions from new sources that are not covered by the cap). The full set of results provides the bases for some conclusions regarding the alternative FP designs.

We used the N_{ew}ERA model—an economy-wide integrated energy and economic model that includes a bottom-up representation of the U.S. electricity sector and a top-down representation of all other sectors of the economy, including households and governments—to evaluate the implications of alternative FP implementation.

We modeled least-cost compliance scenarios that differ based on the FP structure (mass-based vs. rate-based), the level of trading presumed, and two extreme cases for initial allocation of allowances to lower electricity prices by allocating allowances to electricity distribution companies (EDCs). The regional trading case is based on seven regions, as described in the report.

Mass-based trading schemes will require creation of emissions allowances, the initial distribution of which affects the ultimate regulatory cost burdens on different sectors and individuals. NERA presents a range focusing on the extent to which the initial allocation is used to lower retail consumer electricity rates by providing allocations to EDCs.[2] In NERA's 0% allocation case,

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[1] This report compares the effects of FP alternatives, presuming that the CPP will be implemented. NERA (2015) evaluates the energy and consumer effects of the CPP itself. See NERA (2015) for evaluations of the effects of the CPP on U.S. energy sector expenditures, U.S. retail electricity rates, U.S. natural gas prices, and U.S. consumption.

[2] NERA's allocation of the allowance value to electricity distribution companies (EDCs) is different from the proposed approach in the FP of allocating allowances to affected EGUs based on historical generation. It is also somewhat different from the alternative proposed in the FP, to allocate allowances to load-serving entities (LSEs) as a way to enable the value of the allowances to be passed through to consumers. EDCs and LSEs can be different entities. An EDC is the entity responsible for distribution of electricity and maintenance of the local grid that extends into ratepayers' homes or facilities, while an LSE is a company that markets and sells its supply of electrons to retail customers, but may not be an EDC. While an assumption implicit in EPA's alternative allocation proposal is that LSEs can be required to pass through any allocated allowance value in the form of lower rates per kWh at the meter, it is not clear to us which of these two types of entities can be expected to

allowances are auctioned to generators with none of the proceeds distributed to EDCs (but all the proceeds returned to state consumers), and thus electricity prices are not reduced. In NERA's 100% allocation case, all allowances are freely distributed to EDCs and assumed to be used solely as a credit to reduce electricity rates.

Note that in NERA's modeling of the 0% allocation case, each state is assumed to still return all the allowance allocation value to consumers through means other than lowering retail rates, using a mechanism economists refer to as a "lump sum" transfer. Lump sum redistributions could include per-household dividend checks, or per-person income tax rebates, among other means.

NERA modeled all of the core mass-based scenarios using the New Source Complement caps to deal with leakage. This choice is one option provided in the final CPP, though it is not proposed for the FP.[3] NERA has also explored potential leakage under a 5% renewable set aside option, which is discussed separately below.

The resulting set of seven "core" scenarios are listed in Table E-1.

Table E-1. List of Core Scenarios in this Analysis

	Scenario(*)	Trading(**)	Allocations to Reduce Electricity Rates
A	Mass-based	Intra-State	0%
B	Mass-based	Regional Trading	0%
C	Mass-based	National Trading	0%
D	Mass-based	Intra-State	100%
E	Mass-based	National Trading	100%
F	Rate-based	Intra-State	Not applicable
G	Rate-based	National Trading	Not applicable

(*) All of the core mass-based scenarios were implemented using the New Source Complement caps as the means to prevent leakage.
(**) The regional trading case assumes seven regions, as described in the report.

provide such an outcome. We perform an analysis that is comparable in intent to that of EPA's alternative allocation proposal, in that our analysis assumes such a pass-through can be enforced. For our report, we have called this an allocation to an EDC, as that is the entity most commonly associated with the local regulated utility, but it could be interpreted as an allocation to any entity that can be required by a regulator to make retail rates per kWh decline.

[3] In the proposed FP, EPA requires that leakage under the mass-based approach be addressed by implementing output-based allocation set-asides based on historical generation, and a set-aside that encourages the installation of renewable energy. However, EPA requests comment on the proposed treatment of leakage, which is discussed within the report body.

C. Summary of Results

1. State Electricity Prices

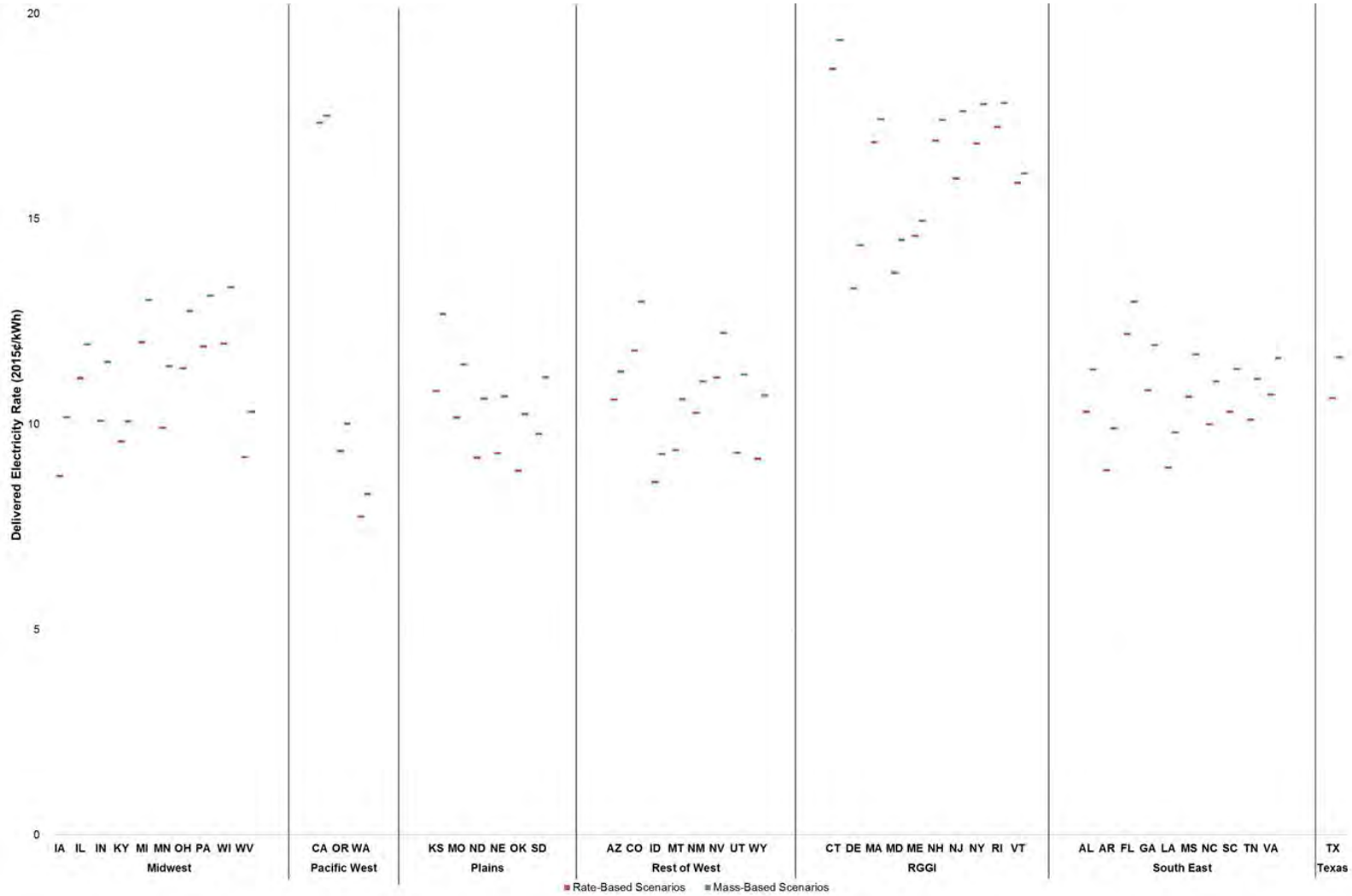
To summarize electricity rate outcomes by state, we report projected retail electricity prices averaged over the period from 2022 to 2033. (More detailed price projections at the rate class level—industrial, commercial and residential—are provided in the report.) We present the results in a comparative format. For each state, we compare the projected outcome under a rate- versus a mass-based approach. The results are provided in a three-step sequence of figures to illustrate the relative importance of key uncertainties that will determine ultimate electricity price levels.

In the three figures, the red bars represent rate-based results and the paired blue bars represent the mass-based results. The state results are organized by trading region. The sequence of comparisons in Figures 1 through 3 is the following:

> Figure E-1: "Basic" Comparison of Rate-Based vs. Mass-Based. Figure E-1 provides comparisons of rate-based to mass-based results for one basic implementation case: the "state-only" trading option with no EDC allowance allocations (0% allocation). That is, this compares results for scenario A to those for scenario F (as defined in Table E-1).
>
> Figure E-2: Addition of Geographic Scope of Trading. Figure E-2 adds the implications of different geographic scopes of emissions trading. This compares results for scenarios A, B and C to those for F and G (as defined in Table E-1). This figure shows a range of projected electricity rates for both the mass- and rate-based alternatives, and this range is represented in the figure as a vertical bar from the lowest to the highest end of the range. (Specific values for each individual scenario are provided in tabular format in the report.)
>
> Figure E-3: Addition of EDC Allocation. Figure E-3 adds the implications for the range of potential electricity rates of EDC allocations for the mass-based alternative. In contrast to the 0% allocation assumption used in Figures E-1 and E-2, this figure now includes the other extreme of 100% EDC allocation. Thus the range of results for scenarios A through E are compared to the range of results from scenarios F and G.

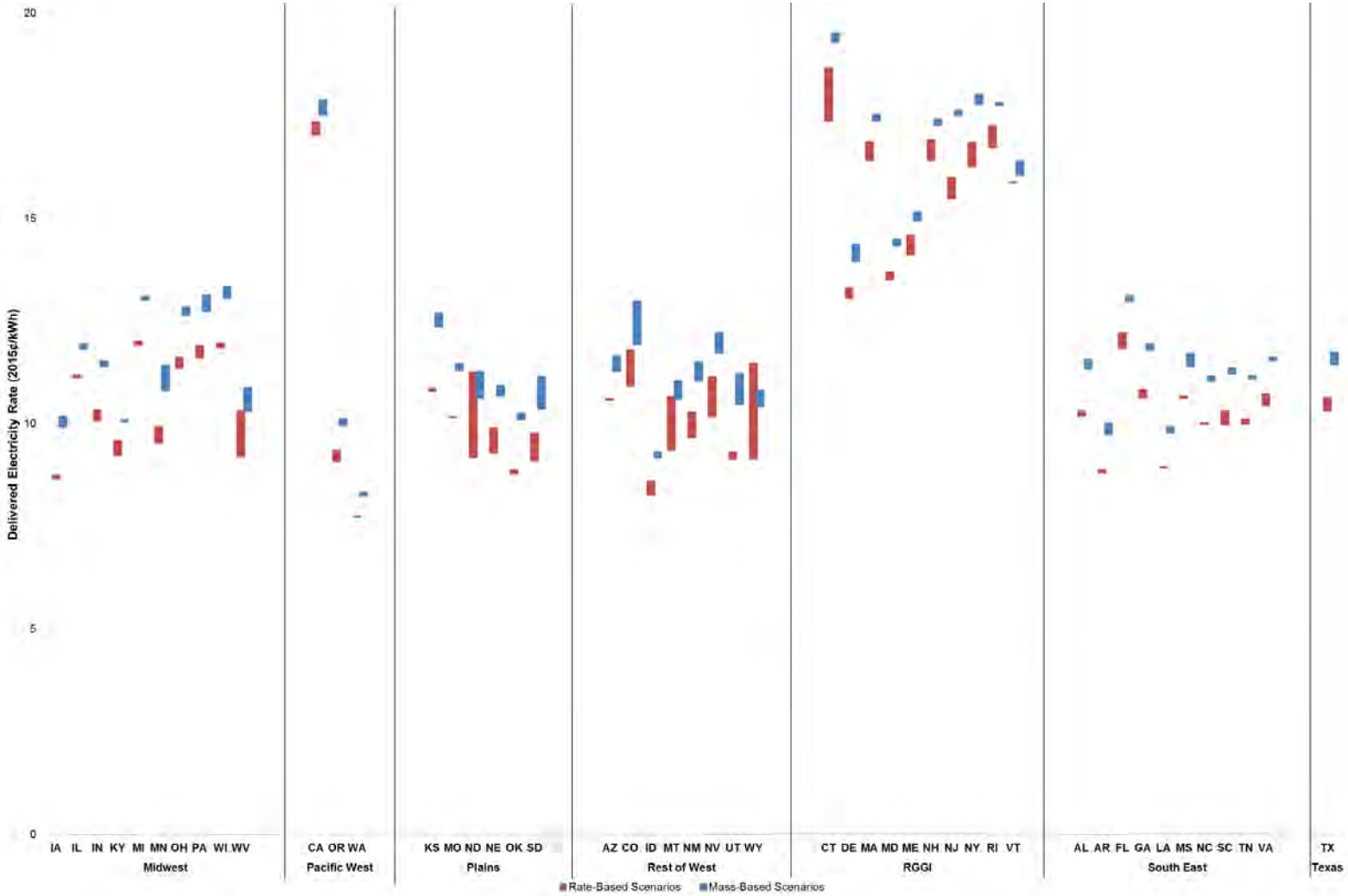
All three figures illustrate the implications for state retail electricity prices of differences in the design of a FP.

Figure E-1. State by state electricity rate projections for state-only trading with 0% free allocations to EDCs (2015¢/kWh)



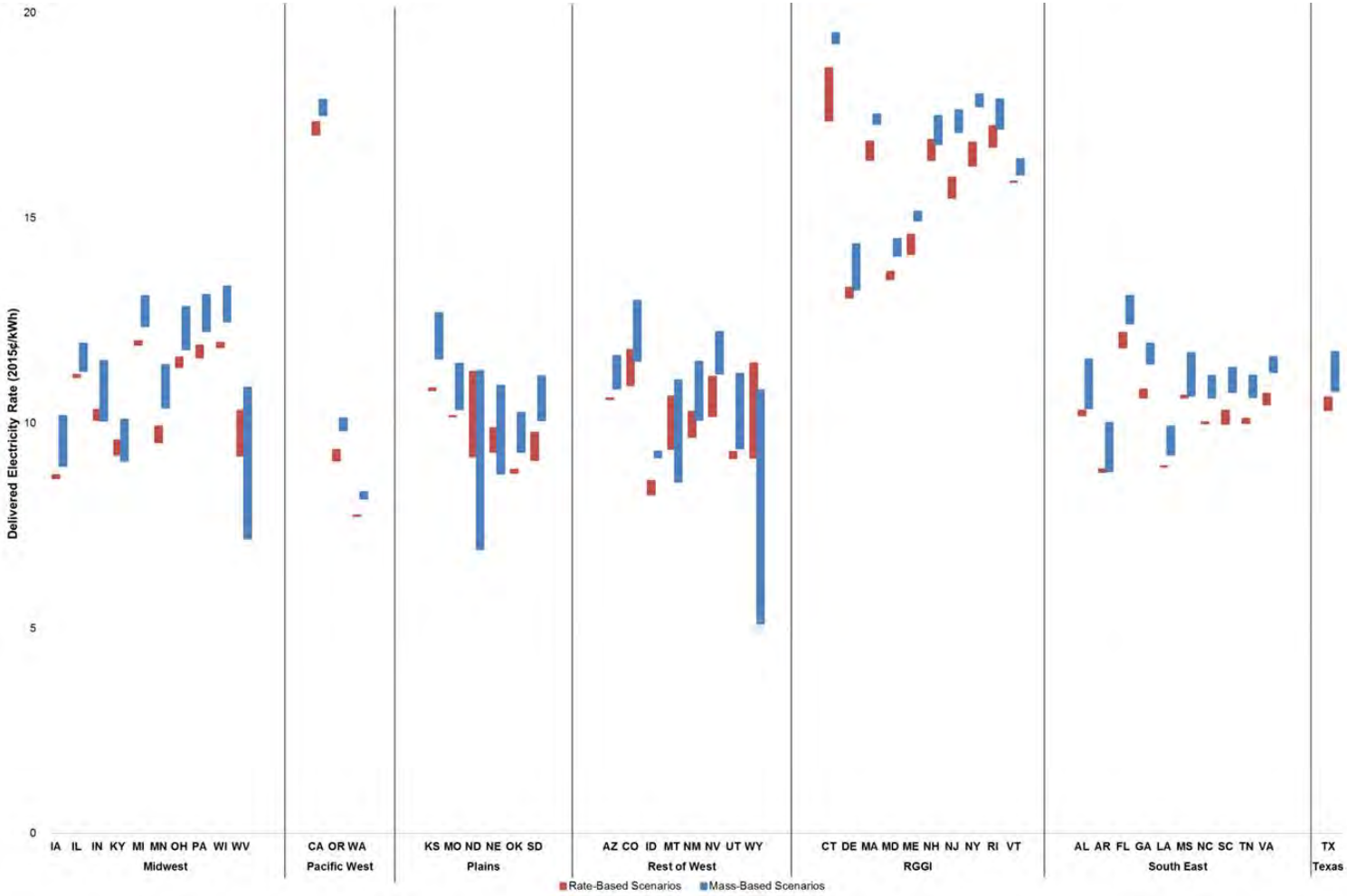
Source: N_{ew}ERA modeling result.

Figure E-2. State by state electricity rate projections for all levels of potential trading, with 0% free allocations to EDCs (2015¢/kWh)



Source: N_{ew}ERA modeling result.

Figure E-3. State by state electricity rate projections for all levels of potential trading, with free allocations to EDCs ranging from 0% to 100% (2015¢/kWh)



Source: N_{ew}ERA modeling result.

Both Figure E-1 and Figure E-2 show that, in the absence of any free allocations to reduce electricity rates, rate-based retail rates are projected to be lower than mass-based retail rates in every state. As explained in the main body of the report, including EE as a compliance option for the rate-based approach would not reverse this finding. The major reason for this difference is the difference in the carbon "adders" under the two approaches. Under the rate-based approach, intra-state trading is implemented in the model by applying CO_2 cost "adders" to covered units with rates greater than the state's limit and emission cost "credits" to covered units with rates less than the state's limit. The sum of all "adders" is equal to the sum of all "credits" in each state and the implications for electricity prices tend to be relatively modest. In contrast, under the mass-based approach, "adders" are applied to all covered fossil-fuel units in direct proportion to their carbon emissions. The resulting increase in electricity price in a particular region and time period depends upon the unit that is the last (*i.e.*, "marginal") unit to be dispatched to meet load but the general effect of the mass-based approach is to reflect carbon costs in electricity prices to a substantially greater extent than under the rate-based approach.

Figure E-2 shows that this general result—that rate-based approaches lead to lower rates than mass-based approaches—is not affected by the degree of trading that is allowed, although inter-state trading does increase the range of estimated electricity rates under each approach. In most states, the effect of inter-state trading is to reduce the projected electricity rates, but they do rise in a few states. These changes occur because under the rate-based approach when there is inter-state trading, the "adders" and "credits" described above (known as Emissions Reduction Credits (ERCs) in the CPP) may not net to zero within a given state. Instead, individual states may become net ERC sellers or net ERC purchasers, leading to effects on retail rates.

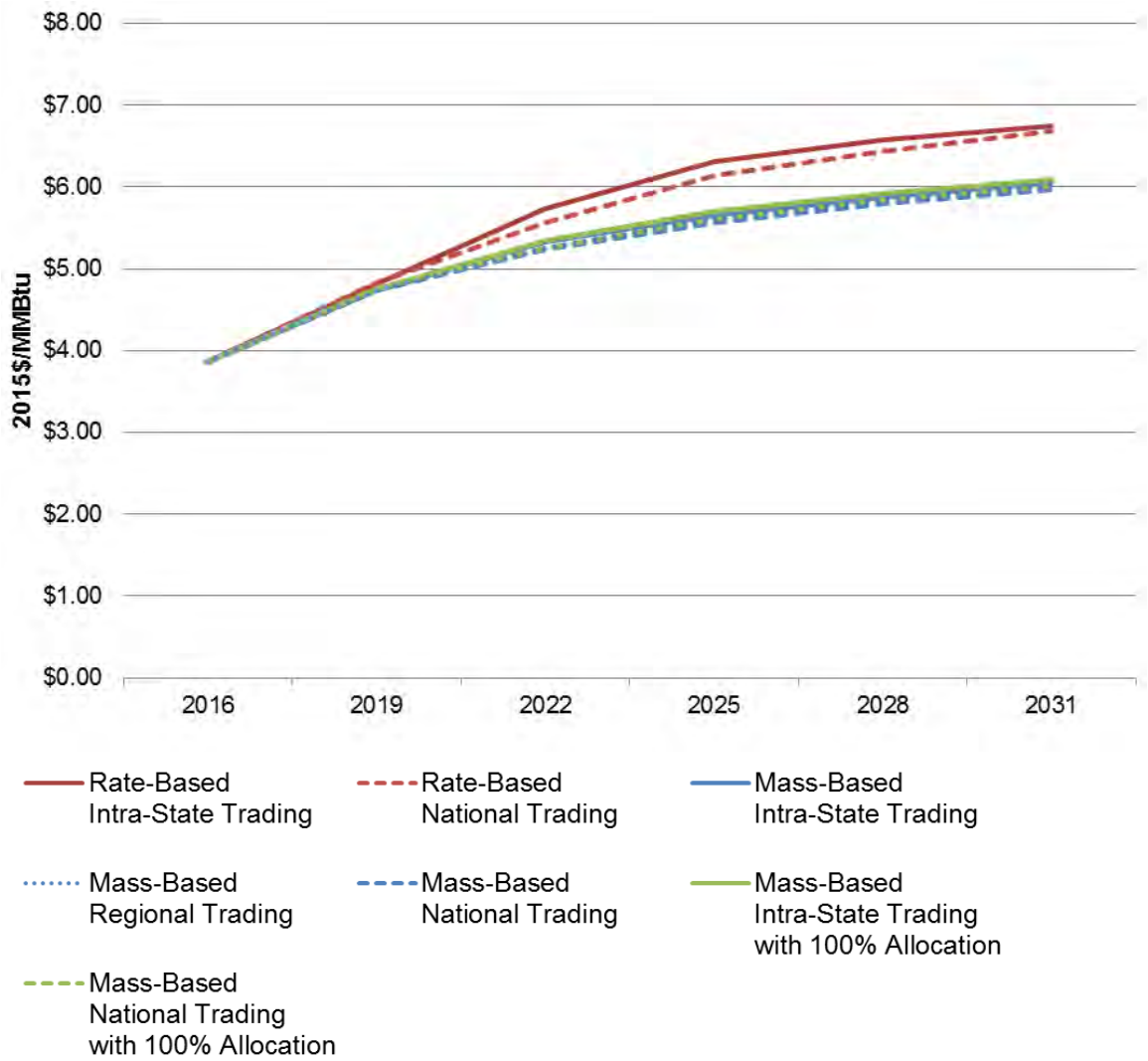
Figure E-3 shows that including the extreme of 100% allowance allocations to lower electricity rates substantially widens the range of potential electricity rates that could result under a mass-based approach. In this case, the effect on projected electricity rates is consistently in the downward direction. Note, however, that even the most extreme theoretically-possible EDC allocation of 100% does not make mass-based retail electricity prices lower than those projected for the rate-based alternative in most states. Note also that the practical relevance of the 100% EDC allocation case for evaluating the choice of mass-based vs. rate-based approach is not clear, given the likelihood that states may use criteria other than electricity rate reduction to allocate some or all of their allowances.

2. Henry Hub Natural Gas Prices

Figure E-4 presents projected Henry Hub natural gas prices for all scenarios in Table E-1. In terms of natural gas prices, the fundamental choice of rate- or mass-based alternative appears to be the critical distinction, with almost no additional variation in projected prices for different degrees of trading or different EDC allocations. Every one of the mass-based FP scenarios has lower natural gas prices than every one of the rate-based options. The higher gas prices under the rate-based approaches are due in part to the lack of end-use energy efficiency as a compliance option in the rate-based scenarios, which means that CO_2 emissions reductions are

accomplished primarily by fuel switching from coal to natural gas, which puts pressure on natural gas prices.

Figure E-4. Henry Hub Natural Gas Prices ($2015/MMBtu)



Source: N_{ew}ERA modeling result.

3. Leakage Under a 5% Allowance Set-Aside for Renewables

As noted above, all of the mass-based scenarios presented above used the New Source Complement approach as the means of addressing the leakage issue under mass-based scenarios whereby some emitting units are covered (*i.e.*, existing fossil generators) and some are not (namely new natural gas combined cycle units). EPA has proposed a combined approach to preventing leakage, the use of output-based allocations *and* a 5% allowance set-aside for new renewable generators. Lacking capability to simulate output-based allocations on the present

timeline for comments, we explored the potential effectiveness of one component of what is proposed—a 5% allowance set-aside for new renewable generators, which we could readily simulate as a sensitivity analysis with our existing model.[4] Our analysis found that a 5% allowance set-aside for new renewable generators would not prevent leakage in any meaningful way. New natural gas combined cycle units are projected to be built and to generate. (In 2031, our analysis shows twice as much generation from new natural gas combined cycle units if they are not subject to the cap as opposed to if they were subject to the cap). Further, this leakage effectively loosens the cap and drives down CO_2 allowance prices as a result. The lower CO_2 allowance prices then reduce the value of the 5% renewable set-aside, making the set-aside ineffective at motivating new renewables generation as well as ineffective at stopping leakage.

A. Implications of Results

Our modeling of the different FP scenarios suggests several implications.

1. **Rate-Based vs. Mass-Based Approach.** With limited exceptions, a rate-based implementation of the FP results in lower delivered electricity prices at the state level compared to a mass-based implementation of the FP, a result consistent with differences in the way that carbon costs are incorporated in electricity generation costs under the two approaches. This relative advantage of a rate-based implementation is offset, however, by the disadvantage of higher natural gas prices under a rate-based implementation (discussed more below).

2. **Intra-State Trading vs. Inter-State Regional and National Trading.** Although there are states that are exceptions, the possibility of inter-state trading generally results in a greater range of potential electricity prices for the rate-based approach than for the mass-based approach. This range of uncertainty has the effect of making mass-based prices even more likely to be higher than rate-based prices.

3. **Energy Efficiency Compliance and Natural Gas Prices.** The use of end-use energy efficiency as a compliance alternative is a major reason for the large difference in natural gas prices under the two approaches. With end-use energy efficiency available and adopted by states (as assumed in our mass-based scenarios), there is less need for fuel switching from coal to natural gas and thus less pressure on wholesale and delivered natural gas prices. In contrast, if end-use energy efficiency is not adopted (for whatever reason), as is the case in our rate-based scenarios, there is a much larger shift towards natural gas-fired generation, increasing demand for natural gas and putting upward pressure on wholesale and delivered natural gas prices throughout the country.

4. **Allowance Allocations.** In the mass-based approach, each state would receive allowance allocations equal to its cap that it would be allowed to distribute in some fashion other

[4] In performing this case, we removed the New Source Complement and left new Natural Gas Combined Cycle (NGCC) units uncovered by the cap.

than the default method that the EPA would take (as it outlines in the proposed FP). For our mass-based scenarios, we considered the effect of states choosing to allocate some of the allowance value to electricity EDCs to be used to reduce electricity rates. The size of the potential rate reduction varies by state—due in large part to differences in the CO_2 price—but in most states, the potential reduction is at most 1¢/kWh (although in a few smaller coal-dependent states the EDC allocation has the potential to lower rates by more). In most but not all states, even 100% free allocations to EDCs does not close the gap between projected mass-based and rate-based price ranges.

5. **Renewable Set-Aside as a Leakage "Solution."** Our analysis of the 5% allowance set-aside for new renewable generators indicates that this component to the "solution" would not reduce or prevent leakage. The modeling shows more new natural gas combined cycle units would be built and generate and, moreover, that CO_2 allowance prices would be reduced, which in turn renders the set-aside itself ineffective at motivating new renewables generation.

I. Introduction

On October 23, 2015, EPA promulgated the Final Clean Power Plan ("CPP") rule to reduce CO_2 emissions from existing fossil fuel-fired power plants and simultaneously published a proposed rule for a Federal Plan ("FP") in the Federal Register. Comments on the proposed FP are due January 21, 2016. In this report, NERA presents modeling results for alternative FP implementations to support comments on the FP. The report focuses primarily on the implications for state-level retail electricity rates and national natural gas prices of alternative FP options. The report also provides some insights about a proposed option to prevent leakage.

A. Overview of Proposed Federal Plan

The CPP is a nationwide regulation under Section 111(d) of the Clean Air Act that regulates existing electricity generating units, specifically fossil fuel-fired steam units and combined-cycle combustion turbines. The rule provides two compliance structures, one based on meeting state-specific emission rate targets in pounds of CO_2 per megawatt-hour (lb/MWh) and the other based on a CO_2 cap for total emissions from the regulated generators in each state ("mass cap"). Each state's mass cap is based on EPA's assessment of the emissions that would be equivalent to complying with the state's rate-based limit. The limits, whether rate- or mass-based, are phased in from 2022 through 2030. The rule also allows states to trade with other states that elect the same generic regulatory option. According to EPA's estimates, the CPP will result in U.S. power sector CO_2 emissions in 2030 that will be 32% below their level in 2005.

EPA is authorized to implement a FP if a state fails to submit a compliance plan or if the state's compliance plan is considered inadequate. EPA released its proposed FP at the same time that it finalized the CPP on October 23, 2105, and it is open for public comments until January 21, 2015. This report focuses on some key elements of the proposed alternatives for the FP, which are similar to but not exactly the same as those of the final CPP. NERA has previously released modeling analyses of the final CPP. A summary of the key elements of the final CPP and its modeled economic impacts is available in NERA (2015) and Smith (2015). Unless otherwise noted, all descriptions of the policies that are discussed in this report should be viewed as reflecting the alternative proposed FPs.

The proposed FP features both a rate-based and mass-based plan. EPA has proposed that only one alternative become the final FP approach. Thus we focus our analysis on comparing outcomes under the two alternatives to each other. Briefly, the two alternatives have the following elements:

- *Rate-based approach.* The rate-based proposed FP would require a state to meet a given average emission rate, in lb/MWh, equal to the state's rate-based limit in the CPP. The proposed rate-based FP specifies the covered emissions and covered generation that would be used to determine compliance. Because the FP can include only measures that are federally-enforceable, end-use efficiency is presumed to be precluded from rate-based plans. Trading among units within the affected state would be allowed, as well as trading

with other states under a rate-based FP or with states whose plans meet the conditions for linkage to the federal plan.

- *Mass-based approach*. The mass-based proposed FP would require aggregate emissions from affected sources within a state—consisting of fossil-fuel steam units, existing natural gas combined cycle units, and combined heat and power facilities—to be less than or equal to a state cap equal to the state's mass-based limit in the CPP. The proposed FP identifies how EPA would set initial allocations of allowances, *i.e.*, the right to emit a ton of CO_2, but states would be allowed to make their own alternative allocation decisions. Affected generating units would be able to buy and sell emission allowances from other affected generating units within the state as well as potentially from affected generating units in other states covered by their own mass-based FP. If a mass-based approach is applied, the state must demonstrate that leakage to non-covered NGCC plants will be prevented.

B. Objectives of This Evaluation

NERA's principal objective was to evaluate the potential electricity and energy price outcomes under alternatives for implementing a FP. We focused on the major choice involved—which is whether to adopt a rate-based or mass-based FP—but we have considered several important implementation uncertainties that may affect that choice. In particular, we consider the level of trading (*i.e.*, state vs. regional vs. national trading) and, for mass-based programs, the nature of initial allowance allocation. We compare these alternatives in terms of their implications for projected state-specific retail electricity rates and for national natural gas prices.[5] We also have considered alternative mechanisms proposed for preventing leakage under a mass-based cap (*i.e.*, increased emissions from new sources that are not covered by the cap). The full set of results provides the bases for some conclusions regarding the alternative FP designs.

We used the N_{ew}ERA model—an economy-wide integrated energy and economic model that includes a bottom-up representation of the U.S. electricity sector and a top-down representation of all other sectors of the economy, including households and governments—to evaluate the implications of alternative FP implementation. The key features of N_{ew}ERA and input assumptions used in this analysis are described in the next section, followed by an explanation of the scenarios we used to represent the range of uncertainties noted above regarding how each alternative FP approach may actually be implemented. Details of results then follow.

[5] The comparisons in this report are of relative levels of prices in a world that has already promulgated the CPP, but for which the implementation of the CPP limits may differ. In a comparison of a world without the CPP versus a world with the CPP, NERA (2015) shows that electricity prices are increased by the imposition of the CPP. See NERA (2015) for assessments of a range of impacts of the CPP, including impacts on U.S. energy sector expenditures, U.S. retail electricity rate U.S. natural gas prices, and U.S. consumption.

We note that the objective of our modeling is to assess ranges of potential electricity price outcomes in all states potentially subject to a FP. To provide a coherent set of comparisons, we run our model assuming all states are subject to each of the FP implementation alternatives we evaluate. This approach simplifies the potential evaluation of a given implementation alternative in a particular state, since other states may implement other alternatives and these choices by other states may have some effects on the particular state results. Note that all states are interconnected by markets for energy and other goods and services affected by a major regulation such as the CPP. Thus, one cannot project market outcomes under a FP in any single state without assuming some form of CPP implementation in other states. The potential number of permutations of implementation choices across these other states is vast; but all affected states will be subject to some kind of state or federal implementation plan for the CPP that will, broadly speaking, have similar stringency regardless of each state's specific legal route to compliance. Thus, we believe that market outcomes in a single state can be reasonably approximated by assuming the same form of implementation in all the other states. Put another way, we expect that variations due to differences in the FP implementation in a given state are likely to be larger and of greater interest than variations due to differences in other states' implementation choices. Thus, we think the range of market price outcomes we report for each individual state is likely to be a reasonable approximation of the degree of uncertainty about price outcomes, but we acknowledge that we have not performed a comprehensive assessment of that uncertainty.

C. Organization of this Report

The remainder of this report is organized as follows.

- Chapter II describes NERA's methodology and the compliance scenarios modeled in this study; and

- Chapter III provides the electricity and energy system modeling results.

Two appendices provide additional information on the methodology and results. Appendix A describes the key features of the N_{ew}ERA model used to produce our results. Appendix B provides tables of the state-level electricity prices shown in the various figures.

II. NERA Methodology

NERA evaluated the potential energy market and price outcomes of the proposed FP on electricity markets using its proprietary N_{ew}ERA model based upon U.S. government information. A brief overview of the N_{ew}ERA model is provided below, followed by an overview of the assumptions we made in modeling the FP compliance alternatives.

B. N_{ew}ERA Model

The N_{ew}ERA model is an economy-wide integrated energy and economic model that includes a bottom-up representation of the U.S. electricity sector and a top-down representation of all other sectors of the economy, including households and governments. The electricity module of N_{ew}ERA features substantial detail, including unit-level information on generating units, detailed coal supply curves by coal type, and regional electricity demand and capacity requirements for 34 U.S. regions. N_{ew}ERA is a long-term, forward-looking model that assumes that households and firms have perfect foresight of future policies and make optimal decisions within those regulatory constraints. The market forecast produced by N_{ew}ERA includes unit-level generation and investment decisions, corresponding CO_2 emissions, and regional fuel and electricity prices.

The N_{ew}ERA model used in this study is calibrated to the Reference Case projection in the *Annual Energy Outlook 2015* (*AEO 2015*) of the U.S. Energy Administration (EIA 2015). This reference case informs N_{ew}ERA assumptions on natural gas prices, electricity demand and capital costs for new builds. This reference case also incorporates current environmental regulations (*e.g.* RGGI, AB 32, MATS), existing state renewable portfolio standards, as well as EIA's most up-to-date projections of energy and economic activity.

NERA models results for three-year periods, with each model year representing three years, the stated year and the next two years. Average annual results and present values in this report are based on results from 2022 to 2033, with 2022 marking the beginning of the ramp up of EPA's rate limits, and 2033 representing a date after the point where the most stringent rates must be achieved, *i.e.*, 2030.

Appendix A provides a detailed documentation of the N_{ew}ERA model structure and solution logic.

A. Input Assumptions Regarding Compliance Options Used in This Analysis

NERA models each state attaining its state-specific interim and final CO_2 emissions targets. Several types of measures are technically feasible to meet the limits, whether under a state implementation plan (SIP) or a FP. EPA has called some of these categories "building blocks" because they were used to attempt to calculate a separate emissions rate limit for each state that

would reflect different market and infrastructure conditions in each state.[6] We organize our discussion of input assumptions around these same categories, but treat them simply as potential components for compliance, and thus important input assumptions to our analysis. Our model assumes each state will choose the least-cost mix of all the components to meet the FP target. Thus, each state's compliance strategy will reflect its own market conditions and electricity generation and supply infrastructure.

1. Coal Unit Heat Rate Improvements

One way to reduce the carbon intensity of electricity generation is to improve the heat rates of existing coal-fired generating units, thereby reducing CO_2 emissions per kWh generated from those sources. The heat rate reflects the efficiency of a power plant, and is defined as the amount of energy a power plant requires to produce one kilowatt-hour (kWh) of electricity. Reducing a fossil-fuel plant's heat rate lowers the amount CO_2 emitted per kWh.

For purposes of this analysis, NERA uses the same assumptions as EPA regarding the availability and costs of potential heat rate improvement in its modeling. NERA has not evaluated EPA's assumptions, and thus the use of EPA's assumptions here and elsewhere should not be viewed as an endorsement. EPA assumes that by 2030, the coal fleets of the Eastern, Western, and Texas interconnections could realize heat rate improvements of 4.3%, 2.1%, and 2.3%, respectively. EPA assumes the coal unit heat rate improvements would require capital costs of $100/kilowatt in 2011$ (EPA 2015b, p. 2-63).

However, unlike EPA, NERA assumes that units undertaking heat rate improvements are subject to New Source Review. This would reduce such retrofits' cost-effectiveness for units that are not already maximally controlled for other types of emissions. This assumption has *de minimis* impact on our results, but it is nevertheless consistent with the legal reality.

2. Re-dispatch to Lower-Emitting Generating Units

Another, and more significant, option for reducing the carbon intensity of electricity generation is by re-dispatching from higher to lower-emitting sources of generation. This could be from inefficient coal-fired units to more efficient coal-fired units, or from coal-fired to a different fueled unit (including natural gas and oil or zero-emitting units such as renewables and nuclear). In the case of possible re-dispatch among already-existing units, cost-effectiveness of re-dispatch depends on assumptions regarding fuel prices and unit-specific operating characteristics. NERA has used the *AEO 2015* Reference Case for its projected fuel prices, which differ from the projected prices of EPA's IPM model. It uses publicly-available data on existing units and their operating characteristics from sources such as Ventyx.[7] In the case of possible re-dispatch from

[6] The legal concept is called "Best System of Emissions Reduction" (BSER). This report takes no position on the appropriate definition of BSER; it analyzes the specific emissions limits defined in the proposed FP.

[7] We used information on exiting units, announced retirements, announced retrofits, and planned units under construction as of August 6, 2015 (just prior to the release of the CPP).

existing units to new, lower carbon-intensity units, cost-effectiveness also depends on the costs of constructing the new technologies. NERA has used cost data from *AEO 2015* for these estimates as well. Table 1 summarizes the relevant input assumptions to our analysis that affect the cost-effectiveness of each new technology.

Table 1. NERA Assumptions on Lower Carbon Generating Technologies

Technology	Capital Cost (2022/2030) ($/kW)	Fixed O&M Cost ($/kWh-yr)	Variable O&M Cost ($/MWh)	Heat Rate (MMBtu/MWh)	Maximum Capacity Factor[2]
Onshore Wind	$2,024 / $1,972	$40.92	$0.01	N/A	24%-41%
Solar PV	$3,325 / $3,055	$25.55	$0.01	N/A	23%-34%
Natural Gas Combined Cycle	$992 / $969	$13.62	$3.73	7,050	87%
Natural Gas Combustion Turbine	$741 / $715	$7.29	$10.74	9,750	70%
Nuclear[1]	$5,158 / $4,890	$96.52	$2.22	10,479	90%

1. NewERA model does not allow any additions of new nuclear generating capacity until 2025.
2. For new renewable units, the maximum capacity factor is stated as a range because it varies by model region.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2015* (EIA 2015).

In an idealized market-based approach, the least cost combination of all of these options would be identified without constraints. The FP and CPP however, do have regulatory constraints that bear on the specific options that may be considered among the universe of re-dispatch options; those constraints are summarized below.

The emissions rate limit of the FP (and CPP) was calculated (in part) based on assessment of potential re-dispatch among only affected units, all of which are *existing* units. As a result, the rate-based approach for the FP contains a regulatory formula that accounts only for generation from *existing* NGCC. This regulatory formula is embodied in NERA's policy scenarios, and thus NERA's simulations of compliance with the FP do not include re-dispatch to any potential new NGCCs. Without this specific feature of the formula determining compliance, the model might choose to build and re-dispatch to new units (*i.e.*, if it is technically cost-effective compared to the remaining compliance options). This possibility is a concern with the mass-based alternatives (for both FP and CPP), because a cap could be met by simply generating less with the deficit in generation being met by units outside the cap, a situation that creates "leakage" if the other units emit carbon, as would be the case with new NGCC units. Unable to prevent leakage through a regulatory formula—as in the rate-based approach—EPA requires that measures be taken to prevent leakage if a mass-based approach is used.

Under a SIP for the CPP, one simple leakage-prevention provision is to incorporate any new NGCCs under the mass-cap, while adjusting the level of the cap upwards by an amount EPA calls the "New Source Complement." However, the U.S. EPA cannot (for purported legal reasons) impose a *federal* implementation plan under Section 111(d) on new units. Thus the proposed FP requires other ways of assuring that leakage will be prevented and seeks comment on whether a combination of output-based allocations of allowances with a 5% set-aside for new renewables generation would be effective in preventing leakage. Model representation of an output-based allocation scheme was not possible within the resource constraints of NERA's

analysis. Thus our core analysis of the FP has assumed the New Source Complement approach, as we can be sure that this does prevent leakage. However, we can use N_{ew}ERA to a 5% set-aside to renewables, and we therefore explore the effectiveness of that option, on its own, as a form of leakage prevention in place of the New Source Complement approach.

Leakage is not a concern when affected units are replaced by generation from low or zero-emitting renewable energy resources, including solar, wind, geothermal and hydropower. These sources are included in both rate-based regulatory formulas, and are unconstrained options under a mass-based approach. Thus, the model chooses the amount of new renewables to build based on the cost-effectiveness of those options compared to all the other options described here as being available in our model.

3. End-Use Energy Efficiency

Projects that improve end-use energy efficiency (EE) do not improve emissions-intensity on a per-kWh basis. However, if each kWh avoided by EE displaces a kWh of emitting generation, the overall emissions from the electricity sector decline. Thus, although EPA has not included EE in its estimates of state-specific emissions rate limits for the CPP and FP, it is a viable option for complying under a mass-based approach, with no legal constraints on its use in the mix of compliance actions if it is cost-effective relative to the other available actions. NERA's modeling of the mass-based approaches therefore includes EE among the available compliance options.

Under the rate-based approach, energy efficiency would need to be an allowable part of the compliance formula. Although it *is* part of the formula that can be used in a CPP SIP, it is not in the rate-based FP compliance formula. (This is apparently due to purported constraints on what is federally enforceable). NERA's modeling of the rate-based alternatives for the FP therefore does not include EE in the regulatory formula, and hence it is not among the model-selected mix of compliance actions.

Our assumptions about the availability and cost of EE are the same as in our analysis of the final CPP (NERA, 2015), which are broadly similar to the assumptions made by EPA. For its analysis of the final CPP, EPA assumes the first 0.5% of improvement costs $1,100/MWh (2011$). However it assumes decreasing costs for incrementally more EE beyond the first 0.5%. EPA assumes that improvements of 0.5% up to 1.0% will cost less ($880/MWh reduced, 2011$), and less still ($660/MWh reduced, 2011$) for 1.0% efficiency improvements. NERA has reviewed EPA's explanations for this declining incremental cost assumption, and we do not find them compelling (Smith 2015). EPA's assumption of declining costs is not consistent with experience in which the "low hanging fruit" for improving energy efficiencies is used up in initial programs and deeper cumulative percentage improvements become more costly. This pattern would lead to a rising $/MWh supply curve for larger percentage reductions, as EPA assumed in its analysis of the proposed rule. However, it is possible that time and technological change will shift supply curves outward and costs will fall as greater energy efficiency is undertaken. To account for these two offsetting effects, NERA's analysis assumes a flat rather than a rising $/MWh curve,

while adopting the same temporal constraints on the amount of improvement per year that EPA has assumed. Thus, NERA has assumed that any of the assumed quantity of end-use energy efficiency improvement can be obtained at a cost of $1,100/MWh of reduction (2011$). While this value is higher than EPA's cost for the larger improvements, it still presumes a large amount of technological progress (*e.g.*, "learning by doing") to offset the natural tendency for costs to rise as more ambitious programs are implemented.

B. Alternative Federal Plan Implementation Scenarios Analyzed

We have modeled least-cost compliance scenarios that differ based on the FP structure (mass-based vs. rate based), the level of trading presumed, and two extreme cases for allocation of allowances with the intent of reducing electricity rates. The set of seven "core" scenarios are listed in Table 2. NERA modeled all of the core mass-based scenarios using the New Source Complement caps to deal with leakage. This choice is one option provided in the final Clean Power Plan Rule, though it is not proposed in the Federal Plan.[8]

Table 2. List of Core Scenarios in this Analysis

	Scenario(*)	Trading(**)	Allocations to Reduce Electricity Rates
A	Mass-based	Intra-State	0%
B	Mass-based	Regional Trading	0%
C	Mass-based	National Trading	0%
D	Mass-based	Intra-State	100%
E	Mass-based	National Trading	100%
F	Rate-based	Intra-State	Not applicable
G	Rate-based	National Trading	Not applicable

(*) All of the core mass-based scenarios were implemented using the New Source Complement caps as the means to prevent leakage.
(**) The regional trading case assumes seven regions, as described below.

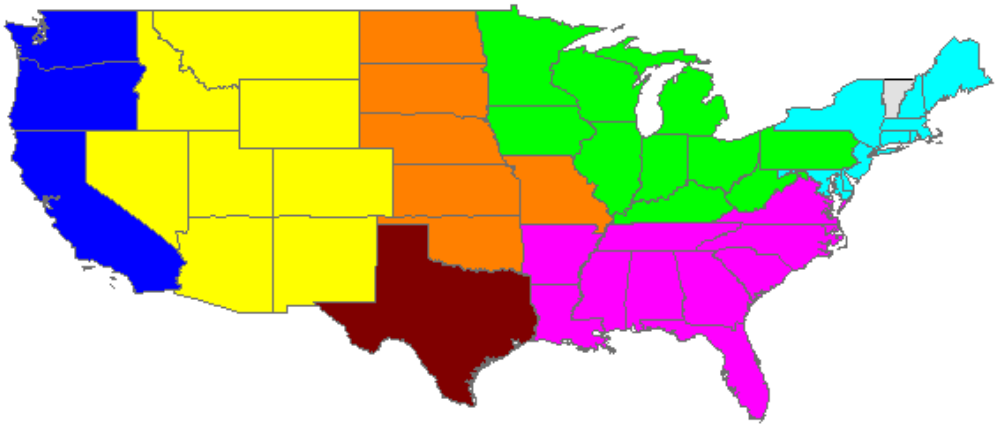
1. Trading Regions

As noted in Table 2, three distinctly different assumptions about the geographic scope of trading were modeled, in order to assess the sensitivity of projected energy prices to the unknown outcome for allowance or credit trading. At the most constrained level, we analyzed trading that is limited to within each state ("intra-state" trading). At the least constrained level, we analyzed

[8] In the FP, EPA has proposed that leakage under the mass-based approach be addressed by implementing output-based allocation set-asides based on historical generation, and a set-aside that encourages the installation of renewable energy. However, EPA requests comment on the proposed treatment of leakage, which is discussed below.

unfettered trading across all states ("national" trading).[9] For the mass-based alternative, NERA also modeled a regional trading scenario with the trading occurring among states within seven regional groupings. The seven regions were determined by the sponsors of this analysis. They are shown in Figure 1.

Figure 1. Seven Trading Regions for "Regional Trading" Scenarios



Source. Regions defined by the sponsors of this study

2. Alternative Allocations to Reduce Retail Electricity Rates

Mass-based trading schemes will require creation of emissions allowances (*i.e.*, rights to emit a ton of CO_2), the initial distribution of which affects the ultimate regulatory cost burdens on different sectors and individuals. This analysis does not focus on policy costs or their distributional impacts. We do focus on potential retail electricity rates associated with each alternative approach, and one choice of allowance allocation can directly alter retail electricity rates in a very significant degree—using the value of free allocations as a credit in the calculation of electricity rates based on the costs of supplying electricity to retail customers. Because of its strong potential impact on electricity rates, we consider the two extreme cases for this single form of allocation decision: 0% and 100% to apply to retail electricity rate reduction.[10]

[9] In every scenario, all states were assumed to be adopting the same general approach of mass-based or rate-based FP. Thus, national trading really does allow for all states to trade with each other. In practice, national trading may never be possible if some states take the rate-based and others the mass-based approach. It is outside the scope of this study to consider the vast number of such potential permutations. Thus "national" trading scenarios reflect an extreme degree of flexibility that is very unlikely to be achieved for this policy.

[10] In NERA's modeling of the zero allocation case, each state is assumed to still return all the allowance allocation value to the consumers through means other than lowering retail rates, using a mechanism economists refer to as a "lump sum" transfer. Lump sum redistributions could include per-household dividend checks, or per-person income tax rebates, among other means.

An allocation of the allowance value to specifically reduce electricity rates is different from the proposed approach in the FP of allocating allowances to affected electricity generating units (EGUs) based on historical generation. Allocation to EGUs would have different impacts on rates depending on the state of electricity deregulation in each state. In deregulated states it would have no expected rate-reduction effect (and thus would be consistent with our 0% allocation case). Even in regulated states, it would be difficult to predict how much of the allowance value would be returned in rates to customers and how much to shareholders; but the amount would likely be less than what we predict in our 100% allocation case (even if 100% of the allowances were allocated to regulated EGUs).

Thus, if retail electricity rate-reduction is to be an objective of a FP allocation formula, it should be done in a much more targeted manner. An alternative noted in the FP proposal, intended to address such an objective, is to allocate to load-serving entities (LSEs) rather than EGUs. Our 100% allocation rule is presented as the most extreme end of the spectrum under such an alternative. We describe this as allocation to EDCs, because EDCs generically are the type of electric sector entity that is most likely to be subject to public utility rate-setting oversight, and thus the most likely to be able to be required to reduce retail electricity rates on a per-kWh basis in an amount fully equal to the value of any free allowance allocations it may be given by the state.

Allocation to EDCs is somewhat different from the alternative proposed in the FP because EDCs and LSEs can be different entities. An EDC is the entity responsible for distribution of electricity and maintenance of the local grid that extends into ratepayers' homes or facilities, while a LSE is a company that markets and sells its supply of electrons to retail customers, but may not be an EDC. While an implication of EPA's alternative allocation proposal is that LSEs can be required to pass through any allocated allowance value in the form of lower rates per kWh at the meter, it is not clear to us which of these two types of entities can be expected to provide such an outcome. Our 100% allocation case is comparable *in intent* to that of EPA's alternative allocation proposal, in that our analysis *assumes such a pass-through can be enforced*. We take no position on whether this would occur with either an EDC or LSE allocation, and only note that there is uncertainty about the degree to which that could be achieved via either entity.

We describe our assumption allocations to EDCs to underscore that the choice of entity may matter if such a rate-reduction objective is to be adopted. However, for purposes of interpreting our results, they could reflect free allocation to any entity that can be required by a regulator to make retail rates per kWh decline in an amount equal to the entire value of a free allocation. The main point is that our 100% allocation analysis *assumes* the full value of the allocation makes its way into retail rate reduction. To the extent that it cannot be achieved as readily as we have assumed, the 100% allocation outcomes should be viewed as beyond the limit of what is achievable via existing regulatory means. Note also that the practical relevance of the 100% allocation case is not clear given the likelihood that states may use criteria other than electricity rate reduction to allocate some or all of their allowances. It represents a bounding case for a comparison of the electricity rate levels under mass-based and rate-based alternatives for the FP.

3. Alternative Assumptions on Which Customer Classes Adopt the Projected Energy Efficiency Programs

Estimates of retail electricity rates are determined by multiple factors. These include model-projected wholesale electricity prices for the electricity supply region(s) relevant for each state, whether the state's electricity markets are deregulated or cost-of-service/regulated, the value of allowances that is assumed to be used to reduce rates on a per-kWh basis, costs of fixed charges (such as for transmission and distribution infrastructure), and the utility portion of the cost of EE projects. In making retail rate calculations, one must also address the question of how these various costs are allocated to different types of customers, or retail rate classes. (The basic rate classes in NERA's modeling are industrial, residential, and commercial.)

In the mass-based cases, a significant driver of the uncertainty about retail rates *by rate class* is related to the EE costs.[11] EPA and NERA have made generic assumptions about the supply curve for EE, meaning that it only identifies the avoided quantity of kWh achieved at different cost per kWh levels. Without more detail in an EE supply curve, such as what technologies or actions are taken to achieve each quantity of avoided kWh, there is no information to guide our assumptions about which types of customers might be the adopters. To address this uncertainty (which in turn affects the retail price estimate for each of the three rate classes), NERA has considered a couple of options. In the core estimates that we present, we assume that historically-observed contributions to total EE are continued for the additional EE that is projected to occur for compliance under the policy scenario. When we present results for the industrial category of retail rates, we also provide sensitivity analyses in which we assume (1) that industrial customers will not adopt any of the projected additional EE, and (2) that industrial customers adopt a share of the EE equal to their share of total electricity consumed in each year. We have selected these cases to reflect the broadest range of uncertainty that we feel can reasonably be expected. We have not developed any opinion on which of the three cases is most reasonable.

[11] Rate-based FP scenario results are not affected by EE assumptions because the compliance formula for the proposed rate-based FP does not create any additional incentive for EE.

III. Modeling Results

This chapter reports the potential electricity and energy sector outcomes under several FP alternatives. Our analysis focuses on average electricity and natural gas price outcomes from the period of 2022-2033, unless otherwise noted. We first provide electricity rate outcomes by state. We start with detailed results for all-sector rates, which reflect the weighted average of the residential, industrial, and commercial prices for a given state. We then provide similarly detailed results for the industrial sector, including some additional sensitivity cases. For residential and commercial sectors, we provide a single summary of the range of potential rates. Full information for all of these rate-class rate estimates is provided in Appendix B.

A. Retail Electricity Rates

1. Average Retail Rates Across All Rate Classes

We present the results in a comparative format. For each state, we compare the projected outcome under a rate- vs. a mass-based approach. The results are provided in a three-step sequence of figures to illustrate the relative importance of key uncertainties that will determine ultimate electricity price levels.

In the three figures, the red bars represent rate-based results and the paired blue bars represent the mass-based results. The state results are organized by trading region. The sequence of comparisons in Figures 1 through 3 is the following:

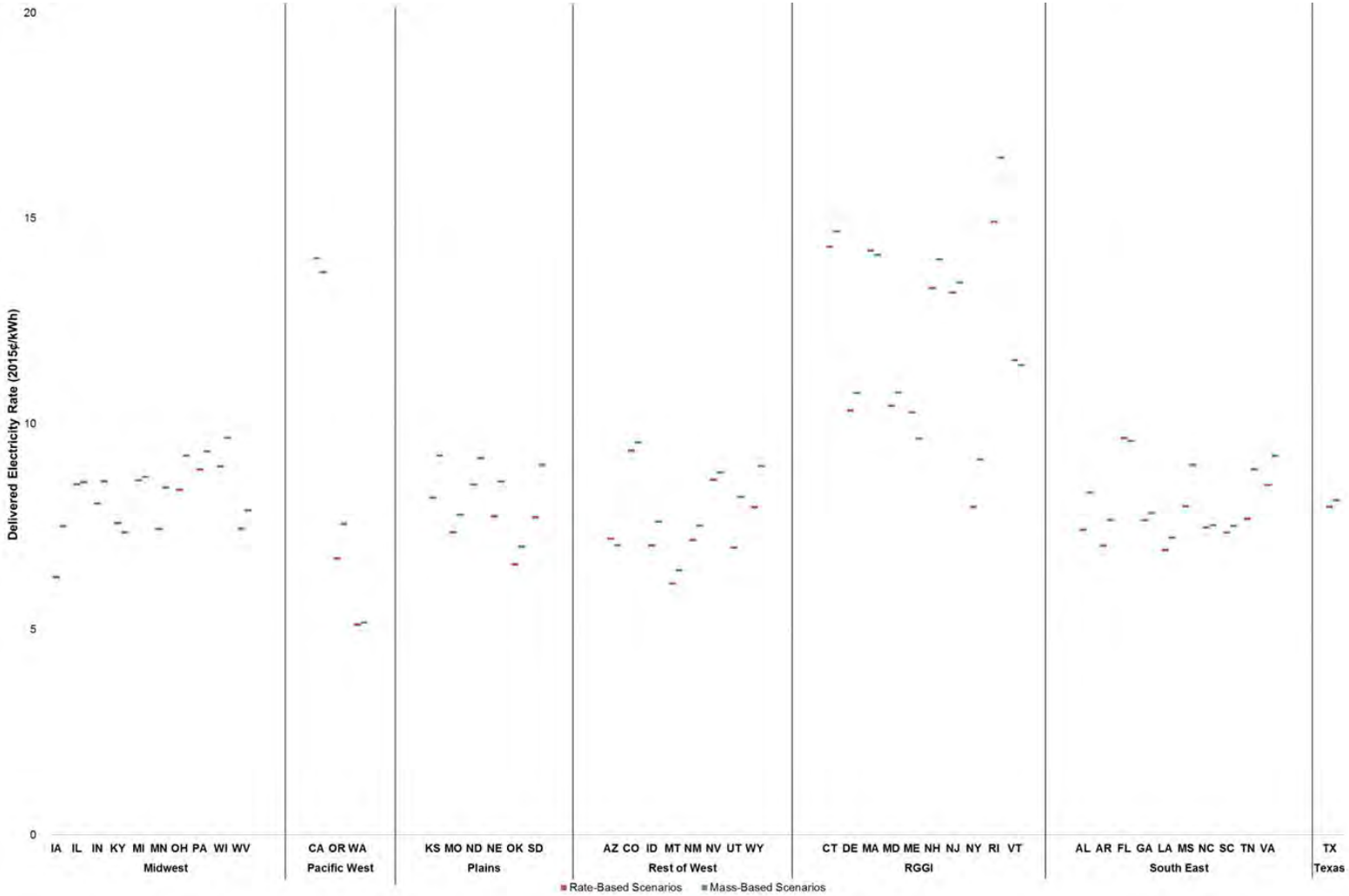
Figure 2. "Basic" Comparison of Rate-Based vs. Mass-Based. Figure 2 provides comparisons of rate-based to mass-based results for one basic implementation case: the "state-only" trading option with no EDC allowance allocations (0% allocation). That is, this compares results for scenario A to those for scenario F (as defined in Table E-1).

Figure 3. Addition of Geographic Scope of Trading. This figure adds the implications of different geographic scopes of emissions trading. This compares results for scenarios A, B and C to those for F and G (as defined in Table 2). This figure shows a range of projected electricity rates for both the mass- and rate-based alternatives, and this range is represented in the figure as a vertical bar from the lowest to the highest end of the range. (Specific values for each individual scenario are provided in tabular format in the report.)

Figure 4. Addition of EDC Allocation. Figure 3 adds the implications for the range of potential electricity rates of EDC allocations for the mass-based alternative. In contrast to the 0% allocation assumption used in Figure 2 and Figure 3, this figure now includes the other extreme of 100% EDC allocation. Thus the range of results for scenarios A through E are compared to the range of results from scenarios F and G.

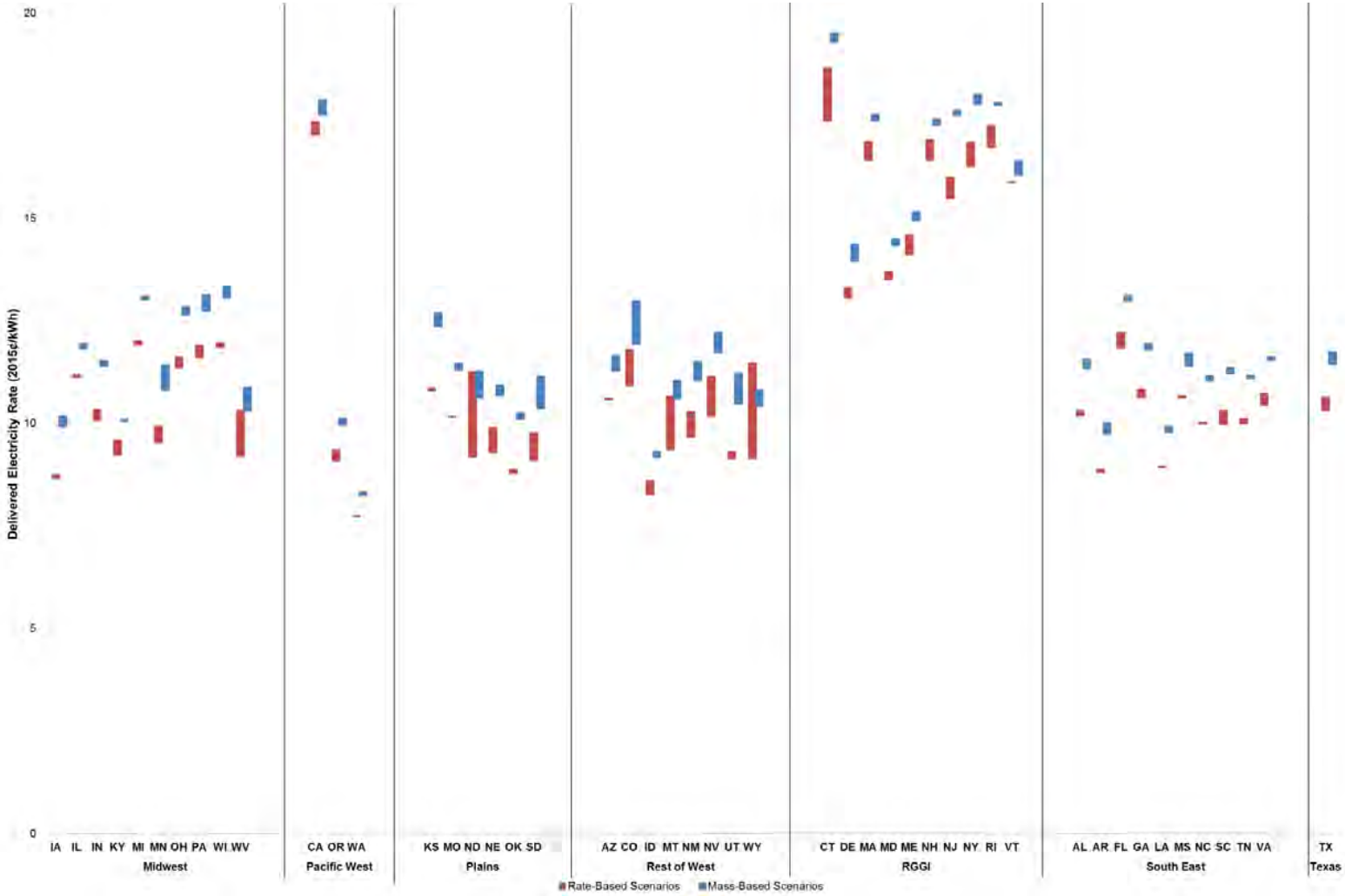
All three figures illustrate the implications for state retail electricity prices of differences in the design of a FP.

Figure 2. State by state electricity rate projections for state-only trading, with 0% free allocations to EDCs (2015¢/kWh, Average 2022-2033)



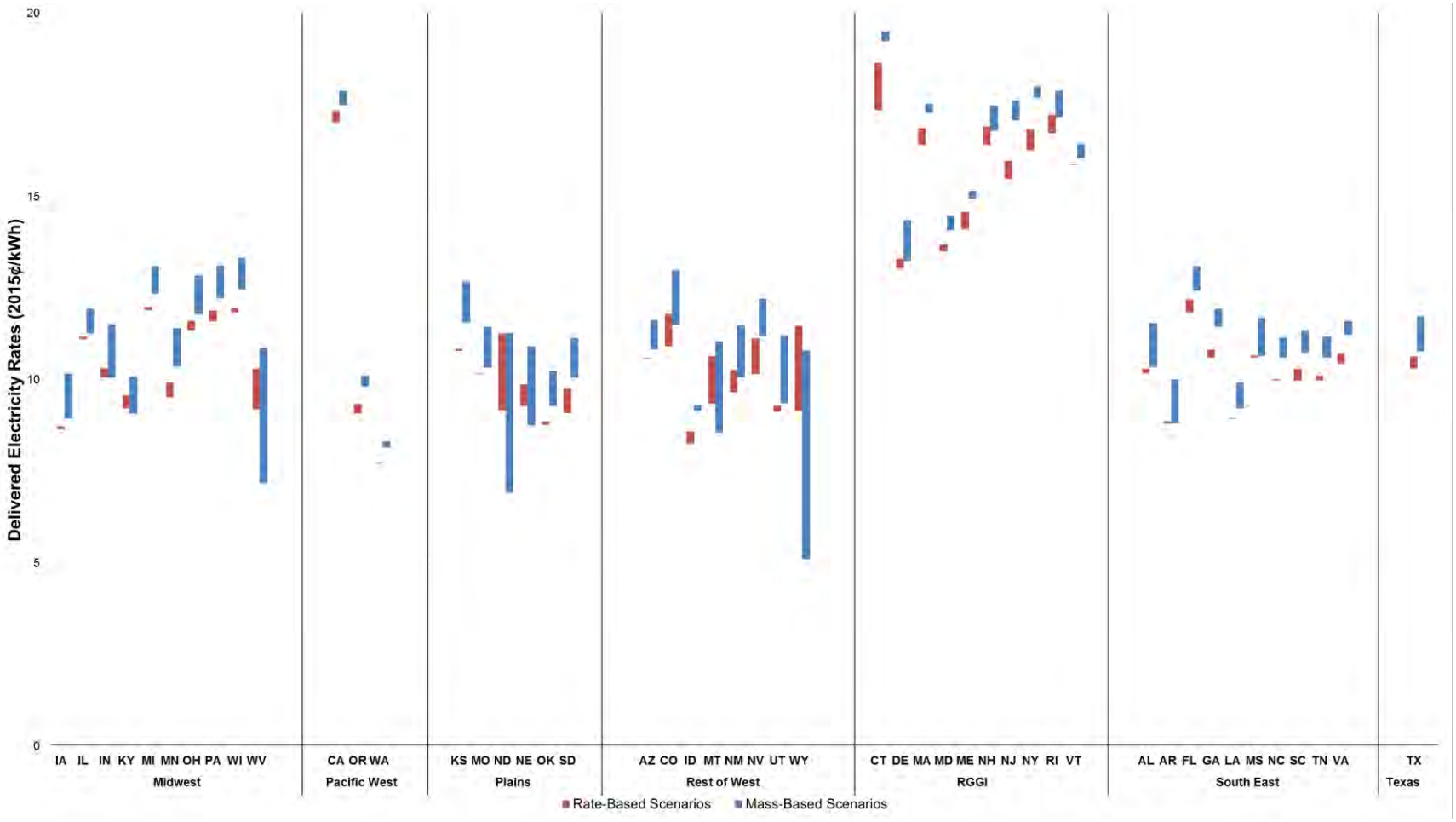
Source: N_{ew}ERA modeling result.

Figure 3. State by state electricity rate projections for all levels of potential trading, with 0% free allocations to EDCs (2015¢/kWh, Average 2022-2033)



Source: N_{ew}ERA modeling result.

Figure 4. State by state electricity rate projections for all levels of potential trading, with free allocations to EDCs ranging from 0% to 100% (2015¢/kWh, Average 2022-2033)



Source: N_{ew}ERA modeling result.

Figure 2 shows that, in the absence of any free allocations to EDCs, rate-based retail rates are projected to be lower than mass-based retail rates in every state. One question we explored was whether the inclusion of EE as a compliance option for the rate-based approach might eliminate this projected gap in the projected retail prices. We noted that some information of relevance to this question could be found in NERA's analysis of the final Clean Power Plan rule (NERA 2015). Because EE is a part of the compliance formula for SIPs under the CPP, EE was included as a compliance option in both the rate-based and mass-based scenarios modeled in that analysis. We found that the rate-based scenario in that study also projected lower retail electricity rates than the mass-based scenarios in that study. Incorporation of EE into a rate-based FP would result in somewhat higher projected electricity prices than those associated with the *proposed* rate-based FP, but electricity prices would continue to be broadly lower than those projected for a mass-based FP (with 0% allocations to EDCs).

We have concluded, from inspection of the model results, that the major reason for the higher retail electricity rates under the mass-based approach is the difference in how carbon "adders" take effect under the two approaches. Under the rate-based approach, intra-state trading is implemented in the model by applying CO_2 cost "adders" to covered units with rates greater than the state's limit and emission cost "credits" to covered units with rates less than the state's limit. The sum of all "adders" is equal to the sum of all "credits" in each state and the implications for electricity prices tend to be relatively modest. In contrast, under the mass-based approach, "adders" are applied to all covered fossil-fuel units in direct proportion to their carbon emissions. The resulting increase in electricity price in a particular region and time period depends upon the unit that is the last (*i.e.,* marginal) unit to be dispatched to meet load, but the general effect of the mass-based approach is to reflect carbon costs in electricity prices to a substantially greater extent than under the rate-based approach.

Figure 3 shows that this general result—that rate-based approaches lead to lower rates than mass-based approaches—is not affected by the degree of trading that is allowed, although inter-state trading does increase the range of estimated electricity rates under each approach. In most states, the effect of inter-state trading is to reduce the projected electricity rates, but they do rise in a few states. These changes occur because under the rate-based approach when there is inter-state trading, the "adders" and "credits" described above (known as Emissions Reduction Credits (ERCs) in the CPP) may not net to zero within a given state. Instead, individual states may become net ERC sellers or net ERC purchasers, leading to effects on retail rates.

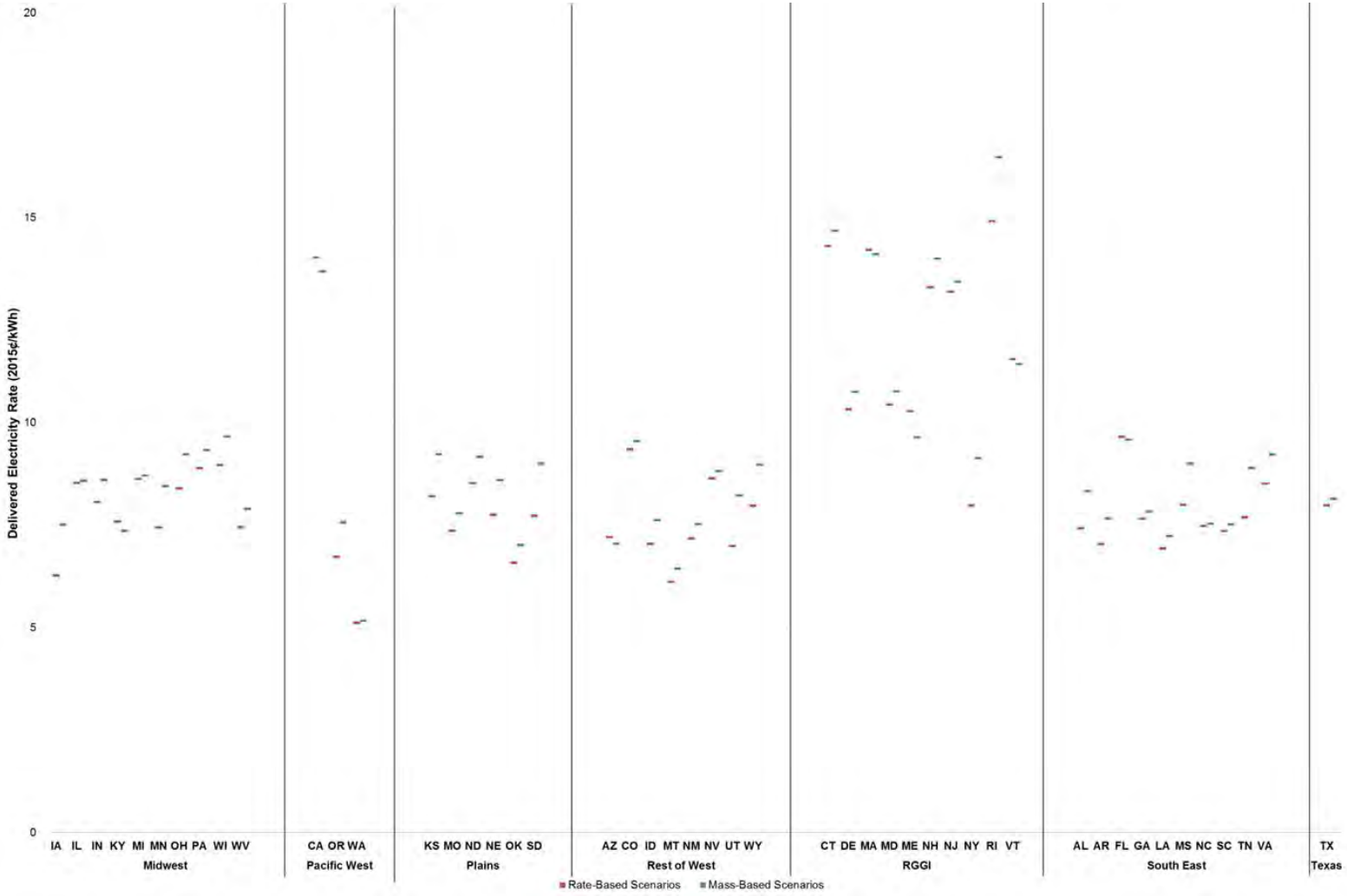
Figure 4 shows that including the extreme of 100% allowance allocations to EDCs substantially widens the range of potential electricity rates that could result under a mass-based approach. In this case, the effect on projected electricity rates is consistently in the downward direction. Note, however, that even the most extreme theoretically possible EDC allocation of 100% does not make mass-based retail electricity prices lower than those projected for the rate-based alternative in every state. Note also that the practical relevance of the 100% EDC allocation case for evaluating the choice of mass-based vs. rate-based approach is not clear, given the likelihood that states may use criteria other than electricity rate reduction to allocate some or all of their allowances.

2. Industrial Sector Retail Electricity Rates

In this section we present industrial sector electricity rate estimates. As noted above, our core assumptions (which were used to estimate the retail rates *averaged over all three rate classes* that have been reported above, were that each sector adopts end-use EE in relative quantities consistent with historical adoption. While this assumption does not substantially affect the estimates of average retail rates, it does affect the class-specific retail rates. As long as we adopt the same EE-sharing assumption, the estimates of industrial sector electricity rates are similar *in pattern* to those for average retail rates. These are shown, with the same progression of case comparisons as above, in Figure 5 through Figure 7.

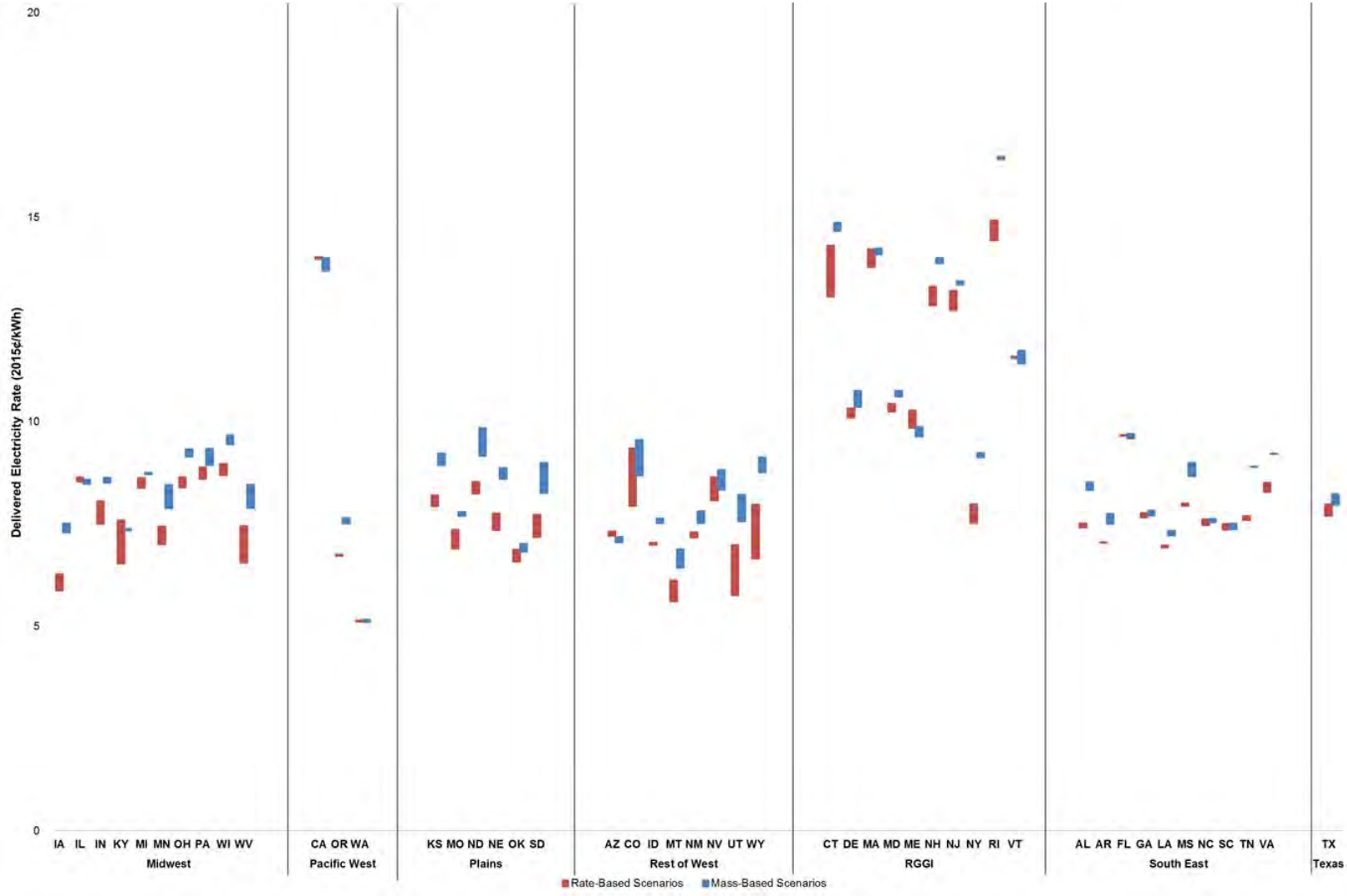
To understand how much the industrial rates may be affected by the assumption about EE-sharing across rate classes, we also present sensitivity results on the industrial rate estimates around a single core case, that of mass-based with regional trading and 0% free allocation to EDCs scenario (Case B in Table 2).

Figure 5. State by state industrial sector electricity rate projections for state-only trading, with 0% free allocations to EDCs (2015¢/kWh, Average 2022-2033)



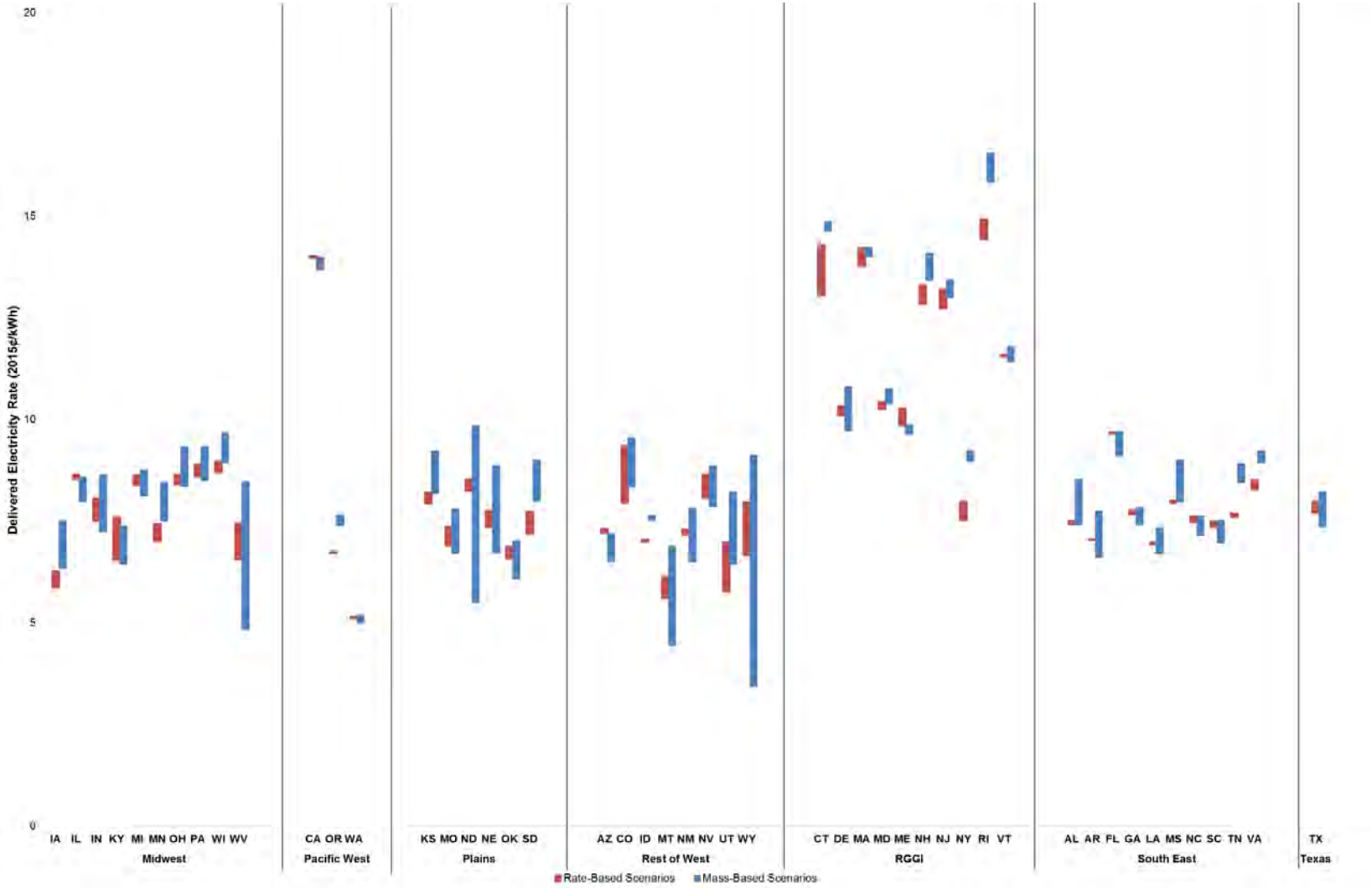
Source: N_{ew}ERA modeling result.

Figure 6. State by state industrial sector electricity rate projections for all levels of potential trading, with 0% free allocations to EDCs (2015¢/kWh, Average 2022-2033)



Source: N_{ew}ERA modeling result.

Figure 7. State by state industrial sector electricity rate projections for all levels of potential trading, with free allocations to EDCs ranging from 0% to 100% (2015¢/kWh, Average 2022-2033)



Source: N_{ew}ERA modeling result.

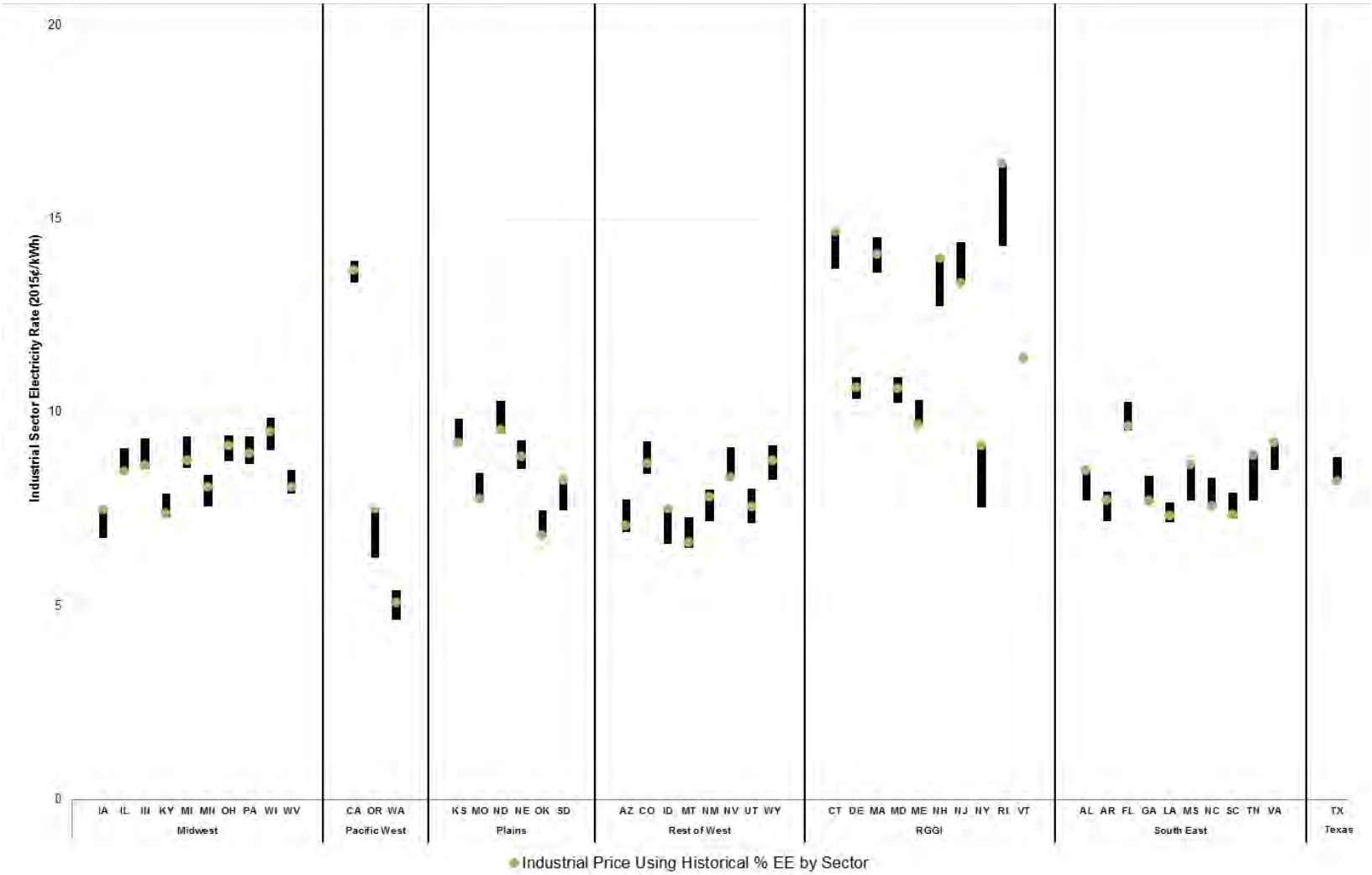
Figure 8 shows variation in the projected industrial rates for this single case with the range of three alternative assumptions about how much of the EE is undertaken (and then paid for) by the industrial sector. The green dot on the range for each state shows the core result for that specific Case B. The black bar shows the lowest to highest estimate for Case B among the three alternative assumptions about EE-sharing among rate classes. There is a substantial range of uncertainty, about comparable in magnitude to the uncertainty in the mass-based rates due to different geographic scopes of trading (*i.e.*, Figure 6). Interestingly, the core assumption of historical shares for EE is not consistently placed as relatively higher or lower within the range, but varies with the state with no apparent pattern.
Thus, our conclusion is that the mass-based approach appears to lead to much greater uncertainty about what the retail rate levels may be than the rate-based approach. One major uncertainty is what amount of allowance allocation will be assigned by a state specifically to reduce retail rates per kWh. But the specific technologies and actions the might lie behind the assumed generic EE supply curve is another potentially important uncertainty that affects the mass-based outcomes but not the rate-based outcomes.

Detailed tables of the specific numerical values that have been presented in graphical form are provided in Appendix B.

3. Commercial and Residential Sector Retail Electricity Rates

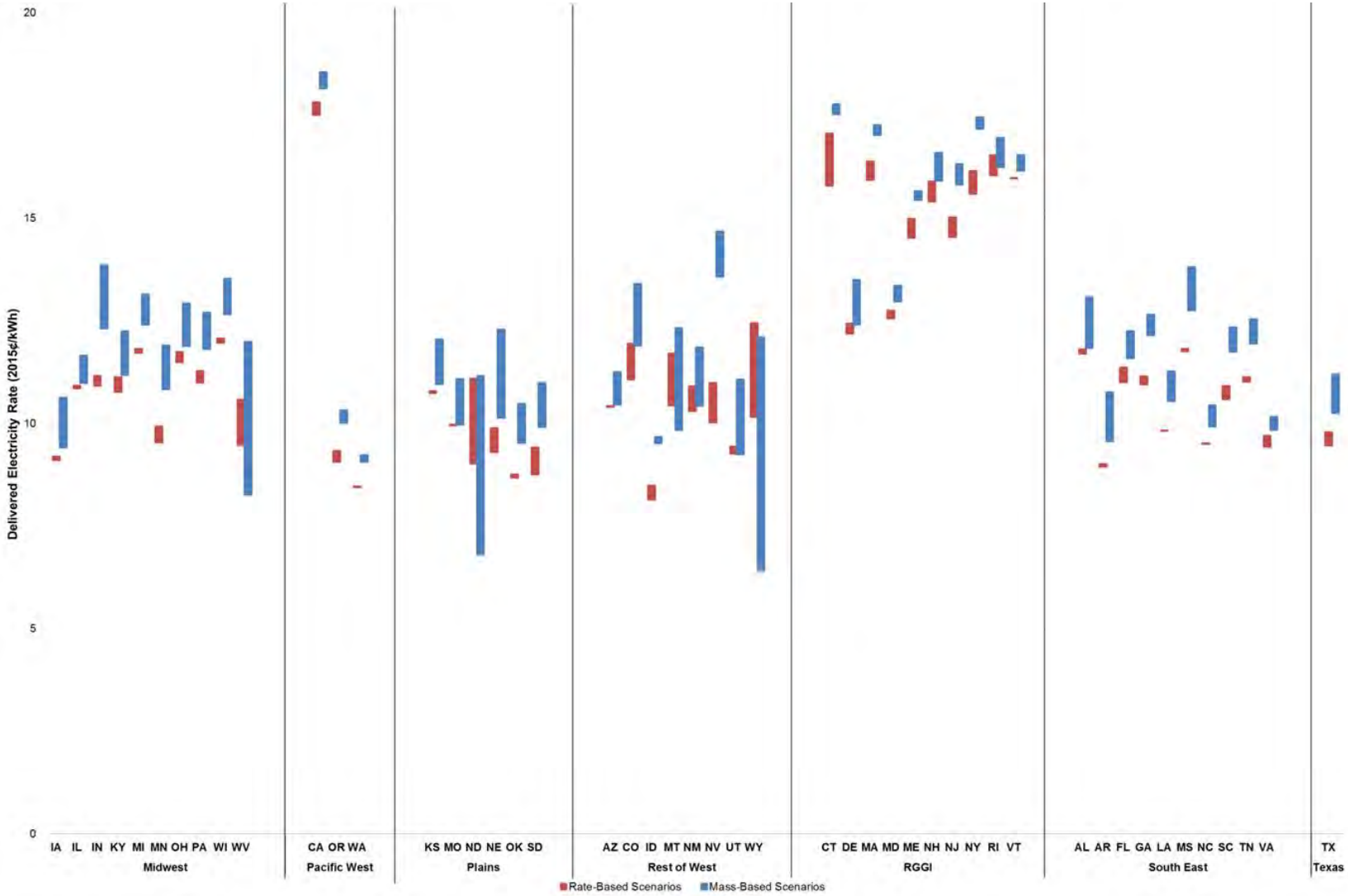
To avoid excessive repetitiveness, the numerical results for commercial and residential electricity rates are provided in tabular form in Appendix B. In brief, they contain very similar comparisons of the rate-based to the mass-based outcomes, and patterns of uncertainty. To demonstrate this fact, Figure 9 provides the graph of all Cases A through F for the commercial rate class, and Figure 10 for the residential rate class. (These graphs are comparable to Figure 4 for average retail rates and to Figure 7 for industrial rates.) Although the level of projected rates are sometimes higher and sometimes lower than the industrial rates projected for a state, the pattern remains that mass-based rates are generally projected to be higher than rate-based rates, even when considering the extreme (perhaps unlikely) case of 100% free allocations to EDCs.

Figure 8. State by state industrial sector electricity rate projections under different EE availability assumptions (2015¢/kWh, Average 2022-2033)



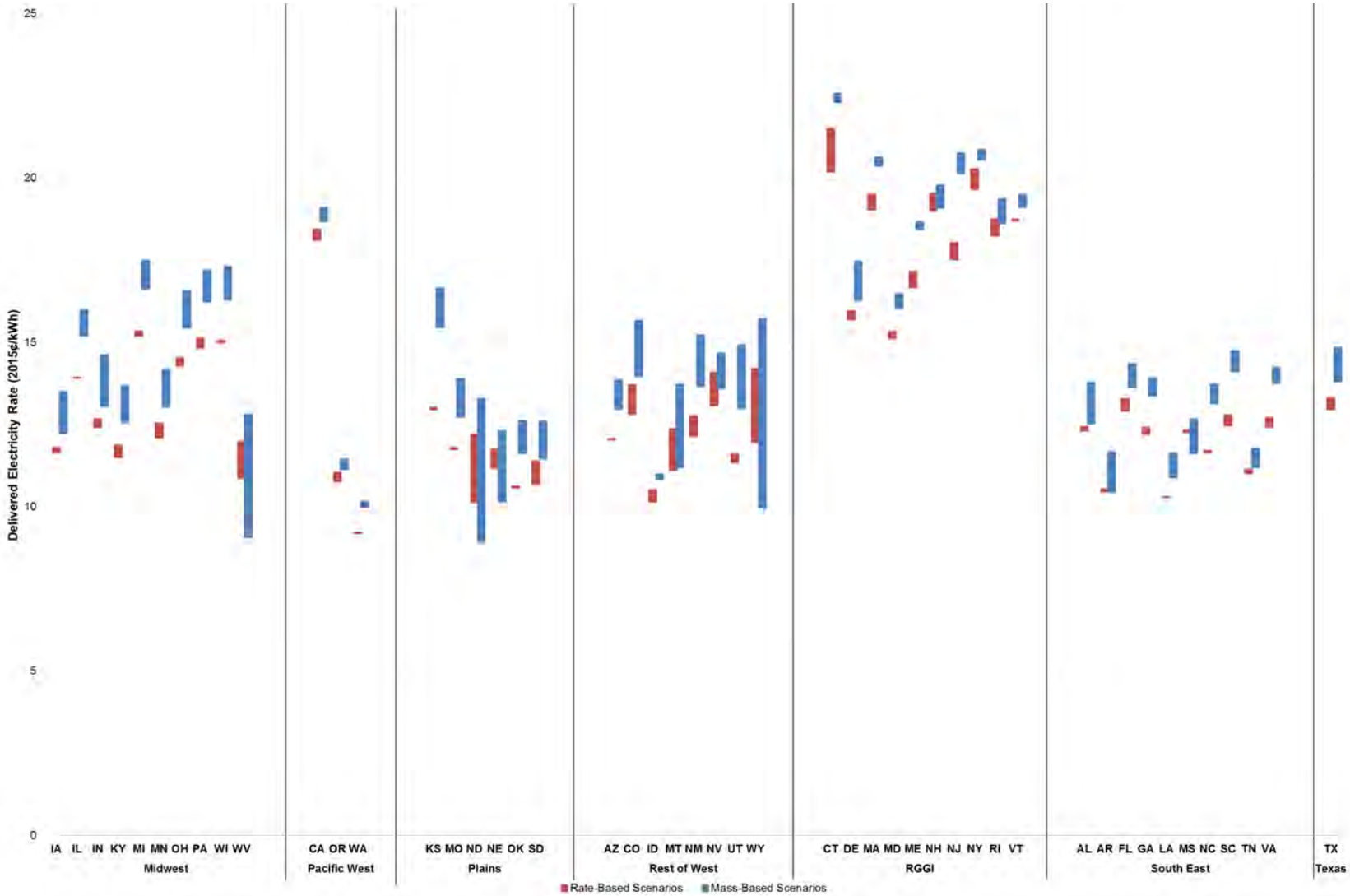
Note: Results shown are for the mass-based with regional trading and 0% free allocation to EDCs scenario.
Source: N_{ew}ERA modeling results and NERA calculations as explained in text.

Figure 9. State by state commercial sector electricity rate projections for all levels of potential trading, with free allocations to EDCs ranging from 0% to 100% (2015¢/kWh, Average 2022-2033)



Source: N_{ew}ERA modeling result.

Figure 10. State by state residential sector electricity rate projections for all levels of potential trading, with free allocations to EDCs ranging from 0% to 100% (2015¢/kWh, Average 2022-2033)



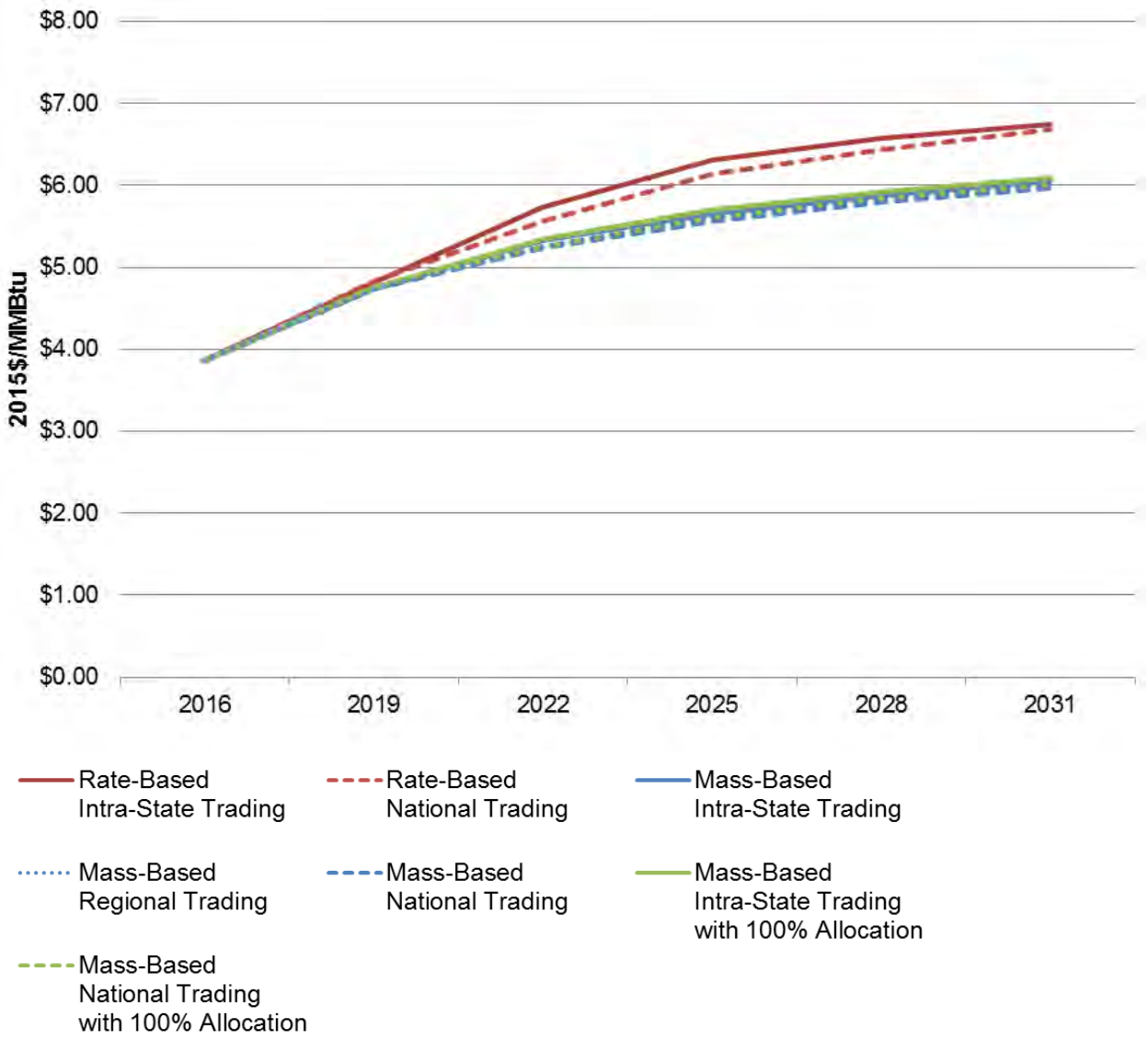
Source: N_{ew}ERA modeling result.

B. Natural Gas Prices

Figure 11 presents projected Henry Hub natural gas prices for all the scenarios we evaluate (see Table E-1). In terms of natural gas prices, the choice of rate- or mass-based alternative appears to be the critical factor determining the results, with almost no additional variation in projected prices for different degrees of trading or different EDC allocations. Indeed, every one of the mass-based FP scenarios has lower natural gas prices than every one of the rate-based options. The higher gas prices under the rate-based approaches are due in part to the lack of energy efficiency as a compliance option in the rate-based scenarios, which means that CO_2 emissions reductions are accomplished primarily by fuel switching from coal to natural gas (which puts pressure on natural gas prices).

As noted above, NERA's analysis of the final Clean Power Plan rule (NERA 2015) included EE projects as a compliance option in the rate-based alternative (because it is a part of the compliance formula for SIPs under the CPP. These other analyses provide insights on the extent to which the proscription of EE as a compliance option in a rate-based FP approach may be contributing to the projected gap between natural gas prices under a rate-based versus a mass-based FP. We note that the average difference between rate-based and mass-based natural gas prices in the CPP analysis of NERA (2015) is roughly 40 percent of the difference estimated in this analysis. Thus, we conclude that even if EE were to be included in the compliance formula for a rate-based FP, one could still expect that natural gas prices would be higher than under any of the various implementations of a mass-based FP that we have analyzed.

Figure 11. Henry Hub Natural Gas Prices ($2015/MMBtu)



Source: N_{ew}ERA modeling result.

C. Leakage Under a 5% Renewable Set-Aside

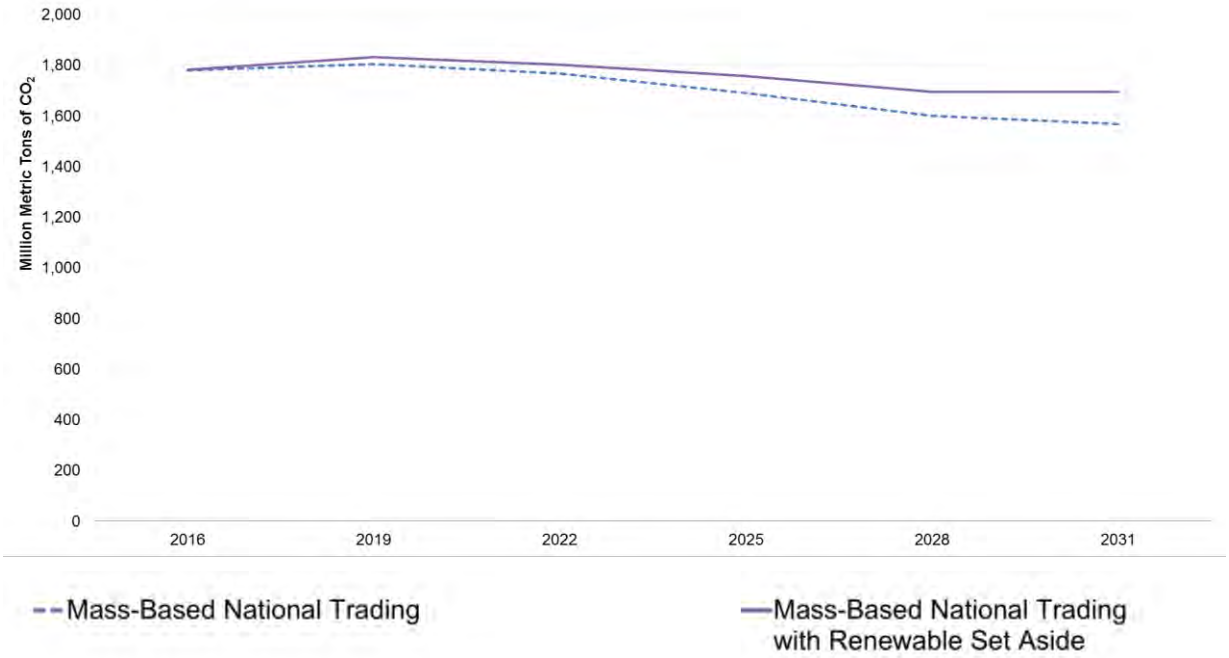
As noted above, all of the mass-based scenarios presented above used the New Source Complement approach as the means of addressing the leakage issue under mass-based scenarios whereby some emitting units are covered (*i.e.*, existing fossil generators) and some are not (namely new natural gas combined cycle units). EPA has proposed a combined approach to preventing leakage, the use of output-based allocations and a 5% allowance set-aside for new renewable generators. Lacking capability to simulate output-based allocations on the present timeline for comments, we explored the potential effectiveness of one component of what is proposed—a 5% allowance set-aside for new renewable generators. Our analysis found that a 5% allowance set-aside for new renewable generators would not likely have any effect on leakage.

New natural gas combined cycle units are projected to be built and to generate. (In 2031, our analysis shows twice as much generation from new NGCC units if they are not subject to the cap as opposed to if they were subject to the cap). Further, this leakage effectively loosens the cap and drives down CO_2 allowance prices as a result. The lower CO_2 allowance prices then reduce the value of the 5% renewable set-aside, making the set-aside ineffective at motivating new renewables generation as well as ineffective at stopping leakage.

Figure 12 shows the effect of this leakage on CO_2 emissions. The mass-based cap that is run with the renewable set-aside has only about half of the intended emissions reductions under the CPP. The higher emissions are traceable to emissions from new NGCCs. The greater amount of generation from new NGCCs with the renewable set-aside is shown in Figure 13.

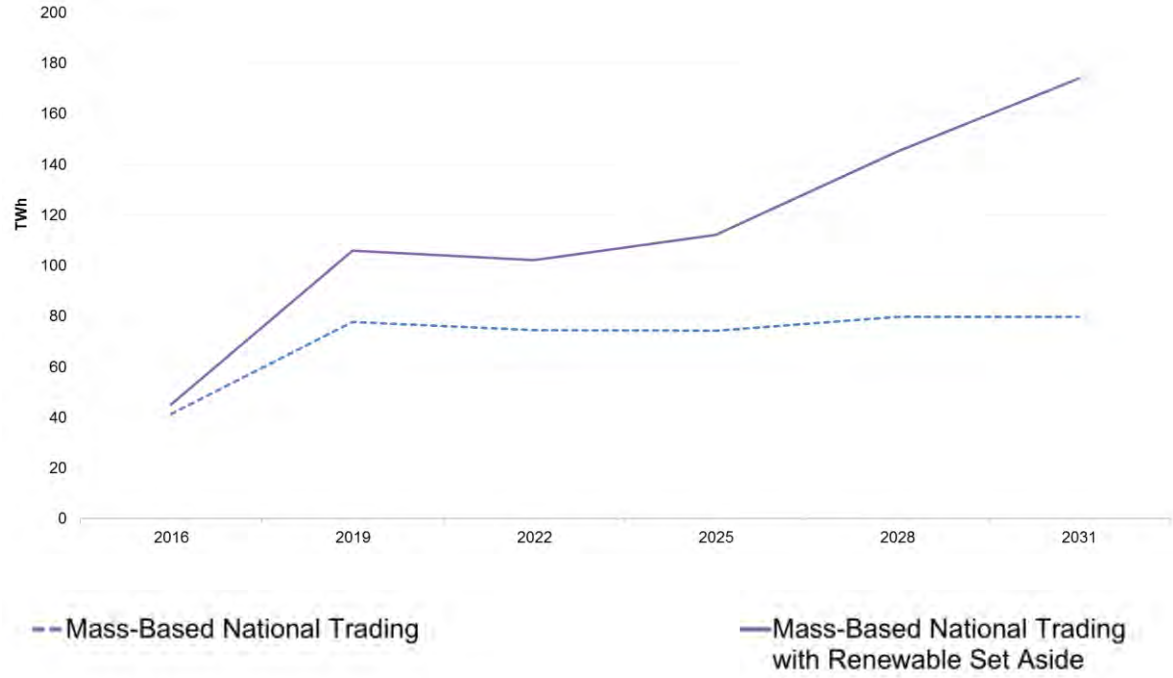
We recognize that the proposed FP calls for a combination of output-based allocations *combined* with a 5% renewable set-aside to prevent leakage. Simulation of an output-based allocation was not feasible within the current study schedule, and we cannot indicate whether it would have any leakage-preventing benefit. However, this analysis implies that a 5% set-aside for renewables would probably have no incremental benefit in controlling leakage.

Figure 12. CO_2 Emissions



Source: N_{ew}ERA modeling result.

Figure 13. New NGCC Generation



Source: N_{ew}ERA modeling result.

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Appendix A. NewERA Model Documentation

Introduction

NERA developed the NewERA model to forecast the impact of policy, regulatory, and economic factors on the energy sectors and the economy. When evaluating policies that have significant impacts on the entire economy, this model specification captures the effects as they ripple through all sectors of the economy and the associated feedback effects. The NewERA model combines a macroeconomic model with all sectors of the economy with a detailed electric sector model that represents electricity production. This combination allows for a complete understanding of the economic impacts of different policies on all sectors of the economy.

The macroeconomic model incorporates all production sectors except electricity and final demand of the economy. Policy consequences are transmitted throughout the economy as sectors respond until the economy reaches equilibrium. The production and consumption functions employed in the model enable gradual substitution of inputs in response to relative price changes, thus avoiding all-or-nothing solutions.

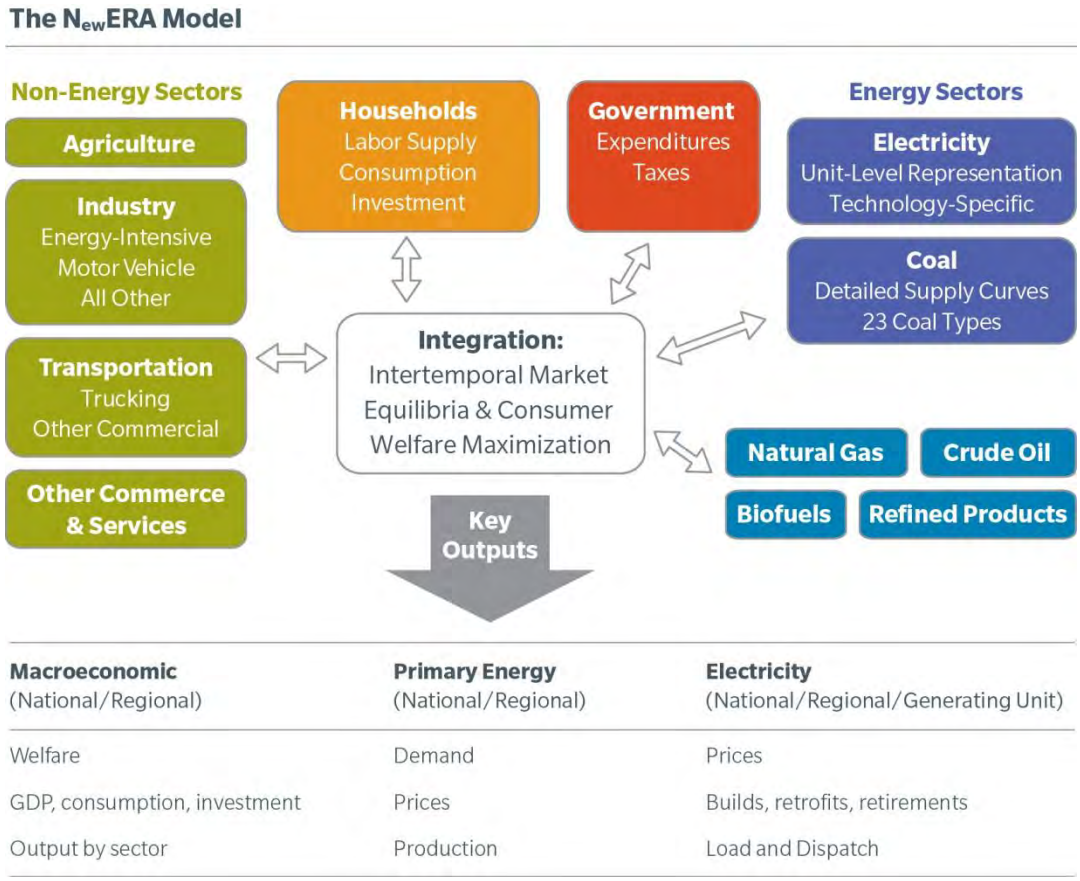
The main benefit of the integrated framework is that the electric sector can be modeled in great detail yet through integration the model captures the interactions and feedbacks between all sectors of the economy. Electric technologies can be well represented according to engineering specifications. The integrated modeling approach also provides consistent price responses since all sectors of the economy are modeled. In addition, under this framework we are able to model electricity demand response.

The electric sector model is a detailed model of the electric and coal sectors. Each of the more than 17,000 electric generating units in the United States is represented in the model. The model minimizes costs while meeting all specified constraints, such as demand, peak demand, emissions limits, and transmission limits. The model determines investments to undertake and unit dispatch. Because the NewERA model is an integrated model of the entire U.S. economy, electricity demand can respond to changes in prices and supplies. The NewERA model represents the domestic and international crude oil and refined petroleum markets.

The NewERA model outputs include demand and supply of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, and changes in "job equivalents" based on labor wage income, as discussed below in the section on macroeconomic modeling.

Figure A-1 provides a simplified representation of the key elements of the N_{ew}ERA modeling system.

Figure A-1. N_{ew}ERA Modeling System Representation



Electric Sector Model

The electric sector model that is part of the N_{ew}ERA modeling system is a bottom-up model of the electric and coal sectors. Consistent with the macroeconomic model, the electric sector model is fully dynamic and includes perfect foresight (under the assumption that future conditions are known). Thus, all decisions within the model are based on minimizing the present value of costs over the entire time horizon of the model while meeting all specified constraints, including demand, peak demand, emissions limits, transmission limits, RPS regulations, fuel availability and costs, and new build limits. The model set-up is intended to mimic (as much as is possible within a model) the approach that electric sector investors use to make decisions. In determining the least-cost method of satisfying all these constraints, the model endogenously decides:

- What investments to undertake (*e.g.,* addition of retrofits, build new capacity, repower unit, add fuel switching capacity, or retire units);

- How to operate each modeled unit (*e.g.,* when and how much to operate units, which fuels to burn) and what is the optimal generation mix; and

- How demand will respond. The model thus assesses the trade-offs between the amount of demand-side management (DSM) to undertake and the level of electricity usage.

Each unit in the model has certain actions that it can undertake. For example, all units can retire, and many can undergo retrofits. Any publicly-announced actions, such as planned retirements, planned retrofits (for existing units), or new units under construction can be specified. Coal units have more potential actions than other types of units. These include retrofits to reduce emissions of SO_2, NO_X, mercury, and CO_2.[12] The costs, timing, and necessity of retrofits may be specified as scenario inputs or left for the model to endogenously select. Coal units can also switch the type of coal that they burn (with practical unit-specific limitations). Finally, coal units may retire if none of the above actions will allow them to remain profitable, after accounting for their revenues from generation and capacity services.

Most of the coal units' actions would be in response to environmental limits that can be added to the model. These include emission caps (for SO_2, NO_X, Hg, and CO_2) that can be applied at the national, regional, state or unit level. We can also specify allowance prices for emissions, emission rates (especially for toxics such as Hg) or heat rate levels that must be met.

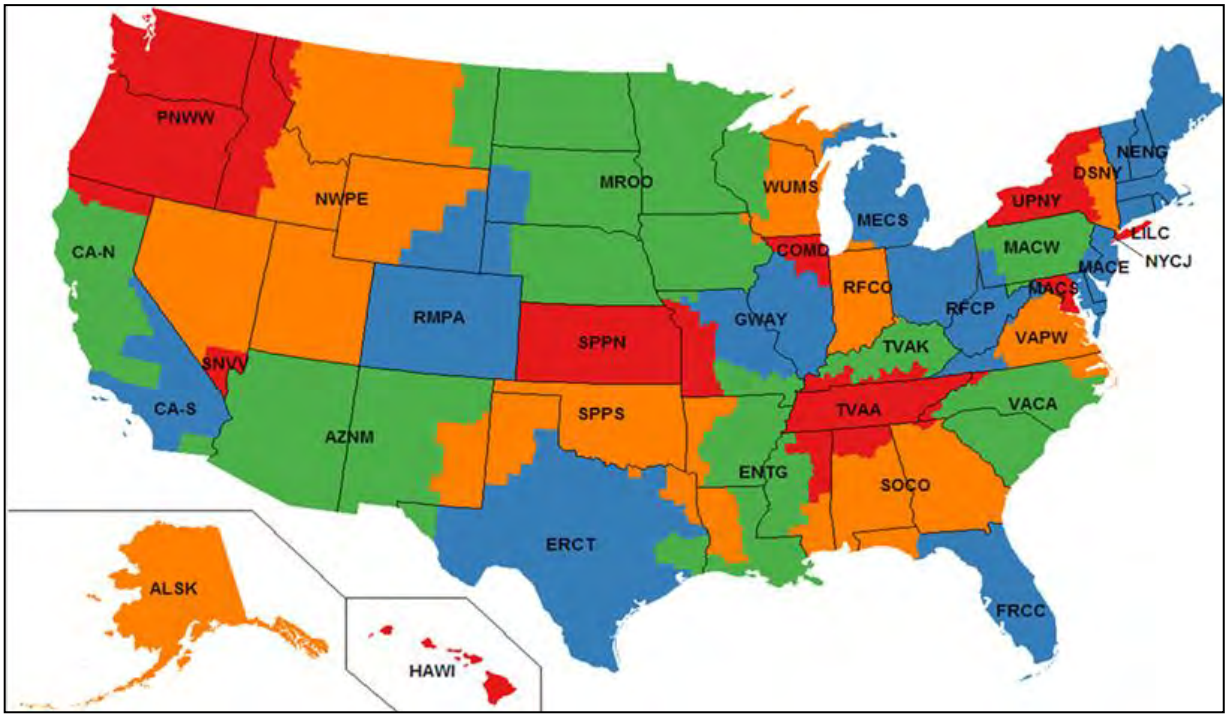
Just as with investment decisions, the operation of each unit in a given year depends on the policies in place (*e.g.*, unit-level standards), electricity demand, and operating costs, especially energy prices. The model accounts for all these conditions in deciding when and how much to operate each unit. The model also considers system-wide operational issues such as environmental regulations, limits on the share of generation from intermittent resources, transmission limits, and operational reserve margin requirements in addition to annual reserve margin constraints.

To meet increasing electricity demand and reserve margin requirements over time, the electric sector must build new generating capacity. Future environmental regulations and forecasted energy prices influence which technologies to build and where. For example, if a national RPS policy is to take effect, some share of new generating capacity will need to come from renewable power. On the other hand, if there is a policy to address emissions, it might elicit a response to retrofit existing fossil-fired units with pollution control technology or enhance existing coal-fired units to burn different types of coals, biomass, or natural gas. Policies calling for improved heat rates may lead to capital expenditure spent on repowering existing units. All of these policies will also likely affect retirement decisions. The N_{ew}ERA electric sector model endogenously captures all of these different types of decisions.

[12] As discussed in the report body, N_{ew}ERA does not incorporate EPA's recently proposed power sector CO_2 rule.

The model contains 34 U.S. electricity regions (and six Canadian electricity regions). Figure A-2 shows the U.S. electricity regions.

Figure A-2. N_{ew}ERA Electric Sector Model – U.S. Regions



The electric sector model is fully flexible in the model horizon and the years for which it solves. When used in an integrated manner with the macroeconomic model, and to analyze long-term effects, the model has the same time steps as in the macroeconomic model (2016 through 2040, modeling every third year).

Macroeconomic Model

1. Overview

The N_{ew}ERA macroeconomic model is a forward-looking dynamic computable general equilibrium (CGE) model of the United States. The model simulates all economic interactions in the U.S. economy, including those among industry, households, and the government. Additional background information on CGE models can be found in Burfisher (2011).

The N_{ew}ERA CGE framework uses the standard theoretical macroeconomic structure to capture the flow of goods and factors of production within the economy. A simplified version of these interdependent macroeconomic flows is shown in Figure A-3. The model implicitly assumes "general equilibrium," which implies that all sectors in the economy are in balance and all

economic flows are endogenously accounted for within the model. In this model, households supply factors of production, including labor and capital, to firms. Firms provide households with payments for the factors of production in return. Firm output is produced from a combination of productive factors and intermediate inputs of goods and services supplied by other firms. Individual firm final output can be consumed within the United States or exported. The model also accounts for imports into the United States. In addition to consuming goods and services, households can accumulate savings, which they provide to firms for investments in new capital. Government receives taxes from both households and firms, contributes to the production of goods and services, and also purchases goods and services. Although the model assumes equilibrium, a region in the model can run deficits or surpluses in current accounts and capital accounts. In aggregate, all markets clear, meaning that the sum of regional commodities and factors of production must equal their demands, and the income of each household must equal its factor endowments plus any net transfers received.

The model uses the standard CGE framework developed by Arrow and Debreu (1954). Behavior of households is represented by a nested Constant Elasticity of Substitution (CES) utility function. The model assumes that households seek to maximize their overall welfare, or utility, across time periods. Households have utility functions that reflect trade-offs between leisure (which reduces the amount of time available for earning income) and an aggregate consumption of goods and services. Households maximize their utility over all time periods subject to an intertemporal budget constraint based on their income from supplying labor, capital, and natural resource to firms. In each time period, household income is used to consume goods and services or to fund investment. Within consumption, households substitute between energy (including electricity, coal, natural gas, and petroleum), personal transportation, and goods and services based on the relative price of these inputs. Figure A-4 illustrates the utility function of the households.

Figure A-3. Interdependent Economic Flows in N_{ew}ERA's Macroeconomic Model

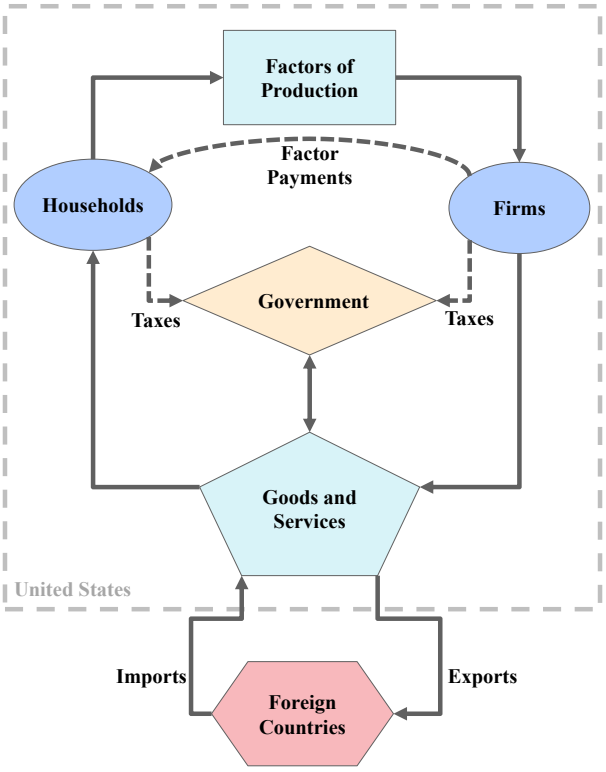
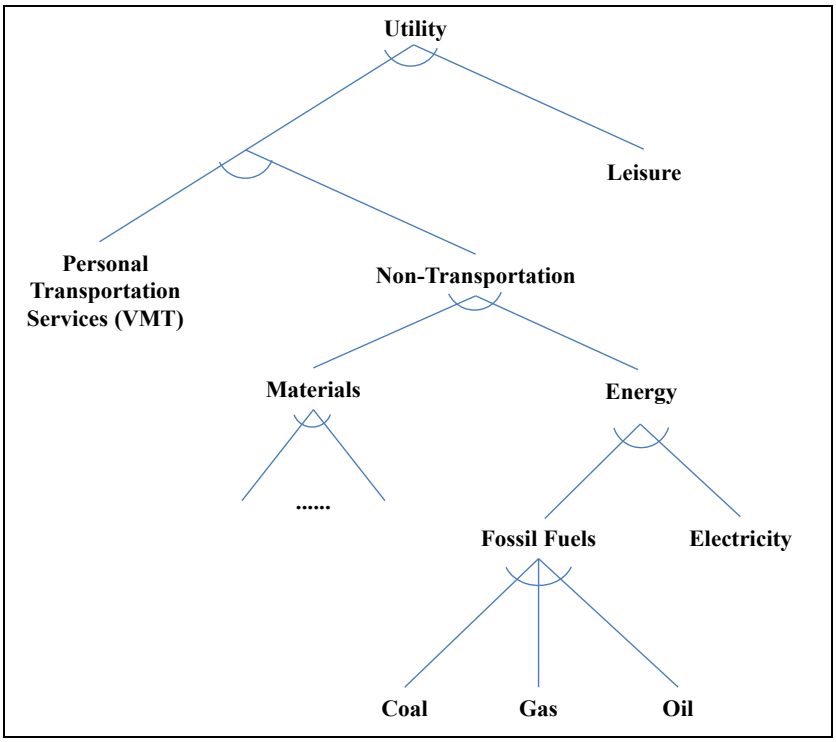


Figure A-4. Household Consumption Structure in N_{ew}ERA's Macroeconomic Model



On the production side, Figure A-5 shows the production structure of the commercial transportation and the trucking sector. Production structure for the rest of the industries is shown in Figure A-6. The model assumes all industries maximize profits subject to technological constraints. The inputs to production are energy (including the same four types noted above for household consumption), capital, and labor. Production also uses inputs from intermediate products (*i.e.*, materials) provided by other firms. The N_{ew}ERA model allows producers to change the technology and the energy source they use to manufacture goods. If, for example, petroleum prices rise, an industry can shift to a cheaper energy source. It can also choose to use more capital or labor in place of petroleum, increasing energy efficiency and maximizing profits with respect to industry constraints.

Figure A-5. Commercial Transportation and Trucking Sector Production Structure in N_{ew}ERA's Macroeconomic Model

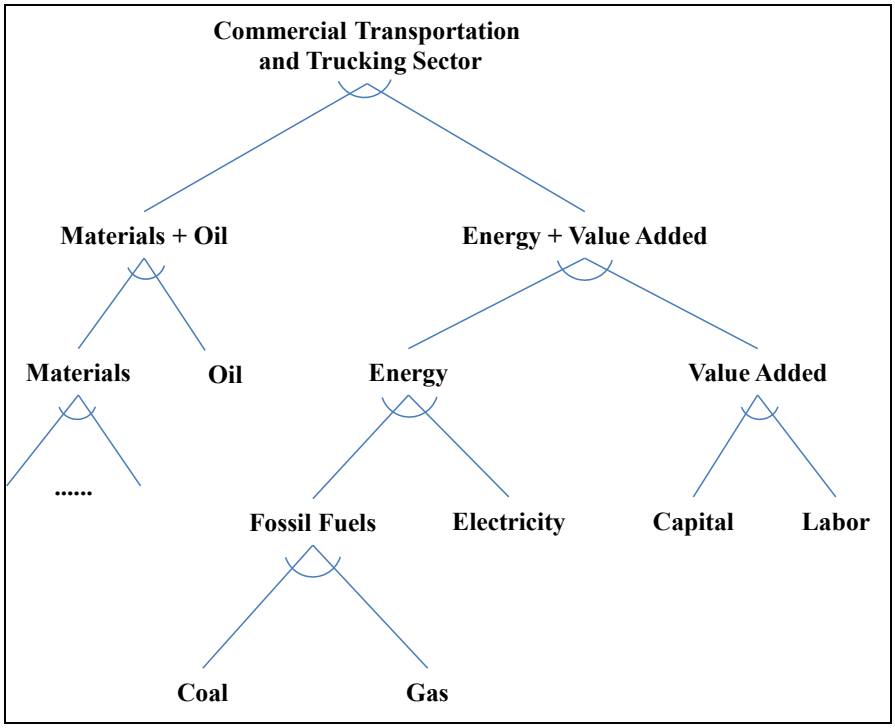
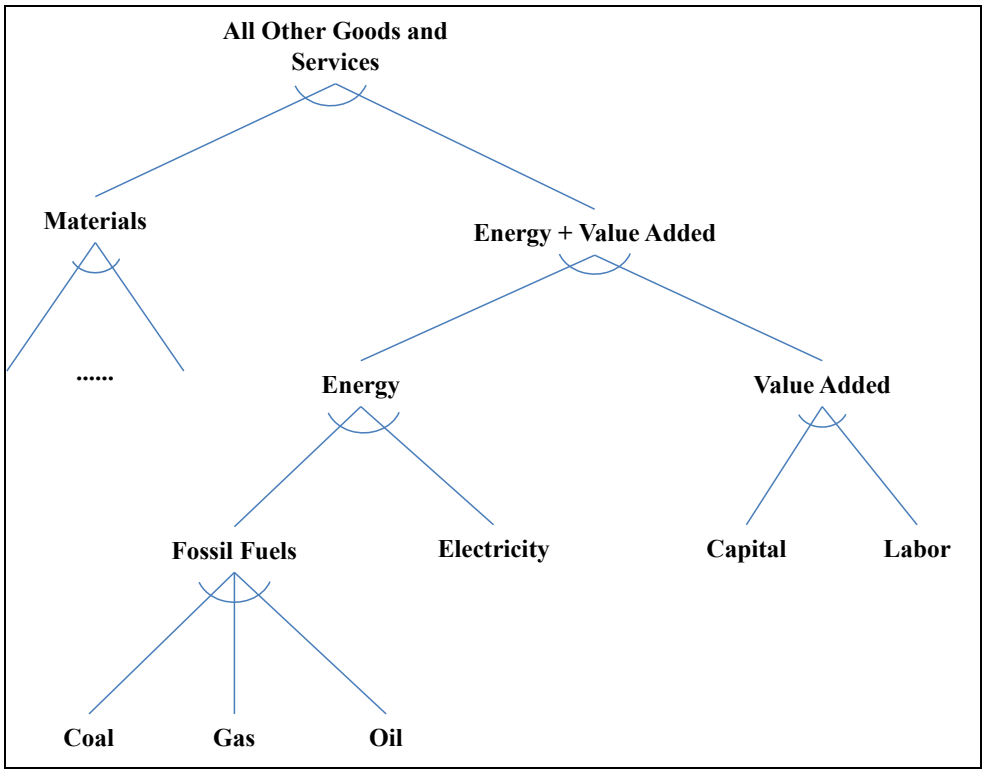


Figure A-6. Production Structure for Other Sectors in N_{ew}ERA's Macroeconomic Model



All goods and services, except crude oil, are treated as Armington goods, which assume the domestic and foreign goods are differentiated and thus are imperfect substitutes (Armington 1969). The level of imports depends upon the elasticity of substitution between the imported and domestic goods. The Armington elasticity among imported goods is assumed to be twice as large as the elasticity between the domestic and imported goods, characterizing the greater substitutability among imported goods.

Business investment decisions are informed by future policies and outlook. The forward-looking characteristic of the model enables businesses and consumers to determine the optimal savings and investment levels while anticipating future policies with perfect foresight.

The benchmark year economic interactions are based on the IMPLAN 2008 database, which includes regional detail on economic interactions among 440 different economic sectors. The macroeconomic and energy forecasts that are used to project the benchmark year going forward are calibrated to EIA's *Annual Energy Outlook* (*AEO*) *2015* Reference case.

2. Interactions between Compliance Costs, Capital Investment, and Household Expenditures

Regulations cause producers in the affected industries to make capital expenditures that they would not make otherwise. In addition, regulations change consumption patterns for households. To model the macroeconomic impacts of regulations, N_{ew}ERA accounts for interactions between compliance costs, capital investments, and household expenditures based on the following three effects.

1. *Compliance costs for producers in the regulated industries*. Producers in the regulated industries have to make capital expenditures to comply with the regulation. These expenditures increase the costs of producing goods and services in the regulated industries. The higher costs lead to higher prices for the goods and services, which in turn lead to lower demand in the regulated industries. Thus, this effect reduces economic activity.

2. *Scarcity effect due to non-optimal capital allocation*. In N_{ew}ERA's modeling framework, the capital expenditures for regulatory compliance are assumed to be unproductive. The capital expenditures in the regulated industries make less capital available to produce goods and services throughout the economy. In other words, the unproductive capital expenditures in the regulated industries "crowd out" productive capital investment in the broader economy. This scarcity effect increases the opportunity cost of capital in the economy, which implies higher costs of capital. This in turn lowers investment in productive capital and slows economic growth.

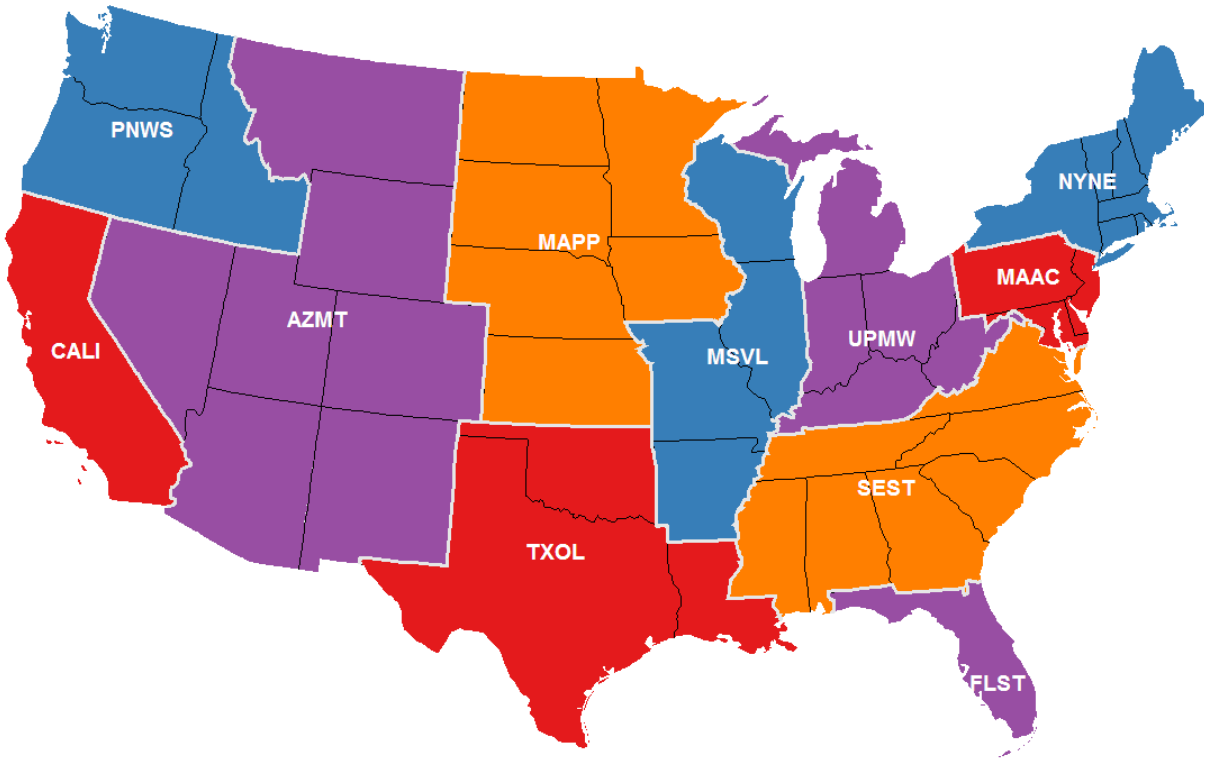
3. *Household purchases of unproductive durable goods*. Regulations also cause households to change their consumption patterns, particularly in terms of durable goods. For example, households may need to purchase new automobiles, lawn mowers, or equipment for compliance with the regulation. These additional expenditures on unproductive durable goods are non-optimal from the standpoint of households, but they represent increased demand for the manufacturing sector. Thus, these additional household purchases increase economic activity.

The net macroeconomic impacts of regulations calculated by N_{ew}ERA reflect the combination of these three effects.

3. Regional Aggregation

The N_{ew}ERA macroeconomic model typically includes 11 regions built up from economic data for the 50 U.S. states and the District of Columbia. The regions are shown in Figure A-7.

Figure A-7. N_{ew}ERA Macroeconomic Model Regions



4. Sectoral Aggregation

The N_{ew}ERA model includes a standard set of 10 economic sectors: five energy (coal, natural gas, crude oil, electricity, and refined petroleum products) and five non-energy sectors (services, manufacturing, agriculture, commercial transportation excluding trucking, and trucking). These sectors are aggregated up from the 440 IMPLAN sectors. The model has the flexibility to represent sectors at different levels of aggregation, when warranted, to better meet the needs of specific analyses.

5. Natural Gas and Crude Oil Markets

As with most commodity markets, there are uncertainties about how the U.S. natural gas market will evolve, and the N_{ew}ERA modeling system is designed explicitly to address the key factors affecting future natural gas supply and prices. To account for natural gas supply uncertainty and the subsequent effect it could have on international markets, the N_{ew}ERA modeling system has the ability to represent supply curves for conventional natural gas and shale gas for each region

of the model. By including each type of natural gas, it is possible to incorporate expert judgments and sensitivity analyses on a variety of uncertainties, such as the extent of shale gas reserves, the cost of shale gas production, and the impacts of environmental regulations.

The N_{ew}ERA model represents the domestic and international crude oil and refined petroleum markets. The international markets are represented by flat supply curves with exogenously specified prices. Because crude oil is treated as a homogeneous good, the international price for crude oil sets the U.S. price for crude oil.

For this study, we calibrated natural gas and crude oil production at the state level based on information from *AEO 2015*. While *AEO 2015* does not provide state-level information, they did provide us with basin-specific production forecasts that we translated into state-level production based on historical state-level production, other publicly-available forecasts by state, and our own expertise.

6. Macroeconomic Outputs

As with other CGE models, the N_{ew}ERA macroeconomic model outputs include demand and supply of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, cost of living or burden on consumers, and changes in "job equivalents" based on changes in labor wage income. All model outputs are calculated by time, sector, and region.

Impacts on workers are often considered an important output of policy evaluations. Impacts on workers are complicated to estimate and to explain because they can include several different impacts, including involuntary unemployment, reductions in wage rates for those who continue to work, and voluntary reductions in hours worked due to lower wage rates. No model addresses all of these potential impacts. The N_{ew}ERA model is a long-run equilibrium model based upon full employment, and thus its results relate to the longer-term effects on labor income and voluntary reductions in hours worked rather than involuntary unemployment impacts. It addresses long-run employment impacts, all of which are based on estimates of changes in labor income, also called the "wage bill" or "payments to labor." Labor income impacts consist of two effects: (1) changes in real wage per hour worked; and (2) changes in labor market participation (hours worked) in response to changed real wage rates. The labor income change can also be expressed on a per-household basis, which represents one of the key components of disposal income per household. (The other key components of disposable income are returns on investments or "payments to capital," and income from ownership of natural resources). The labor income change can also be stated in terms of job-equivalents, by dividing the labor income change by the annual income from the average job. A loss of one job-equivalent does not necessarily mean one less employed person—it may be manifested as a combination of fewer people working and less income per person who is working. However, this measure allows us to

express employment-related impacts in terms of an equivalent number of employees earning the average prevailing wage.

For modeling the economic impacts of changes in energy prices, we assume that 50% of the wealth impacts would accrue to local residents in each energy production region (state), and the remaining 50% of wealth impacts would accrue to energy company shareholders based on national population percentages. We are not aware of any recent studies of the geographic distribution of potential energy sector gains, so we used an even division between state and national impacts given that some energy companies are in-state and some gains to national companies would accrue to local residents. A large fraction of energy production (particularly for natural gas shale developments that have become available through horizontal drilling techniques and hydraulic fracturing, or "fracking") is on private land and generates payments to local residents (payments, severance taxes, renegotiated leases, etc.). The remaining wealth impacts from changes in energy prices would affect shareholders in large publicly-traded energy companies, who are spread throughout the country.

Integrated N_{ew}ERA Model

The N_{ew}ERA modeling framework fully integrates the macroeconomic model and the electric sector model so that the final solution is a consistent equilibrium for both models and thus for the entire U.S. economy.

To analyze any policy scenario, the system first solves for a consistent baseline solution; it then iterates between the two models to find the equilibrium solution for the scenario of interest. For the baseline, the electric sector model is solved first under initial economic assumptions and forecasts for electricity demand and energy prices. The equilibrium solution provides the baseline electricity prices, demand, and supply by region as well as the consumption of inputs—capital, labor, energy, and materials—by the electric sector. These solution values are passed to the macroeconomic model.

Using these outputs from the electric sector model, the macroeconomic model solves the baseline while constraining the electric sector to replicate the solution from the electric sector model and imposing the same energy price forecasts as those used to solve the electric sector baseline. In addition to the energy price forecasts, the macroeconomic model's non-electric energy sectors are calibrated to the desired exogenous forecast (EIA's *AEO 2015* forecast) for energy consumption, energy production, and macroeconomic growth. The macroeconomic model solves for equilibrium prices and quantities in all markets subject to meeting these exogenous forecasts.

After solving the baseline, the integrated N_{ew}ERA modeling system solves for the scenario. First the electric sector model reads in the scenario definition. The electric sector model then solves for the equilibrium level of electricity demand, electricity supply, and inputs used by the electric sector (*i.e.*, capital, labor, energy, emission permits). The electric sector model passes these

equilibrium solution quantities to the macroeconomic model, which solves for the equilibrium prices and quantities in all markets. The macroeconomic model then passes to the electric sector model the following (solved for equilibrium prices):

- Electricity prices by region;
- Prices of non-coal fuels used by the electric sector (*e.g.*, natural gas and oil); and
- Prices of any permits that are tradable between the non-electric and electric sectors (*e.g.*, carbon permits under a nationwide greenhouse gas cap-and-trade program).

The electric sector model then solves for the new electric sector equilibrium, taking the prices from the macroeconomic model as exogenous inputs. The models iterate—prices being sent from the macroeconomic model to the electric sector model and quantities being sent from the electric sector model to the macroeconomic model—until the prices and quantities in the two models differ by less than a fraction of a percent.

This decomposition algorithm allows the N_{ew}ERA model to retain the information in the detailed electricity model, while at the same time accounting for interactions with the rest of the economy. The detailed information on the electricity sector enables the model to represent regulatory policies that are imposed on the electricity sector in terms of their impacts at a unit level.

References to the Appendix

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Appendix B. Tables of Electricity Rate Estimates

This appendix contains tables with the numerical values for each of the Cases A through F that have been summarized in the main report as ranges and in graphical format.

Table B-1. All-Sector Delivered Electricity Prices (2015$ ¢/kWh, Average 2022-2033)

	Rate-Based Scenarios		Mass-Based Scenarios				
State	Intra-State Trading	National Trading	Intra-State Trading	Regional Trading	National Trading	Intra-State Trading 100% Allocation	National Trading 100% Allocation
AL	10.3	10.2	11.3	11.5	11.6	10.4	10.7
AR	8.9	8.8	9.9	10.0	9.7	9.3	8.8
AZ	10.6	10.6	11.3	11.5	11.6	11.0	10.8
CA	17.3	17.0	17.5	17.5	17.9	17.5	17.7
CO	11.8	10.9	13.0	11.9	12.2	11.8	11.5
CT	18.7	17.4	19.4	19.3	19.5	19.4	19.3
DE	13.3	13.1	14.4	14.2	14.0	14.3	13.3
FL	12.2	11.9	13.0	13.0	13.1	12.6	12.4
GA	10.8	10.6	11.9	11.8	11.9	11.6	11.5
IA	8.7	8.7	10.2	10.1	9.9	9.0	9.2
ID	8.6	8.3	9.3	9.2	9.3	9.2	9.2
IL	11.1	11.2	11.9	11.8	11.8	11.3	11.3
IN	10.1	10.3	11.5	11.5	11.4	10.1	10.4
KS	10.8	10.9	12.7	12.7	12.4	11.6	11.7
KY	9.6	9.2	10.1	10.1	10.1	9.1	9.1
LA	8.9	9.0	9.8	9.9	9.8	9.5	9.2
MA	16.9	16.4	17.4	17.4	17.5	17.5	17.3
MD	13.7	13.5	14.5	14.4	14.4	14.4	14.1
ME	14.6	14.1	15.0	14.9	15.2	15.0	15.0
MI	12.0	11.9	13.0	13.1	13.1	12.5	12.4
MN	9.9	9.5	11.4	11.0	10.8	10.9	10.4
MO	10.2	10.2	11.5	11.4	11.3	10.3	10.5
MS	10.7	10.6	11.7	11.4	11.4	11.1	10.7
MT	9.4	10.7	10.6	10.8	11.1	8.6	9.9
NC	10.0	10.0	11.0	11.1	11.2	10.7	10.6
ND	9.2	11.3	10.6	11.0	11.3	6.9	9.3
NE	9.3	9.9	10.7	10.9	10.7	8.8	9.9
NH	16.9	16.4	17.4	17.4	17.3	17.5	16.8
NJ	16.0	15.5	17.6	17.5	17.5	17.5	17.1
NM	10.3	9.7	11.0	11.5	11.5	10.4	10.1
NV	11.1	10.2	12.2	11.7	11.8	12.2	11.2
NY	16.8	16.3	17.8	17.9	18.0	17.8	17.7
OH	11.4	11.6	12.8	12.7	12.8	11.8	12.1
OK	8.9	8.8	10.3	10.1	10.2	9.4	9.3
OR	9.3	9.1	10.0	10.0	10.1	9.8	9.9
PA	11.9	11.6	13.1	12.7	13.1	12.4	12.2
RI	17.2	16.7	17.8	17.8	17.8	17.9	17.2
SC	10.3	10.0	11.3	11.2	11.2	11.0	10.8
SD	9.8	9.1	11.1	10.4	10.5	10.8	10.1
TN	10.1	10.0	11.1	11.2	11.1	10.6	10.7
TX	10.6	10.3	11.6	11.7	11.4	10.8	10.9
UT	9.3	9.1	11.2	10.5	10.8	9.4	9.5
VA	10.7	10.5	11.6	11.6	11.6	11.3	11.2
VT	15.9	15.9	16.1	16.1	16.4	16.1	16.4
WA	7.8	7.7	8.3	8.2	8.3	8.3	8.2
WI	12.0	11.9	13.3	13.1	13.1	12.6	12.5
WV	9.2	10.3	10.3	10.5	10.9	7.2	8.6
WY	9.2	11.5	10.7	10.4	10.8	5.1	7.7
US	11.6	11.4	12.6	12.5	12.6	12.0	11.9

Source: N_{ew}ERA modeling results.

Table B-2. Industrial Sector Delivered Electricity Prices (2015$ ¢/kWh, Average 2022-2033)

	Rate-Based Scenarios		Mass-Based Scnarios				
State	Intra-State Trading	National Trading	Intra-State Trading	Regional Trading	National Trading	Intra-State Trading 100% Allocation	National Trading 100% Allocation
AL	7.4	7.5	8.3	8.5	8.5	7.4	7.7
AR	7.0	7.0	7.7	7.8	7.5	7.1	6.6
AZ	7.2	7.3	7.1	7.1	7.2	6.9	6.5
CA	14.0	14.0	13.7	13.7	14.0	13.7	13.8
CO	9.3	7.9	9.6	8.7	8.9	8.5	8.3
CT	14.3	13.1	14.7	14.7	14.9	14.8	14.6
DE	10.3	10.1	10.8	10.7	10.4	10.8	9.7
FL	9.7	9.7	9.6	9.6	9.7	9.3	9.1
GA	7.7	7.8	7.8	7.7	7.8	7.6	7.4
IA	6.3	5.9	7.5	7.5	7.3	6.3	6.6
ID	7.0	7.0	7.6	7.5	7.6	7.5	7.6
IL	8.5	8.6	8.6	8.5	8.5	8.0	8.0
IN	8.1	7.5	8.6	8.6	8.5	7.2	7.6
KS	8.2	7.9	9.2	9.2	8.9	8.2	8.3
KY	7.6	6.5	7.4	7.4	7.3	6.5	6.4
LA	6.9	7.0	7.2	7.3	7.2	7.0	6.7
MA	14.2	13.8	14.1	14.1	14.2	14.2	14.0
MD	10.4	10.3	10.8	10.6	10.6	10.7	10.4
ME	10.3	9.9	9.6	9.7	9.9	9.8	9.7
MI	8.6	8.4	8.7	8.8	8.7	8.3	8.1
MN	7.4	7.0	8.5	8.1	7.9	8.0	7.5
MO	7.4	6.9	7.8	7.8	7.7	6.7	7.0
MS	8.0	8.0	9.0	8.7	8.7	8.5	8.0
MT	6.1	5.6	6.4	6.6	6.9	4.4	5.8
NC	7.5	7.6	7.5	7.6	7.6	7.2	7.2
ND	8.5	8.2	9.2	9.6	9.8	5.5	7.9
NE	7.8	7.4	8.6	8.9	8.6	6.7	7.9
NH	13.3	12.8	14.0	14.0	13.9	14.1	13.4
NJ	13.2	12.7	13.4	13.4	13.4	13.4	13.0
NM	7.2	7.3	7.5	7.8	7.8	6.9	6.5
NV	8.6	8.1	8.8	8.3	8.4	8.9	7.9
NY	8.0	7.5	9.1	9.2	9.2	9.2	9.0
OH	8.4	8.6	9.2	9.2	9.3	8.4	8.7
OK	6.6	6.9	7.0	6.8	7.0	6.3	6.1
OR	6.7	6.8	7.6	7.5	7.6	7.4	7.4
PA	8.9	8.6	9.3	8.9	9.3	8.6	8.5
RI	14.9	14.4	16.5	16.4	16.4	16.6	15.8
SC	7.4	7.5	7.5	7.4	7.4	7.3	7.0
SD	7.7	7.2	9.0	8.3	8.4	8.7	8.0
TN	7.7	7.6	8.9	8.9	8.9	8.5	8.5
TX	8.0	7.7	8.1	8.2	8.0	7.4	7.5
UT	7.0	5.8	8.2	7.6	7.8	6.5	6.6
VA	8.5	8.3	9.2	9.2	9.2	8.9	8.9
VT	11.6	11.6	11.4	11.4	11.7	11.4	11.8
WA	5.1	5.2	5.2	5.1	5.1	5.2	5.0
WI	9.0	8.7	9.7	9.5	9.4	9.0	8.9
WV	7.4	6.6	7.9	8.1	8.5	4.8	6.2
WY	8.0	6.7	9.0	8.8	9.1	3.4	6.1
US	8.3	8.1	8.7	8.7	8.7	8.0	8.1

Source: N_{ew}ERA modeling results.

Table B-3. Industrial Sector Delivered Electricity Prices Under Different EE Availability Assumptions (2015$ ¢/kWh, Average 2022-2033)

State	Historical Fraction of EE (Current)	Historical Fraction of Retail Sales	No Industrial EE
AL	8.5	8.4	7.7
AR	7.8	8.0	7.2
AZ	7.1	7.8	6.9
CA	13.7	13.9	13.4
CO	8.7	9.3	8.4
CT	14.7	14.6	13.7
DE	10.7	10.9	10.4
FL	9.6	10.3	9.6
GA	7.7	8.4	7.7
IA	7.5	7.5	6.8
ID	7.5	7.5	6.6
IL	8.5	9.1	8.5
IN	8.6	9.3	8.6
KS	9.2	9.9	9.2
KY	7.4	7.9	7.3
LA	7.3	7.7	7.2
MA	14.1	14.5	13.6
MD	10.6	10.9	10.3
ME	9.7	10.3	9.7
MI	8.8	9.4	8.6
MN	8.1	8.4	7.6
MO	7.8	8.4	7.7
MS	8.7	8.5	7.7
MT	6.6	7.3	6.5
NC	7.6	8.3	7.6
ND	9.6	10.3	9.5
NE	8.9	9.3	8.6
NH	14.0	13.5	12.8
NJ	13.4	14.4	13.4
NM	7.8	8.0	7.2
NV	8.3	9.1	8.3
NY	9.2	8.2	7.5
OH	9.2	9.4	8.7
OK	6.8	7.5	6.8
OR	7.5	7.1	6.2
PA	8.9	9.4	8.7
RI	16.4	15.3	14.3
SC	7.4	7.9	7.3
SD	8.3	8.2	7.5
TN	8.9	8.5	7.7
TX	8.2	8.9	8.2
UT	7.6	8.0	7.2
VA	9.2	9.2	8.5
VT	11.4	11.4	11.4
WA	5.1	5.4	4.6
WI	9.5	9.9	9.0
WV	8.1	8.5	7.9
WY	8.8	9.2	8.3

Source: N_{ew}ERA modeling results.

Table B-4. Commercial Sector Delivered Electricity Prices (2015$ ¢/kWh, Average 2022-2033)

	Rate-Based Scenarios		Mass-Based Scenarios				
State	Intra-State Trading	National Trading	Intra-State Trading	Regional Trading	National Trading	Intra-State Trading 100% Allocation	National Trading 100% Allocation
AL	11.8	11.7	12.8	13.0	13.1	11.8	12.2
AR	9.0	8.9	10.7	10.8	10.5	10.0	9.6
AZ	10.4	10.4	10.9	11.1	11.2	10.7	10.5
CA	17.8	17.5	18.2	18.2	18.6	18.2	18.3
CO	11.9	11.1	13.4	12.3	12.6	12.2	11.9
CT	17.1	15.8	17.6	17.6	17.8	17.7	17.5
DE	12.4	12.2	13.5	13.4	13.1	13.5	12.4
FL	11.4	11.0	12.1	12.2	12.2	11.8	11.6
GA	11.1	10.9	12.6	12.5	12.7	12.3	12.1
IA	9.2	9.1	10.6	10.6	10.4	9.4	9.7
ID	8.5	8.1	9.6	9.5	9.7	9.5	9.6
IL	10.9	10.9	11.7	11.5	11.5	11.0	11.0
IN	10.9	11.2	13.9	13.8	13.7	12.3	12.7
KS	10.7	10.8	12.0	12.0	11.7	11.0	11.1
KY	11.1	10.8	12.2	12.2	12.2	11.2	11.2
LA	9.8	9.8	11.1	11.3	11.1	10.8	10.5
MA	16.4	15.9	17.2	17.1	17.3	17.2	17.0
MD	12.7	12.6	13.4	13.2	13.3	13.3	13.0
ME	15.0	14.5	15.5	15.4	15.7	15.5	15.5
MI	11.8	11.7	13.1	13.1	13.1	12.5	12.4
MN	9.9	9.5	11.9	11.5	11.3	11.4	10.8
MO	10.0	10.0	11.1	11.0	10.9	10.0	10.2
MS	11.8	11.8	13.8	13.6	13.5	13.2	12.8
MT	10.4	11.7	11.9	12.0	12.3	9.8	11.2
NC	9.5	9.5	10.3	10.4	10.4	10.0	9.9
ND	9.0	11.1	10.5	10.9	11.2	6.8	9.2
NE	9.3	9.9	12.1	12.3	12.1	10.1	11.2
NH	15.9	15.4	16.5	16.5	16.4	16.6	15.9
NJ	15.0	14.5	16.3	16.2	16.2	16.2	15.8
NM	10.9	10.3	11.4	11.8	11.8	10.7	10.4
NV	11.0	10.0	14.7	14.2	14.3	14.5	13.6
NY	16.1	15.6	17.2	17.3	17.5	17.3	17.2
OH	11.5	11.7	12.8	12.7	12.9	11.9	12.2
OK	8.8	8.7	10.5	10.3	10.5	9.6	9.5
OR	9.3	9.1	10.2	10.2	10.3	10.0	10.1
PA	11.3	11.0	12.7	12.3	12.6	11.9	11.8
RI	16.5	16.0	16.9	16.8	16.8	17.0	16.2
SC	10.9	10.6	12.3	12.2	12.2	12.0	11.7
SD	9.4	8.8	11.0	10.2	10.3	10.6	9.9
TN	11.1	11.0	12.4	12.5	12.5	11.9	12.1
TX	9.8	9.5	11.1	11.2	10.9	10.3	10.4
UT	9.4	9.3	11.1	10.3	10.6	9.2	9.4
VA	9.7	9.4	10.2	10.1	10.1	9.9	9.8
VT	16.0	16.0	16.2	16.2	16.5	16.2	16.5
WA	8.5	8.4	9.2	9.1	9.2	9.2	9.1
WI	12.1	12.0	13.5	13.3	13.2	12.7	12.7
WV	9.5	10.6	11.4	11.6	12.0	8.3	9.6
WY	10.2	12.4	12.0	11.7	12.1	6.4	9.0
US	11.8	11.6	12.9	12.9	13.0	12.4	12.4

Source: N_{ew}ERA modeling results.

Table B-5. Residential Sector Delivered Electricity Prices (2015$ ¢/kWh, Average 2022-2033)

	Rate-Based Scenarios		Mass-Based Scnarios				
State	Intra-State Trading	National Trading	Intra-State Trading	Regional Trading	National Trading	Intra-State Trading 100% Allocation	National Trading 100% Allocation
AL	12.4	12.3	13.5	13.7	13.8	12.5	12.9
AR	10.5	10.5	11.5	11.7	11.4	10.9	10.5
AZ	12.1	12.0	13.4	13.8	13.8	13.1	13.0
CA	18.4	18.1	18.7	18.7	19.1	18.7	18.9
CO	13.7	12.8	15.7	14.5	14.7	14.4	14.0
CT	21.5	20.2	22.4	22.4	22.6	22.5	22.3
DE	16.0	15.7	17.5	17.3	17.0	17.3	16.3
FL	13.3	12.9	14.2	14.3	14.3	13.8	13.6
GA	12.4	12.2	13.9	13.8	13.9	13.5	13.4
IA	11.8	11.7	13.5	13.4	13.2	12.2	12.4
ID	10.5	10.2	10.9	10.8	11.0	10.8	10.9
IL	13.9	13.9	16.0	15.8	15.8	15.3	15.2
IN	12.4	12.7	14.6	14.6	14.5	13.1	13.4
KS	13.0	13.0	16.7	16.6	16.3	15.5	15.5
KY	11.9	11.5	13.7	13.7	13.6	12.6	12.6
LA	10.3	10.3	11.5	11.6	11.5	11.1	10.9
MA	19.5	19.0	20.6	20.5	20.6	20.6	20.4
MD	15.3	15.1	16.5	16.3	16.4	16.4	16.0
ME	17.2	16.7	18.5	18.4	18.7	18.6	18.5
MI	15.3	15.2	17.4	17.5	17.4	16.7	16.6
MN	12.5	12.1	14.2	13.7	13.5	13.6	13.0
MO	11.8	11.8	13.9	13.8	13.7	12.7	12.9
MS	12.3	12.3	12.7	12.4	12.4	12.1	11.6
MT	11.1	12.4	13.3	13.4	13.7	11.2	12.5
NC	11.7	11.7	13.6	13.7	13.7	13.2	13.1
ND	10.1	12.2	12.7	13.0	13.3	8.9	11.3
NE	11.2	11.7	12.1	12.3	12.1	10.2	11.3
NH	19.5	19.0	19.7	19.6	19.6	19.8	19.1
NJ	18.0	17.5	20.8	20.6	20.7	20.5	20.1
NM	12.8	12.2	14.6	15.2	15.2	13.8	13.7
NV	14.1	13.1	14.7	14.2	14.3	14.6	13.6
NY	20.3	19.7	20.6	20.7	20.9	20.6	20.6
OH	14.3	14.5	16.5	16.4	16.6	15.4	15.8
OK	10.6	10.6	12.6	12.5	12.6	11.7	11.6
OR	11.0	10.8	11.3	11.3	11.4	11.1	11.2
PA	15.1	14.8	17.2	16.8	17.1	16.4	16.2
RI	18.8	18.2	19.3	19.2	19.2	19.4	18.6
SC	12.8	12.5	14.7	14.6	14.7	14.4	14.1
SD	11.4	10.7	12.6	11.8	11.9	12.2	11.5
TN	11.1	11.0	11.7	11.8	11.7	11.2	11.3
TX	13.3	13.0	14.7	14.8	14.5	13.8	14.0
UT	11.6	11.4	14.9	14.1	14.4	13.0	13.1
VA	12.7	12.4	14.2	14.1	14.1	13.8	13.8
VT	18.7	18.7	19.2	19.1	19.5	19.2	19.5
WA	9.2	9.2	10.1	10.1	10.2	10.1	10.0
WI	15.1	15.0	17.3	17.0	17.0	16.4	16.3
WV	10.9	12.0	12.2	12.4	12.8	9.1	10.5
WY	12.0	14.2	15.7	15.2	15.7	10.0	12.4
US	13.7	13.5	15.1	15.1	15.1	14.5	14.5

Source: N_{ew}ERA modeling results.

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NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT

GREENHOUSE GAS AND FOSSIL FUEL REDUCTION BENEFITS OF USING BIOMASS MANUFACTURING RESIDUALS FOR ENERGY PRODUCTION IN FOREST PRODUCTS FACILITIES

TECHNICAL BULLETIN NO. 1016

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PRESIDENT'S NOTE

NCASI continues its work to address the United States Environmental Protection Agency's expressed interest in the life cycle greenhouse gas (GHG) benefits associated with using biomass. The regulatory decisions EPA makes on this topic have the potential to greatly affect the costs of doing business and the perception of the forest industry's products in the marketplace. The forest products industry, therefore, has a great deal at stake in ensuring that the agency's deliberations on this topic are well informed.

In an earlier report, NCASI examined the life cycle greenhouse gas and non-renewable energy benefits of using black liquor in the kraft recovery system. In the study described herein, NCASI extends this work to other types of biomass-based manufacturing residuals used for energy generation within the industry (woody mill residuals, waste water treatment plant residuals, and paper recycling residuals). While there are numerous studies examining the life cycle impacts of biomass energy, none has applied the comprehensive approach used here by NCASI to characterize the impacts of the industry's use of energy produced from biomass residuals.

In this study, NCASI has compared systems involving the use of biomass-based manufacturing residuals for energy to comparable systems relying on fossil fuels. The results indicate that the use of residuals examined in this study produces significant reductions in atmospheric GHGs. Combining the results of this study with the results of the previous NCASI study on black liquor reveals that each year's use of manufacturing residuals, including black liquor, in the US forest products industry avoids the emission of approximately 181 million metric tons of CO_2E, an amount approximately three times that of the annual direct emissions of CO_2 from fossil fuel combustion in the industry.

This study is one of a series of ongoing NCASI projects having the objective of helping the forest products industry and its stakeholders better understand the greenhouse gas and energy impacts of using forest biomass as a raw material and fuel.

Ronald A. Yeske

October 2013

NOTE DU PRÉSIDENT

NCASI poursuit son travail dans le contexte de l'intérêt exprimé par la United States Environmental Protection Agency (EPA) pour les bénéfices en terme de gaz à effet de serre (GES) de l'utilisation de la biomasse, et ce en adoptant une perspective cycle de vie. Les décisions réglementaires de l'EPA à ce sujet ont le potentiel d'affecter considérablement le coût de faire des affaires et la perception des produits forestiers dans le marché. L'industrie des produits forestiers a, par conséquent, beaucoup en jeu pour assurer que les délibérations de l'EPA sur ce sujet soient bien informées.

Dans un rapport antérieur, NCASI a examiné les bénéfices du cycle de vie pour les GES et la consommation d'énergie non-renouvelable lié à la récupération de la liqueur noire. Dans l'étude décrite ici, NCASI étend ce travail à d'autres types de résidus de fabrication de produits forestiers utilisés pour la production d'énergie dans cette même industrie (résidus d'usine ligneux, résidus de traitement des eaux usées et résidus de recyclage du papier). Bien qu'il existe de nombreuses études sur les impacts du cycle de vie associés à la production d'énergie à partir de biomasse, aucune n'a appliqué l'approche globale utilisée ici par NCASI pour caractériser les impacts de la production d'énergie produite à partir de résidus de biomasse de l'industrie.

Dans cette étude, NCASI a comparé des systèmes impliquant l'utilisation des résidus de fabrication à base de biomasse pour l'énergie à des systèmes comparables utilisant plutôt des combustibles fossiles. Les résultats indiquent que l'utilisation des résidus examinés dans cette étude génère des réductions significatives des GES. La combinaison des résultats de cette étude avec les résultats de l'étude précédente de NCASI sur la liqueur noire révèle que l'utilisation annuelle de résidus de fabrication, y compris la liqueur noire, dans l'industrie des produits forestiers des États-Unis permet d'éviter l'émission d'environ 181 millions de tonnes d'équivalents CO_2, une quantité environ trois fois supérieure à celle des émissions annuelles directes de CO_2 provenant de la combustion de combustibles fossiles par cette industrie.

Cette étude fait partie d'une série de projets en cours de NCASI ayant pour objectif d'aider l'industrie des produits forestiers et ses parties prenantes à mieux comprendre les impacts pour les GES et la consommation énergétique de l'utilisation de la biomasse forestière comme matière première et combustible.

Ronald A. Yeske

Octobre 2013

GREENHOUSE GAS AND FOSSIL FUEL REDUCTION BENEFITS OF USING BIOMASS MANUFACTURING RESIDUALS FOR ENERGY PRODUCTION IN FOREST PRODUCTS FACILITIES

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ABSTRACT

This study examined the life cycle greenhouse gas (GHG) and fossil fuel-related implications of using various manufacturing biomass residuals for energy production at pulp and paper mills and wood products manufacturing facilities. Woody mill residuals (e.g., bark, sawdust, etc.), wastewater treatment plant (WWTP) residuals, and paper recycling residuals were studied. Results from an earlier study of black liquor were also included and extended. Two product systems were compared: a product system in which the biomass residuals are burned for energy in a forest products industry facility (biomass energy system), and a product system in which the biomass residuals are disposed of and fossil fuels are used instead (non-use system). The systems were compared on the basis of a functional unit of 1 GJ energy output in same form for each system. For each residual type, various scenarios were evaluated, including one (the typical scenario) that best represents the industry average. A variety of residual characteristics were subjected to sensitivity analyses. The impacts of the systems were characterized dynamically, using cumulative radiative forcing attributable to the GHG emissions from each system over time. Impacts were calculated in terms of the differences between the biomass and non-use systems over 100 years, expressed as CO_2E, as well as the time required for the net difference in cumulative radiative forcing to reach zero (i.e., the break-even time). Reductions in consumption of fossil fuels were also computed.

In the case of woody mill and WWTP residuals, the systems using residuals for energy produced GHG emissions, not including biogenic CO_2, that were more than 98% lower than those from the systems disposing of the residuals. Paper recycling residuals and black liquor resulted in significant, but lower, benefits (86.4% and 90.5% reductions in GHG emissions, respectively, in the typical scenario). Even when biogenic CO_2 was included in the analysis, over 100 years, the GHG impacts for typical scenarios involving a) woody mill residuals, b) WWTP residuals, c) paper recycling residuals, and d) black liquor solids were lower than the comparable non-use systems by 116 kg CO_2E/GJ, 295 kg CO_2E/GJ, 112 kg CO_2E/GJ, and 184 CO_2E/GJ, respectively. Relative to the comparable fossil fuel-based systems, fossil fuel consumption was found to be lower by more than 99% for all residuals examined in this study, except black liquor, for which the reduction was 89.8%. Break-even times ranged from 0 to 1.2 years under typical scenarios.

A gate-to-gate analysis addressing only biogenic GHGs, not considering fossil fuel substitution benefits, was also performed. In this case, the net GHG impacts over 100 years for typical scenarios involving a) woody mill residuals, b) wastewater treatment plant residuals, c) paper recycling residuals, and d) black liquor were lower than the comparable non-use systems by 8.5 kg CO_2E/GJ, 190 kg CO_2E/GJ, 132 kg CO_2E/GJ, and 0 kg CO_2E/GJ, respectively. The break-even times ranged from 0 years for black liquor, which comprises 57% of the biomass used by the industry for energy, to 19.5 years for woody mill residuals, which comprise 37%. For several residuals, the results were shown to be very sensitive to the parameter value describing the extent to which residuals decompose in mill landfills, a parameter with significant uncertainty.

KEYWORDS

biomass residuals, energy, greenhouse gases, life cycle assessment

RELATED NCASI PUBLICATIONS

Technical Bulletin No. 984 (April 2011). *Greenhouse gas and non-renewable energy benefits of black liquor recovery*.

RÉDUCTION DES ÉMISSIONS DE GAZ À EFFET DE SERRE ET DE LA CONSOMMATION D'ÉNERGIE FOSSILE DUE À L'UTILISATION DE RÉSIDUS MANUFACTURIERS DE BIOMASSE POUR LA PRODUCTION D'ÉNERGIE PAR LES USINES DE PRODUITS FORESTIERS

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RÉSUMÉ

Cette étude a examiné les implications pour les gaz à effet de serre (GES) et l'utilisation de combustibles fossiles de l'utilisation de divers résidus de biomasse provenant de la fabrication de produits forestiers pour la production d'énergie à ces usines de fabrication. Les résidus d'usine ligneux (par exemple, l'écorce, la sciure de bois, etc.), les résidus de traitement des eaux usées et les résidus de recyclage du papier ont été étudiés. Les résultats d'une étude antérieure portant sur la liqueur noire ont également été inclus et étendus. Deux systèmes de produit ont été comparés: un système de produit dans lequel les résidus de biomasse sont brûlés à une usine de fabrication de produits forestiers pour produire de l'énergie (système "énergie de biomasse") et un système de produit dans lequel les résidus de biomasse sont éliminés et des combustibles fossiles sont utilisés à la place (système "non utilisation"). Les systèmes ont été comparés sur la base d'une unité fonctionnelle de production de 1 GJ d'énergie utilisable et ce, sous la même forme pour chacun des systèmes comparés. Pour chaque type de résidus, divers scénarios ont été évalués dont un, le scénario typique, qui représente le mieux la moyenne de l'industrie. Une variété de caractéristiques des résidus a été soumise à des analyses de sensibilité. Les impacts des systèmes ont été caractérisés de façon dynamique, en utilisant le forçage radiatif cumulatif attribuable aux émissions de GES de chaque système dans le temps. Les impacts ont été calculés sous forme de différences observées sur 100 ans entre les systèmes "énergie de biomasse" et "non utilisation", exprimés en CO_2E. Le temps nécessaire pour observer les bénéfices pour les GES liés à l'utilisation de la biomasse et la réduction de la consommation de combustibles fossiles ont également été calculés.

Dans le cas des résidus d'usine ligneux et des résidus de traitement des eaux usées, les systèmes utilisant les résidus pour la production d'énergie produisent des émissions de GES plus de 98% inférieures à celles des systèmes disposant des résidus lorsque le CO_2 biogénique est exclus. Les résidus de recyclage du papier et la liqueur noire présentent aussi des réductions significatives, mais moins élevées (86.4% et 90.5% de réduction des émissions de GES, respectivement, dans le scénario typique). Lorsque le CO_2 biogénique est inclus dans l'analyse, les réductions de GES observées sur 100 ans, dans le cas du scénario typique sont de 116 kg de CO_2E/GJ, 295 kg CO_2E/GJ, 112 kg CO_2E/GJ et 184 CO_2E/GJ pour les résidus d'usine ligneux, les résidus du traitement des eaux usées, les résidus de recyclage du papier et la liqueur noire, respectivement. La consommation de combustibles fossiles est plus de 99% inférieure dans les systèmes "énergie de biomasse" que dans les systèmes "non utilisation" à l'exception du cas de la liqueur noire pour lequel la réduction observée est de 89,8%. Dans les scénarios typiques, le temps nécessaire pour observer les bénéfices liés aux GES varie entre 0 et 1.2 années.

Une analyse plus restreinte, ne portant que sur les émissions de GES biogénique et ne considérant pas la substitution des combustibles fossiles, a également été réalisée. Dans ce cas, les réductions de GES (systèmes "énergie de biomasse" versus systèmes "non utilisation") observées sur 100 ans dans les scénarios typiques sont de 8.5 kg CO_2E/GJ, 190 kg CO_2E/GJ, 132 kg CO_2E/ GJ et 0 kg CO_2E/GJ pour les résidus d'usine ligneux, les résidus du traitement des eaux usées, les résidus de recyclage du papier

et la liqueur noire, respectivement. Le temps nécessaire pour observer ces réductions varie de 0 an pour la liqueur noire qui représente 57% de l'énergie produite à partir de biomasse par l'industrie forestière à 19.5 ans pour les résidus d'usines ligneux qui en représente 37%. Pour plusieurs résidus, les résultats se sont avérés être très sensibles à la valeur du paramètre décrivant la mesure dans laquelle les résidus se décomposent dans les sites d'enfouissement, un paramètre avec une incertitude importante.

MOTS-CLÉS

résidus de biomasse, énergie, gaz à effet de serre, analyse du cycle de vie

PUBLICATIONS DE NCASI RELIÉES

Bulletin Technique No. 984 (Avril 2011). *Avantages pours les émissions de gaz à effet de serre et la consommation d'énergie non renouvelable de la récupération de liqueur noire*.

GREENHOUSE GAS AND FOSSIL FUEL REDUCTION BENEFITS OF USING BIOMASS MANUFACTURING RESIDUALS FOR ENERGY PRODUCTION IN FOREST PRODUCTS FACILITIES

TECHNICAL BULLETIN NO. 1016
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EXECUTIVE SUMMARY

Wood handling and processing activities in log yards, sawmills, pulp and paper mills, and other forest products activities produce a significant amount of residuals, most of which consist of black liquor, bark, sawdust, shavings, and other woody debris. These currently available residuals have long been used as a source of renewable energy in the forest products industry. In this study, the greenhouse gas (GHG) impacts attributable to the industry's use of these materials for energy, compared to not using them, were assessed.

ES.1 Significance of Findings

Combining the results of this study with the results of the previous NCASI study on black liquor reveals that, when considering biogenic and non-biogenic life cycle GHG emissions, each year's use of manufacturing residuals in the US forest products industry avoids the eventual release of approximately 181 million tonnes of CO_2E. The break-even times (i.e., the times required for the GHG impacts of using biomass to be the same or less than the impacts of using an alternative source of energy) range from 0 to1.2 years under typical scenarios, depending on the residual.

An analysis addressing only biogenic GHGs, not considering fossil fuel substitution benefits, was also performed. Even ignoring fossil fuel avoidance benefits, the annual use of manufacturing residuals, including black liquor, avoids the eventual release of 5 million tonnes CO_2E with the break-even times ranging from 0 years for black liquor, which comprises 57% of the biomass used by the industry for energy, to 19.5 years for woody mill residuals, which comprise 37%.

These results have been developed by comparing the GHG emissions from systems using manufacturing residuals for energy in the forest products industry to the emissions from alternative systems producing the same amount of energy from fossil fuels while disposing of the residuals by landfilling or a combination of landfilling and incineration. In cases where it is assumed that the alternative to burning manufacturing residuals for energy is incineration, the break-even times for all residuals are zero, whether or not fossil fuel substitution is considered. Where landfilling is assumed to be the alternative, the results can be very sensitive to assumptions about the degree to which biomass carbon decomposes in landfills, a parameter with large uncertainty.

Because manufacturing residuals have been used for energy in the forest products industry for many years, estimates were also made of the time required to show net benefits from ongoing use of residuals for energy. The results provided strong evidence that the ongoing use of manufacturing residuals for energy in the forest products industry has been yielding net benefits for many years.

ES.2 Objective

The overall objective of this study was to evaluate the life cycle (cradle-to-final energy analysis) greenhouse gas and fossil fuel reduction benefits of using forest products manufacturing-related biomass residuals for energy in forest products manufacturing facilities in contrast to disposal of these

residuals coupled with production of the same quantity and form of energy using fossil fuels. This study also incorporates and expands upon the results of a previous NCASI study that analyzed the greenhouse gas reduction benefits of using spent pulping liquor, known as black liquor, for energy in the forest products industry

This study also included two secondary objectives: 1) to analyze the emissions of biogenic GHGs directly released from the units in which the residuals are managed (i.e., combustion units or landfills, also called a gate-to-gate analysis)[1] and 2) to analyze the cumulative emissions attributable to the use of the residuals for energy as an ongoing, long-standing practice (both in terms of cradle-to-final energy and gate-to-gate boundaries).

The biomass residuals specifically studied in this project were

- woody mill residuals (e.g., bark, sawdust and other similar manufacturing residuals from sawmills, panel plants, and pulp and paper mills);
- wastewater treatment plant (WWTP) residuals;
- paper recycling residuals (e.g., old corrugated container (OCC) rejects)[2]; and
- black liquor (based on the results of an earlier NCASI study).

ES.3 Methods

ES.3.1 Methods for the Cradle-to-Final Energy Analysis

For each type of residual, the study compared two different product systems:

1) one in which the biomass residuals are burned for energy (**biomass energy system**); and
2) one in which the biomass residuals are disposed of and fossil fuels are used instead to generate an identical amount and form of energy (**non-use system**).

More specifically, the methodology used in this study followed life cycle principles by calculating emissions from "cradle to final energy," including fuel conversion efficiency. The primary functional unit employed in this study was ***the production of 1 GJ of energy***. It is important to note that whether manufacturing residuals are used for energy or disposed of, the same number of trees would be harvested and the same quantity of resources would be required to produce the related forest products.

The overall analysis approach employed in this study is as follows. First, for each system component of the study (size reduction, biomass energy production, alternative fate of the residuals, and fossil fuel displaced), several scenarios were defined. These scenarios were intended to represent a broad range of conditions in the US forest products industry. Then, a typical scenario was defined for each residual type representing the best estimate of average conditions in the US in terms of the system components mentioned above. The typical scenario was analyzed to determine 1) typical benefits obtained by using a given residual type, 2) the contribution of each different system component to the overall results, 3) the sensitivity of various parameters (i.e., biomass properties such as higher heating value, water content, etc.) to the results, and 4) the timing of emissions. Where possible, each parameter was analyzed using a base case, low, and high value. Finally, a number of system configuration scenarios were also analyzed.

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[1] In this gate-to-gate analysis, the benefits of avoided fossil fuel use are not included.
[2] Paper recycling residuals are materials removed during processing to eliminate contaminants and yield reusable fiber. They generally consist of a fiber and plastic fraction.

The difference in greenhouse gas impact (GHGI) between product systems was determined by calculating the differences in annual GHG emissions from the systems and determining the cumulative radiative forcing impacts associated with these differences over time, out to 100 years. The difference in GHGI between the two systems was calculated twice, once with biogenic CO_2 included in the analysis and once with biogenic CO_2 excluded. In addition to characterizing the total difference in GHGI over 100 years, this study examined the implications of using biomass residuals for energy as a function of time. When residuals are burned for energy, the biogenic carbon is immediately released to the atmosphere. In contrast, residuals placed into landfills degrade and release the carbon over time.[3] In such cases, the emissions from the biomass energy system could sometimes be higher in the short term than those from the non-use system, but the emissions from the non-use system typically overtake those from the biomass energy system relatively quickly. For each residual, this study computed the number of years required for the cumulative radiative forcing associated with the emissions from the non-use system to equal the cumulative radiative forcing associated with the emissions from the biomass energy system (referred to as the "break-even time" in this report). After this point, the cumulative radiative forcing associated with the non-use system remains higher than that associated with the biomass energy system for the remainder of the 100-year period. Dynamic calculations of cumulative radiative forcing were used in the analysis rather than conventional global warming potentials because the intent was to capture the time-dependent impacts of each system, which is not possible using global warming potentials which assess cumulative radiative forcing over a single period (e.g., 100 years).

The difference in fossil fuel consumption between the two systems was also calculated.

ES.3.2 Methods for Additional Analyses

In addition to the life cycle analyses described above, two secondary analyses were undertaken.

The first involved limiting the analysis to the fate of the biomass carbon, without regard to fossil fuel substitution benefits. In this analysis, the two compared systems (i.e., the biomass energy system and the non-use system) were compared in terms of the emissions coming directly out of the units receiving the residuals (i.e., combustion units or landfills). In the case of paper recycling residuals, only the fiber fraction was considered as the focus here was on the fate of the biomass carbon. The results were computed for two indicators: difference in GHGI over 100 years and break-even time.

The second analysis consisted of changing the frame of analysis to evaluate the cumulative emissions attributable to the ongoing use of the residuals. For this analysis, a different functional unit was used, defined as ***the yearly production of 1 GJ of energy as an ongoing practice***. The differential GHGI indicator was computed on a yearly basis so as to estimate when in the past the practice would have had to begin in order for the difference in GHGI to become zero in 2014. These results were computed both for the full life cycle (i.e., including fossil fuel substitution) and for the more constrained analysis looking only at the biogenic GHG emissions from the units receiving the residuals.

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[3] The results of an earlier study of the benefits of using black liquor are also included in this report. For black liquor, it is difficult to construct an alternative fate scenario because the material is integral to pulp production. Nonetheless, in the earlier study it was assumed that, if not used in the kraft recovery cycle, black liquor would be incinerated or treated in aerobic wastewater treatment plants. In both cases, the carbon returns to the atmosphere far too rapidly for carbon storage to be important in the calculations. It was assumed that all carbon is emitted as biogenic CO_2. If, however, some of the carbon was emitted as methane, the benefits of using the liquor in the kraft recovery cycle would be greater than estimated in the previous study.

ES.4 Results from the Cradle-to-Final Energy Analysis, Including the Benefits of Displacing Fossil Fuels

ES.4.1 Difference in GHGI, Including Biogenic CO_2

Table ES.1 summarizes the differences in life cycle GHG impact, over 100 years, between the systems using residuals for energy and the systems using fossil fuels when biogenic CO_2 is included in the emissions. The negative values in this table indicate that the biomass energy system produced less impact (a reduction) compared to the non-use system. The weighted average reduction observed in the biomass energy system compared to the non-use system (including all residuals and black liquor) was 158 kg CO_2E/GJ. Given current fuel consumption, this means that the annual use of manufacturing residuals (including black liquor) in the industry avoids the eventual release of approximately 181 million tonnes CO_2E . The reduction occurs across a range of system configuration scenarios (boiler type, assumptions about the displaced fossil fuel, the GHG intensity of the electricity grid, and the level of cogeneration at forest products facilities) and without affecting the amount of wood harvested or the amount of forest products produced.

Table ES.1 Difference in Total Life Cycle GHG Emissions (including Biogenic CO_2) over 100 Years: Biomass Energy System Compared to Comparable Fossil Fuel-Based System Where the Residuals are Disposed

Residual Type	Differential GHGI: Difference in Emissions Impact for Typical Scenario (kg CO_2E/GJ)
Woody mill residuals	-116*
WWTP residuals	-295
Paper recycling residuals	-112
Spent liquor (incl. black liquor)†	-184
Weighted average	-158

* The results for woody mill residuals are very sensitive to the parameter used to characterize the extent to which these residuals decompose in landfills. The results shown here are based on the most conservative (i.e., least decomposition in the landfill) of several parameter values used by EPA for various purposes. Other values used by EPA, based on IPCC guidelines, yield far larger benefits (-295 kg CO_2E/GJ). †The various analyses were performed for black liquor only, which represents approximately 92% of the total spent liquor. In computing the weighted averages, it was assumed that black liquor was representative of any spent liquor.

ES.4.2 Relative Difference in GHGI, Excluding Biogenic CO_2

Table ES.2 summarizes the differences in life cycle GHG impacts, over 100 years, between the systems using residuals for energy and the systems using fossil fuels when biogenic CO_2 is excluded from the life cycle emissions. The negative results in this table indicate that the biomass energy system produces a smaller greenhouse gas impact than the non-use system. Using woody mill residuals and WWTP residuals for energy produces a reduction in impact from non-biogenic CO_2 GHGs of more than 98% compared to the non-use systems. Paper recycling residuals also result in significant, but lower, benefits (86.4% reduction in the typical scenario) mainly because these residuals are comprised of a portion of plastic. The previous study of black liquor by NCASI showed emissions of non-biogenic CO_2 GHGs that were lower by 90.5% for a system using black liquor in the kraft recovery system compared to a comparable system based on fossil fuels. The weighted average reduction in non-biogenic CO_2 GHG impact observed in the biomass energy system compared to the non-use system (including woody mill residuals, WWTP residuals, recycling residuals and black liquor) was 93.7% when compared to the non-use systems.

Table ES.2 Life Cycle GHG Emissions (Not Including Biogenic CO_2), over 100 Years: Percent Difference in GHG Impact between the Biomass-Based System and the Comparable Fossil Fuel-Based System Where the Residuals are Disposed

Residual Type	Relative GHGI: Difference in Typical Scenarios (%)
Woody mill residuals	-98.7*
WWTP residuals	-98.7
Paper recycling residuals	-86.4
Spent liquor (incl. black liquor)	-90.5
Weighted average	-93.7

* The results for woody mill residuals are sensitive to the parameter used to characterize the extent to which these residuals decompose in landfills. The results shown here are based on the most conservative (i.e., least decomposition in the landfill) of several parameter values used by EPA for various purposes. Other values used by EPA, based on IPCC guidelines, yield a difference of -99.2%.

ES.4.3 Emissions Timing

While not traditionally considered in LCA studies, the timing of emissions can be an important consideration for certain policy discussion/design contexts. When residuals are burned for energy, the biogenic carbon is immediately released to the atmosphere. In contrast, residuals placed into landfills release carbon over time. This delay is one of the reasons why forest biomass energy systems could initially emit more GHGs than the corresponding fossil fuel systems which dispose of the residuals. In a relatively short period, however, the cumulative radiative forcing associated with emissions from the fossil fuel systems becomes greater than that from the corresponding biomass systems due to the GHGs (including methane) produced by the decaying residuals and the GHG emissions from fossil fuel combustion. An assessment performed to address the timing of benefits produced the results summarized in Table ES.3. The results indicate that, when fossil fuel substitution is considered, it takes from 0 to 1.2 years for the cumulative radiative forcing associated with the biomass energy system to be less than that associated with the non-use system.

Table ES.3 Time for Biomass Energy Systems to Have Lower Cumulative Radiative Forcing from GHG Emissions (Including Biogenic CO_2) Than the Corresponding Non-Use Systems

Residual Type	Break-Even Time: Typical Scenarios (years)
Woody mill residuals	1.2*
WWTP residuals	0
Paper recycling residuals	0
Spent liquor (incl. black liquor)	0
Weighted average	0.5

* The results for woody mill residuals are sensitive to the parameter used to characterize the extent to which these residuals decompose in landfills. The results shown here are based on the most conservative (i.e., least decomposition in the landfill) of several parameter values used by EPA for different purposes. Other values used by EPA, based on IPCC guidelines, yield a break-even time of 0.5 years.

ES.4.4 Fossil Fuel Consumption

Table ES.4 summarizes the results obtained for the Fossil Fuel Consumption indicator. The negative values in this table indicate that the biomass energy systems use less fossil fuel than the corresponding non-use systems. For all residual types analyzed in this report (not including black liquor), considering all system configuration scenarios and sensitivity analyses performed, it was shown that fossil fuel consumption was lower by more than 99% in the biomass energy systems compared to the non-use systems. Note that a previous study by NCASI showed 89.8% lower fossil fuel consumption for a system using black liquor when compared to a scenario based on fossil fuel. The weighted average reduction in fossil fuel consumption observed in the biomass energy system compared to the non-use system (including all residuals and black liquor) was 93.8% when compared to the non-use systems.

Table ES.4 Fossil Fuel Consumption: Percent Difference between the Biomass-Based Systems and the Comparable Fossil Fuel-Based Systems Where the Residuals are Disposed

Residual type	Relative Fossil Fuel Consumption: Difference in Typical Scenarios (%)
Woody mill residuals	-100
WWTP residuals	-99.3
Paper recycling residuals*	-99.9
Spent liquor (incl. black liquor)	-89.8
Weighted average	-93.8

*Considering that the plastic fraction of paper recycling residuals is not a new input of fossil fuel.

ES.5 Results from Additional Analyses

ES.5.1 Analysis of Biogenic GHGs, Ignoring Fossil Fuel Displacement (Gate-to-Gate Analysis)

The results presented above were computed using a life cycle approach that considered the fossil fuels being displaced by biomass residuals. The typical scenarios for the two product systems (one system using residuals for energy and the other system managing the residuals by some other means) have also been compared in terms of the emissions coming directly out of the units receiving the residuals (i.e., combustion units or landfills). In this analysis, the benefits of fossil fuel substitution were ignored.

As shown in Table ES.5, even in this highly constrained analysis, using the biomass residuals for energy generation resulted in lower GHG impact. A previous, similarly constrained analysis on black liquor assumed that the alternative management scenario would involve returning the biogenic carbon in the liquor to the atmosphere. To be conservative, it was assumed in that study that the carbon would return to the atmosphere as CO_2 via incineration or treatment in aerobic wastewater treatment plants. This resulted in net zero biogenic GHG releases for energy production compared to an alternative fate. The reduction in biogenic GHG emissions impact over 100 years associated with the use of all manufacturing residuals (weighted according to usage), including black liquor, was shown to be 4.6 kg CO_2E/GJ. Given current fuel consumption, this means that the annual use of manufacturing residuals (including black liquor) in the industry avoids approximately 5 million tonnes CO_2E.

When the benefits of fossil fuel displacement are ignored, it takes longer for the biomass energy systems to arrive at the point where cumulative radiative forcing is lower than for the corresponding non-use systems. Considering only biogenic emissions, the break-even times ranged from 0 to 19.5 years.

Table ES.5 Results of Analysis of Biogenic GHGs, Ignoring Fossil Fuel Displacement

Residual Type	Differential GHGI (kg CO_2E/GJ)	Break-Even Time (years)
Woody mill residuals	-8.5*	19.5*
WWTP residuals	-190	5.9
Fiber fraction of paper recycling residuals†	-132	7.7
Spent liquor (incl. black liquor)	0	0
Weighted average	-4.6	7.6

* The results for woody mill residuals are very sensitive to the parameter used to characterize the extent to which these residuals decompose in landfills. The results shown here are based on the most conservative (i.e., least decomposition in the landfill) of several parameter values used by EPA for various purposes. Other values used by EPA, based on IPCC guidelines, yield far larger benefits (-187 kg CO_2E/GJ) and far shorter break-even times (6.6 years). † In addition to biomass, paper recycling residuals contain plastics which are produced from fossil fuels. For the purpose of the biomass carbon fate analysis, only the biomass fraction was considered.

ES.5.2 GHG Emissions from Ongoing Use of Residuals for Energy Production

The analysis above examined the impact over time associated with producing 1 GJ of energy on a one-time basis. The practice of burning residuals for energy, however, is a long-standing one in the forest products industry. It is also of interest, therefore, to examine the net impact from using residuals for energy on an ongoing basis. To do this, one can compare two facilities that are identical, except that one burns residuals for energy year after year while the other facility disposes of the residuals and uses fossil fuels for energy instead. Table ES.6 below, based on the typical scenarios used elsewhere in this study, shows the year when ongoing practices would have to have been initiated in order for the facilities using the residuals for energy production to show net benefits, in terms of cumulative radiative forcing, in 2014. The table also contains information on the industry's past use of these materials for energy. In the worst case, the use of woody mill residuals for energy without considering avoided fossil fuel emissions, the practice would have had to have started in the late 1970s in order for the "carbon debt" to be eliminated. In fact, woody mill residuals have been used for energy in the solid wood industry since the 1800s and in the paper industry since the early decades of the 1900s. The evidence is strong, therefore, that any carbon debt that might have been incurred in using manufacturing residuals for energy was eliminated long ago.

Table ES.6 Ongoing Use of Residuals for Energy Production: Comparing Facilities Using Biomass Residuals for Energy with Similar Facilities Using Fossil Fuels for Energy and Disposing of the Residuals

Residual		Year in the Past When Ongoing Practice Would Have Had To Be Initiated for Cumulative Radiative Forcing from the Two Facilities To Be in 2014 (under typical scenario)	Past Industry Practice in Using the Residuals for Energy
Woody mill residuals	With benefits of the displaced fossil fuels	2012*	Wood residuals have been used in saw mills going back to the mid-1800s and in paper mills back to the early decades of the 1900s. AF&PA statistics date to 1971, at which point woody mill residuals represented 7% of the fuel (16% of the biomass) burned at pulp and paper mills.
	Without benefits of the displaced fossil fuels	1979*	
WWTP residuals	With benefits of the displaced fossil fuels	2014	NCASI statistics on WWTP residuals management go back to 1979, at which point 11% of these residuals was being burned for energy.
	Without benefits of the displaced fossil fuels	2004	
Paper recycling residuals	With benefits of the displaced fossil fuels	2014	NCASI has published information showing the use of recycling residuals for energy in 1975.
	Without benefits of the displaced fossil fuels†	2001	
Spent liquor (incl. black liquor)	With benefits of the displaced fossil fuels	2014	The burning of kraft black liquor for energy and chemicals dates to before the 1950s. Based on AF&PA statistics, in 1971, 35% of the fuel (84% of the biomass) burned at pulp and paper mills was black liquor. By 1980, this had increased to 40% of the fuel (79% of the biomass).
	Without benefits of the displaced fossil fuels	2014	

* The results for woody mill residuals are very sensitive to the parameter used to characterize the extent to which these residuals decompose in landfills. The results shown here are based on the most conservative (i.e., least decomposition in the landfill) of several parameter values used by EPA for various purposes. Other values used by EPA, based on IPCC guidelines, yield dates of 2013 and 2003 when the benefits of displaced fossil fuels are included and excluded, respectively.
†Fiber fraction only.

ES.6 Conclusions

In this study, the GHG and fossil fuel-related impacts of using woody manufacturing residuals, recycling residuals, and wastewater treatment plant residuals for energy production within the forest products industry have been analyzed using life cycle principles and other methods. A previous study of the use of black liquor for producing energy and pulping chemicals has also been updated and expanded. It has been shown that using all types of residuals for energy produces benefits both in terms of reduced fossil fuel consumption and reduced greenhouse gas emissions impacts. This result is valid across a range of system configuration scenarios (boiler type, assumptions about the displaced fossil fuel, the GHG intensity of the electricity grid, and the level of cogeneration at forest products facilities), residual characteristics (e.g., heating value, moisture content), and whether or not the

benefits from fossil fuel substitution are considered. These findings hold true whether biogenic CO_2 is included in the analysis or excluded by giving it an emission factor of zero (equivalent to what is sometimes called "carbon neutrality"). The benefits occur without affecting the amount of wood harvested or the amount of wood products produced.

It was shown that it takes from 0 to 1.2 years for the cumulative radiative forcing associated with emissions from the biomass energy system to be lower than that of the corresponding non-use system. Even ignoring the benefits of displacing fossil fuel and limiting the analysis to biogenic emissions, the cumulative radiative forcing impacts associated with emissions from the biomass energy systems are lower than those from the non-use systems in times ranging from 0 years for black liquor, which comprises 57% of the residuals used by the energy for industry, to 19.5 years for woody mill residuals which comprise 37% of that used by the industry.

These results have been developed by comparing the GHG emissions from systems using manufacturing residuals for energy in the forest products industry to the emissions from alternative systems producing the same amount of energy from fossil fuels while disposing of the residuals by landfilling or a combination of landfilling and incineration. In cases where it is assumed that the alternative to burning manufacturing residuals for energy is incineration, the break-even times for all residuals are zero, whether or not fossil fuel substitution is considered. Where the alternative is assumed to be landfilling, results can be very sensitive to assumptions about the degree to which biomass carbon decomposes in landfills, a parameter with large uncertainty.

When considered as an ongoing practice (e.g., ongoing production of 1 GJ energy per year), and when displaced fossil fuels are considered, net benefits from using residuals for energy are observed in less than two years. In the case where the benefits of displacing fossil fuels are ignored, the break-even times are longer. Even in the worst case, however, which is the ongoing use of woody mill residuals for energy without considering fossil fuel substitution, any "carbon debt" would be eliminated if the practice began before the late 1970s. Woody mill residuals have been used for energy in solid wood manufacturing since the 1800s and in paper mills since the early decades of the 1900s, providing strong evidence that any carbon debt incurred in the past from using manufacturing residuals for energy in the forest products industry was eliminated many years ago.

The GHG emissions reduction benefits of using manufacturing residuals for energy in the forest products industry are large. Given current fuel consumption, the use of manufacturing residuals (including black liquor) in the industry for one year avoids an emissions impact of approximately 181 million tonnes CO_2E, equal to approximately three times the annual direct emissions associated with the combustion of fossil fuels in the forest products industry.

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GREENHOUSE GAS AND FOSSIL FUEL REDUCTION BENEFITS OF USING BIOMASS MANUFACTURING RESIDUALS FOR ENERGY PRODUCTION IN FOREST PRODUCTS FACILITIES

1.0 INTRODUCTION AND BACKGROUND

1.1 Background

The use of wood for energy has attracted considerable attention as a greenhouse gas mitigation option (FAO 2008). The United States (US) and Canada are among the largest OECD[4] users of wood for industrial bioenergy, primarily from indirect sources including black liquor and other manufacturing residuals (FAO 2008, Steierer 2007). Wood harvesting and handling, as well as processing activities in log yards, pulp and paper mills, sawmills, and other forest products activities produce a significant amount of residuals, most of which consist of bark, sawdust, shavings, and harvest residuals and other woody debris. These residuals are increasingly being used as a source of renewable energy. Often, however, the residuals that are not beneficially used are either incinerated or placed in a municipal or on-site industrial landfill.

Recent years have seen a rise in both the interest in substituting biomass for fossil fuels and in the skepticism about the greenhouse gas (GHG) benefits of this substitution. While programs that promote the use of biomass as a substitute for fossil fuel have important connections to the issues of energy security and economic sustainability, it is the questions about greenhouse gas mitigation benefits that have been at the center of the debate on whether and how to increase the reliance on the use of biomass for energy.

An important distinction between biomass carbon (also known as biogenic carbon) and the carbon in fossil fuels is that biogenic carbon was only recently removed from the atmosphere. When biomass is burned, decays, or is otherwise oxidized, the resulting CO_2 is returned to the atmosphere. The net transfers of biogenic carbon to the atmosphere can be zero if the uptake of carbon (in CO_2) by growing trees is equivalent to the biogenic carbon released in the combustion and decay of biomass (sometimes referred to as representing “carbon neutrality”). Where the amounts of biogenic CO_2 that return to the atmosphere are less than the amounts removed, the difference represents increases in stocks of stored carbon (net removals from the atmosphere). Where net returns are greater than the amounts removed, the difference represents depleted stocks of stored carbon.

The net transfers of biogenic CO_2 to the atmosphere associated with the production and use of biomass can be used to characterize the GHG emissions associated with a biomass energy system, often called the “carbon footprint” of the system. Understanding the impacts of using biomass for energy, however, requires a different analytical framework than used for a carbon footprint. In studying the impacts of using biomass for energy, one must consider how that energy might be produced if biomass was not used and the fate of the biomass if not used for energy. In this study, the objective was to understand the impacts of using biomass for energy so the life cycle emissions from a system using biomass for energy are compared to the life cycle emissions from alternative systems where the biomass undergoes an alternative fate and fossil fuels are used to produce an equivalent amount of energy.

[4] Organisation for Economic Co-operation and Development.

1.2 Review of LCA Studies

In recent years, there has been a rapidly increasing number of life cycle assessment (LCA) studies of woody biomass residual energy systems. Table 1.1 provides an overview of the main studies recently published that compared woody biomass residual energy systems with fossil fuel-based energy systems and focused on direct energy production from the residuals, not including studies looking at liquid biofuels. Only studies published in the peer-reviewed literature are presented in this table. The overview does not purport to be exhaustive.

It can be seen from Table 1.1 that these studies have mainly focused on electricity generation and direct heating and that, in cases where the authors looked at the use of woody biomass residuals by forest products facilities (e.g., sawmills), they typically did not consider alternative fates for the residuals. It is also interesting to note that there are very few studies covering other manufacturing residuals from the forest products industry, such as wastewater treatment residuals and paper recycling residuals, and their use for energy production.

In addition, while not traditionally considered in typical LCA studies, the timing of emissions may be an important consideration for certain policy discussion/design contexts. When residuals are burned for energy, the biogenic carbon is immediately released to the atmosphere. In contrast, residuals placed into landfills or left on forest sites degrade slowly, releasing carbon over time. In these cases, the emissions from burning biomass for energy could be higher in the short term than those associated with disposing of the biomass, but this is generally compensated for relatively quickly by the benefits from fossil fuel substitution or benefits from avoiding the disposal emissions of the biomass residuals.

Table 1.1 Published Studies Regarding Life Cycle GHG Mitigation Benefits for Biomass Residuals Energy Systems

Study	Biomass Type	Fossil Fuel Offset	Type of Facility in Which the Biofuel Is Used	Alternative Fate Considered	GHG Mitigation*	Break-Even Time
Boman and Turnbull (1997)	Agricultural residuals, energy crops, forest harvest residuals and sawmill residuals	Coal (power)	US power plants/pulp mill	Not considered	> 90%	Not applicable
Mann and Spath (2001)	Various woody residuals	Coal (power, cofiring)	US power plants	46% landfilling, 54% mulch or conversion to short-lived products	123%†	Not available
Robinson et al. (2003)	Forest harvest and agriculture residuals	Coal (power, cofiring)	US power plants	Not considered	≈ 95%	Not applicable
Wihersaari (2005)	Forest harvest residuals	Coal, peat	Finnish power plant	Decomposition in forest	> 75%	Not available
Pehnt (2006)	Forest harvest residuals, woody biomass energy crops, waste wood	German energy mix (power, home heating)	German power plants and homes	Not considered	85-95%	Not applicable
Petersen Raymer (2006)	Fuel wood, sawdust, wood pellets, demolition wood, briquettes, bark	Coal (power, cofiring) and oil (home heating)	Power plants (imports to Norway), Norwegian homes, sawmills, large combustion facilities	Not considered	81-98%	Not applicable
Kirkinen et al. (2008)	Forest harvest residuals (other biomasses not considered here)	Coal, natural gas	Finnish energy sector	Decomposition in forest	Not available	< 20 years‡
Cherubini et al. (2009)	Forest harvest residuals	Various fossil fuels used for heat, power and CHP	Various	Unknown	70-98%	Not applicable

(Continued on next page. See notes at end of table.)

Table 1.1 (Cont'd)

Study	Biomass Type	Fossil Fuel Offset	Type of Facility in Which the Biofuel Is Used	Alternative Fate Considered	GHG Mitigation*	Break-Even Time
Froese et al. (2010)	Forest harvest residuals	Coal (power, cofiring)	US Great Lakes region power plants	Not considered	100%	Not applicable
Jones et al. (2010)	Forest harvest residuals	Natural gas, distillate oil (heat)	Unspecified	Burn at landing	≈ 40-50%‡	Not applicable
Puettmann and Lippke (2012)	Sawmill biomass residuals, pellets, forest harvest residuals	Natural gas (heat, power)	US sawmills	Not considered	57-66%§	Not applicable
Repo et al. (2012)	Forest harvest residuals	Coal, heavy oil, natural gas	Unspecified Finnish facility	Decomposition in forest	29-81%**	< 100 years
Ruhul Kabir and Kumar (2012)	Agricultural residuals, forest harvest residuals	Coal (power, cofiring)	Canadian power plants	Not considered	74-88%*	Not applicable
Zanchi et al. (2012)	Forest harvest residuals	Coal, oil, natural gas	Austrian power plants	Decomposition in forest	76-85%**	0 - 16 years
Gaudreault et al. (2012)	Black liquor	Coal, natural gas (heat and power); US electricity grid	US pulp and paper mills	Biogenic carbon released into CO_2	69-92%	Not applicable

*Percent for full substitution; for cofiring situations the mitigation pertains to the cofire rate (e.g., if 10% fossil fuel is replaced by biomass and emissions decrease by 9%, mitigation of 90% is assigned); includes all GHGs excluding biogenic CO_2. † Mitigation greater than 100% due to avoided end-of-life methane emissions. ‡Estimated. §One of the reasons why Puettmann and Lippke obtained lower mitigation results than other authors for manufacturing residuals is that they allocated a fraction of the load from manufacturing to the residuals. **Values at 100 years.

2.0 STUDY OBJECTIVES

The main objective of this study was to evaluate the life cycle (cradle-to-final energy analysis) greenhouse gas impact (GHGI) and fossil fuel reduction benefits of using various forms of forest biomass residuals (manufacturing-related) for energy production in forest products manufacturing facilities in contrast to no beneficial use of these residuals coupled with production of the same quantity and form of energy using fossil fuels. The total 100-year and yearly impacts were investigated.

The study also included two secondary objectives: 1) to analyze the greenhouse gas impact from the emissions of biogenic GHGs released from the units in which the residuals are managed (i.e., combustion units or landfills, gate-to-gate analysis); and 2) to analyze the cumulative greenhouse gas

impact associated with the net emissions attributable to the use of the residuals for energy as an ongoing, long-standing, practice (both in terms of cradle-to-final energy and gate-to-gate boundaries).

The biomass residuals studied in this project were

- woody mill residuals (e.g., bark, sawdust, and other similar manufacturing woody residuals from sawmills, panel plants, and pulp and paper mills);
- wastewater treatment plant (WWTP) residuals; and
- paper recycling residuals (e.g., old corrugated container (OCC) rejects)[5].

For each type of residuals, the study compared a base case of no beneficial use of residuals (including their alternative fates) with 100% use for energy generation. Note that whether or not these residuals are used for energy production, the same number of trees would be harvested and the same quantity of resources would still be required to produce the related forest products. In addition to heat production, the study also included combined heat and power (CHP) as a second option for using the residuals. Other options for processing or using the wood residuals (e.g., torrefaction, gasification, hydrolysis and fermentation, other beneficial uses) were not analyzed.

3.0 INTENDED APPLICATION AND TARGETED AUDIENCE

The intended application is to inform the discussion and development of policies that require an understanding of the impacts of using biomass-based manufacturing residuals for energy at forest products manufacturing facilities. The targeted audience of this report is individuals interested in understanding these impacts.

4.0 METHODS

4.1 Cradle-to-Final Energy Analysis

4.1.1 Overview Methodology Employed

Life Cycle Assessment (LCA) is the *"compilation and evaluation of the inputs, outputs and the potential environmental impacts of a product system throughout its life cycle,"* the life cycle being *"consecutive and interlinked stages of a product system, from raw material acquisition or generation from natural resources to final disposal"* (ISO 2006a, p. 2).

LCA principles and methodology are framed by a set of standards (ISO 2006a, b) and technical reports and specifications (ISO 2002, 2012a, b) from the International Organization for Standardization (ISO). ISO describes LCA methodology in four phases:

1) **Goal and scope definition,** in which the aim of the study, the product system under study, its function and functional unit, the intended audience, and the methodological details on how the study will be performed are defined;
2) **Life cycle inventory analysis (LCI),** which is the *"phase of life cycle assessment involving the compilation and quantification of inputs and outputs for a product throughout its life cycle"*(ISO 2006a, p. 2);

[5] Paper recycling residuals are materials removed during processing to eliminate contaminants and yield reusable fiber.

3) **Life cycle impact assessment (LCIA),** which is the "phase of life cycle assessment aimed at understanding and evaluating the magnitude and significance of the potential environmental impacts for a product system throughout the life cycle of the product" (ISO 2006a, p. 2); and
4) **Life cycle interpretation,** which is the *"phase of life cycle assessment in which the findings of either the inventory analysis or the impact assessment, or both, are evaluated in relation to the defined goal and scope in order to reach conclusions and recommendations"* (ISO 2006a, p. 2).

This study

- used widely accepted LCA concepts, such as those described in LCA ISO standards 14040 and 14044 (International Organization for Standardization (ISO) 2006a, b);
- was built on the approaches by others [e.g., US Environmental Protection Agency (EPA), Consortium for Research on Renewable Materials (CORRIM)];
- was based on known and established competitive materials and alternative fates for biomass residuals; and
- did not consider any "export" of the residuals outside the forest products industry (e.g., to utilities).

More specifically, the methodology used in this study followed life cycle principles, by calculating emissions from "cradle to final energy" including fuel conversion efficiency. However, a simplified (streamlined) LCA methodology was applied. Streamlining generally can be accomplished by limiting the scope of the study or simplifying the modeling procedures, thereby limiting the amount of data or information needed for the assessment (Todd and Curran 1999). Many different streamlining approaches can be applied. In this study, two main approaches were taken: limiting the impact assessment to two indicators (global warming, fossil fuel consumption) and using generic information for the most part. Because of this, this study does not fully comply with ISO 14044 requirements for comparative assertions disclosed publicly. However, the study aligns as much as possible with this standard.

4.1.2 Functions and Functional Units

In this study, the primary functional unit was ***the production of 1 GJ of energy***. The product systems being compared also fulfilled an additional implicit function, which is the management of the quantity of residuals required to produce 1 GJ of energy. This is further discussed in Section 4.1.4.

4.1.3 Scenario and Sensitivity Analyses

The overall analysis approach employed in this study is depicted in Figure 4.1. First, for each system component of the study (size reduction, biomass energy production, alternative fates of the residuals and fossil fuel displaced), possible scenarios were defined. These scenarios were intended to represent a broad range of conditions in the US forest products industry.

Then, a typical scenario was established for each residual type as the best estimate for representing average conditions in the US in terms of the different system components mentioned above. The typical scenario was analyzed to determine typical benefits obtained by using a given residual type, the contribution of each different system component to the overall results, the sensitivity of various parameters (e.g., higher heating value, water content, etc.) to the results, and the effect of time on the results. Where possible, each parameter was analyzed using a base case, low, and high value, and the base case values were derived from EPA. Perturbation analyses were also performed. The general idea behind perturbation analyses is that perturbations of the input parameters propagate as smaller or

larger deviations to the resulting output (Heijungs and Kleijn 2001). The objectives of perturbation analyses are to provide 1) a list of those input parameters for which a small imprecision already leads to important changes in the results, and 2) interesting suggestions for improving the environmental performance of the system. For each parameter tested in sensitivity analysis, a perturbation analysis was also performed and a sensitivity ratio was calculated as outlined below.

Sensitivity ratio = Percent change in output variable/Percent change in input variable

The input variable is the parameter tested in sensitivity analysis while the output variable is a given environmental indicator (see more detail in Section 4.1.6). For instance, a sensitivity ratio of +1.0 means that the score of the environmental indicator increases by 1% when the parameter value is increased by 1%. The more negative an environmental indicator score, the better the performance of the biomass energy system compared to the non-use system. The more positive or the more negative a sensitivity ratio is, the more sensitive a parameter is.

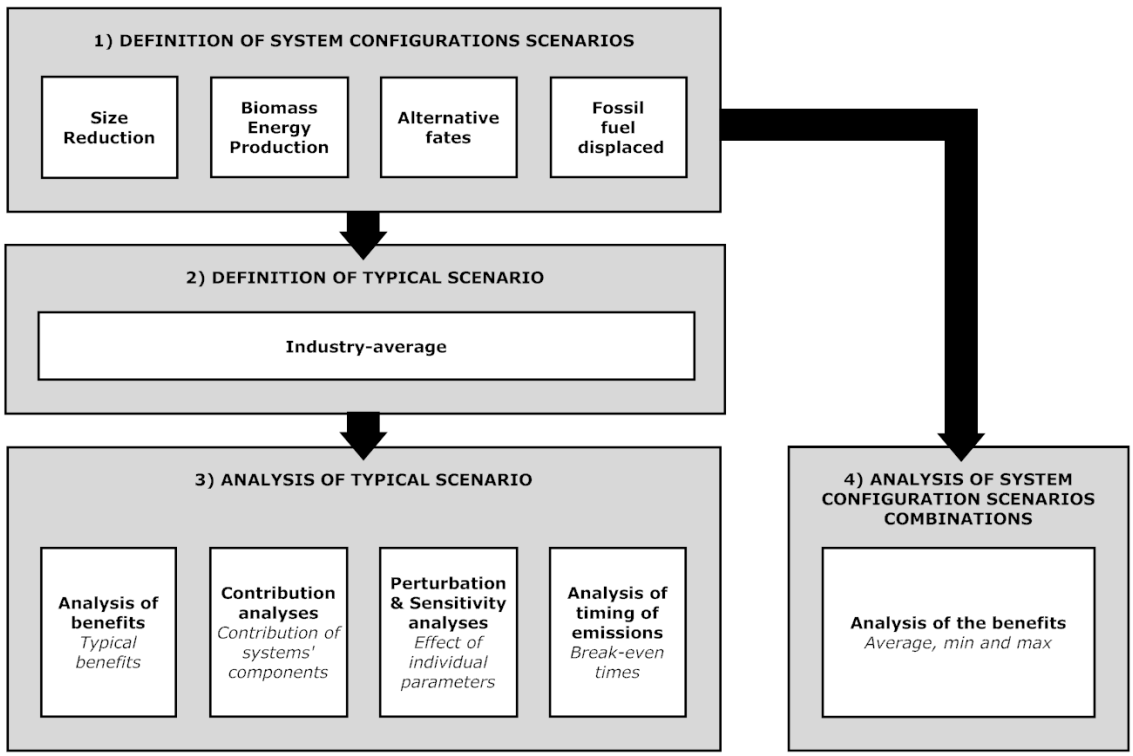

Figure 4.1 Study Overall Approach for the Life Cycle Based Analyses

4.1.4 Product Systems Studied, System Boundaries, and Allocation

For each type of residual, the study compared a base case of no beneficial use of residuals (while accounting for their alternative fate) with 100% use for energy generation. The different product systems studied and compared in this study are discussed next. The general approach was to include within the system boundary only the processes that were different between the biomass and non-use systems.

4.1.4.1 Woody Mill Residuals

Major sources of manufacturing residuals include sawmills, panel plants, and pulp and paper mills. These residuals consist primarily of bark and fine residuals (e.g., sawdust, planer shavings, sanderdust). In this study, all woody mill residuals were considered as a whole, in a single analysis. Sensitivity analyses were performed to encompass the variability in residual types (see Section 5.1).

Figure 4.2 illustrates the two product systems that were compared in the case of woody mill residuals.

1) **Biomass Energy System:** Production of 1 GJ of energy (heat or combined heat and power) using manufacturing residuals.
2) **Non-Use System:** Production of 1 GJ of energy (in the same form as in #1) using fossil fuels and alternative fate of the residuals.

Figure 4.2 also shows that the accounting started with the manufacturing-related biomass residuals and ended at the point at which the energy has been generated. All of these materials would be generated whether or not they would be used for energy generation, and thus there should be no effects on upstream processes attributable to the use of the materials for energy. Therefore, upstream emissions from the production of these materials were assumed to be the same for both systems and they were not included in the analysis.

In some cases, size reduction of manufacturing residuals is required. As depicted in Figure 4.2, three scenarios were considered regarding size reduction (SR0: no size reduction, SR1: size reduction in mobile chipper, and SR2: size reduction in stationary chipper). These processes, as well as any related upstream emissions, were included in the system boundary of the biomass energy system only as they were considered to be unnecessary in the non-use system. The system boundary of the biomass energy system also included the processes required to produce the energy at forest products facilities. Five system configuration scenarios were considered: heat production only in a stoker boiler (SB), heat production only in a fluidized bed boiler (FB), and three levels of combined heat and power (CHP1, CHP2, and CHP3) in which the heat is produced in a stoker boiler.

The non-use system included the upstream emissions for producing the fossil fuel and the energy production processes at forest products facilities or utilities. The energy produced was set to be in the same form as in the biomass energy system. Figure 4.2 shows the different system configurations that were analyzed regarding energy production in the non-use system. It was assumed that heat could be produced in forest products facilities using either coal (A) or natural gas (B). Electricity production at utilities (see Section 5.1) was assumed to be represented by the US average grid (C), coal (D), or natural gas combined cycle (E). When using woody mill residuals to produce 1 GJ of energy, an implicit secondary function is accomplished: the management of the quantity of residuals necessary to produce 1 GJ of energy (Q_R). For the two compared systems to be equivalent, it was necessary to expand the boundary of the non-use system to account for an alternative fate for these residuals. Figure 4.2 shows the two scenarios that were considered for the alternative fate of residuals in the non-use systems: 1) placed in landfills (MR1), and 2) incinerated without recovering the energy

(MR2). The typical scenario definition and rationale, and more details on the various unit processes involved in both systems, are provided in Section 5.1.

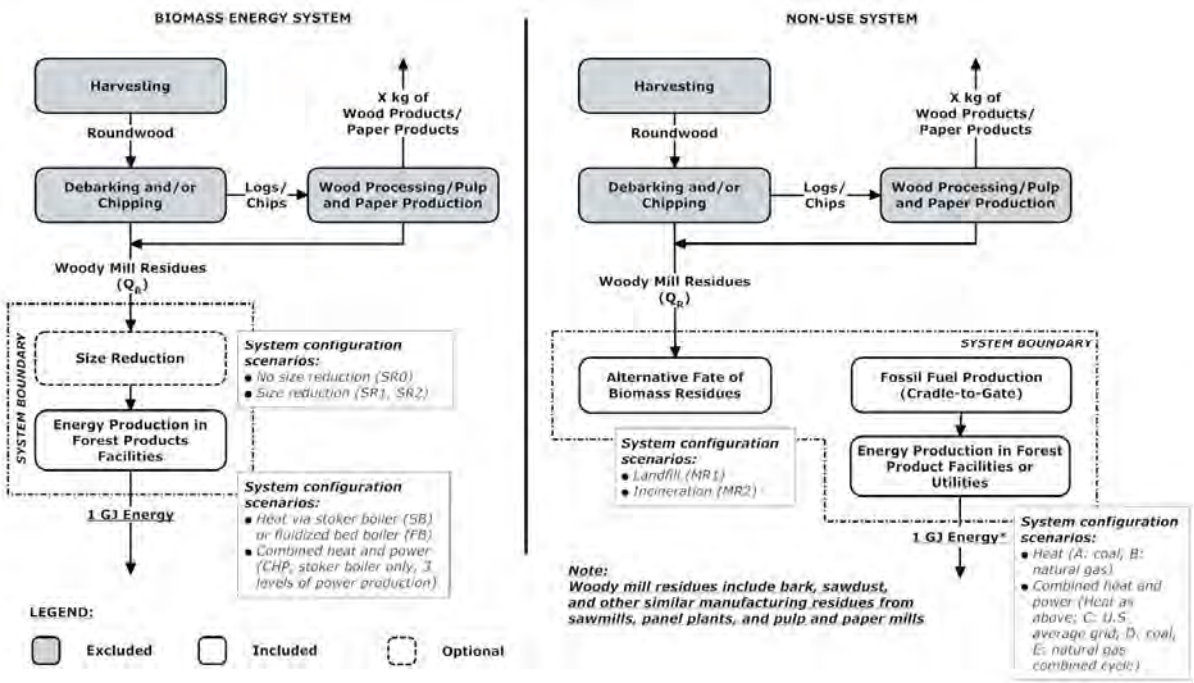

Figure 4.2 Compared Product Systems for Woody Mill Residuals

4.1.4.2 WWTP Residuals

Another manufacturing residual that was included in the study is wastewater treatment plant (WWTP) residuals. Figure 4.3 illustrates the two systems that were compared for WWTP residuals.

1) **Biomass Energy System:** Production of 1 GJ of energy (heat, power or combined heat and power) using the WWTP residuals; and
2) **Non-use System:** Production of 1 GJ of energy (in the same form as in #1) using fossil fuels and alternative fate of the WWTP residuals.

Figure 4.3 also shows that the accounting started with the WWTP residuals and ended at the point at which the energy has been generated. WWTP residuals would be generated whether or not they are used for energy generation, and thus there should be no effects on upstream processes attributable to the use of these materials for producing energy. Therefore, upstream emissions from the production of these materials were assumed to be the same for both systems and they were not included in the analysis. It was also assumed that mechanical dewatering would be required whether the residuals would be used for energy generation or disposed of, and hence was not included in the study.

The system boundary of the biomass energy system included the processes required to produce the energy at forest products facilities. Four system configuration scenarios were considered: heat production only in a stoker boiler (SB), and three levels of combined heat and power (CHP1, CHP2, and CHP3) in which the heat is produced in a stoker boiler.

The non-use system included the upstream emissions for producing the fossil fuel and the energy production processes at forest products facilities or utilities. Figure 4.3 shows the different system

configurations that were analyzed. It was assumed that heat could be produced in forest products facilities using either coal (A) or natural gas (B). Electricity production at utilities (see Section 5.1) was assumed to be represented by the US average grid (C), coal (D), or natural gas combined cycle (E). When using WWTP residuals to produce 1 GJ of energy, an implicit secondary function is accomplished: the management of the quantity of residuals necessary to produce 1 GJ of energy (Q_R). For the two compared systems to be equivalent, it was necessary to expand the boundary of the non-use system to account for an alternative fate for these residuals. Figure 4.3 shows the two scenarios that were considered for the alternative fate of residuals in the non-use systems: 1) placed in landfills (MR1), and 2) incinerated without recovering the energy (MR2). The non-use system included the upstream emissions for producing the fossil fuel and the energy production processes at forest products facilities or utilities. The typical scenario definition and rationale, and more details on the various unit processes involved in both systems, are provided in Section 5.1.

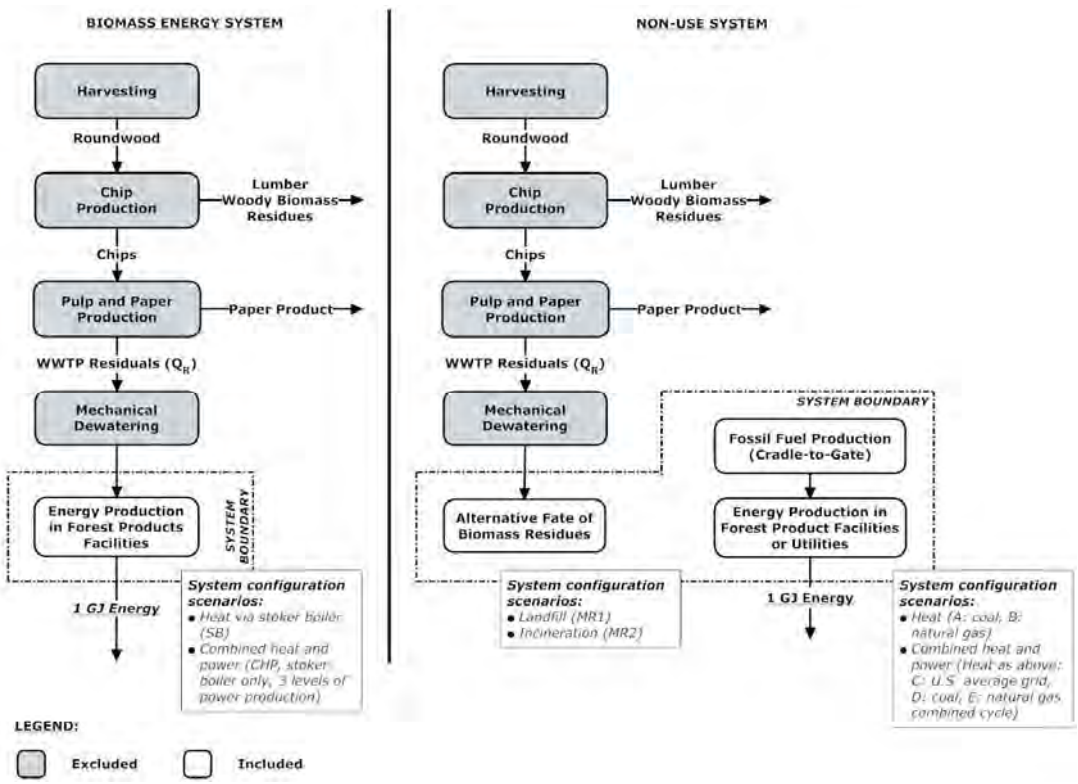

Figure 4.3 Compared Product Systems for WWTP Residuals

4.1.4.3 ***Paper Recycling Residuals***

The last manufacturing residual that was included in the study is paper recycling residuals, and more specifically old corrugated container (OCC) rejects. Figure 4.4 illustrates the two systems that were compared for paper recycling residuals.

1) **Biomass Energy System:** Production of 1 GJ of energy (heat, power or combined heat and power) using the paper recycling residuals.
2) **Non-Use System:** Production of 1 GJ of energy (in the same form as in #1) using fossil fuels and alternative fate of the paper recycling residuals.

Figure 4.4 also shows that the accounting started with the paper recycling residuals and ended at the point at which the energy has been generated. Paper recycling residuals would be generated whether

or not they would be used for energy generation, and thus there should be no effects on upstream processes attributable to the use of the materials for energy. Therefore, upstream emissions from the production of these materials were assumed to be the same for both systems and they were not included in the analysis.

The system boundary of the biomass energy system included the processes required to produce the energy at forest products facilities. Four system configuration scenarios were considered: heat production only in a stoker boiler (SB), and three levels of combined heat and power (CHP1, CHP2, and CHP3) in which the heat is produced in a stoker boiler.

The non-use system included the upstream emissions for producing the fossil fuel and the energy production processes at forest products facilities or utilities. Figure 4.4 shows the different system configurations that were analyzed. It was assumed that heat could be produced in forest products facilities using either coal (A) or natural gas (B). Electricity production at utilities (see Section 5.1) was assumed to be represented by the US average grid (C), coal (D), or natural gas combined cycle (E). When using paper recycling residuals to produce 1 GJ of energy, an implicit secondary function is accomplished: the management of the quantity of residuals necessary to produce 1 GJ of energy (Q_R). For the two compared systems to be equivalent, it was necessary to expand the boundary of the non-use system to account for an alternative fate for these residuals. Figure 4.4 shows the two scenarios that were considered for the alternative fate of residuals in the non-use systems: 1) placed in landfills (MR1), and 2) incinerated without recovering the energy (MR2). The non-use system included the upstream emissions for producing the fossil fuel and the energy production processes at forest products facilities or utilities. The typical scenario definition and rationale, and more details on the various unit processes involved in both systems, are provided in Section 5.1.

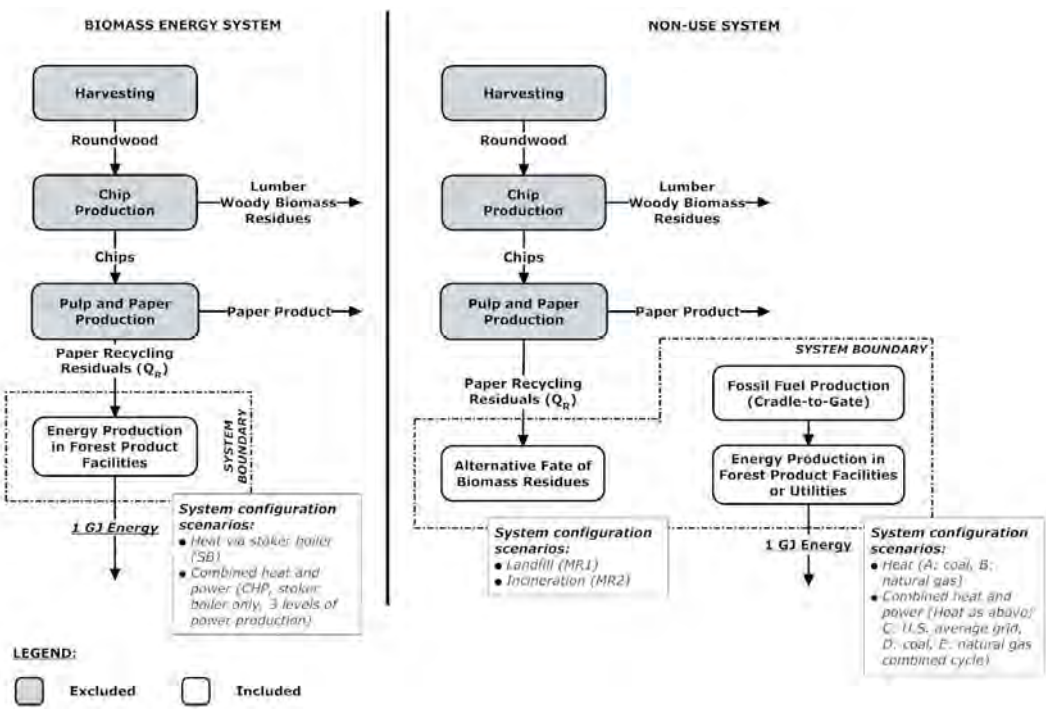

Figure 4.4 Compared Product Systems for Paper Recycling Residuals

4.1.5 Exclusions and Cut-Off Criteria

For each of the groups described above, the following components of each product system were not included in this study: manufacture of capital equipment, human activities, and unit processes common to the systems compared.

All required data were available. No cut-offs were applied.

4.1.6 Environmental Indicators Analyzed

Two main environmental aspects were studied in this study: greenhouse gases (GHGs) and fossil fuel consumption.

Note that in LCA studies, environmental indicator results are relative expressions and do not predict impacts on category endpoints, nor the exceeding of thresholds, safety margins, or risks.

4.1.6.1 Greenhouse Gas Impact (GHGI)

In this report, the term "greenhouse gas impact" is used to describe the cumulative radiative forcing over a period of time that is attributable to emissions of greenhouse gases. Various approaches can be used to calculate the greenhouse gas impact. The most common approach is to use the 100-year global warming potentials (GWPs) published by the Intergovernmental Panel on Climate Change (IPCC 2006a). The 100-year global warming potentials calculated by IPCC represent the cumulative radiative forcing over 100 years attributable to a pulse release of a GHG relative to the forcing attributable to a pulse release of the same mass of CO_2. Using this approach, the 100-year greenhouse impact is assumed to occur the same year as the pulse emission. The results are typically expressed as kilograms of CO_2 equivalents (kg CO_2E). GWPs are useful in developing GHG inventories in a way that allows the impacts associated with different types of emissions to be compared over 100 years, or some other period. IPCC has published GWPs for periods of 20, 100, and 500 years. In this study, the timing of impacts was of particular interest, which required a dynamic calculation of cumulative radiative forcing as a function of time. To accomplish this, a dynamic carbon footprinting approach developed by Levasseur (2013) and Levasseur et al. (2010) was used. This approach produces time-dependent global warming results based on the cumulative radiative forcing concept. The same scientific models are used in the dynamic carbon footprinting approach as used by IPCC to develop global warming potentials but the equations are integrated continuously over time with the exception of one element (see below). Although the results are typically expressed in units of radiative forcing (Wm^{-2}), they can also be presented in terms of kg CO_2E, especially if the objective is to compare the results to those obtained using GWPs. Approaches similar to the approach proposed by Levasseur et al. (2010) have been used elsewhere (e.g., Alvarez et al. 2012).

A difference between the dynamic approach proposed by Levasseur et al. (2010) and IPCC's scientific models was mentioned above. The approach proposed by Levasseur et al. includes the radiative forcing associated with CO_2 formed when methane decomposes in the atmosphere while IPCC's GWPs for methane do not (IPCC 2007, Chapter 2, paragraph 2.10.3). Because this study is attempting to identify the difference in total impacts between systems over time, it is appropriate to include the radiative forcing associated with CO_2 produced from the decomposition of methane in the atmosphere. Simulations performed by NCASI comparing the method of Levasseur et al. to IPCC global warming potentials indicate that the effect of this difference on results is relatively small over periods of interest in this study (i.e., 100 years and less). Table 4.1 shows the results of applying the dynamic approach compared to 100-year global warming potentials from IPCC (IPCC 2006a). The results using both approaches are also shown in several places in this report.

Table 4.1 Comparison of IPCC GWPs to Results Obtained Using the Dynamic Carbon Footprint Calculator by Levasseur et al.

GHG	20-Year		100-year		500-year	
	IPCC GWPs	**Dynamic Calculator**	**IPCC GWPs**	**Dynamic Calculator**	**IPCC GWPs**	**Dynamic Calculator**
Methane	72	72.9	25	27.5	7.6	10.3
Nitrous Oxide	289	289	298	298	153	153

In this study, the results for the GHGI indicator have been computed in three different ways, both for the IPCC 100-year GWPs and using the dynamic calculator.

First, the absolute difference in impact attributable to releases of GHGs over 100 years, including biogenic CO_2 emissions and removals[6] was used to calculate the results of the greenhouse gas impact indicator ("Differential GHGI") as follows:

Differential GHGI (kg CO_2E/GJ) = Total greenhouse gas impact caused by GHG releases, including biogenic CO_2 emissions and removals, for energy production using residuals – Total greenhouse gas impact of GHG releases, including biogenic CO_2 emissions and removals, for energy production using fossil fuels, including alternative fate of residuals,

or in a shorter form,

Differential GHGI (kg CO_2E/GJ) =
[Total GHGI[7]]$_{Biomass\ system}$ - [Total GHGI]$_{Non\text{-}use\ system}$

Second, the greenhouse gases impact was computed using the percent difference in radiative forcing or GHGI impact calculated using IPCC GWPs attributable to GHGs released over 100 years, not including biogenic CO_2 ($BioCO_2$), of the biomass energy system compared to the non-use system ("Relative Non-$BioCO_2$ GHGI") as follows:

Relative Non-$BioCO_2$ GHGI (%) = (greenhouse gas impact caused by GHG releases, not including biogenic CO_2, for energy production using residuals – greenhouse gas impact caused by GHG releases, not including biogenic CO_2, for energy production using fossil fuels, including alternative fate of residuals)/(greenhouse gas impact caused by GHG releases, not including biogenic CO_2, for energy production using fossil fuels, including alternative fate of residuals),

or in a shorter form,

Relative Non-$BioCO_2$ GHGI (%) =
[(GHGI, excl. $BioCO_2$)$_{Biomass\ energy\ system}$ - (GHGI, excl. $BioCO_2$)$_{Non\text{-}use\ system}$]/ (GHGI, excl. $BioCO_2$)$_{Non\text{-}use\ system}$

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[6] As described in Figures 4.2 to 4.4, the system boundary for the product systems did not include harvesting and forest-related activities because they are the same in the biomass and non-use systems. This means that the associated forest-related CO_2 removals, i.e., the sequestration or absorption of CO_2 from the atmosphere by the trees, were not included in this study.

[7] In this report, "Total GHG releases" is used as a short form for the sum of non-biogenic CO_2 GHGs and biogenic CO_2 GHGs.

Third, while not traditionally considered in typical LCA studies, the timing of emissions and of greenhouse gas impact may be an important consideration for certain policy discussion/design contexts. For instance, in the context of this study, timing may be important in cases where the alternative to using residuals is allowing them to decay in waste disposal sites. Therefore, this study examined the life cycle implications of using biomass residuals for energy as a function of time. For each residual, the study computed the number of years it would take for the cumulative greenhouse gas impact from the two systems to be equal (break-even time). After this time, the cumulative greenhouse gas impacts from the biomass systems remain lower than that from the non-use system for remainder of the 100-year period of study. While the Differential GHGI results are presented in terms of kg CO_2E to facilitate comparison with using the 100-year IPCC GWPs, the yearly differential impact is presented in terms of radiative forcing because the graphical results are much easier to interpret when presented in terms of radiative forcing units (Wm^{-2}).

Notes:

- The materials being examined are biomass residuals. Their use was assumed to have no effect on carbon in growing biomass or gross removals of carbon from the atmosphere by the forest.
- Carbon in products-in-use was not modeled in this study because the fate of carbon in products is not affected by the fate of the residuals.

*4.1.6.2 **Fossil Fuel Consumption***

Fossil fuel used in the life cycle of each of the product systems studied was computed. The relative fossil fuel consumption ("Relative FF CON") was calculated as follows:

Relative FF CON (%) = (fossil fuel consumption score for energy production using residuals – fossil fuel consumption score for energy production using fossil fuels, including alternative fate of residuals)/(fossil fuel consumption score for energy production using fossil fuels, including alternative fate of residuals)

Fossil fuel consumption indicators are not based on an impact assessment model but rather on a quantification of the energy inputs to the studied product system. The cumulative energy demand method (Hischier and Weidema 2009) was used to quantify fossil fuel consumption because it is the most consistent with the life cycle inventory database used in this study. This method uses higher heating values in an attempt to characterize the total amount of energy consumed rather than only the energy directly used within the system being studied. The cumulative energy demand method tracks energy from the point of extraction.

Note: In this report, when a percent reduction is discussed, it is compared to the non-use system as defined in this study, unless otherwise mentioned.

4.1.7 Temporal Boundary

The temporal boundary describes the time horizon within which the results of the LCA are analyzed. The temporal boundary applies to inventory data and to the impact assessment. In this study, a temporal boundary of 100 years was selected because anything beyond that was judged to be too uncertain in relation to the goal of the study. This means that emissions were considered within 100 years after the residuals are used for energy or discarded. The greenhouse gas impact was also analyzed within this same 100-year time frame. When using IPCC GWPs, the greenhouse gas impact of an emission over 100 years is assumed to occur in the same year as the emissions. As a result, when using 100-year GWPs to study systems where emissions occur over time, some of the impacts associated with emissions occurring after year 1 actually occur after the 100-year period is ended.

4.2 Methodology for Additional Analyses

In addition to the life cycle analyses described above, the study also included two secondary analyses: a gate-to-gate analysis of the fate of biomass carbon, and one of the GHG emissions from the ongoing use of residuals for energy production.

4.2.1 Gate-to-Gate Analysis of Biogenic GHGs

The gate-to-gate analysis consisted of a more constrained analysis of the emissions of biogenic GHGs (mainly CO_2, CH_4, and N_2O) in isolation from any fossil fuel substitution benefits. In this analysis, the two compared systems (the biomass energy system and the non-use system) have been compared in terms of the emissions coming directly out of the units receiving the residuals (combustion units or landfills). In the case of paper recycling residuals, only their fiber fraction was considered because the focus here was on the fate of the biomass carbon. In this analysis, the system boundary for the various product systems was limited to the units receiving the residuals (i.e., "Energy Production in Forest Products Facilities" and "Alternative Fate of Biomass Residuals" in Figure 4.2 to Figure 4.4). The results were computed for two indicators described previously: differential GHGI and break-even times. A temporal boundary of 100 years was also used for that analysis.

4.2.2 GHG Emissions from Ongoing Use of Residuals for Energy Production

The analyses presented above focused on the one-time production of 1 GJ of energy (the functional unit) and looked forward in time to estimate the number of years it will take before the emissions impact attributable to the one-time use of biomass for energy is less than the emissions impact from a comparable system that disposes of the residuals. The practice of burning residuals for energy, however, is a long-standing one in the forest products industry. Therefore, it was also of interest to examine the net greenhouse gas impact over time attributable to the use of manufacturing residuals for energy on an ongoing basis. To look at the greenhouse gas impact from the ongoing use of biomass for energy production, a different functional unit is required. The functional unit used to assess emissions from ongoing practice is ***"the yearly production of 1 GJ of energy using biomass residuals as an ongoing practice."***

The definition of the temporal boundary is slightly different when analyzing the emissions attributable to ongoing practice. In fact, the time it takes for the cumulative greenhouse gas impact from a facility using residuals for energy on an ongoing basis to equal the cumulative greenhouse gas impact of a facility disposing of those residuals needs to be considered.

Data from AF&PA and NCASI were used to document the forest product industry's practices related to the use of biomass residuals for energy production.

4.3 Summary of Data Sources

North American data were used where possible and data gaps were filled using European data. The main data sources are summarized in Table 4.2.

Table 4.2 Data Sources

Process	Data Source
Direct combustion of wood residuals	NCASI, USEPA emission factors, literature
Direct combustion of WWTP residuals	Literature, NCASI
Combined heat and power from direct combustion	NCASI data
Landfilling	USEPA, IPCC, NCASI
Production of energy using fossil fuels	US-EI Database* (EarthShift 2009) modified to US 2010 power grid
Transportation distances	US Census 2002 (United States Department of Transportation and United States Department of Commerce 2004)
Transportation processes	US-EI Database (EarthShift 2009)

* The US-EI database (EarthShift 2009) bridges the current gap in the US LCI database (National Renewable Energy Laboratory 2008) and applies US electrical conditions to the ecoinvent database (ecoinvent Centre 2010). The database includes modified processes for the 423 processes contained in the US LCI database (version 1.6) and for the 3,974 unit processes contained in the ecoinvent database (version 2.2). Specifically, for the US LCI Database, most dummy processes (processes for which no life cycle information was available) were replaced with ecoinvent proxies using US electricity. Some of the dummy processes were not replaced if they were not available in the ecoinvent data set. For the ecoinvent data set, all processes using electricity from Switzerland or one of the European regions (RER, UCTE, CENTREL or NORDEL) were indirectly adapted to instead use US electricity. This was done by rerouting data for electricity production/distribution to data for US electricity production/distribution. NCASI also updated the data for electricity production to the most recent available data. The main data sets from the US-EI database that were used in this study are documented in this report. A data set with the "WITH US ELECTRICITY" mentioned in its title was originally developed by ecoinvent, while a data set with the "NREL" mentioned in its title was originally developed by the US LCI database.

4.4 Data Quality Goals

The ISO 14044 Standard (ISO 2006b) characterizes various aspects related to data quality and data quality analysis. It lists three critical data quality requirements: time-related coverage, geographical coverage, and technology coverage. The geographic coverage for this study is related to energy produced in US forest products facilities and utilities. When feasible, the most current available data were collected, which were most frequently for 2010. For data from secondary sources (literature, databases), the most current publicly available data for North America were used. A data quality goal of this study was to depict the GHG benefits of using biomass residuals within the forest products industry in a way that is representative of current average technology across the entire industry. Data were most frequently available from the members of the American Forest and Paper Association (AF&PA) and/or NCASI. Data obtained from these members were considered representative of the broader industry. The precision of the data is discussed where appropriate.

4.5 Energy Considerations

Energy requirement calculations were made using higher heating values (HHVs). HHVs account for the total heat content of the fuel when it is burned, some of which provides useful energy to the system in which the fuel is burned and some of which is used to evaporate the water in the combustion products. The latter is generally not available for use. For life cycle purposes, HHV is a more complete method of energy accounting compared to using the lower heating value (LHV), as LHV does not account for the energy content of the fuel that was used to evaporate the water. For this reason, HHVs were used in this study.

4.6 Software Package

This modeling for this study was performed using SimaPro™ version 7.3.3 and DynCO_2 (Levasseur 2013).

4.7 Critical Review and Public Use of the Results

Section 5.2 of ISO 14044 (ISO 2006b, p. 28) specifies that *"when results of the LCA are to be communicated to any third party (i.e., interested party other than the commissioner or the practitioner of the study), regardless of the form of communication, a third-party report shall be prepared"*. This Technical Bulletin is intended to serve as a third-party report. The Standard also specifies that *"in order to decrease the likelihood of misunderstandings or negative effects on external interested parties, a panel of interested parties shall conduct critical reviews on LCA studies where the results are intended to be used to support a comparative assertion intended to be disclosed to the public"* (ISO 2006b, p. 31). This study constitutes a comparative assertion of biomass and non-use systems. However, no formal peer review was performed, meaning that the study is not fully compliant with the ISO 14044 Standard.

5.0 DETAILED DATA SOURCES AND STUDY ASSUMPTIONS

This section describes the life cycle inventory step of the LCA, in which the typical scenarios studied are described, as are the unit processes modeled, the related system configuration scenarios, and sensitivity analyses.

5.1 Detailed Description of Unit Processes, System Configurations and Sensitivity Analyses

Table 5.1 presents an overview of the individual components that were combined into the various system configurations scenarios that were studied in this project. All possible combinations were studied, with a few exceptions that are discussed later in this section of the report, as appropriate. From these possible configurations, a typical scenario was also constructed for each of the biomass residuals studied. These are presented in Section 5.1.2.5. The next paragraphs describe in detail each of the unit processes that were involved in the various system configurations and typical scenarios.

Table 5.1 Summary of Components Used to Derive Possible System Configurations

Pre-Processing		Energy Produced at Forest Products Facilities Using Biomass Residuals		Energy Produced at Forest Products Facilities Using Fossil Fuels		Alternative Fate of Residuals	
SR0	No size reduction	SB	Heat from stoker boiler	A	Heat from natural gas	MR1	Landfill
		FB	Heat from fluidized bed	B	Heat from coal		
SR1	Size reduction	CHP1	Combined heat and power: low power to steam ratio*	C	Power from average US grid	MR2	Incineration
		CHP2	Combined heat and power: medium power to steam ratio*	D	Power from coal		
		CHP3	Combined heat and power: high power to steam ratio*	E	Power from natural gas combined cycle		

*All CHP scenarios were based on the use of a stoker boiler to produce the heat from biomass residuals. CHP configurations vary from facility to facility. In some cases, the turbines used to produce the power receive steam from all boilers of the facility (biomass and fossil fuel boilers). In other cases, they receive steam only from specific boilers (biomass or fossil fuel). Analyzing a case where the same amount of CHP would be achieved using biomass or fossil fuel boilers would have led to results that are very similar to those obtained for cases where it was assumed there was only heat produced because the only difference would have been due to energy losses in the CHP system. Therefore, in this project, a more useful CHP scenario for comparison is one where there would be CHP production only in the biomass energy system; if biomass residuals would not be used for energy production at wood products facilities, then the facility would have burned fossil fuel without CHP and would have to purchase the power from local utilities.

5.1.1 Size Reduction of Biomass Residuals

In some cases, additional size reduction is necessary before using biomass residuals for energy production. In this study, it was assumed that size reduction would sometimes be required for woody mill biomass residuals fuel and other similar manufacturing biomass residuals and never required for WWTP and paper recycling residuals.

Size reduction is typically accomplished by means of chippers, hogs, and shredders. Chippers can slice logs and mill residuals and produce chips with two surfaces and clean edges of pre-specified dimensions. Hogs (e.g., hammermills) and shredders reduce wood particles through impact force, and thus produce coarse and multi-surface particles. Hybrid size reduction equipment, such as rotary knife hogs or pan-and-disc grinders, combine the durability of hogging equipment with the sharp cutting action of chippers to produce wood chunks with cleaner edges than those produced by shredders or hogs.

A few data sets, summarized in Table 5.2, were found in the literature concerning size reduction of wood. These served as the basis for this study. More specifically, size reduction-related emissions were modeled using the US-EI database, modified with the use of diesel and electricity as presented in this table. The following US-EI data sets were used:

- **Mobile chipper:** “Wood chopping, mobile chopper, in forest/RER WITH US ELECTRICITY”; and
- **Stationary chipper:** “Industrial residual wood chopping, stationary electric chopper, at plant/RER WITH US ELECTRICITY.”

Table 5.2 Various Available Data Sets for Size Reduction and Assumptions Made in This Study

Source	Operation		Diesel (L/BDmT)	Lubricants (L/BDmT)	Electricity (kWh/BDmt)
Johnson et al. (2012)	Grinding of logging residuals		2.51 - 3.76	0.05 - 0.07	0
Johnson et al. (2012)	Chipping of thinnings		1.08 - 1.62	0.02 - 0.03	0
Werner et al. (2007)	Chopping of wood in mobile choppers		3.89*	0.06†	0
Werner et al. (2007)	Chopping in stationary chopper		0	0.002†	20
Jones et al. (2010)	Grinding of thinnings		2.42	N/Av.‡	0
System Configuration Scenarios and Sensitivity Analyses Considered in This Study					
SR0	No additional size reduction		0	0	0
SR1	Additional size reduction in mobile chipper	BC	2.49§	0.05	0
		Low	1.08	0.02	0
		High	3.89	0.07	0
SR2	Additional size reduction in stationary chipper	BC	0	0.002	20

*Werner et al. report 0.141 MJ of diesel burned per kg of residues and Kellenberger et al. (2007), 0.0234 kg of diesel per MJ. Using a density of 847.31 kg/m^3 (American Petroleum Institute 2009), this is equivalent to 3.89 L per BDmt. † Assuming a density of 900 kg/m^3.‡Not available. §Base case was taken as the middle of the range.

5.1.2 Energy Production Processes

5.1.2.1 Combustion of Woody Mill Residuals

Combustion of woody mill residuals is one of the unit processes that needed to be modeled to analyze the effects of producing energy using biomass residuals. Two types of boilers were modeled. First, a stoker boiler was assumed as it is the most commonly used firing method for burning woody biomass in the US forest products industry (NCASI 2011a). Stoker boiler efficiencies vary as a function of water content of the fuel. This is depicted in Figure 5.1. Sensitivity analyses were performed on water content and higher heating values. Second, to analyze the effect of the technology choice, a fluidized bed was also modeled using a single average residual water content and a single average higher heating value. Because smaller particles are required for a fluidized bed boiler, the analyses always incorporated size reduction. Table 5.3 summarizes the parameters that were varied for the modeling of manufacturing biomass residual combustion.

In addition, woody mill residuals are either used for energy production in the facility where they are generated or transported to another wood products facility. No transportation has been considered for the base case and transportation by truck over 130 km (United States Department of Transportation and United States Department of Commerce 2004, Table 14 available online only, value for trucking wood chips and particles) was modeled as a sensitivity analysis. The US-EI data set for single unit truck (“Transport, single unit truck, diesel powered NREL/US”), originally a US LCI Database data set, was used in this study.

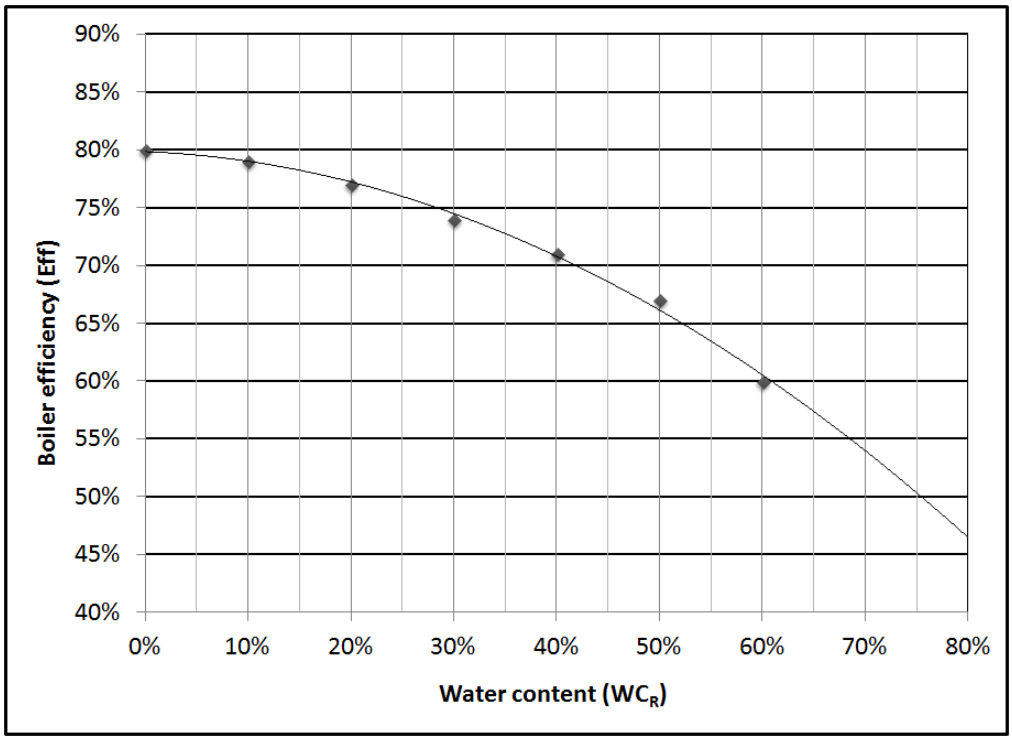

Figure 5.1 Stoker Boiler Efficiency as a Function of Fuel Water Content (WC_R)
[Based on Kostiuk and Pfaff (1997)]

The amount of residuals (Q_R) in dry tonnes required to produce a given amount of usable energy was calculated as follows:

$$Q_R = \frac{E_{DC}}{HHV \times Eff}$$

Where:

E_{DC}: Usable energy from direct combustion (GJ);
HHV: Higher heating value (GJ HHV/BDmT); and
Eff: Boiler efficiency (fraction between zero and 1).

GHG emissions due to biomass residual combustion were modeled using emission factors from USEPA (2009, Tables C-1 and C-2), converted to physical units[8]:

- 1,807 kg $BioCO_2$[9]/BDmT;
- 0.617 kg CH_4/BDmT; and
- 0.0809 kg N_2O/BDmT.

Ashes (2%) were assumed to be disposed of in facility landfills. Landfilling of wood ashes was modeled using data from the US-EI database ("Disposal, wood ash mixture, pure, 0% water, to sanitary landfill/CH WITH US ELECTRICITY U").

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[8] Heating value and emission factors for wood and wood residuals specified by USEPA are as follows: 15.38 mmBtu HHV/short ton @12% water, 93.80 kg CO_2/mmBtu, 3.2E-2 kg CH_4/mmBtu and 4.2E-3 kg N_2O/mmBtu.
[9] $BioCO_2$: biogenic CO_2.

Table 5.3 Base Case and Sensitivity Analyses for Manufacturing Biomass Residual Combustion

Technology Scenario		Parameter Analyzed	Value Analyzed		Comments
SB	Stoker boiler	Water content (W_R)	BC	50% (Eff = 66%)	The range of water content for wood residuals was based on rounded values from a literature review by NCASI (2011a) and assumed to be representative of the full range of wood residuals (e.g., chips, sawdust, etc.). The base case was selected as 50% because the moisture content of as-fired wood is typically near 50% for the pulp, paper and lumber industries (USEPA 1995). Efficiencies were based on Forintek (Kostiuk and Pfaff 1997). According to NCASI's literature review, water content of residuals can be as high as 75%, but this is not very realistic.
			Low	10% (Eff = 79%)	
			High	60% (Eff = 60%)	
		Higher heating value (HHV)	BC	20 GJ/BDmT	The range of heating values is based on a literature review by NCASI (2011a) and is assumed to be representative of the full range of wood species (hardwood and softwood). USEPA (2009, Tables C-1 and C-2) proposed heating value for wood is 20.3 GJ/BDmT (see below for more details).
			Low	13 GJ/BDmT	
			High	26 GJ/BDmT	
FB	Fluidized bed	Water content	50% (Eff = 80%)		Water content was assumed the same as above. Efficiency for the fluidized bed was from a NCASI literature review (2011a).
		Higher heating value	20 GJ/BDmT		

5.1.2.2 Combustion of Wastewater Residuals

Residuals from pulp and paper mill wastewater treatment plant (WWTP) operations are often burned in mill boilers both to recover energy and for solid waste minimization.

Table 5.4 presents example characteristics of WWTP residuals that can affect their suitability for combustion. From this table, it can be seen that characteristics of residuals vary significantly. In this study, sensitivity analyses for residuals combustion were set to account for this variation.

Co-firing with bark in a stoker boiler was assumed; however, only the fraction of heat from the WWTP residuals was analyzed. Burning WWTP residuals is more difficult than burning bark mainly because of their high ash and low oxygen content. To compensate for the effects of higher ash and lower oxygen contents, the moisture of the residuals must be lower to produce the same efficiency in stoker boilers (Kraft and Orender 1993). The authors suggested that for sludge to burn like bark, the equivalent of 5 moisture points must be compensated for in some way. Switching from all bark to all residuals is worth 5 equivalent moisture points (1 moisture point being the same as 1% water content) and

- co-firing 90% bark with 10% sludge is worth 0.5 moisture points; and
- co-firing 80% bark with 20% sludge is worth 1.0 moisture point.

In this study, the latter, which is more conservative, was assumed. However, as mentioned above, only the heat fraction from the residuals was analyzed. Only stoker boilers were analyzed.

Table 5.4 Characteristics of WWTP Residuals

Source	WWTP Residual	Ash Content (%wt, dry basis)	Carbon Content (%wt, dry basis)	Water Content (%wt, wet basis)	Heat Content (GJ HHV/BDmT)*
Durai-Swami et al. (1991)	Recycled paper mill and kraft mill	5.5 - 18.9	47.2 - 48.2	49.5 - 62.4	20.6 - 24.1
James and Kane (1991)	Kraft mill	8.0	48.0	37.5	19.8
Nickull et al. (1991)	Clarifier and dredged from sulfite mill	1.9	48.7	66.6	20.1
Kraft (1994), Kraft and Orender (1991, 1993)	Deinking, pulp mill, unspecified	11.3 - 48.1	28.8 - 51.8	58.0 - 60.6	5.0 - 21.5
Aghamohammadi and Durai-Swamy (1993)	Recycled paper and cardboard	2.8 - 3.0	48.4 - 48.6	50 - 85	20.6 - 20.8
Douglas et al. (1994)	Deinking	31.9 - 33.2	32.7 - 38.2	42.7 - 68.6	12.3 - 15.3
Frederik et al. (1996)	Recycled paper mill	43.8	16.1	42.0	8.38
La Fond et al. (1997)	Secondary	N/Av	49.3	N/Av	23.1
Hischier (2007)	Mechanical, primary and secondary Deinking	36.4 - 67.3 (deink only, wet)	19.0 - 35.8	25 - 70.6	2.6 - 8.6 GJ (LHV)
NCASI (2005a) and USEPA (ERG 2002)	Bleached kraft, unbleached kraft, unbleached kraft colored, deinked, mechanical, groundwood, chemi-mechanical – mixed and secondary	9.9 - 56.8	37.4 - 45.5	36.2 - 80.6†	7.6 - 18.1†
USEPA GHG Reporting Rule (2009, Tables C-1 and C-2)	Wastewater from paper mills	N/Av	N/Av	N/Av	20.3§
Woodruff et al. (2012)	Pulping, deinking	10 - 50	N/Av	50 - 60	9.3 - 23.3
NCASI unpublished lab experiments	Bleached kraft combined, deinking combined, non-integrated combined, non-integrated primary, deinking primary	26.1 - 74.4	23.1 - 37.3	N/Av	N/Av
IPCC (2006b, Chapter 2, Section 2.3.2)	"Industrial sludge" including WWTP residuals from pulp and paper industry	N/Av	27**	N/Av	N/Av

*When unknown, assumed to be HHV. †Includes dewatered and not dewatered residuals. ‡Assuming USEPA values are expressed in Btu HHV/lb. §According to USEPA (2010b, p. 79138), wood residuals means materials recovered from three principal sources: municipal solid waste (MSW); construction and demolition debris; and primary timber processing. Wood residuals recovered from MSW include wooden furniture, cabinets, pallets and containers, scrap lumber (from sources other than construction and demolition activities), and urban tree and landscape residuals. Wood residuals from construction and demolition debris originate from the construction, repair, remodeling and demolition of houses and non-residential structures. Wood residuals from primary timber processing include bark, sawmill slabs and edgings, sawdust, and peeler log cores. Other sources of wood residuals include, but are not limited to, railroad ties, telephone and utility poles, pier and dock timbers, wastewater process sludge from paper mills, trim, sander dust, and sawdust from wood products manufacturing (including resinated wood products residuals), and logging residuals. **Example from Japan.

Water content of WWTP residuals (WC_R, primary and secondary treatment, deinking residuals) can vary widely; see Table 5.4. Residuals are typically mechanically dewatered. The general objective of dewatering is to remove water to the extent that the solids volume is reduced and the resulting residuals behave as a solid and not as a liquid. Residuals dewatering is accomplished at pulp and paper facilities by incorporating equipment and practices that result in increased WWTP residuals solids content. Employing residuals dewatering a) reduces the costs associated with residuals hauling, b) maximizes the use of remaining landfill capacity, c) makes residuals a more attractive fuel for combination fuel-fired boilers, and d) makes residuals more attractive for beneficial use opportunities (NCASI 2008). WWTP residuals can be dewatered using several technologies, of which belt filter presses and screw presses are the most frequently used in the US industry (NCASI 2008). Solids contents achievable using belt filter and screw presses are over 30% (WC_R < 70%[10]) and 40% (WC_R < 60%), respectively. A lower value of 50% water was also analyzed.

In this study, it was assumed that WWTP residuals were dewatered to 40% solids content, whether they were to be burned or landfilled, i.e., dewatering is assumed to happen both in the biomass and non-use systems. For this reason, dewatering was not included in the study. Ashes from residuals combustion were assumed to be landfilled on site. Landfilling of sludge ashes was modeled using the US-EI database (Disposal, wood ash mixture, pure, 0% water, to sanitary landfill/CH WITH US ELECTRICITY), assuming landfilling of wood ash could be taken as a proxy. Sensitivity analyses were performed on water content, heating value, and ash content. These are summarized in Table 5.5. Efficiencies have been derived from Figure 5.1 (assuming WC_R + 1%).

Table 5.5 Scenarios/Sensitivity Analyses for WWTP Residual Combustion

Parameter Analyzed	Value Analyzed		Rationale/Sources
Water content (WC_R)	BC	60% (Eff =60%)	BC and high values are based on achievable dry contents for screw presses. NCASI analysis of data in Table 5.4 was used to determine the low value by eliminating less probable drier residuals.
	Low	50% (Eff =66%)	
	High	70% (Eff =53%)	
Higher heating value (HHV)	BC	15 GJ/BDmT	BC, low, and high values are based on NCASI analysis of data in Table 5.4.
	Low	10 GJ/BDmT	
	High	20 GJ/BDmT	
Ash content	BC	30%	BC, low, and high values are based on NCASI analysis of data in Table 5.4.
	Low	10%	
	High	50%	

According to USEPA (2009), emission factors for wood and wood residuals should be used for WWTP sludge. However, the carbon content of WWTP residuals can vary significantly depending on the type of residuals. In this study, USEPA emission factors are used as a base case and sensitivity analyses are performed to accommodate the variability in the carbon content of WWTP residuals. This is summarized in Table 5.6. It is also assumed that the higher carbon contents are associated with the higher HHVs.

[10] WC_R: water content of residuals.

Table 5.6 Emission Factors for Burning WWTP Residuals

Parameter Analyzed		Value Analyzed		Rationale/Sources
Biogenic CO_2	kg CO_2/BDmT	BC	1,807 (CC = 49%)	According to USEPA (2010b, p. 79138), wood residuals include WWTP residuals. Hence, the same emission factor as for woody mill residuals was used (USEPA 2009, Tables C-1 and C-2).
		Low	733 (CC = 20%)	Low and high values are based on NCASI analysis of data in Table 5.4.
		High	2017 (CC = 55%)	
CH_4	kg CH_4/BDmT	BC	0.617	According to USEPA (2010b, p. 79138), wood residuals include WWTP residuals. Hence, the same emission factor as for woody mill residuals was used (USEPA 2009, Tables C-1 and C-2).
N_2O	kg N_2O/BDmT	BC	0.0809	

5.1.2.3 ***Combustion of Paper Recycling Residuals (OCC Rejects)***

Paper recycling residuals, and more specifically OCC rejects, are often burned in boilers at pulp and paper mills that process recovered paper. This is done both for volume reduction and for energy recovery. Table 5.7 presents some general characteristics of OCC rejects, as well as the assumptions that were made in this study. OCC rejects were considered representative of the broader paper recycling residuals category. Ranges provided in the table are based on typical characteristics at a number of mills. They are intended to capture the breadth of anticipated variation for these materials.

Paper recycling residuals are a mix of fiber and plastic. In a stoker boiler, the fiber fraction is likely to behave as WWTP residuals (lower efficiency than that for wood biomass residuals). The plastic fraction is likely to behave like a fossil fuel (higher efficiency than that for woody biomass residuals). In this study, it was assumed that the boiler efficiency would be the same as that for woody biomass residuals at similar water content. Only stoker boilers were analyzed.

Ashes from residuals combustion were assumed to be landfilled on site. Landfilling of paper recycling residuals ashes was modeled using the US-EI database (Disposal, wood ash mixture, pure, 0% water, to sanitary landfill/CH WITH US ELECTRICITY), under the assumption that landfilling of wood ash could be taken as a proxy.

Table 5.7 General Characteristics of OCC Rejects and Sensitivity Analyses

Parameter		Range	Source	Range Analyzed in This Study		
				BC	Low	High
Fiber	% dry wt.	30 - 95	NCASI (2000)	60	30	90
Plastics	% dry wt.	5 - 70	NCASI (2000)	40	10	70
Ashes	% dry wt.	1 - 10	NCASI (2000)	5		
Biogenic CO_2 emissions when burning fiber fraction of OCC	kg CO_2/kg fiber	1.807*-1.833†	USEPA (2009, Tables C-1 and C-2)	1.807	N/A	N/A
CH_4 emissions when burning fiber fraction of OCC	kg CH_4/kg fiber		Estimated*	6.17E-5*		
N_2O emissions when burning fiber fraction of OCC	kg N_2O/kg fiber		Estimated*	8.09-6*		
Fossil CO_2 emissions when burning plastic fraction	kg CO_2/kg plastic	2.30	US-EI (EarthShift 2009)‡	2.30		
CH_4 emissions when burning plastic fraction of OCC	kg CH_4/kg plastic	6.38E-6	US-EI (EarthShift 2009)‡	6.38E-6		
N_2O emissions when burning plastic fraction of OCC	kg N_2O/kg plastic	2.58E-5	US-EI (EarthShift 2009)‡	2.58E-5		
Higher heating value	GJ HHV/BDmT	18.8-27.7	NCASI (2000)	Fiber fraction: 19.1 Plastic fraction: 40.9		
Water content (boiler efficiency)	% wet wt. (%)	35-70	NCASI (2000)	55(63)	40 (71)	70 (54)

NOTE: Ranges are based on NCASI analysis of the literature. Base case is selected as the middle of the range unless otherwise selected.
* USEPA (2009) emission factors for wood and wood residuals, expressed based in physical units, are used for the fiber fraction of OCC rejects. † Assuming all carbon emitted as CO_2. ‡Disposal, plastics, mixture, 15.3% water, to municipal incineration/CH WITH US ELECTRICITY.

The carbon dioxide produced when plastics are burned is commonly accounted for using the same methods as for carbon dioxide produced in burning fossil fuels (USEPA 2010c, Table C-1 and Section 98.33(e)). For the gate-to-gate analyses of the biogenic GHG releases, it is only the accounting methods for biogenic carbon that are in question. For this reason, for these analyses, only the fiber fraction of paper recycling residuals was considered.

The heating values of the individual plastic and fiber fractions were presented in Table 5.7. There is no available information for the individual water contents of each of the fractions. However, it was shown in Table 5.7 that water content of paper recycling residuals varies significantly and it can be assumed that, while the plastic fraction of the residuals may contain some water, most of it would be found in the in the fiber fraction. In this analysis, the same water content as paper recycling residuals was applied to its fiber fraction. This resulted in 66% water for base case condition, which is very similar to WWTP residuals.

5.1.2.4 Combined Heat and Power (CHP)

In this study, a hypothetical combined heat and power configuration (CHP) representative of those commonly used in the forest products industry was modeled. This system, depicted in Figure 5.2, consisted of a biomass-fired boiler with high pressure steam routed to a back pressure turbine.

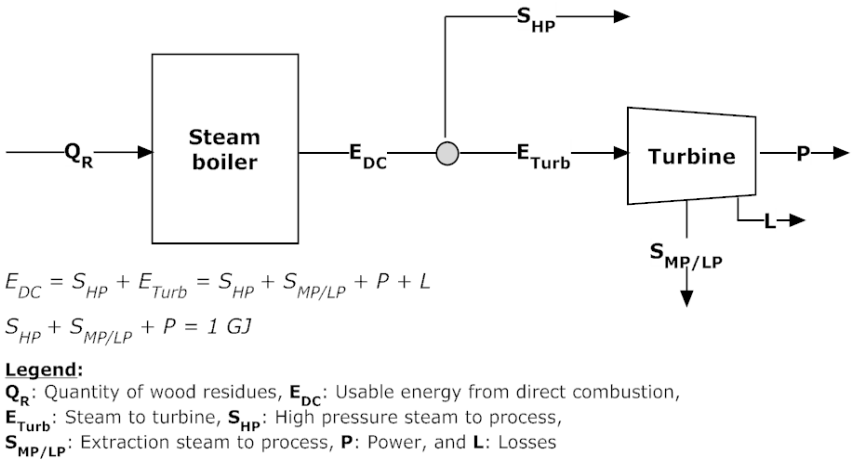


Figure 5.2 Hypothetical CHP Configuration Considered in This Study

The relationship between Q_R and E_{DC} is described above in Section 5.1.2.1. Three scenarios were considered: 1) one representing an older pulp and paper mill (CHP1), 2) one representing a newer pulp and paper mill (CHP2), and 3) one considering the maximum power production through use of a condensing turbine. This last scenario could be considered representative of cases where very little steam is required. All three scenarios are presented in Table 5.8.

All the CHP scenarios were performed with base case stoker boiler conditions.

Table 5.8 CHP Scenarios

Scenario #	E_{DC}	E_{Turb}	S_{HP}	P	$S_{MP/LP}$	$S_{HP}+S_{MP/LP}$	L
	(GJ)						
CHP1	1.0499	0.9974	0.05 E_{DC} = 0.0525	0.18 E_{Turb} = 0.1795	0.77 E_{Turb} = 0.7680	0.8205	0.05 E_{Turb} = 0.0499*
CHP2	1.0499	0.9974	0.05 E_{DC} = 0.0525	0.29 E_{Turb} = 0.2892	0.66 E_{Turb} = 0.6583	0.7108	0.05 E_{Turb} = 0.0499*
CHP3	1.0499	0.9974	0.05 E_{DC} = 0.0525	0.95 E_{Turb} = 0.9475	0	0.0525	0.05 E_{Turb} = 0.0499*

* Used for sootblowing.

5.1.2.5 Energy Production Using Fossil Fuels

Two possible options for producing energy from biomass residuals were considered: heat and combined heat and power. This means that an equivalent system needed to be studied regarding fossil fuels. For cases where the biomass energy system included heat production at the forest products facility, it was assumed that in the fossil fuel-based system an equivalent quantity of heat would be produced at the facility using either coal (A) or natural gas (B).

A somewhat different approach was taken for cases where combined heat and power would be applied to the biomass energy system. CHP configurations vary from facility to facility. In some cases, the turbines used to produce power receive steam from all boilers at the facility (i.e., both biomass and fossil fuel boilers). In other cases, they receive steam only from specific boilers (biomass or fossil fuel). Analyzing a case where the same amount of CHP would be achieved using biomass or fossil fuel boilers would have led to results that are very similar to those that were obtained for the case where it was assumed there was only heat produced, because the only difference would have been due to energy losses in the CHP system, which are typically very small. Therefore, in this project, a more useful CHP scenario for comparison is one where there would be CHP production only in the biomass energy system; if biomass residuals were not used for energy production at forest products facilities, then the facility would have burned fossil fuel without CHP and would have to purchase the power from local utilities. Three scenarios were analyzed: C) US average electrical grid mix, D) power generated using coal, and E) power generated using natural gas combined cycle. These scenarios were selected in order to cover a large spectrum of possible mill situations.

All energy production processes from fossil fuel-related processes were modeled using the US-EI database. In specific, the following data sets were used for heat production:

- **Heat from coal:** "Bituminous coal, combusted in industrial boiler NREL/US" (this data set includes transportation of the coal to the boiler); and
- **Heat from natural gas:** "Natural gas, combusted in industrial boiler NREL/US" (this data set includes transportation of the natural gas to the boiler).

Both these data sets are expressed based on the quantity of fuel burned and not on the quantity of energy produced. To calculate the energy produced, the following was assumed:

- **Coal:** boiler efficiency of 85% and higher heating value of 24.93 MMBtu per short ton (29.0 GJ/tonne); and
- **Natural gas:** boiler efficiency of 80% and HHV of 1.028E-3 MMBtu per cubic feet (0.0383 GJ/m^3).

Heating values were obtained from USEPA (2009, Table C-1). GHG emission factors were also derived from EPA. The emission factors for natural gas are 93.4 kg CO_2, 1.1E-2 kg CH_4 and 1.6E-3 kg N_2O per MMBtu. The emission factors for coal are 53.02 kg CO_2, 1.0E-3 kg CH_4 and 1.0E-4 kg N_2O per MMBtu.

The following data sets were used for electricity production at utilities:

- Electricity, bituminous coal, at power plant NREL/US; and
- Electricity, natural gas, at turbine, 10MW/GLO WITH US ELECTRICITY.

The US average consumption grid mix was also modeled using processes from the US-EI Database. It was calculated by considering the quantity of power produced in the US by type of fuel, the quantity of power exported, and the quantity imported from Canada and Mexico. The production mix for the United States was calculated using 2010 data from the US Department of Energy, Energy Information Administration (EIA 2012, Forms EIA-906, EIA-920 and EIA-923). Data for 2009 from the International Energy Agency were used for Mexico (IEA 2013), as these were the most recent data available. Since electricity imports from Mexico represent less than 3% of the total energy consumed in the US, these data are not expected to have a significant effect on the results. Canadian data were taken from Statistics Canada (2013a, b, c). Table 5.9 presents the fuel mix for US average electricity consumption as well as the US-EI data sets that were used to model it.

Table 5.9 US Average Electricity Grid Fuel Consumption Mix

Fuel Type	%	US-EI Data Set Used
Coal (including CHP)	45	Electricity, bituminous coal, at power plant NREL/US
Petroleum	1	Electricity, residual fuel oil, at power plant NREL/US
Natural gas (including CHP)	24	Electricity, natural gas, at power plant NREL/US
Nuclear	20	Electricity, nuclear, at power plant NREL/US
Hydroelectric	7	Electricity, hydropower, at power plant/SE WITH US ELECTRICITY U (89%), and Electricity, hydropower, at pumped storage power plant/US WITH US ELECTRICITY U (11%)
Wind	2	Electricity, at wind power plant/RER WITH US ELECTRICITY
Wood and wood derived fuels (CHP)	1	Electricity, biomass, at power plant NREL/US

Note that this US average grid mix was also used for the background electricity consumption of all processes modeled with the US-EI database.

Different fuels may be associated with different energy requirements for air emissions control of combustion units. In this study, it was assumed that the differences in energy requirements for emissions control were insignificant compared to the energy produced by the combustion units. This assumption was tested using sensitivity analyses.

5.1.3 Alternative Fates

5.1.3.1 Landfilling of Manufacturing Residuals

In landfills, a fraction of the biogenic carbon in wood-based material decays, primarily into gas. The remaining fraction is non-degradable under anaerobic conditions. The non-degradable fraction varies by type of product, being generally higher in materials with more lignin. In this study, the degradable fraction of the biogenic carbon in landfills was assumed to decay according to a first order decay equation, with a variable rate constant. This approach is recommended by IPCC (IPCC 2006b) and used by EPA (2010a, 2014a) for a number of purposes.

Reported decay rates are highly variable from one material to another and from one study or program to another. The factors that affect the rate of decomposition in landfills include waste management and processing variables (such as the size of the waste particles), the waste properties, factors that influence bacterial growth (such as moisture, available nutrients, pH, and temperature), and the design of the landfill (Micales and Skog 1997). EPA tested 52 municipal solid waste landfills and found decay rates that varied on average from 0.020 to 0.057, depending on precipitation conditions (USEPA 2014a, Annex 3.14, Table A-262). Published values for wood product and pulp and paper waste, branches, and solid wood products vary from 0.01 to 0.1 (De la Cruz and Barlaz 2010, IPCC 2006b, Chapter 3, Table 3.3, Micales and Skog 1997, NCASI 2005b, Section 14.2, Skog 2008, U.S. EPA 2012a, U.S. EPA 2013, Table TT-1, U.S. EPA 2014a, Annex 3.14). These values were mostly derived from laboratory experiments. NCASI knows of no published data, however, on decay rates specific to forest products industry manufacturing residuals in industry landfills based on actual measurements. Therefore, in this study, the EPA decay rates for municipal solid waste (MSW) were used (US EPA 2014a, Annex 3.14, Table A-262). These were used because 1) 50 to 60% of the biodegradable material in discarded MSW in the US (after recovery for recycling) is paper, paperboard, wood, and yard trimmings (USEPA 2014b, Table 3), 2) unlike most of the decay rates

found in the literature, these decay rates are derived from field data instead of laboratory experiments, and 3) they are based on a robust data set, having been derived from 52 representative landfills from across the United States with varying amounts of precipitation. These EPA MSW decay rates are somewhat higher than those used in the EPA GHG emissions reporting program for pulp, paper, and wood products mill landfills, somewhat lower than those used for pulp and paper mills in the EPA national GHG inventory, and are within the range of those reported elsewhere for forest-derived materials.

The fraction of material degradable under anaerobic conditions must also be known in order to estimate GHG emissions from landfills receiving manufacturing residuals. Data are available for some of the specific residuals in this study; the parameter values used to characterize the extent of decomposition are discussed below in the sections dealing with individual types of residuals.

Under anaerobic conditions, about one-half of the degradable carbon is converted to biogenic CO_2 while the other half is converted to CH_4. Under aerobic conditions (e.g., in shallow unmanaged landfills), a much smaller fraction of the gas consists of CH_4. The methane correction factor (MCF, fraction between zero and 1) is used to reflect the fraction of material that is degraded under anaerobic conditions.

Another factor influencing the releases of landfill CO_2 and CH_4 methane to the atmosphere is the extent to which CH_4 is oxidized to biogenic CO_2 before exiting the landfill. Even in the absence of systems designed to capture and destroy methane, it is commonly assumed that about 10% of the methane is oxidized as it moves through the surface layers of the landfill (IPCC 2006b, Chapter 3, Table 3.2, U.S. EPA 2014a, Section 8.1). Finally, some landfills are equipped with cover systems to collect and destroy methane by burning, and assumptions need to be made regarding the fraction of the methane that is collected and burned. In this study, it was assumed that manufacturing residuals are landfilled in a landfill receiving primarily forest product industry waste and that for these landfills there is no methane capture, assumptions consistent with current practice in the industry and with the approach used by EPA to calculate landfill emissions from pulp and paper mills landfills for the national inventory (USEPA 2014a, Annex 3.14).

Cumulative quantities of carbon dioxide and methane from mill landfills emitted at a given time are calculated as follows.

Quantity of Carbon Converted to Gas at a Given Time Under Anaerobic Conditions:

$$Q_{C\rightarrow Gas,ana} = MCF \times Q_R\left(1 - e^{-kt}\right) \times CC \times (1 - F_{CCND})$$

where Q_R is the quantity of residuals required to produce a given amount of usable energy in the biomass product system, t the time in years, CC the carbon content of residuals, F_{CCND} the fraction of carbon that is non-degradable under anaerobic condition, and k the decay rate.

Quantity of Carbon in Gas Converted to Methane ($Q_{C\text{->}CH4}$):

$$Q_{C\rightarrow CH4} = Q_{C\rightarrow Gas,an} \times F$$

where F is the fraction of gas converted to methane under anaerobic conditions.

Quantity of Methane Not Collected and Burned (Q_{CH4NCB})

$$Q_{CH4NCB} = Q_{C\rightarrow CH4} \times \frac{16}{12}(1 - F_{CH4CB})$$

where F_{CH4CB} is the fraction of methane collected and burned or oxidized.

Quantity of Methane Released to the Environment ($Q_{CH4,Landfill}$):

$$Q_{CH4,Landfill} = Q_{CH4NCB} \times (1 - F_{CH4OX})$$

where F_{CH4OX} is the fraction of methane oxidized in landfill covers.

Quantity of Carbon Converted to Gas at a Given Time Under Aerobic Conditions:

$$Q_{C\rightarrow Gas,ae} = (1 - MCF) \times Q_R\left(1 - e^{-kt}\right) \times CC$$

Total Quantity of Gas at a Given time:

$$Q_{C\rightarrow Gas} = Q_R\left(1 - e^{-kt}\right) \times CC \times [1 - MCF * F_{CCND}]$$

Quantity of Carbon Dioxide Released to the Environment ($Q_{CO2,Landfill}$):

$$Q_{CO2,Landfill} = \left(Q_{C\rightarrow Gas} - Q_{CH4,landfill} \times \frac{12}{16}\right) \times \frac{44}{12}$$

Other environmental loads related to landfilling activities were modeled using the US-EI database (Disposal, wood untreated, 20% water, to sanitary landfill/CH WITH US ELECTRICITY).

5.1.3.1.1 Woody Mill Residuals

As mentioned above, an important factor in calculating emissions from landfills is the fraction of the original biogenic carbon that is non-degradable under anaerobic conditions. There is a wide variation of values for this parameter in the case of wood and wood-derived materials. Values published in the literature for woody materials vary from 50% (IPCC 2006b) to over 90% (Wang et al. 2011). Values for paper-based materials can be significantly lower than those for woody materials (USEPA 2012a). In this study, the value used in the EPA GHG Inventory for wood products disposed in MSW landfills was used in the typical scenario. This was done because 1) in the context of this study, it is more conservative than lower values sometimes used by EPA (i.e., it results in lower methane emissions from landfilling, reducing the relative benefits of burning for energy); and 2) given recent studies (e.g., Wang et al. 2011), it is likely more realistic than lower values sometimes used by EPA. There is large uncertainty in this parameter however. Materials like bark and sawdust that comprise woody mill residuals have not been studied to NCASI's knowledge. Landfill parameter values selected in this study for woody mill residuals are summarized in Table 5.10.

Table 5.10 Parameters Affecting Emissions from Landfilling of Woody Mill Residuals

Parameter Analyzed	Value Analyzed		Rationale/Source(s)
Biogenic carbon content (CC)	BC	50%	IPCC (2006c, Table 12.4, default value for carbon fraction of wood residues)
Non-degradable carbon under anaerobic conditions (F_{CCND})	BC	77%	USEPA (2014a, Annex 3.13); see rationale above
	Low	50%	IPCC (2006b, Chapter 3, p. 3.13) and USEPA (2010a, p. 39773, 2013, Table TT-1) recommend using a default value of 50% for the fraction of carbon that decomposes under anaerobic conditions for all waste
	High	90.0%	Mid-point of the range for wood and wood products (Wang 2011, Table 2)
Decay rate (k)	BC	0.038 yr^{-1}	USEPA (2012b), value representative of 52 US municipal solid waste landfills and various precipitation conditions; see rationale above
	Low	0.020 yr^{-1}	
	High	0.057 yr^{-1}	
Methane correction factor (MCF) i.e., fraction of landfill under anaerobic conditions	BC	1	IPCC (2006b), methane correction factors set up to be representative of managed anaerobic
Fraction of gas converted to methane under anaerobic conditions (F)	BC	0.5	IPCC (2006b)
Fraction of methane oxidized in landfill covers (F_{CH4OX})	BC	10%	IPCC (2006b)
Fraction of methane burned or oxidized (F_{CH4CB})	BC	0%	Assuming no mill landfill is equipped with methane collection systems (USEPA 2014a)

5.1.3.1.2 WWTP Residuals

Assumptions made to model GHG emissions from landfilling WWTP residuals are summarized in Table 5.11. Detailed calculations were presented in Section 5.1.3.1. Other environmental loads from landfilling of WWTP residuals were modeled using the US-EI database (Disposal, sludge from pulp and paper production, 25% water, to sanitary landfill/CH WITH US ELECTRICITY).

Table 5.11 Parameters Affecting Emissions from Landfilling of WWTP Residuals

Parameter Analyzed	Value Analyzed		Source(s)
Biogenic carbon content (CC)	BC	49%	See Table 5.6.
	Low	19%	
	High	55%	
Non-degradable carbon under anaerobic conditions (F_{CCND})	BC	50%	From NCASI unpublished experiments
	Low	40%	
	High	60%	
Decay rate (k)	BC	0.038	USEPA (2012b), value representative of 52 US municipal solid waste landfills and various precipitation conditions, see rationale above
	Low	0.020	
	High	0.057	
Methane correction factor (MCF)	BC	1	IPCC (2006b), methane correction factors set up to be representative of managed anaerobic landfills
Fraction of gas converted to methane under anaerobic conditions (F)	BC	0.5	IPCC (2006b)
Fraction of methane oxidized in landfill covers (F_{CH4OX})	BC	10%	IPCC (2006b)
Fraction of methane burned or oxidized (F_{CH4CB})	BC	0%	Assuming no mill landfill is equipped with methane collection systems

5.1.3.1.3 Paper Recycling Residuals

Assumptions made to model GHG emissions from landfilling the fiber fraction of OCC rejects are summarized in Table 5.12. Detailed equations were provided in Section 5.1.3.1. Other environmental emissions related to the use of resources for landfilling the fiber fraction, as well as for landfilling the plastic fraction of OCC rejects, were modeled using the US-EI database.

- **Fiber fraction of residuals:** Disposal, sludge from pulp and paper production, 25% water, to sanitary landfill/CH WITH US ELECTRICITY, assuming WWTP residuals are representative of the fiber fraction of the paper recycling residuals
- **Plastic fraction of residuals:** Disposal, paper, 11.2% water, to sanitary landfill/CH WITH US ELECTRICITY

Table 5.12 Parameters Affecting Emissions from Landfilling the Fiber Fraction of OCC Rejects

Parameter Analyzed	Value Analyzed		Source(s)
Biogenic carbon content (CC)	BC	50%	IPCC (2006b)
Non-degradable carbon under anaerobic conditions (F_{CCND})	BC	61%	Based on NCASI (2004)
	Low	40%	Based on lower value for WWTP residuals (see Table 5.11)
Decay rate (k)	BC	0.038	USEPA (2012b), value representative of 52 US municipal solid waste landfills and various precipitation conditions, see rationale above
	Low	0.020	
	High	0.057	
Methane correction factor (MCF)	BC	1	IPCC (2006b), methane correction factors set up to be representative of managed anaerobic
Fraction of gas converted to methane under anaerobic conditions (F)	BC	0.5	IPCC (2006b)
Fraction of methane oxidized in landfill covers (F_{CH4OX})	BC	10%	IPCC (2006b), assuming no mill landfill is equipped with methane collection systems
Fraction of methane burned or oxidized (F_{CH4CB})	BC	0%	Assuming no mill landfill is equipped with a methane collection system

5.1.3.2 Incineration of Woody Mill Residuals

Incinerating the woody mill residuals without recovering the energy is modeled in this study as a way to illustrate the simplest way by which biogenic carbon can return to the atmosphere. Emissions from incineration are assumed the same as those for combustion for energy generation (see Section 5.1.2.1).

5.1.3.3 Incineration of WWTP Residuals

Emissions from incineration are assumed to be the same as those related to combustion for energy generation (see Section 5.1.2.2).

5.1.3.4 Incineration of Paper Recycling Residuals

Emissions from the incineration of paper recycling residuals are assumed to be the same as those related to combustion for energy generation (see Section 5.1.2.3).

5.2 Definition of Typical Scenarios

5.2.1 Current Energy Use and Waste Management Practices at Forest Products Facilities

Energy production and waste management data were compiled for the US forest products facilities (both pulp and paper and wood products) using data collected by AF&PA, NCASI, and the American Wood Council (AWC) and are summarized in Table 5.13 and

Table 5.14. Most data are from 2010. Waste management data for the wood products facilities were compiled through 2008 only. For this reason, to produce a representative number for the entire forest products industry in 2010, the ratio of management options in 2008 was applied to 2010 production data. There are no "waste management" data available for bark, sawdust, and similar woody mill residuals produced at pulp and paper facilities, as they are not a waste but rather almost always being burned for energy.

Table 5.13 US Forest Products Facilities Estimated Fuel Mix
(Not Including Purchased Power and Steam)

Fuel Type	Paper Products Facilities	Wood Products Facilities	Forest Products Industry (AF&PA, NCASI and AWC members used as a proxy for the entire US industry)
	%		
Biomass fuels	**70.9**	**90.1**	**72.1**
Fossil fuels	**29.1**	**9.9**	**27.9**
Natural gas	13.9%	8.6%	13.5%
Coal	10.9%	0.3%	10.2%
Other fossil	4.4%	0.9%	4.1%
Power produced through combined heat and power	**GJ/GJ fuel input**	0.06	

Table 5.14 Waste Management Practices at US Forest Products Facilities

Waste Type	% Beneficial Use	Disposal		
		Total	% Landfill (% of disposal)	% Burning* (% of disposal)
Paper Products Facilities				
WWTP residuals	32.5%	67.5%	44.4% (65.8%)	23.1% (34.2%)
All others (causticizing wastes, general mill trash, construction debris, OCC rejects, landfilled broke, bark, wood residual, sawdust, knots, metal and other recyclable)	26.9%	73.1%	68.4% (93.6%)	4.7% (6.4%)
Wood Products Facilities				
All waste types (incl.: unusable sawdust, shavings, bark, garbage, recyclables, used oil, pallets, etc.)	96.2%	3.8%	3.8% (100%)	Negligible
Forest Products Industry (AF&PA and NCASI members used as a proxy for the whole US industry)				
Other waste from pulp and paper facilities and all waste from wood products facilities	57.8%	42.2%	39.6% (93.8%)	2.6% (6.2%)

*This does not include burning for energy.

Typical scenarios were modeled to be as representative as possible of current practices within US forest products manufacturing facilities using the information in the tables above. In addition, all parameters were set to their base case values for typical scenarios.

5.2.2 Woody Mill Residuals

The typical scenario considered for woody mill residuals is summarized in Table 5.15. A stoker boiler was assumed in the typical scenario as it is the most commonly used firing method for burning woody biomass (NCASI 2011a). Size reduction is sometimes required to process oversized particles prior to burning. Stoker boilers can be used to burn biomass residuals for a broad spectrum of sizes (NCASI 2011a). Woody mill residuals are generally found in sizes suitable for stoker boilers (NCASI 2011a). For this reason, as a typical scenario, no size reduction was considered. The ratio of steam to power produced was set based on industry data for CHP (from AF&PA, NCASI, and AWC). This study analyzed only cases where steam and electricity would be produced via CHP using biomass boilers and not fossil fuel boilers. Therefore, it was assumed that, at the industry level, the total power produced from CHP would be generated from biomass and fossil fuels in forest products facilities in the same ratio as overall fuel usage, and only the fraction from biomass was considered. Power to heat ratio ($P/S_{MP/LP}$) assumed for the CHP1 scenario above was assumed for the typical scenario as a conservative assumption. The actual heat/CHP configuration assumed for this system is depicted in Figure 5.3.

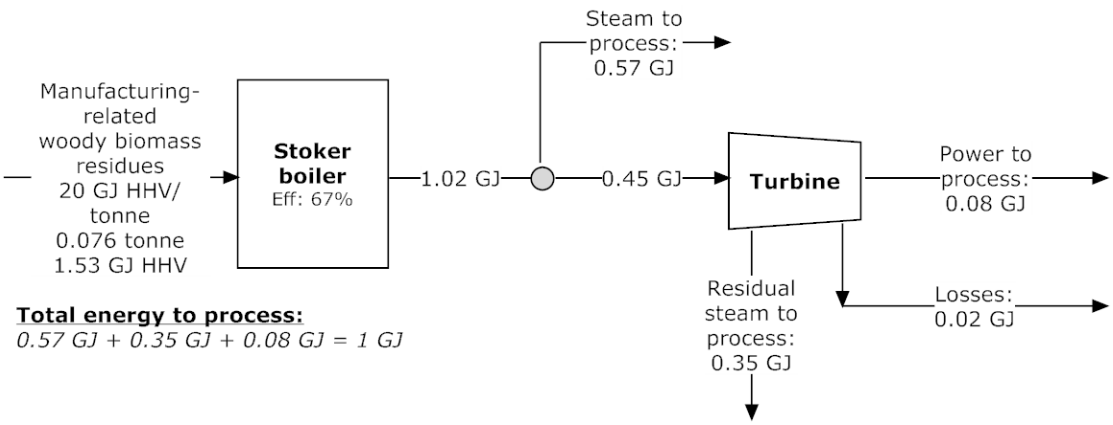


Figure 5.3 Heat/CHP Configuration Considered in the Typical Scenario for Woody Mill Residuals

The typical scenario considered was based on the data presented earlier in Table 5.13 for the entire forest products industry. It can be seen from this table that natural gas and coal are the main fossil fuels used by the US forest products industry. Therefore, in the typical scenario, only those two were considered in the ratio used by the industry. It was hence assumed that 57% of the steam produced from biomass would displace heat from natural gas and 43% would displace heat from coal. All (100%) of the displaced power was assumed to be from the US power consumption grid mix average. As shown previously in

Table 5.14, when woody mill residuals are disposed of, they are either landfilled (94%) or burned (6%). However, as the burning reported by NCASI/AF&PA members most likely involves recovery of energy, this was not considered to be an alternative fate for the typical scenario. Instead, 100% landfilling was considered. It should be noted however, that there are very few data on what would be a reasonable “typical” alternative fate for woody mill residuals as it is not a common practice of the industry to dispose of these.

Table 5.15 Typical Scenario for Woody Mill Residuals

Pre-Processing			Energy Produced at Forest Products Facilities/Utilities				Alternative Fate of Residuals		
			Biomass Residuals		Corresponding Fossil Fuels				
SR0	No size reduction	100%	Heat from stoker boiler and residual steam from CHP	92%	Heat from natural gas	57%	MR1	Landfill	100%
					Heat from coal	43%			
SR1	Size reduction - Mobile chipper	0%	Power from CHP	8%	US average power consumption mix	100%	MR2	Incineration	0%
SR2	Size reduction - Stationary chipper	0%							

5.2.3 WWTP Residuals

The typical scenario considered for WWTP residuals is summarized in Table 5.16. A stoker boiler was also assumed in the typical scenario as a conservative assumption. The ratio of steam to power produced was set based on industry data (from AF&PA, NCASI, and AWC) regarding CHP. This study analyzed only cases where CHP would be produced using biomass boilers and not fossil fuel boilers. Therefore, it was assumed that, at the industry level, the total power produced from CHP would be generated from biomass and fossil fuels in forest products facilities in the same ratio as overall fuel usage and only the fraction from biomass was considered. Power to heat ratio ($P/S_{LP/MP}$) assumed for the CHP1 scenario above was used for the typical scenario as a conservative assumption. The actual heat/CHP configuration assumed for this system is depicted below in Figure 5.4.

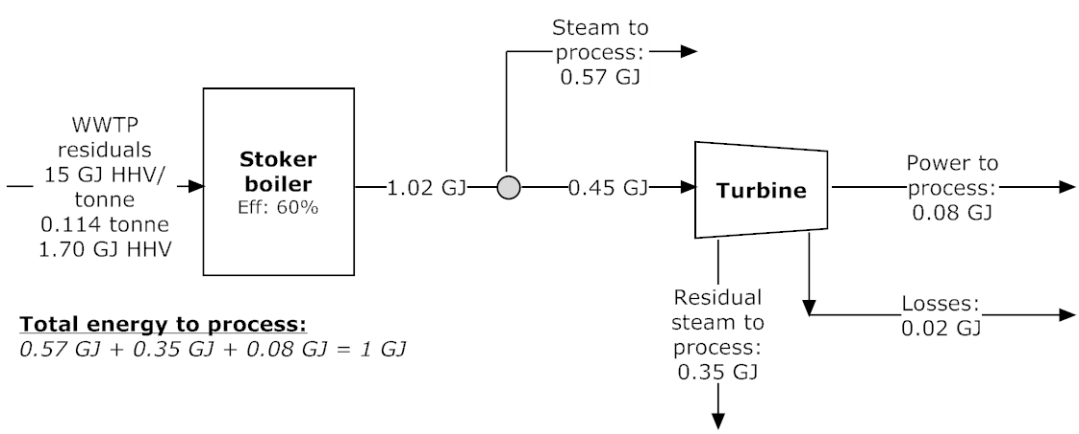


Figure 5.4 Heat/CHP Configuration Considered in the Typical Scenario for WWTP Residuals

The typical scenario considered was based on the data presented in Table 5.13 for the whole industry. It can be seen from this table that natural gas and coal are the main fossil fuels used by the US forest products industry. In the typical scenario, therefore, only these two fuels were considered in the ratio used by the industry. It was hence assumed that 57% of the steam produced from biomass would

displace heat from natural gas and 43% would displace heat from coal. All (100%) of the displaced power was assumed to be from the US power consumption grid mix average. Finally, as shown previously in Table 5.14, WWTP residuals that are not beneficially used are typically landfilled (66%) or burned (34%). As it is not necessary that burning residuals would involve recovery of energy (for instance, in cases where the heating value would be too low), this ratio was assumed in the typical scenario.

Table 5.16 Typical Scenario for WWTP Residuals

Energy Produced at Forest Products Facilities/Utilities				Alternative Fate of Residuals		
Biomass Residuals		Corresponding Fossil Fuels				
Heat from stoker boiler and residual steam from CHP	92%	Heat from natural gas	57%	MR1	Landfill	66%
		Heat from coal	43%			
Power from CHP	8%	US average power consumption mix	100%	MR2	Incineration	34%

5.2.4 Paper Recycling Residuals

The typical scenario considered for paper recycling residuals is summarized in Table 5.17. A stoker boiler was assumed in the typical scenario as a conservative assumption. The ratio of steam to power produced was set based on industry data (from AF&PA, NCASI, and AWC) for CHP. This study analyzed only cases where CHP would be produced using biomass boilers and not fossil fuel boilers. Therefore, it was assumed that, at the industry level, the total power produced from CHP would be generated from biomass and fossil fuels in forest products facilities in the same ratio as overall fuel usage and only the fraction from biomass was considered. Turbine efficiency assumed for the CHP1 scenario above was used for the typical scenario as a conservative assumption. The actual heat/CHP configuration assumed for this system is depicted below in Figure 5.5.

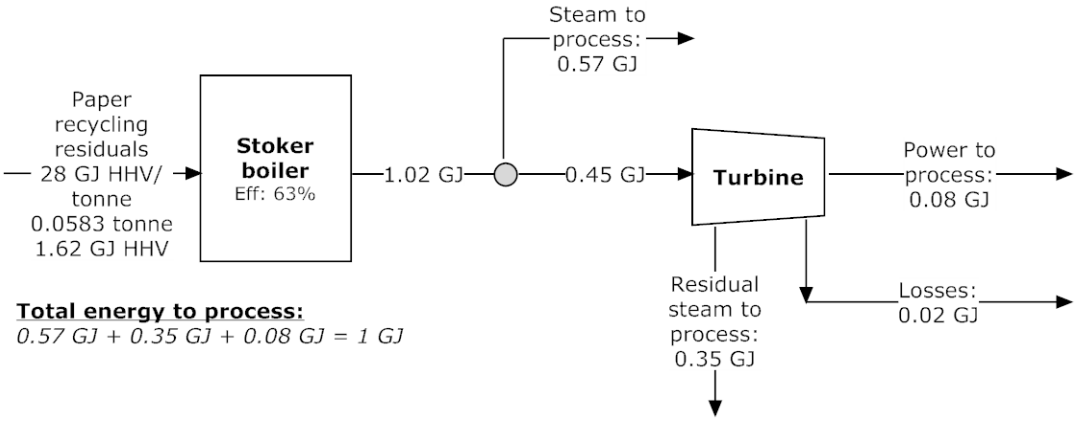


Figure 5.5 Heat/CHP Configuration Considered in the Typical Scenario for Paper Recycling Residuals

The typical scenario considered was based on the data presented above in Table 5.13 for the whole industry. It can be seen from this table that natural gas and coal are the main fossil fuels used by the US forest products industry. In the typical scenario, only those two were considered in the ratio used by the industry. It was hence assumed that 57% of the steam produced from biomass would displace heat from natural gas and 43% would displace heat from coal. All (100%) of the displaced power was assumed to be from the US power consumption mix average. Finally, as shown in Table 5.14, paper

recycling residuals that are not beneficially used are typically landfilled (93.6%) or burned (6.4%). As it is not necessary that burning residuals would involve recovery of energy (for instance if they were disposed of in municipal facilities), this ratio was assumed in the typical scenario.

Table 5.17 Typical Scenario for Paper Recycling Residuals

Energy Produced at Forest Products Facilities/Utilities				Alternative Fate of Residuals		
Biomass Residuals		**Corresponding Fossil Fuels**				
Heat from stoker boiler and residual steam from CHP	92%	Heat from natural gas	57%	MR1	Landfill	93.6%
		Heat from coal	43%			
Power from CHP	8%	US average power consumption mix	100%	MR2	Incineration	6.4%

6.0 RESULTS AND DISCUSSION: CRADLE-TO-FINAL ENERGY

This section discusses the results of the cradle-to-final energy analysis, including fossil fuel substitution.

Note: For the GHGIs indicators, the results at 100 years developed by applying the dynamic carbon footprinting approach are compared with those obtained using the IPCC 100-year GWPs. Because the comparisons reveal that the differences at 100 years are small, for simplicity, the contribution, scenarios, and sensitivity analyses results are presented using only 100-year GWPs.

6.1 Woody Mill Residuals

This section presents the results for the woody mill residuals.

6.1.1 Typical Scenario: Base Case Results

The typical scenario was first analyzed with all parameters at their base case values.

6.1.1.1 Greenhouse Gas Impact: Differential GHGI

When using the dynamic carbon footprinting approach, the biomass energy system produces, after 100 years, a greenhouse gas impact that is **116 kg CO_2E lower**[11] per gigajoule of energy produced compared to the defined non-use system. This reduction is **111 kg CO_2E** when applying IPCC 100-year GWPs.

Figure 6.1 presents the 100-year differential GHGI for the biomass energy system compared to the non-use system as well as the contribution of each system component to the results using IPCC 100-year GWPs. In this figure,

- the GHGI indicator results from the non-biogenic CO_2 releases [which include fossil fuel-related CO_2, CH_4 and N_2O as well as biomass-related CH_4 and N_2O and other GHGs (fossil

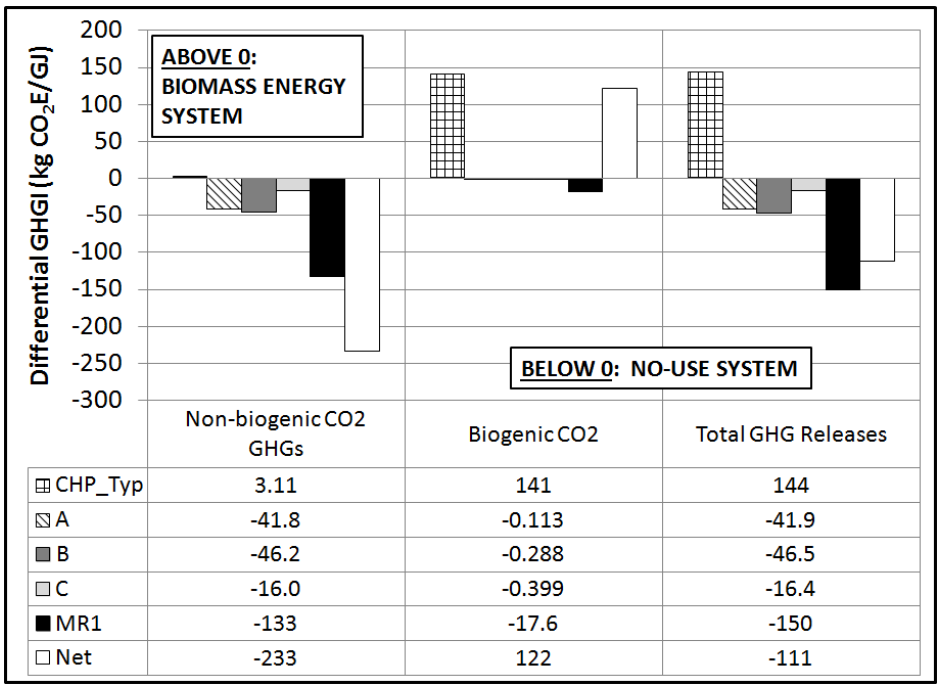
[11] Results in this report are always presented as differences (i.e., biomass energy system minus non-use system). The "Relative GHGI" indicator does not include biogenic CO_2. The "Differential GHGI" indicator includes emissions and removals of biogenic CO_2.

fuel- and biomass-related)], the GHGI indicator results from biogenic CO_2 releases and the total GHG releases[12] are depicted separately;

- the results from the biomass energy system are shown as positive numbers;
- the results from the non-use system are shown as negative numbers (because they are avoided);
- the "net" bars represent the sum of the different system components; and
- a net positive indicates that the biomass energy system impacts are greater than the non-use system and a net negative indicates that the biomass energy system impacts are lower than the non-use system (in other words, the more net negative the indicator result, the more beneficial is the biomass energy system).

As shown in this figure, a significant fraction of the difference between the biomass energy and non-use systems is attributable to non-biogenic CO_2 GHGs, i.e., GHGs other than biogenic CO_2. More specifically, the methane emissions from landfills (most of MR1) avoided when burning residuals to produce energy is responsible for a large portion of the benefits from the biomass energy system. Reducing energy production from fossil fuels [i.e., heat from coal (A), heat from natural gas (B), and US average power grid (C)] also contributes to the difference, but to a lesser extent. The greenhouse gas impact caused by the emissions of biogenic CO_2 is different in the two systems (i.e., the net is not zero) for two reasons. First, much of the biogenic carbon is released as methane in the non-use system (included within non-biogenic CO_2 GHGs) and mostly as carbon dioxide in the biomass energy system. Second, some of the carbon is stored in landfills in the non-use system.

[12] In this report, "Total GHG releases" is used as a short form for the sum of non-biogenic CO_2 GHGs and biogenic CO_2 GHGs.



	Non-biogenic CO2 GHGs	Biogenic CO2	Total GHG Releases
CHP_Typ	3.11	141	144
A	-41.8	-0.113	-41.9
B	-46.2	-0.288	-46.5
C	-16.0	-0.399	-16.4
MR1	-133	-17.6	-150
Net	-233	122	-111

Figure 6.1 Contribution Analysis for the Differential GHGI (at 100 Years) for Woody Mill Residuals - Typical Scenario
[In the figure, the different components of the biomass energy system are depicted as follows: CHP system as described in Figure 5.3 (CHP_Typ). The components of the non-use system are depicted as follows: heat from coal (A), heat from natural gas (B), US average power grid (C), residuals in landfills (MR1). Results reflect the use of 100-year GWPs.]

6.1.1.2 Greenhouse Gas Impact: Relative Non-BioCO$_2$ GHGI

The result for the "Relative Non-BioCO$_2$ GHGs" indicator is -98.7%[13] for both the dynamic carbon footprinting approach and IPCC 100-year GWPs, meaning that the biomass product system generates almost no GHGs when ignoring biogenic CO$_2$.

6.1.1.3 Greenhouse Gases: Timing of Impacts

When residuals are burned for energy, the biogenic carbon is immediately released to the atmosphere. In contrast, residuals placed into landfills degrade relatively slowly, releasing the carbon (both CO$_2$ and CH$_4$) over time.

Figure 6.2 shows the annual radiative forcing attributable to greenhouse gas emissions from producing 1 GJ of energy in the biomass energy and non-use systems. These values have been calculated based on the dynamic radiative forcing approach, described in Section 4.1.6.1 of this report.[14] An explanation of the factors contributing to the radiative forcing is shown in Table 6.1.

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[13] Non-biogenic CO$_2$ GHGs only. Calculated as follows: (CHP_Typ - A - B - C - MR1)/(A+B+C+MR1).
[14] In Figure 6.2 and Figure 6.3, radiative forcing due to the GHG emissions is plotted in units of Wm^{-2} instead of units of CO$_2$E because, when using dynamic radiative forcing calculations, the relationship between annual and cumulative results is much easier to illustrate visually using units of Wm^{-2}. For other residuals addressed later in this report, only the differential cumulative results are shown.

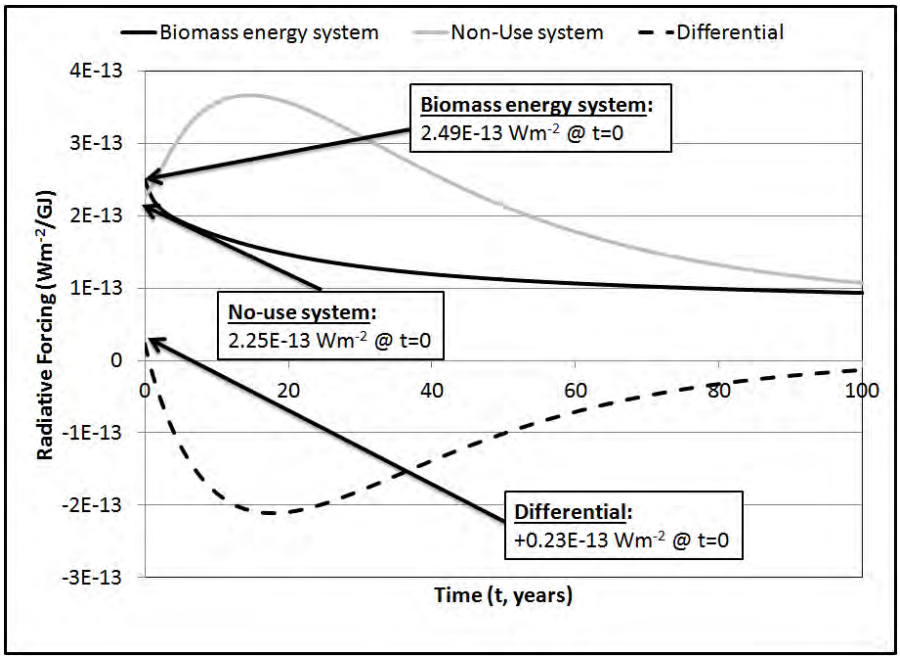


Figure 6.2 Annual GHG Impact for the Biomass Energy and Non-Use Systems: Woody Mill Residuals - Typical Scenario

Table 6.1 Explanation of Annual Emissions, Woody Mill Residuals, Dynamic Carbon Footprinting

Time (years)	Biomass Energy System	Non-Use System	Differential (i.e., biomass energy system minus non-use system)
t = 0	The woody residuals are burned, releasing GHGs, which result in radiative forcing at the time of combustion of 2.49E-13 Wm^{-2}.	The fossil fuels are burned, releasing GHGs, which result in radiative forcing at the time of combustion of 2.25E-13 Wm^{-2}. Biomass residuals are placed in landfills. There are no releases from the landfills at time 0.	The differential radiative forcing is positive (0.23E-13 Wm^{-2}) because at time 0 there is more forcing from the emissions released by the biomass energy system than from the non-use system.
$0 < t < \infty$	There are no additional emissions from the biomass energy system. The radiative forcing caused each year by GHGs released in year 0 slowly declines as these GHGs degrade (e.g., CH_4) or are removed from the atmosphere (e.g., CO_2).	Although there are no additional emissions from combustion, residuals start degrading in landfills releasing GHGs. In each year, there is radiative forcing from landfill GHGs released in the current year plus forcing due to GHGs released in previous years that are still in the atmosphere. During the period that landfill emissions are high, annual radiative forcing increases because the forcing from new emissions increases faster than previously emitted GHGs are removed from the atmosphere. Over time, however, the GHG releases from landfills decline and approach zero and the GHGs in the atmosphere degrade (e.g., CH_4) or are removed from the atmosphere (e.g., CO_2). As a result, the annual radiative forcing approaches zero.	The differential radiative forcing goes through a minimum and then increases, approaching zero, because the emissions from both systems eventually degrade or are removed from the atmosphere.

While Figure 6.2 shows the annual radiative forcing, Figure 6.3 shows the same data but plotted as cumulative radiative forcing, in units of Wm^{-2}, associated with emissions of GHGs in the biomass energy and non-use systems for woody mill residuals as a function of time. An explanation of the sources of this radiative forcing is provided in Table 6.2. Figure 6.3 shows that the differential radiative forcing is initially positive because the forcing due to the emissions from the biomass energy system is higher than that for the non-use system. The differential cumulative greenhouse gas impact quickly becomes negative, however, as landfill emissions increase in the non-use scenario. The figure shows that, under the typical scenario assumptions (e.g., alternative fate is 100% landfill), it takes 1.2 years before the cumulative radiative forcing due to GHG releases in the biomass energy system is less than the radiative forcing due to releases in the non-use system.

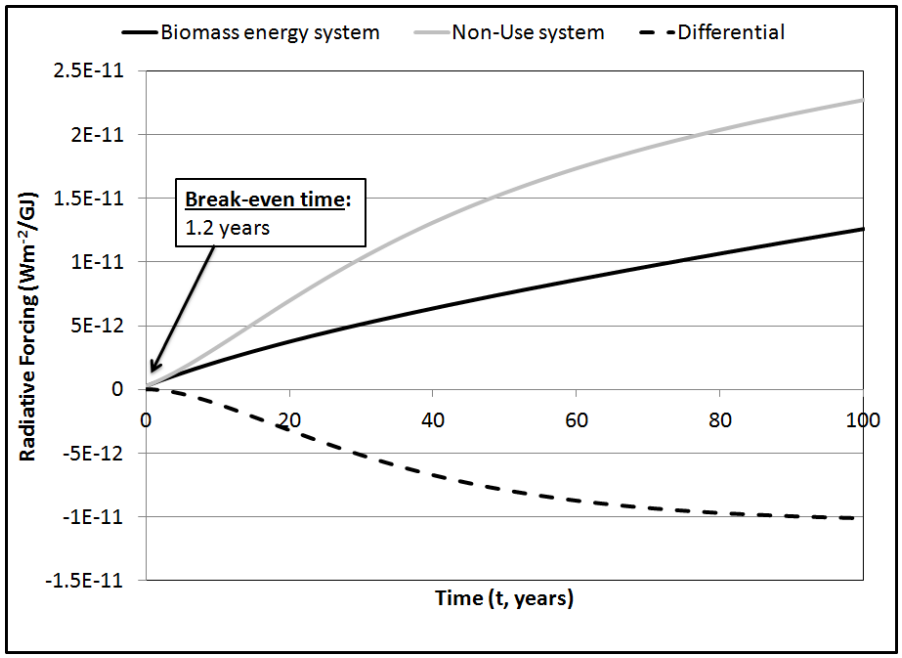


Figure 6.3 Cumulative GHG Impact for the Biomass Energy and Non-use Systems: Woody Mill Residuals - Typical Scenario

Table 6.2 Explanation of Cumulative Emissions, Woody Mill Residuals

Time (years)	Biomass Energy System	Non-Use System	Differential (i.e., biomass energy system minus non-use system)
t = 0	The woody residuals are burned, releasing GHGs, which result in radiative forcing at the time of combustion of 2.49E-13 Wm^{-2}.	The fossil fuels are burned, releasing GHGs, which result in radiative forcing at the time of combustion of 2.25E-13 Wm^{-2}. Biomass residuals are placed in landfills. There are no releases from the landfills at time 0.	The differential radiative forcing is positive (0.23E-13 Wm^{-2}) because at time 0, there is more forcing from the emissions released by the biomass energy system than from the non-use system.
$0 < t < 1.2$	There are no new emissions from the biomass energy system. The initially released GHGs remain in the atmosphere for a period of time, so each year, the cumulative radiative forcing increases.	Biomass residuals placed in landfills start to degrade, releasing GHGs. The cumulative GHG emissions, and their cumulative radiative forcing, increase rapidly.	The difference in cumulative radiative forcing decreases as the forcing associated with the non-use system increases more rapidly that that associated with the biomass energy system.
t = 1.2	Cumulative radiative forcing reaches 5.2E-13 Wm^{-2}.	Cumulative radiative forcing reaches 5.2E-13 Wm^{-2}.	The cumulative differential radiative forcing is 0 (break-even time).
$1.2 < t < \infty$	There are no new emissions from the biomass energy system but cumulative forcing continues to increase until all GHGs are removed from the atmosphere.	The emissions from the landfill continue for a considerable period. Cumulative radiative forcing continues to increase until all GHGs released from fossil fuel combustion and from disposal operations are removed from the atmosphere.	At 100 years, the difference in cumulative radiative forcing is -1.01E-11 Wm^{-2}. The difference changes only slowly after this point.

Figure 6.4 compares the timing of differential cumulative GHGI results obtained using the dynamic carbon footprinting approach with those obtained using IPCC 100-year GWPs, both in units of kg CO_2E. In both approaches, the difference in emissions between the two systems is computed for each year. The dynamic approach calculates the environmental impact in terms of the radiative forcing that is associated with GHGs remaining in the atmosphere attributable to all current and past emissions. Each year's forcing is added to past years to obtain cumulative radiative forcing. The IPCC approach calculates impact by assigning each year's emissions an impact equal to the cumulative radiative forcing occurring over 100 years, using 100-year GWPs. Both approaches consider the timing of emissions but only the dynamic approach accurately characterizes the timing of the warming associated with those emissions.

The first observation that can be made from Figure 6.4 is that the differential cumulative GHGI results decline faster when using the dynamic carbon footprinting approach than with IPCC GWPs. In other words, more short-term benefits from using biomass residuals for energy production are observed when applying dynamic carbon footprinting. The break-even time is 1.2 years using dynamic carbon footprinting and 7.5 years when using IPCC global warming potentials. The difference is due to the methane released from the landfills under the non-use scenario. Methane is a potent greenhouse gas but it has a short lifetime in the atmosphere so its greenhouse gas impact is

concentrated in the years immediately following its release, as opposed to carbon dioxide, which is much more persistent. This short-term warming effect of methane is captured by the dynamic approach but not by the use of 100-year GWPs.

Because both approaches are affected by the timing of emissions, and because methane emissions are higher in the earlier years of the simulation, both approaches show the benefits (i.e., negative differential impacts) increasing more rapidly in the early years. Because the 100-year GWPs approach is affected only by emissions timing, the curve flattens out as methane generation slows. In the case of the dynamic approach, the benefits accrue more rapidly in the early years but diminish later in the simulation as methane in the atmosphere decomposes to CO_2, exerting a lower radiative forcing effect and reducing the differences between the biomass energy and non-use systems. As methane generation ceases and all of the methane in the atmosphere decomposes to CO_2, the results for the two approaches converge.

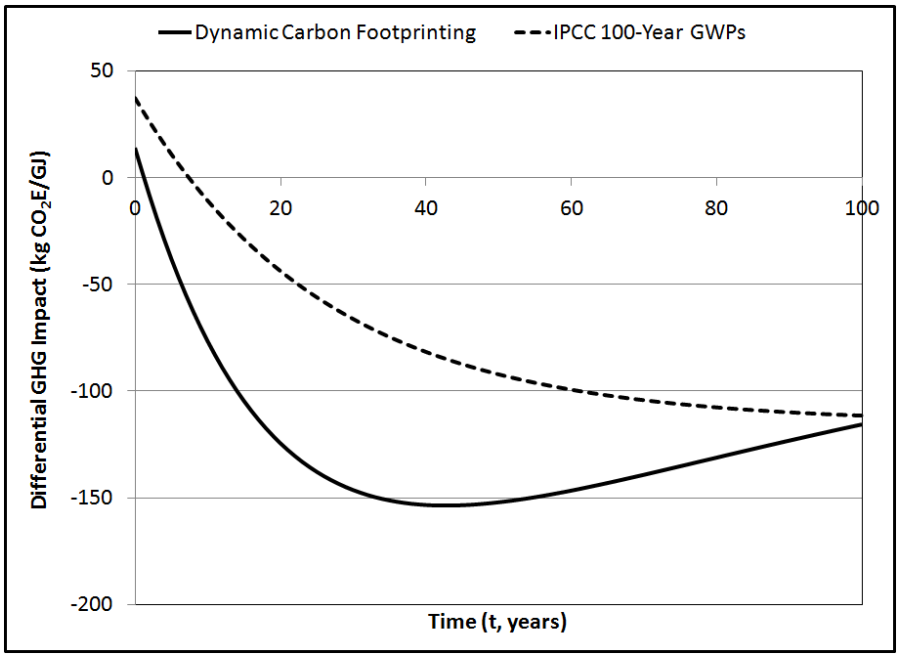


Figure 6.4 Emissions Timing: Comparing Results Based on Dynamic Carbon Footprinting and IPCC 100-Year GWPs

6.1.1.4 ***Consumption of Fossil Fuels***

Figure 6.5 shows the relative consumption of fossil fuels ("Relative FF CON," biomass energy system compared to non-use system). It can be seen from the figure that fossil fuel use in the biomass energy system is 100% lower; virtually no fossil fuels are used in the biomass energy system. It can also be seen from the figure that the main contributor to the difference between the systems is the heat from natural gas in the non-use system.

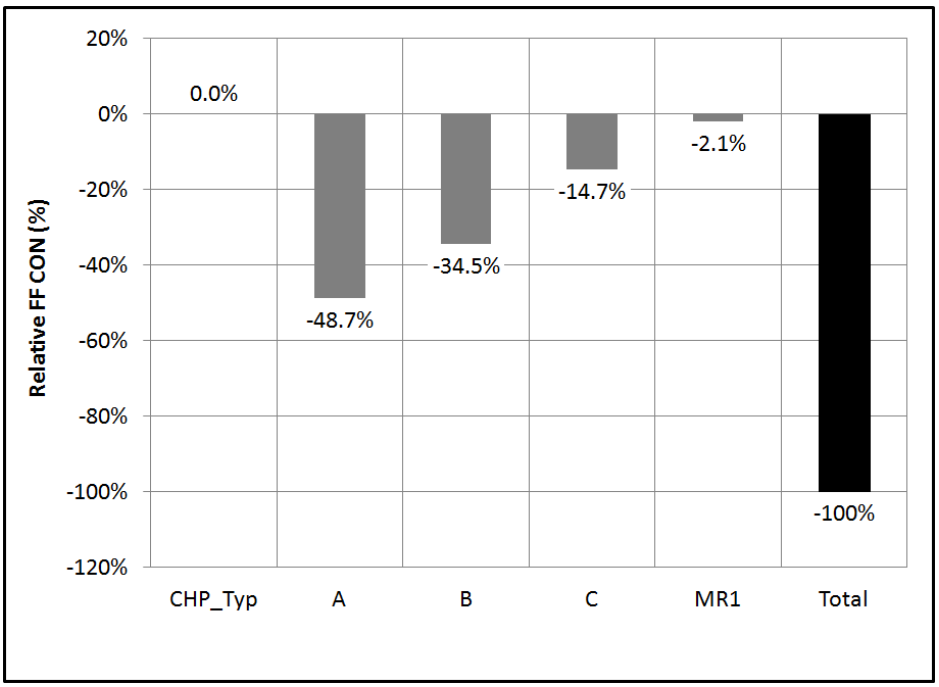


Figure 6.5 Relative Consumption of Fossil Fuels for Woody Mill Residuals - Typical Scenario [In the figure, the different components of the biomass energy system are depicted as follows: CHP system as described in Figure 5.3 (CHP_Typ). The components of the non-use system are depicted as follows: heat from coal (A), heat from natural gas (B), US average power grid (C), residual in landfills (MR1).]

6.1.2 Typical Scenario: Perturbation and Sensitivity Analyses

6.1.2.1 Perturbation Analyses

As mentioned in Section 4.1.3, sensitivity ratios represent the percent change in an output variable caused by a 1% change in one given input variable. For simplicity and given that the GHGI results do not vary significantly over a 100-year period depending on the approach used, perturbation analyses were performed using IPCC 100-year GWPs. Figure 6.6 shows the sensitivity ratios for the four indicators analyzed in this study, for woody mill residuals. The following input variables were tested in sensitivity analyses: transportation distance of the residuals (Distance), their water content (WC_R), their heating value (HHV), and the fraction of their carbon content that is non-degradable carbon (F_{CCND}).

The results depicted in Figure 6.6 should be interpreted as follows. A sensitivity ratio of +1.0 means that value of the output variable increases by 1% when the input variable value is increased by 1%. The greater the absolute value of the sensitivity ratio, the more intrinsically sensitive a parameter was.

It can be seen from Figure 6.6 that transportation distance of residuals to the boiler had very little effect on the "Differential GHGI" indicator results when compared to the other studied parameters. The fraction of non-degradable carbon (F_{CCND}) had the most significant effect on the results, with sensitivity ratios of 4.5. The positive ratio means that when increasing the value of the parameter, the indicator result is also increased, indicating a declining performance of the biomass energy system compared to the non-use system. Increasing the water content of the residuals, and thus reducing the boiler efficiency, produced a negative sensitivity ratio, i.e., a positive effect on the results. This is because on a per gigajoule basis, more residuals are required to produce the energy and thus more

landfilling, and associated methane emissions from landfills, are avoided. The opposite can be seen when increasing the higher heating value.

The time for the biomass energy system to have lower cumulative emissions than the non-use system ("break-even time" in Figure 6.6) was significantly affected, relatively speaking, by the various parameters analyzed, except for the transportation distance of residuals.

Finally, overall, the relative GHGI and relative fossil fuel consumption (FF CON) indicator results were not significantly affected by the parameters analyzed.

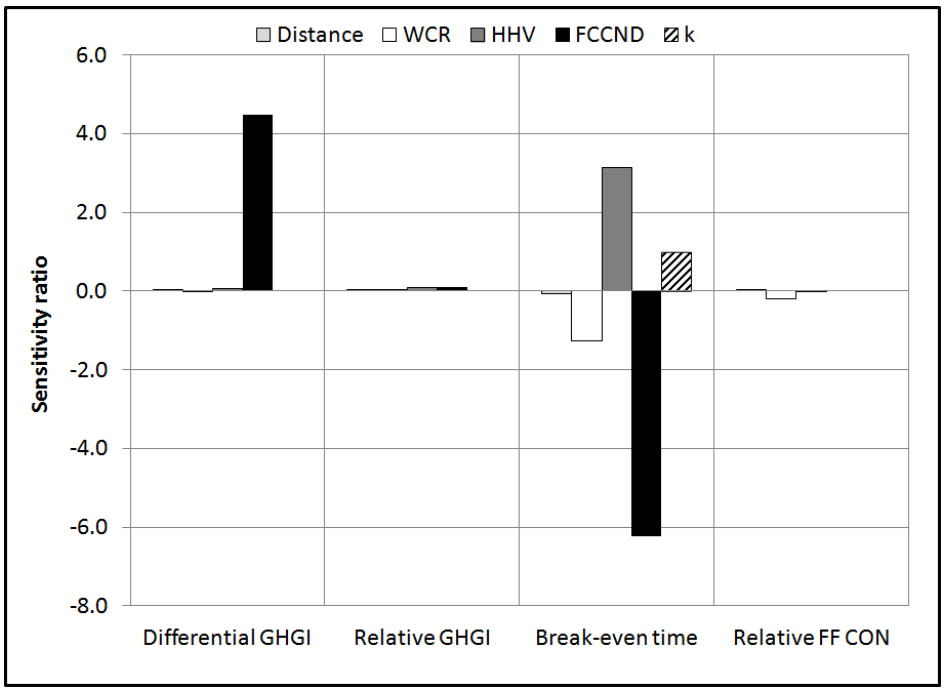


Figure 6.6 Sensitivity Ratios for Woody Mill Residuals

*6.1.2.2 **Sensitivity Analyses***

Table 6.3 shows the results of sensitivity analyses considering the actual possible ranges of variation for each parameter. It is shown that the range of the fraction of carbon in woody mill residuals that is non-degradable under anaerobic conditions (F_{CCND}) had the most effect on the results. With the higher fraction considered, smaller benefits are observed from the combustion of woody mill residuals, whereas with the lower value of F_{CCND}, benefits are far higher and break-even times far shorter than those calculated in the typical scenario.

Table 6.3 Sensitivity Analyses on Indicator Results for the Typical Scenario, Woody Mill Residuals

Para-meter	Differential GHGI* (kg CO_2E/GJ)			Relative Non-BioCO_2 GHGI* (%)			Break-Even Time* (years)			Relative FF CON (%)		
	Typ	Min	Max	Typ	Min	Max	Typ	Min	Max	Typ	Min	Max
WC_R	-111†	-110	-112	-98.7‡	-98.6	-98.8	7.5§	3.2	9.6	-100	-100	-100
HHV		-110	-115		-98.4	-98.8		1.1	17.6		-100	-100
F_{CCND}		-27.2	-286		-97.5	-99.2		3.2	22.0		-100	-100
Transp. of residuals		-109	-111		-97.8	-98.7		7.5	7.9		-98.2	-100
k		-94.1	-114		-98.6	-98.7		1.3	3.5		-100	-100

*Computed using IPCC 100-Year GWPs. †-116 kg CO_2E/GJ using dynamic modeling of cumulative radiative forcing. ‡ -98.7% using dynamic modeling of cumulative radiative forcing. §1.2 years using dynamic modeling of cumulative radiative forcing.

6.1.3 System Configuration Scenarios

In Section 5.0, various system configuration scenarios were presented. For instance, it was noted that the alternative fate of woody mill residuals was difficult to determine. System configuration scenarios were used to analyze those system configuration assumptions that were uncertain.

All possible scenario combinations presented in Section 5.1 were analyzed (132 combinations). The calculations were performed using IPCC 100-year GWPs. Results are presented in Table 6.4 for cases where parameters would be at their base case value. GHG releases and fossil fuel consumption are significantly lower for all scenarios. Maximum differences were obtained in scenarios in which

- there is no size reduction;
- combined heat and power with maximum power production is produced;
- coal is being displaced (for both heat and power production);
- there is no transportation; and
- alternative fate is landfilling.

Minimum differences were obtained in scenarios in which

- there is size reduction;
- only heat is produced;
- natural gas is being displaced (for both heat and power production);
- there is transportation; and
- alternative fate is incineration.

Results in Table 6.4 also show that the time for the biomass energy system to have lower cumulative emissions than the non-use system varies between 0 and 9.7 years, the lowest being observed when incineration is the alternative fate.

Table 6.4 Indicator Results for Various System Configuration Scenarios, Woody Mill Residuals

Indicator	Unit	Typical	Min	Max
Differential GHGI*	kg CO_2E/GJ	-111†	-78.4	-312
Relative non-BioCO_2 GHGI*	%	-98.7‡	-94.9	-99.3
Break-even time*	years	7.5§	0	9.7
Relative FF CON	%	-100%	-98.5	-100

*Computed using IPCC 100-Year GWPs. † -116kgCO_2E/GJ using dynamic modeling of cumulative radiative forcing. ‡ -98.7% using dynamic modeling of cumulative radiative forcing. §1.2 years using dynamic modeling of cumulative radiative forcing.

6.2 WWTP Residuals

This section presents results for the WWTP residuals.

6.2.1 Typical Scenario: Base Case Results

The typical scenario was first analyzed with all parameters at their base case values.

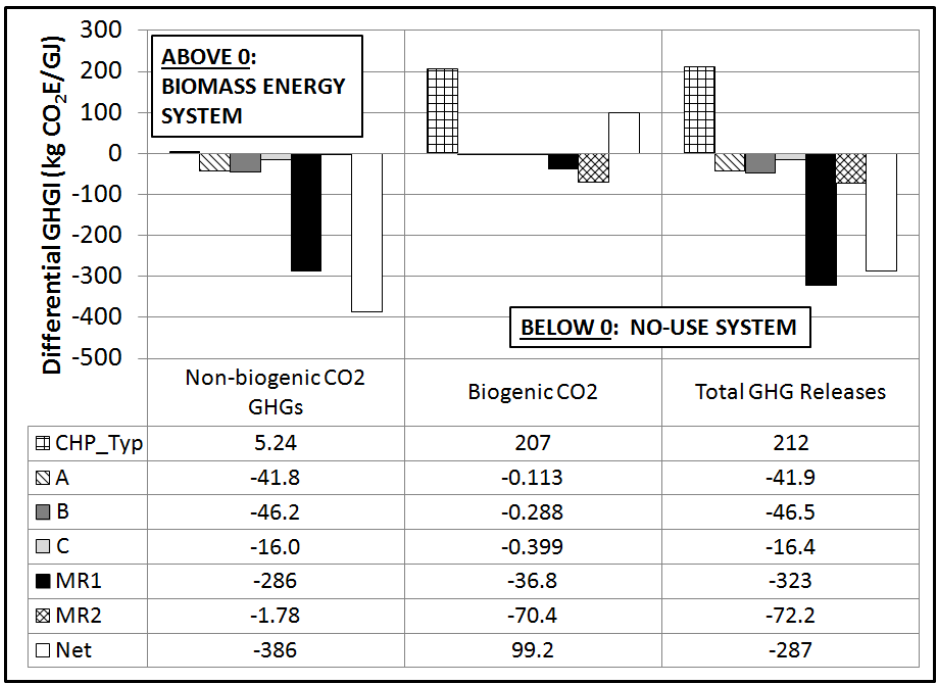
6.2.1.1 Greenhouse Gases: Differential GHGs

When using the dynamic carbon footprinting approach, the biomass energy system produces, after 100 years, a greenhouse gas impact that is **295 kg CO_2E lower**[15] per gigajoule of energy produced compared to the defined non-use system. This reduction is **287 kg CO_2E** when applying IPCC 100-year GWPs.

Figure 6.7 presents the 100-year differential GHGI for the biomass energy system compared to the non-use system as well as the contribution of each system component to the results using IPCC 100-year GWPs. In this figure, emissions from the non-use system are shown as a negative number because to obtain the Differential GHGs indicator overall result, the emissions of the non-use scenario were subtracted from those of the biomass energy system.

The figure shows that non-biogenic CO_2 GHGI is mostly lower because when burning residuals to produce energy, there are no methane emissions from landfills. The fact that there is less heat generated from fossil fuels also contributes to the lower impact, but to a lesser extent. Emissions of biogenic CO_2 are different in the two systems for two reasons. First, much of the biogenic carbon is released as methane in the non-use system (included within non-biogenic CO_2 GHGs) and mostly as CO_2 in the biomass energy system. Second, some of the carbon is stored in landfills in the non-use system.

[15] Results in this report are always presented as differences (i.e., biomass energy system minus non-use system). The "Relative GHGI" indicator does not include biogenic CO_2. The "Differential GHGI" indicator includes emissions and removals of biogenic CO_2.



	Non-biogenic CO2 GHGs	Biogenic CO2	Total GHG Releases
CHP_Typ	5.24	207	212
A	-41.8	-0.113	-41.9
B	-46.2	-0.288	-46.5
C	-16.0	-0.399	-16.4
MR1	-286	-36.8	-323
MR2	-1.78	-70.4	-72.2
Net	-386	99.2	-287

Figure 6.7 Contribution Analysis for the Differential GHGI (at 100 Years) for WWTP Residuals - Typical Scenario
[In the figure, the different components of the biomass energy system are depicted as follows: CHP system as described in Figure 5.4 (CHP_Typ). The components of the non-use system are depicted as follows: heat from coal (A), heat from natural gas (B), US average power grid (C), residual in landfills (MR1), incineration of residuals (MR2). Results reflect the use of 100-year GWPs.]

6.2.1.2 Greenhouse Gases: Relative Non-BioCO$_2$ GHGs

The result for the "Relative Non-BioCO$_2$ GHGs" indicator is -98.7%[16] (-99.1% using IPCC GWPs), meaning that the biomass energy system generates almost no GHGs when ignoring biogenic CO$_2$ and hence, produces a significant reduction when compared to the non-use system.

6.2.1.3 Greenhouse Gases: Timing of Impacts

When WWTP residuals are burned for energy, the related biogenic carbon is released to the atmosphere immediately. In contrast, WWTP residuals placed into landfills degrade slowly, releasing the related biogenic carbon (both CO$_2$ and CH$_4$) over time. Figure 6.8 presents the results of the "Differential GHGI" indicator over time using U.S. EPA's decay rates for materials placed in municipal landfills, for the typical scenario. These results were developed using the dynamic carbon footprinting approach described in Section 4.1.6.1 of this report and are expressed in units of radiative forcing (Wm^{-2}). The net difference is initially negative (i.e., the impact from the biomass energy system is lower than that from the no-use system from time equals zero, meaning that the break-even time is zero) and then declines over time as the material degrades in landfills. When using IPCC 100-year GWPS, the difference in impact is initially positive and the break-even time is observed at 1.8 years.

[16] Non-biogenic CO$_2$ GHGs only. Calculated as follows: (CHP_Typ - A - B - C - MR1- MR2)/ (A+B+C+MR1+MR2).

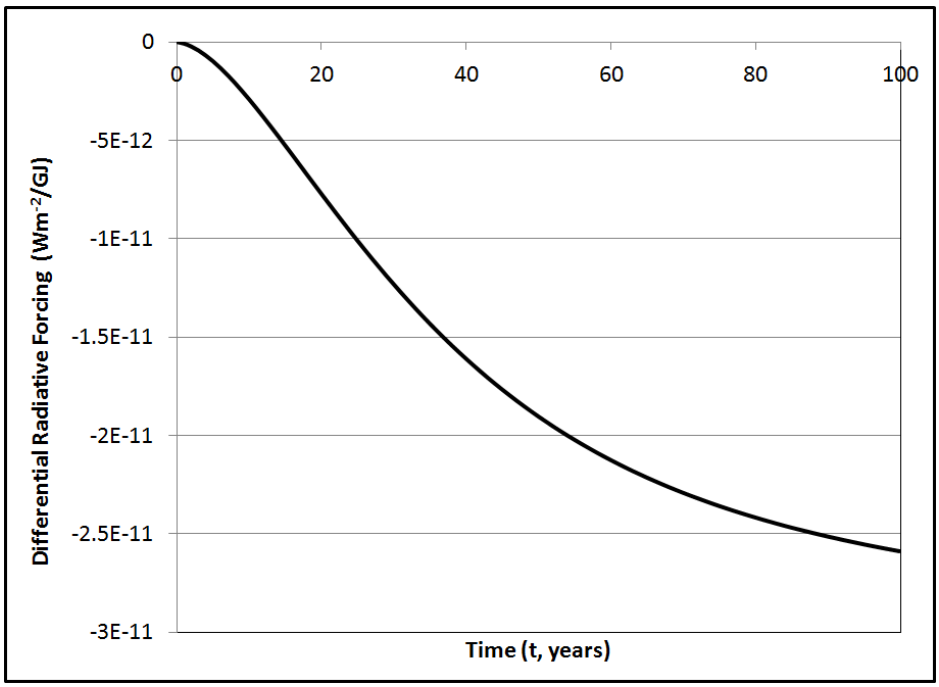


Figure 6.8 Cumulative Differential GHGI Indicator Results as a Function of Time for WWTP Residuals - Typical Scenario

6.2.1.4 ***Consumption of Fossil Fuels***

Figure 6.9 shows the results for the relative consumption of fossil fuels indicator ("Relative FF CON," biomass energy system compared to non-use system).

It can be seen from Figure 6.9 that the biomass energy system used 99.3% less fossil fuel when compared to the non-use system defined in this study. This is due to the fact that virtually no fossil fuels are used in the biomass energy system. It can also be seen from the figure that the main contributor to the lower emissions is avoided heat from natural gas.

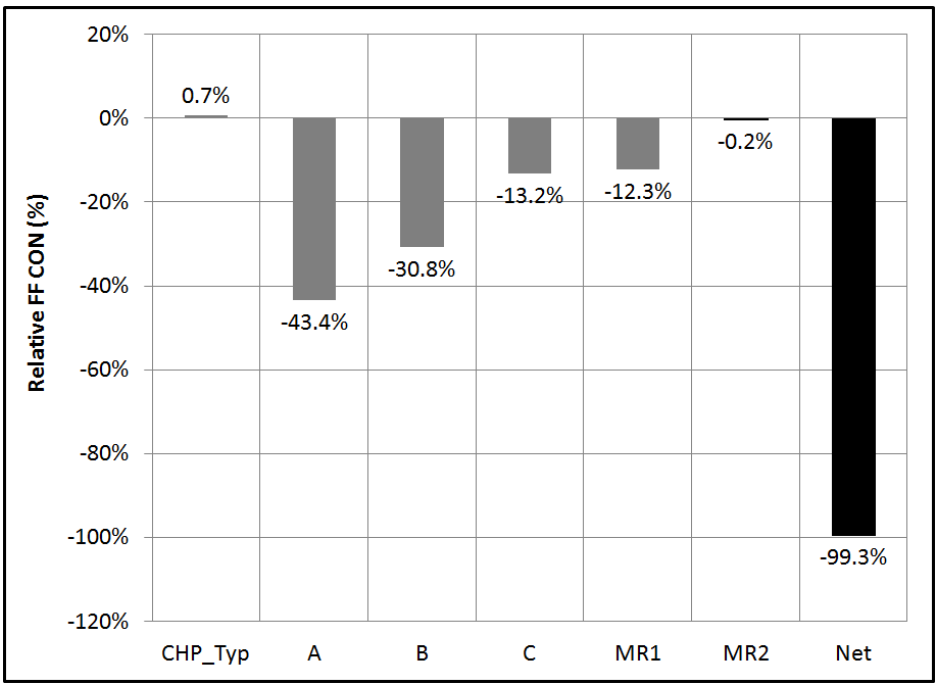


Figure 6.9 Relative FF CON Indicator Results for WWTP Residuals - Typical Scenario
[In the figure, the different components of the biomass energy system are depicted as follows: CHP system as described in Figure 5.4 (CHP_Typ). The components of the non-use system are depicted as follows: heat from coal (A), heat from natural gas (B), US average power grid (C), residual in landfills (MR1), incineration of residuals (MR2).]

6.2.2 Typical Scenario: Perturbation and Sensitivity Analyses

6.2.2.1 Perturbation Analyses

Various parameters were analyzed in perturbation analyses. For each of these parameters, a sensitivity ratio was calculated (see Section 4.1.3). For simplicity and given that the GHGI results do not vary significantly over a 100-year period depending on the approach used, perturbation analyses were performed using IPCC 100-year GWPs.

Sensitivity ratios for the parameters tested in this study are presented in Figure 6.10. It can be seen from that figure that the carbon content of the residuals has the most significant effect on the GHGI results, with a sensitivity ratio of -1.3. The negative ratio means that when increasing the value of the parameter, the score is decreased, indicating an improving performance of the biomass energy system compared to the non-use system. The fraction of non-degradable carbon (F_{CCND}) also has a significant effect on the Differential GHGs results, with a sensitivity ratio of 1.1. The positive ratio means that when increasing the value of the parameter, the score is also increased, indicating a declining performance of the biomass energy system compared to the non-use system. Increasing the water content of the residuals, and thus reducing the boiler efficiency, produced a negative sensitivity ratio, i.e., a positive effect on the results. This is because on a per gigajoule basis, more residuals are required to produce the energy; thus, more landfilling and associated methane emissions from landfills are avoided. The opposite can be seen when increasing the higher heating value. Overall, Relative GHGs and fossil fuel consumption results were not significantly affected by the parameters analyzed. Break-even time was shown, relatively speaking, to be highly sensitive to all parameters tested, with the exception of the ash content.

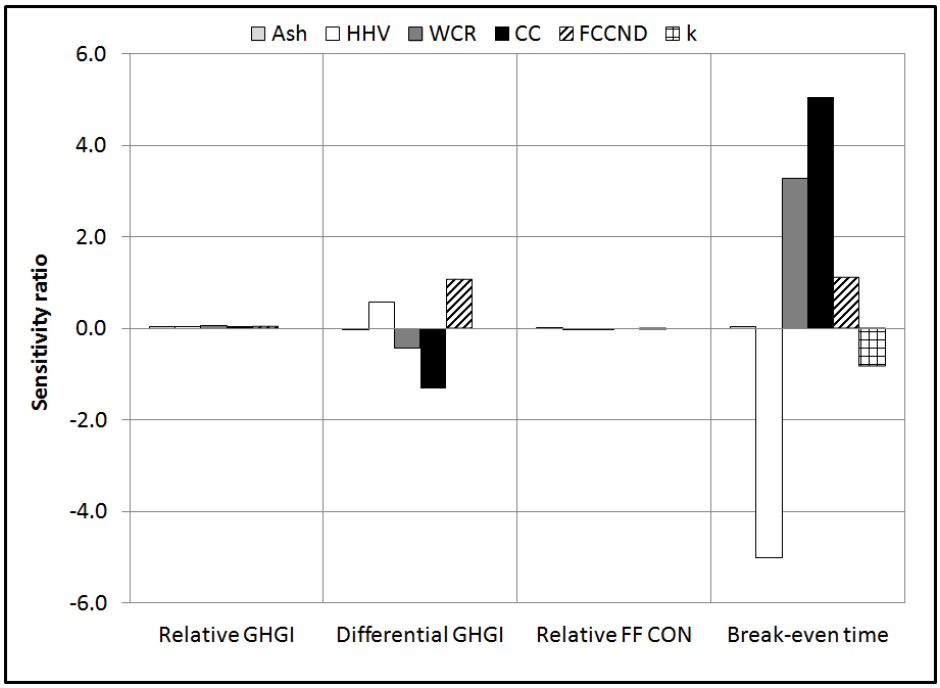


Figure 6.10 Sensitivity Ratios for WWTP Residuals

6.2.2.2 Sensitivity Analyses

Above, perturbation analyses were applied to determine which parameters were intrinsically the most sensitive to the results without considering the actual ranges of possible values for these parameters. In Table 6.8, the results of sensitivity analyses considering the actual possible ranges of variation for each parameter are presented. It is shown that the range of possible heating values and carbon content for WWTP residuals had the most effect on the results. Also, even in the worst conditions, the GHG benefits of the biomass energy system compared to the non-use system are still considerable.

Table 6.5 Sensitivity Analyses on Indicator Results for the Typical Scenario, WWTP Residuals

Para-meter	Differential GHGI* (kg CO_2E/GJ)			Relative Non-BioCO_2 GHGI* (%)			Break-Even Time* (years)			Relative FF CON (%)		
	Typ	Min	Max	Typ	Min	Max	Typ	Min	Max	Typ	Min	Max
WC_R	-287†	-271	-310	-99.1 ‡	-98.6	-98.7	1.8§	1.0	3.0	-99.3	-99.2	-99.4
HHV		-242	-378		-98.5	-98.8		0	5.6		-99.0	-99.5
Ash		-287	-288		-98.5	-98.8		1.9	3.0		-98.8	-99.8
CC		-178	-309		-97.7	-98.8		0	3.0		-99.3	-99.3
F_{CCND}		-226	-349		-98.4	-98.8		1.6	2.4		-99.3	-99.3
k		-287	-287		-98.7	-98.7		1.3	3.5		-99.3	-99.3

*Computed using 100-year GWPs.†-295 kg CO_2E/GJ using dynamic modeling of cumulative radiative forcing. ‡-98.7% using dynamic modeling of cumulative radiative forcing. §0.0 years using dynamic modeling of cumulative radiative forcing.

6.2.3 System Configuration Scenarios

In Section 5.0, various system configuration scenarios were presented. All relevant scenario combinations were analyzed (40 combinations). Results are presented in Table 6.6 for scenarios where parameters would be at their base case values. Results obtained for the typical scenarios are also reproduced in this table for comparison purposes. GHG releases and fossil fuel consumption are significantly lower for all scenarios. Maximum differences were obtained in scenarios in which

- combined heat and power with maximum power production is produced;
- coal is being displaced (for both heat and power production); and
- alternative fate is landfilling.

Minimum differences were obtained in scenarios in which

- only heat is produced;
- natural gas is being displaced (for both heat and power production); and
- alternative fate is incineration.

Table 6.6 Indicator Results for Various System Configuration Scenarios - WWTP Residuals

Indicator	Unit	Typical	Min	Max
Differential GHGI*	kg CO_2E/GJ	-287†	-79.5	-589
Relative Non-BioCO_2 GHGs *	%	-99.1‡	-93.9	-99.3
Break-even time*	years	1.8§	0	6.4
Relative FF CON	%	-99.3	-99.1	-99.7

*Computed using 100-year GWPs.†-295 kg CO_2E/GJ using dynamic modeling of cumulative radiative forcing. ‡-98.7% using dynamic modeling of cumulative radiative forcing. §0.0 years using dynamic modeling of cumulative radiative forcing

6.3 Paper Recycling Residuals

6.3.1 Typical Scenario: Base Case Results

The typical scenario was first analyzed with all parameters at their base case values.

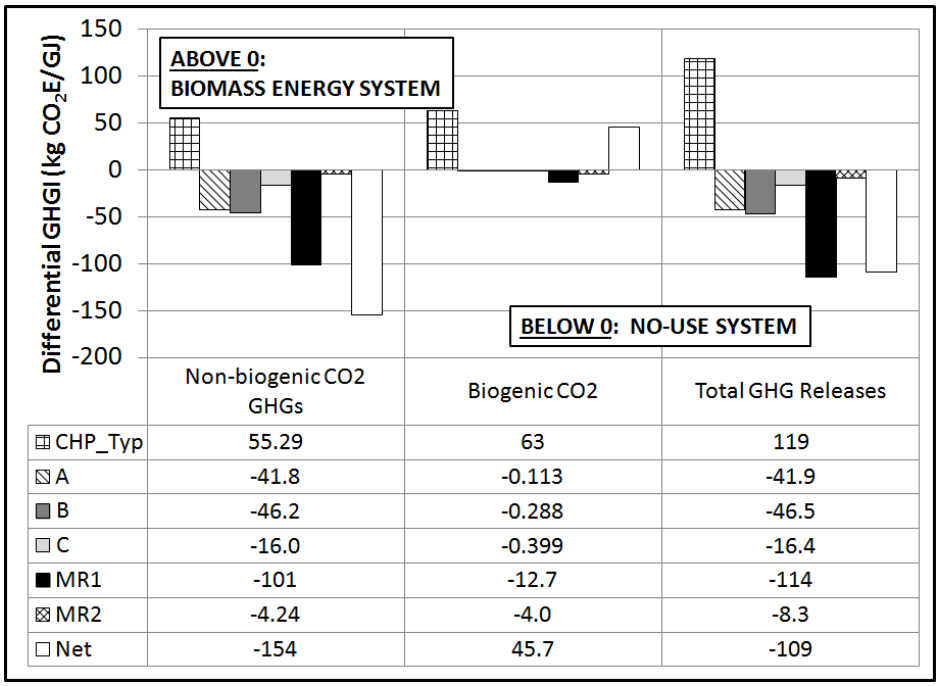
6.3.1.1 Greenhouse Gases: Differential GHGs

When using the dynamic carbon footprinting approach, the biomass energy system produces, after 100 years, a greenhouse gas impact that is **112 kg CO_2E lower**[17] per gigajoule of energy produced compared to the defined non-use system. This reduction is **109 kg CO_2E** when applying IPCC 100-year GWPs.

Figure 6.11 shows that the non-biogenic CO_2 GHGI is mostly lower because when burning residuals to produce energy, there are no methane emissions from landfills. Alone, the avoided methane emissions from landfills lower the impact by 154 kg CO_2E/GJ. The fact that there is less heat from fossil fuels also contributes to the lower impact, but to a lesser extent. Emissions of biogenic CO_2 are

[17] Results in this report are always presented as differences (i.e., biomass energy system minus non-use system). The "Relative GHGI" indicator does not include biogenic CO_2. The "Differential GHGI" indicator includes emissions and removals of biogenic CO_2.

different in the two systems for two reasons. First, much of the biogenic carbon is released as methane in the non-use system (included within non-biogenic CO_2 GHGs) and mostly as CO_2 in the biomass energy system. Second, some of the carbon is stored in landfills in the non-use system.



	Non-biogenic CO2 GHGs	Biogenic CO2	Total GHG Releases
CHP_Typ	55.29	63	119
A	-41.8	-0.113	-41.9
B	-46.2	-0.288	-46.5
C	-16.0	-0.399	-16.4
MR1	-101	-12.7	-114
MR2	-4.24	-4.0	-8.3
Net	-154	45.7	-109

Figure 6.11 Contribution Analysis for the Differential GHGI (at 100 Years) for Paper Recycling Residuals - Typical Scenario

[In the figure, the different components of the biomass energy system are depicted as follows: CHP system as described in Figure 5.5 (CHP_Typ). The components of the non-use system are depicted as follows: heat from coal (A), heat from natural gas (B), US average power grid (C), residual in landfills (MR1), incineration of residuals (MR2). Results reflect the use of 100-year GWPs.]

6.3.1.2 Greenhouse Gases: Relative Non-BioCO$_2$ GHGs

The result for the "Relative Non-BioCO$_2$ GHGI" indicator is -86.4%[18] (-75.2% when using IPCC GWPs), meaning that the biomass product system generates almost no GHGs when ignoring biogenic CO_2. When compared to other types of residuals presented above (woody mill residuals and WWTP residuals), the use of paper recycling residuals presents significantly lower overall benefits. This is because paper recycling residuals are composed of an important fraction of plastic which, when combusted, releases fossil fuel GHGs.

6.3.1.3 Greenhouse Gases: Emissions Timing

When paper recycling residuals are burned for energy, the biogenic carbon (both CO_2 and CH_4) is immediately released to the atmosphere. In contrast, residuals placed into landfills degrade slowly, releasing the carbon over time. Figure 6.12 analyzes the "Differential GHGI" indicator results over time using U.S. EPA's decay rate for materials placed in municipal landfills for the typical scenario.

[18] Non-biogenic CO_2 GHGs only. Calculated as follows: (CHP_Typ - A - B - C - MR1 - MR2)/ (A+B+C+MR1+MR2).

It shows that the differential impact is initially slightly negative (i.e., the impact from the biomass-based system is lower than that from the fossil fuel-based system, meaning that the break-even time is zero) and declines over time as the material degrades in landfills. When using the IPCC GWPs, the break-even time is also zero years.

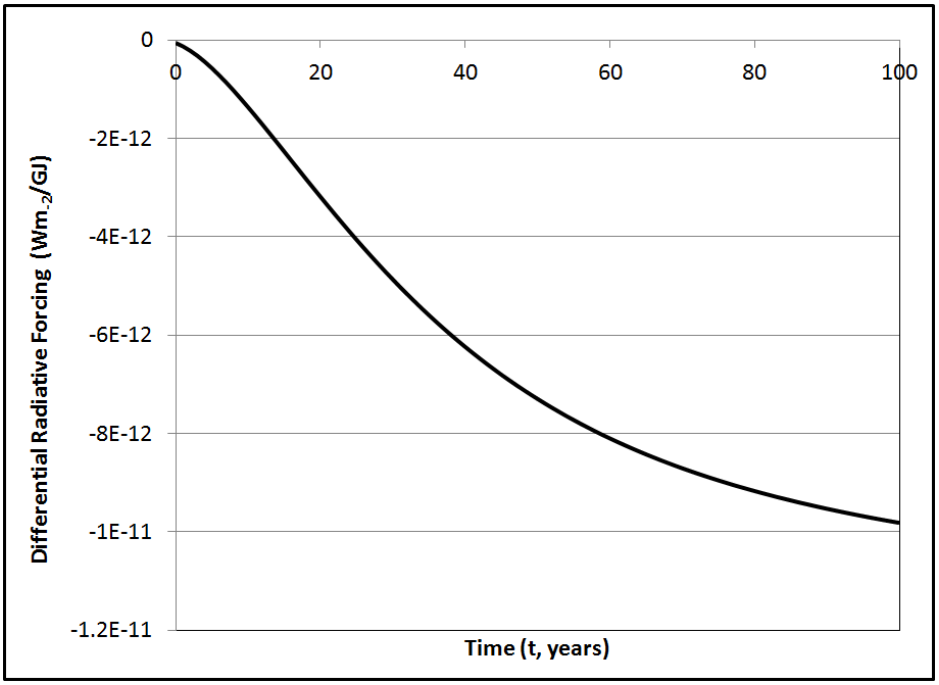


Figure 6.12 Cumulative Differential GHGI Indicator Results as a Function of Time for Paper Recycling Residuals - Typical Scenario

6.3.1.4 ***Consumption of Fossil Fuels***

Figure 6.13 shows the relative consumption of fossil fuels ("Relative FF CON," biomass energy system compared to non-use system) for paper recycling residuals.

It can be seen from that figure that the biomass energy system uses 99.9% less fossil fuel than the non-use system. This is due to the fact that virtually no fossil fuels are used in the biomass energy system. It can also be seen from the figure that the main contributor to the lower emissions is avoided heat from natural gas. Note that the plastic fraction of paper recycling residuals was not considered to be fossil fuel.

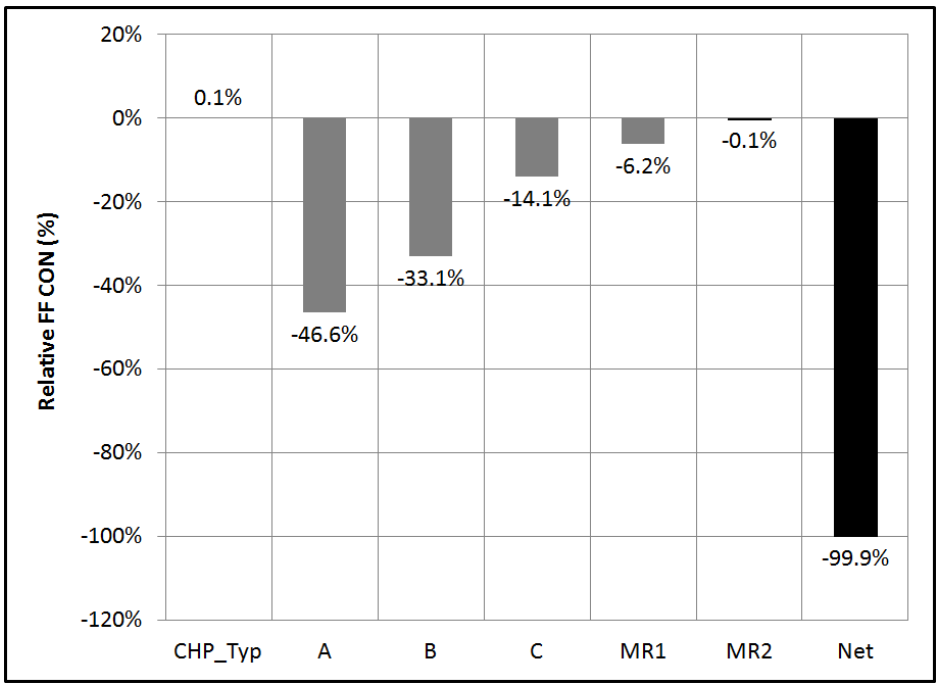


Figure 6.13 Relative Consumption of Fossil Fuels for Paper Recycling Residuals - Typical Scenario [In the figure, the different components of the biomass energy system are depicted as follows: CHP system as described in Figure 5.5 (CHP_Typ). The components of the non-use system are depicted as follows: heat from coal (A), heat from natural gas (B), US average power grid (C), residual in landfills (MR1), incineration of residuals (MR2).]

6.3.2 Typical Scenario: Perturbation and Sensitivity Analyses

6.3.2.1 Perturbation Analyses

Various parameters were analyzed in perturbation analyses. For each of these parameters, a sensitivity ratio was calculated (see Section 4.1.3). Sensitivity ratios for the parameters tested in this study are presented in Figure 6.14. Sensitivity ratios are not shown for break-even times as they were initially zero. It can be seen from Figure 6.14 that the fraction of non-degradable carbon (F_{CCND}) and the fiber fraction of paper recycling residuals have the most significant effect on the results, with sensitivity ratios up to 1.5. The positive ratio obtained for F_{CCND} means that when increasing the value of the parameter, the score is also increased, indicating a declining performance of the biomass energy system compared to that of the non-use system. Increasing the fiber fraction resulted in a negative sensitivity ratio. This means the biomass energy system generated lower emissions or consumed less fossil fuel than the non-use system. The water content of the residuals had little effect on the results compared to the other parameters. Finally, overall, fossil fuel consumption scores were not significantly affected by the parameters analyzed.

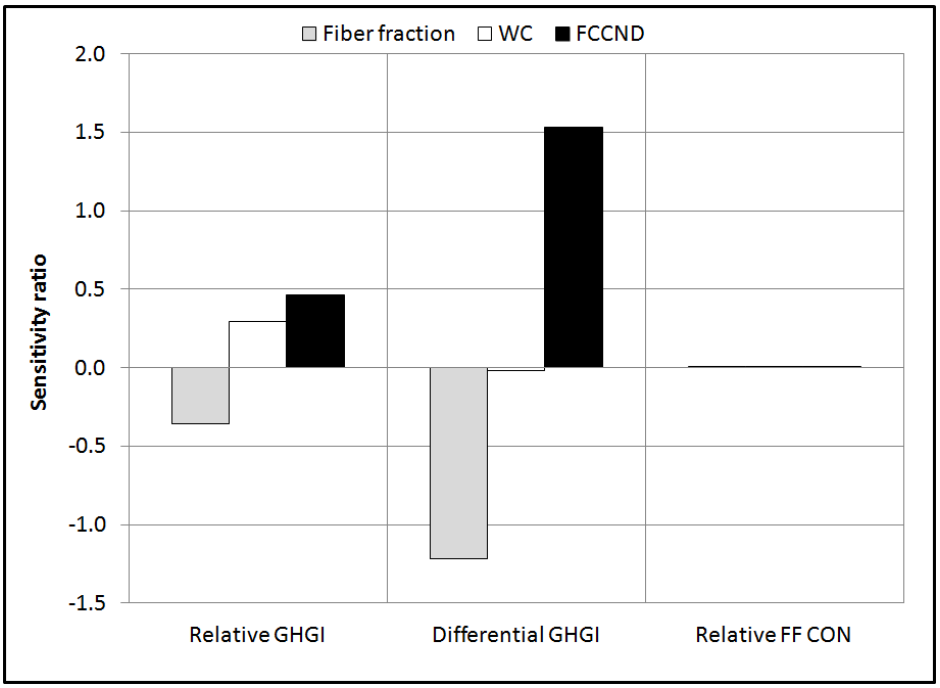


Figure 6.14 Sensitivity Ratios for Paper Recycling Residuals: Relative Non-BioCO_2 GHGs, Differential GHGs, and Relative FF CON

*6.3.2.2 **Sensitivity Analyses***

Above, perturbation analyses were applied to determine which parameters were intrinsically the most sensitive to the results without considering the actual ranges of possible values for these parameters. In Table 6.7, the results of sensitivity analyses considering the actual possible ranges of variation for each parameter are presented. It is shown that the range of possible heating values for paper recycling residuals had the most effect on the results. Also, even with the highest heating value for residuals, the GHG benefits of the biomass energy system compared to the non-use system are still considerable.

Table 6.7 Sensitivity Analyses on Indicator Results for the Typical Scenario, Paper Recycling Residuals

Para-meter	Differential GHGI* (kg CO_2E/GJ)			Relative Non-BioCO_2 GHGI* (%)			Break-Even Time* (years)			Relative FF CON (%)		
	Typ	Min	Max	Typ	Min	Max	Typ	Min	Max	Typ	Min	Max
Fiber fraction	-109 †	-57.8	-191	-75.2 ‡	-49.6	-93.2	0§	0	2.3	-99.9	-99.9	-99.9
WC_R		-108	-109		-71.5	-75.1		0	3.4		-99.9	-99.9
FCCND		-109	-166		-75.2	-78.7		0	0		-99.9	-99.9
K		-109	-109		-75.2	-75.2		0	-0.7		-99.9	-99.9

*Computed using 100-year GWPs. †-112 kg CO_2E/GJ using dynamic modeling of cumulative radiative forcing. ‡-86.4% using dynamic modeling of cumulative radiative forcing. §0 years using dynamic modeling of cumulative radiative forcing.

6.3.3 System Configuration Scenarios

In Section 5.0, various system configuration scenarios were presented. All relevant scenario combinations were analyzed (40 combinations). Results are presented in Table 6.8 for scenarios where parameters would be at their base case values. Results obtained for the typical scenarios are also reproduced in that table for comparison purposes. The biomass energy system resulted in lower GHG releases and fossil fuel consumption in all scenarios. Maximum differences were obtained in scenarios in which

- the fiber fraction of paper recycling residuals is higher;
- combined heat and power with maximum power production is employed;
- coal is being displaced (for both heat and power production); and
- alternative fate is landfilling.

Minimum differences were obtained in cases in which

- the plastic fraction of paper recycling residuals is higher;
- only heat is produced;
- natural gas is being displaced (for both heat and power production); and
- alternative fate is incineration.

Table 6.8 Indicator Results for Various System Configuration Scenarios - Paper Recycling Residuals

Indicator	Unit	Typical	Min	Max
Differential GHGs*	kg CO_2E/GJ	-109†	-82.9	-316
Relative GHGs *	%	-75.2‡	-62.5%	-86.3%
Break-even time*	years	0§	0	7.6
Relative FF CON	%	-99.9	-99.9	-100

*Computed using 100-year GWPs. †- 112 kg CO_2E/GJ using dynamic modeling of cumulative radiative forcing. ‡-86.4% using dynamic modeling of cumulative radiative forcing. §0 years using dynamic modeling of cumulative radiative forcing.

6.4 Black Liquor

In a previous study by NCASI (Gaudreault et al. 2012, NCASI 2011b), the benefits of recovering black liquor for production of energy and pulping chemicals that would otherwise need to be produced from other resources were analyzed. In that study, it was determined that developing a detailed model of the alternative fate of black liquor would have required too much speculation because black liquor is not disposed of. Its use in the kraft recovery cycle is integral to pulp production. Nonetheless, it was reasonable to assume that alternative management would involve returning the biogenic carbon in the liquor to the atmosphere, perhaps via incineration (in which case the carbon is emitted immediately), or aerobic wastewater treatment (in which case the carbon would be emitted over a period of hours to months depending on the type of treatment system in use). In either case, the carbon is returned to the atmosphere far too quickly to make carbon storage a significant factor in the calculations. To be conservative, it was also assumed that all of the carbon in the black liquor would be emitted as CO_2. If, in the alternative management scenario, some of the carbon was emitted as methane, the benefits of using black liquor in the kraft recovery cycle would be larger than estimated in the study.

The detailed results obtained for black liquor can be found in NCASI (2011b) and Gaudreault et al. (2012). These are summarized in Table 6.9. At the time of this earlier study, no dynamic carbon footprint approach was applied and the results were not limited to 100 years. The break-even time

would remain zero using dynamic carbon footprinting but limiting the analysis to 100 years would slightly reduce the GHG benefits.

Table 6.9 Summary of Indicator Results for Black Liquor

Indicator	Unit	Typical	Min	Max
Differential GHGI*	kg CO_2E/GJ	-182 (184‡)	-97.9	-192
Relative Non-BioCO_2 GHGI*	%	-90.5	-69.0	-92.4
Break-even time*,†	years	0	Not available	
Relative FF CON	%	-89.8	-71.1	-90.7

* Based on 100-year GWPs. † Break-even time was not analyzed in NCASI (2011b) and Gaudreault et al. (2012). However, assuming that the most likely alternative fate for black liquor is incineration, consistent with the conservative assumption made regarding carbon emission from this alternative fate, the break-even time would be zero years. ‡Computed using dynamic cumulative radiative forcing.

6.5 Comparison of the Residuals

Figure 6.15 compares the GHG benefits for the different types of biomass residuals on 1) a functional unit basis (i.e., 1 GJ of energy), and 2) a tonne of residual basis. “Differential GHGs” indicator results are depicted for the biomass energy system compared to the non-use system.

The figure shows that producing 1 GJ of energy using WWTP residuals produces greater benefits than does using woody mill residuals. This may seem counterintuitive, as WWTP residuals are a fuel of lesser quality than woody biomass residuals. This result was obtained because to produce 1 GJ of energy, more WWTP residuals are needed than when using woody biomass residuals, which also means diverting more WWTP residuals from landfills and hence avoiding more methane emissions. Paper recycling residuals generated relatively lower benefits than woody mill residuals and WWTP residuals on a per GJ basis. This was due to the plastic fraction of the residuals, which produce fossil fuel GHGs when burned.

On a per tonne of residual basis, fuels with higher HHV, lower water content, and greater degradable fraction in landfills led to greater benefits. The plastic fraction of paper recycling residuals was also an important factor explaining the lower benefits observed for this material.

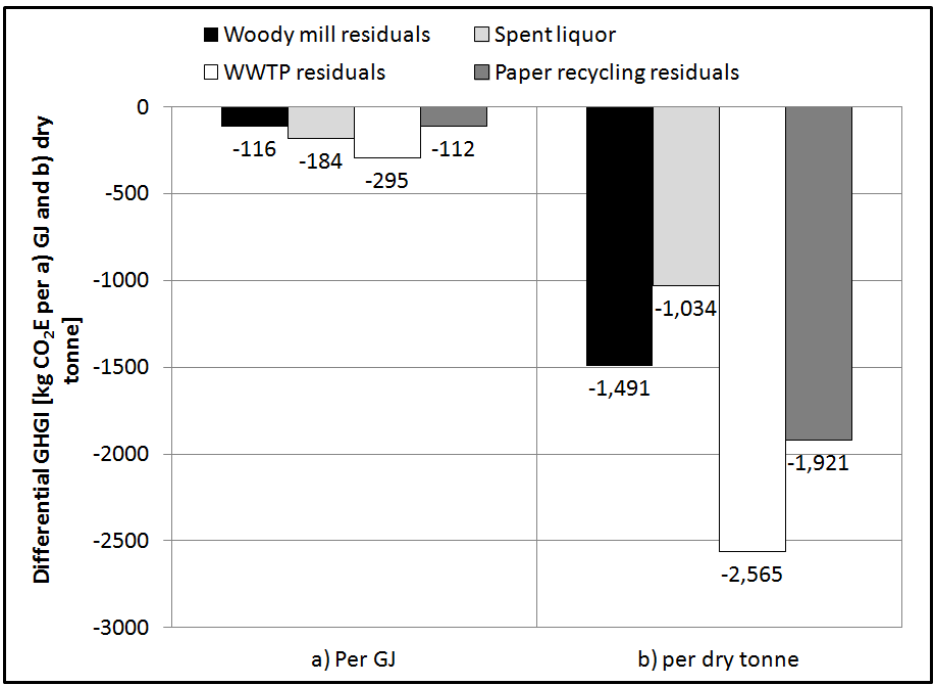


Figure 6.15 Comparison of the Differential Releases for the Different Residual Types a) per Gigajoule, b) per dry Tonne

It is also possible to use the numbers presented in Table 6.14 below to calculate typical scenario weighted average indicator results for all residuals included in this study. In calculating these averages, it was assumed that the results were the same for other spent liquor as for black liquor. Residuals other than black liquor and those analyzed in this study were not included. The weighted average results are presented in Table 6.10.

Table 6.10 Weighted Average Indicator Results, Typical Scenarios, Life Cycle Results

Indicator	Unit	Weighted Average Result (all manufacturing residuals)	
		Dynamic Carbon Footprint	IPCC GWPs
Differential GHGI	kg CO_2E/GJ	-158	-155
Relative non-bioCO_2 GHGI	%	-93.7%	-94.3%
Break-even time	Years	0.5	2.9
Relative FF CON	%	-93.8%	-93.8%

6.6 Additional Sensitivity Analysis on Air Emission Control Equipment

As mentioned in Section 5.1.2.1, it was assumed in this study that the difference in energy requirements for air emission control was negligible for boilers combusting biomass residuals, coal, and/or natural gas. There is very little information available regarding air emission control device energy requirements and what information is available is rarely in a format that is usable for this study. Some of the available information is summarized in Table 6.11. Table 6.12 presents common air emission control equipment used for various boiler types within the forest products industry.

Based on the information in Table 6.11 and Table 6.12, two sensitivity analyses were performed to test the significance of the differences in control equipment and are summarized in Table 6.13. The results of the sensitivity analyses, presented in Figure 6.16, indicate that neglecting the differences in energy requirements for air emission control has likely led to a slight overestimation (of less than 3%) of the benefits related to the biomass energy system, especially in the context of fossil fuel consumption benefits.

Table 6.11 Power Consumption for Various Air Emission Control Devices

Air Emission Control Equipment	Power Consumption (% of energy output)	Applicability	Reference
Electrostatic precipitator	0.1 - 1.8%	Power utilities	European Commission (2006)
	0.2%*	Heat from coal	NCASI (1998)
	0.3%†	Heat from biomass	NCASI (1998)
	≈ 0.6%	Heat from coal‡	USEPA (2002)
Wet scrubber	≤ 3.0%	Power utilities	European Commission (2006)
Dry scrubber	0.3% - 1.0%	Power utilities	European Commission (2006)
	0.5% - 1.0%	Heat production	Kitto (1996)
Unspecified scrubber	1.0%*	Heat from coal	NCASI (1998)
	1.0%†	Heat from biomass	NCASI (1998)
Selective catalytic reduction (SCR)	0.5%	Power utilities	European Commission (2006)
Selective non-catalytic reduction (SNCR)	0.1 - 0.3%	Power utilities	European Commission (2006)

*Assuming 0.04 - 1.3 W/acfm, 0.5 acfm/(lb steam/hr) and 1.52E-03 GJ/lb steam. †Assuming 0.04 - 1.3 W/acfm, 0.92 acfm/(lb steam/hr) and 1.27E-03 GJ/lb steam. ‡Assuming 8640 hr/yr, 0.06$/kWh, 9780dscf/MMBtu, 3% O_2 at T=325°F.

Table 6.12 Common Combustion-Related Air Emission Control Equipment

Fuel Burned	Most Common Control Equipment
Coal	ESP, low NO_x burner
Biomass	ESP, wet scrubber (newer boilers have SNCR for NO_x control)
Natural gas	Low NO_x burner, flue gas recirculation

Table 6.13 Sensitivity Analyses on Air Emission Control Equipment

#	Electricity Consumption for Air Emission Control (% of heat output)		
	Biomass	Natural Gas	Coal
S1	0.3%	0.0%	0.2%
S2	2.1%	0.0%	1.8%

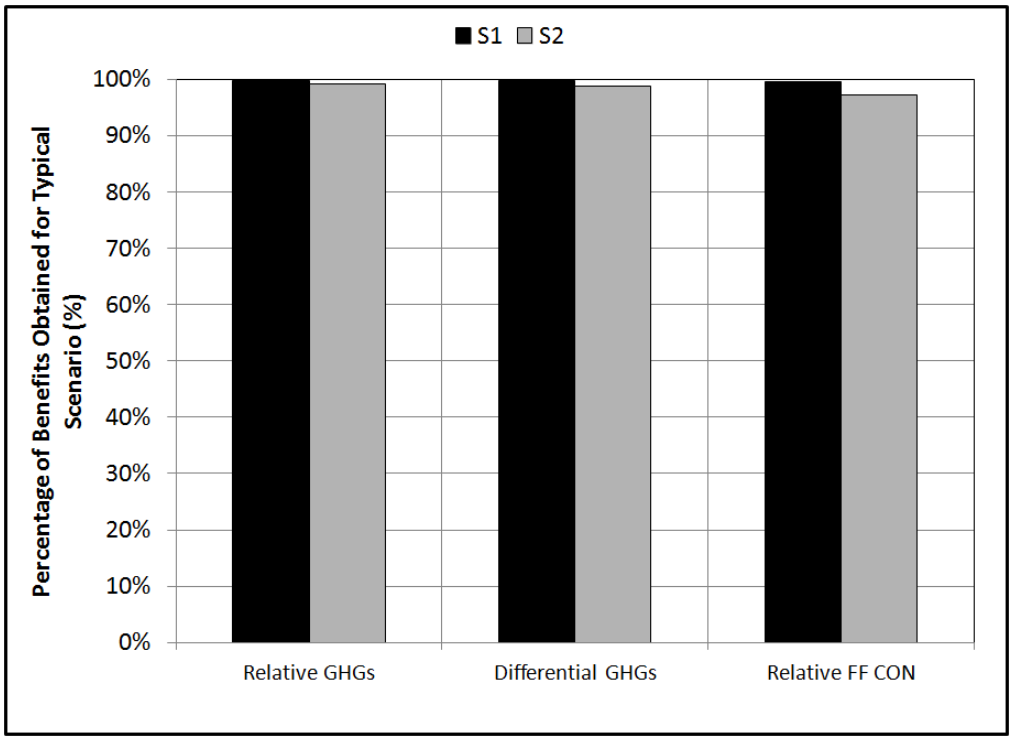


Figure 6.16 Sensitivity Analyses on Air Emission Control Equipment - Manufacturing-Related Woody Biomass Residuals - Typical Scenario

6.7 Life Cycle Results in Context

In this study, the life cycle GHG emissions and non-renewable energy consumption associated with the US forest products industry's use of biomass residuals (biomass energy system) have been compared to the GHG emissions and the non-renewable energy consumption that would occur if fossil fuels were used instead (non-use system). The results have been calculated in terms of the differences between these two systems, expressed in terms of value chain GHG emissions. In this section of the report, the calculated GHG benefits are put in the context of total emissions from the forest products industry value chain.

Table 6.13 presents data that allow calculation of the greenhouse gas benefits of using biomass residuals for energy generation. From this table, it can be seen that kraft black liquor and woody mill residuals represent 24.3% and 34.6%, respectively, of the total energy used by the industry, for an overall total of 58.9%.

Table 6.14 Various Contextual Data Regarding the US Forest Products Industry

Element	Value			Reference
Total energy consumption	2.58E9 GJ/yr			2010 data collected by AF&PA, NCASI, and AWC and scaled up to total US production* Total energy includes purchased power
Fraction of energy from various sources (may not sum to 100% due to rounding)	**Source**	**Biomass Energy**	**Total Energy**	2010 data collected by AF&PA, NCASI, and AWC and scaled up to total US production*
	Black liquor	52.3%	34.6%	
	Other spent liquor	4.6%	3.0%	
	Woody mill residuals	36.8%	24.3%	
	WWTP residuals	0.63%	0.42%	
	Paper recycling residuals	0.05%	0.03%	
	Others	5.7%	3.9%	
	Fossil fuels	N/A	33.7%†	
GHG benefits from black liquor recovery	Base Case	184 kg CO_2E/GJ in steam		The base case was recalculated in this report; min and max are from Gaudreault et al. (2012)
	Min	98 kg CO_2E/GJ in steam		
	Max	192 kg CO_2E/GJ in steam		
Value chain emissions of the US forest products industry	Scope 1	64.6 million tonnes CO_2E/yr (62.0 million tonnes CO_2E/yr from fossil fuels use)		Heath et al. (2010)
	Scopes 2 and 3	147 million tonnes CO_2E/yr		
	Net biogenic carbon flows	-109 million tonnes CO_2E/yr		
	Net value chain emissions	104 million tonnes CO_2E/yr		

*Together, AF&PA, NCASI, and AWC members comprise 96% of total US pulp production, 86% of total paper and paperboard production and 36% of wood products production. † Including purchased electricity, based on the energy content at the fence line (i.e., 3412 BTU per kWh) and assuming that it is 100% fossil fuel-based.

Based on the data in Table 6.10 and Table 6.14, it is possible to estimate the increase in value chain emissions that would accompany the forest products industry's changing from biomass manufacturing residuals (including black liquor) for energy to fossil fuels. Overall, the use of biomass manufacturing residuals (including black liquor) in the forest products industry for one year avoids, for typical scenarios, the emission of 181 million tonnes CO_2E. In an earlier study, it was determined that direct emissions of GHGs from fossil fuel combustion in the US forest products industry in 2004 were approximately 65 million tonnes CO_2E per year (Heath et al. 2010). The use of biomass-based manufacturing residuals for one year, therefore, avoids a quantity of GHG emissions approximately three times the annual fossil-fuel related direct GHG emissions from the forest products industry.

7.0 RESULTS AND DISCUSSION: ADDITIONAL ANALYSES

This section presents the results of the gate-to-gate analysis of biogenic GHGs and the analysis of the emissions of GHGs in the context of ongoing practices.

7.1 Gate-to-Gate Analysis of Biogenic GHGs

All the results presented above were computed using a life cycle approach that considered the fossil fuels being displaced by biomass residuals. The typical scenarios for the two product systems (one system using biomass for energy and the other system managing it by some other means) have also been compared in terms of the emissions coming directly out of the units receiving the residuals (i.e., combustion units or landfills). In this analysis, the benefits of fossil fuel substitution were ignored. For this gate-to-gate analysis, paper recycling residuals were analyzed in terms of their fiber fraction only.

Gate-to-gate Differential GHGI results are summarized in Table 7.1. These show that, even in this highly constrained analysis, using the biomass residuals for energy generation resulted in reductions in GHG releases. The results in Table 7.1 also highlight the effects of using dynamic modeling of radiative forcing instead of 100-year GWPs, with the effects being especially significant on estimated break-even times. A significant fraction of the emissions benefits were attributable to avoidance of landfill methane. A previous, similarly constrained analysis on black liquor assumed that the alternative management would likely involve returning the biogenic carbon in the liquor to the atmosphere. In order to be conservative, in that study, it was assumed that the carbon would return to the atmosphere as CO_2 via incineration or treatment in aerobic wastewater treatment plants. This resulted in net zero GHG releases for energy production from black liquor compared to an alternative fate. When not considering fossil fuel substitution, the weighted average reduction in GHG emissions considering all residuals is 4.6 kg CO_2E/GJ.

Because the benefits of displacing fossil fuels are not included, the times required for cumulative emissions impact from the biomass energy system to fall below the cumulative emissions impact from the non-use system are longer than calculated earlier in this report. Depending on the residual, it required 0 to 19.5 years for the cumulative emissions impact from the biomass system to become lower than the cumulative emissions impact from the non-use system.

A sensitivity analysis was also performed that uses the IPCC default value of 50% (instead of 77% in the typical scenario) for the percentage of carbon in woody mill residuals that is non-degradable under landfill anaerobic conditions. These results, presented in parentheses in Table 7.1, show that the results are highly affected by this parameter.

Table 7.1 Results of the Gate-to-Gate Analysis of Biogenic GHGs

Residual Type	Differential GHGs over 100 Years (kg CO_2E/GJ)		Break-Even Time (years)	
	Dynamic CF	IPCC 100-Year GWPs	Dynamic CF	IPCC 100-Year GWPs
Woody mill residuals	-8.5 (-187)†	-5.1	19.5 (6.6) †	77.0
WWTP residuals	-190	-182	5.9	13.4
Fiber fraction of paper recycling residuals*	-132	-126	7.7	18.2
Spent liquor (incl. black liquor)	0	0	0	0
Weighted average	-4.6 (-74.2) †	-3.3	7.6 (2.6) †	30.1

*In addition to biomass, paper recycling residuals contain plastics which are produced from fossil fuels. For the purpose of the biomass carbon fate analysis, only their fiber fraction was considered. †Numbers in parentheses were derived using IPCC default for fraction of carbon that is non-degradable under anaerobic conditions, that is 50% instead of 77%.

7.2 GHG Emissions from Ongoing Use of Residuals for Energy Production

Table 7.2 shows the times required for cumulative emissions from a facility using residuals for energy to be equal to the emissions from a facility disposing of the residuals, both for the cradle-to-energy (including fossil fuel substitution) and gate-to-gate (excluding fossil fuel substitution) analyses. The results are presented for the dynamic carbon footprint approach only. The table also indicates when in the past the ongoing practice would need to have begun in order for the cumulative emissions from the two systems to be equal in 2014. The table includes text describing the practices in the industry at points in the past. It should be noted that there is considerable uncertainty in the estimates of break-even times, especially where fossil fuel substitution is ignored. This is because, in cases where fossil fuel substitution benefits are ignored, the curve describing the difference in cumulative emissions between the two scenarios is relatively flat as it approaches zero (because the initial difference between the scenarios is large). The break-even time is equal to the point at which the curve passes through zero, so the results are sensitive to small changes in assumptions, particularly assumptions about landfill decay and methane production. By contrast, where fossil fuel substitution is considered, the curve is steeper where it passes through zero because of the smaller initial difference between the two scenarios, thus reducing the uncertainty about break-even time.

Table 7.2 The Use of Residuals for Energy as an Ongoing Practice

Residual		Years For Emissions from Facility Using Residuals for Energy on an Ongoing Basis to Be Equal to Emissions from a Facility Disposing of These Residuals (Under Typical Scenario)	Year in the Past When Ongoing Practice Would Have Had to Be Initiated for Emissions from the Two Facilities to Be Equal at the in 2014 (Under Typical Scenario)	Past Industry Practice in Using the Residuals for Energy
Woody mill residuals	w/ benefits of the displaced fossil fuels (cradle-to-energy)	1.9 (0.9)*	2012 (2013)*	The literature mentions the use of wood residuals in boilers used for wood drying at sawmills going back to at least 1920 and in steam engines in sawmills going back to the mid-1800s. Based on AF&PA statistics, in 1971, woody mill residuals represented 7% of the fuel (16% of the biomass) burned at pulp and paper mills. By 1980, this had increased to 11% of the fuel (21% of the biomass). Between 1987 and 1999, it varied between 15% and 18% of the fuel (25% to 29% of the biomass).
	w/o benefits of the displaced fossil fuels (gate-to-gate)	34.5 (10.4)*	1979 (2003)*	
WWTP residuals	w/ benefits of the displaced fossil fuels (cradle-to-energy)	0	2014	NCASI statistics on WWTP residuals management go back to 1979, at which point 11% of these residuals was being burned for energy. By 1988, this had increased to 21%.
	w/o benefits of the displaced fossil fuels (gate-to-gate)	9.3	2004	

(Continued on next page. See notes at end of table.)

Table 7.2 (Cont'd)

Residual		Years For Emissions from Facility Using Residuals for Energy on an Ongoing Basis to Be Equal to Emissions from a Facility Disposing of These Residuals (Under Typical Scenario)	Year in the Past When Ongoing Practice Would Have Had to Be Initiated for Emissions from the Two Facilities to Be Equal in 2014 (Under Typical Scenario)	Past Industry Practice in Using the Residuals for Energy
Paper recycling residuals	w/ benefits of the displaced fossil fuels (cradle-to-energy)	0	2014	There are different types of recycling residuals generated by mills using recovered paper. Some of these are combined with WWTP residuals and managed similarly to what is described above; i.e., in 1979 11% of WWTP residuals were burned for energy, increasing to 21% in 1988. OCC rejects, however, are often managed separately. NCASI has published information showing that using recycling residuals for energy started as early as 1975.
	w/o benefits of the displaced fossil fuels (gate-to-gate)	12.2	2001	
Spent liquor (incl. black liquor)	w/ benefits of the displaced fossil fuels (cradle-to-energy)	0	2014	Based on AF&PA statistics, in 1971, 35% of the fuel (84% of the biomass) burned at pulp and paper mills was black liquor. By 1980, this had increased to 40% of the fuel (79% of the biomass). Between 1987 and 1999, it varied between 43% and 46% of the fuel (71% to 75% of the biomass).
	w/o benefits of the displaced fossil fuels (gate-to-gate)	0	2014	

*Numbers within brackets were derived using IPCC defaults for the fraction of carbon in woody mill residuals that does not degrade under anaerobic conditions (50%) rather than that of U.S. EPA (77%).

8.0 UNCERTAINTY AND LIMITATIONS

This section provides further interpretation of the robustness of the results presented above.

8.1 Data Accuracy and Uncertainty

Evaluating data accuracy and uncertainty is an important aspect of LCA studies. An LCA is a complex model made up of thousands of data points and the accuracy of these data can significantly affect the results. Analyzing the uncertainty of such a complex model is not straightforward. Techniques such as Monte Carlo analysis can be used to evaluate uncertainty, but an important challenge is the lack of uncertainty data for the different variables that comprise the LCA model. Therefore, in many cases, the robustness of the results and conclusions of LCA studies are assessed using other methods. In this study, the parameters with potential effects on the results were analyzed using sensitivity analyses covering their most probable range of variation and results were discussed given these variations. However, without comprehensive uncertainty data, it was impossible to quantitatively assess the statistical significance of the differences between the compared systems.

The data collection process met the data quality goals as set out in Section 4.4.

8.2 Limitations

The main limitations of this study are summarized in this section. They relate primarily to the conformity of the study with ISO LCA standards (ISO 2006a, b) and to the data used and assumptions made.

8.2.1 ISO Conformity

As mentioned previously, a streamlined LCA methodology was used in this study. As a consequence, it was not possible to fully comply with ISO 14044 requirements for comparative assertions disclosed publicly. The main non-conformances are outlined below.

- Although the assumptions, models, and results were reviewed by a committee of stakeholders, no formal external critical review was performed.
- While the Standard requires that for studies intended to be used for publicly disclosed comparative assertions, a sufficiently comprehensive set of impact categories be employed, only two were used in this study, in accordance with the study objective.
- No formal uncertainty analysis was performed.

In addition, the gate-to-gate analyses need to be understood as additional information rather than as an LCA result.

8.2.2 Data and Assumptions

Some of the generic data sets used in this study were not specific to the US, although the study employed a version of these data sets modified to use US electricity production.

The relevant characteristics related to the residuals analyzed in this study are typically quite variable. This variability was analyzed in sensitivity analyses and results were shown for range of characteristic values sufficiently large to cover most of the variability.

The data identified for size reduction were fixed on a per tonne basis and did not account for the extent of size reduction. That said, size reduction was not found to significantly affect the study results.

Several assumptions were made regarding WWTP residuals that could have affected the study results. The main ones are discussed here.

- It was assumed that mechanical dewatering can achieve 40% solids, that this was sufficient for combustion, and that the same level of dewatering was also suitable for transporting them to a landfill disposal site. The main reason for this assumption was that no data were available concerning the energy consumption for additional dewatering. Assuming additional dewatering would have had two main effects on the results. First, this would have decreased the overall performance of the biomass energy system by increasing its consumption of energy and related releases. Second, assuming drier WWTP residuals would have increased boiler efficiency, and thus reduced the quantity of residuals required to produce 1 GJ of energy, which would have resulted in lower benefits when analyzing the results on a per gigajoule basis, but greater benefits on a per tonne of residuals basis.
- It was also assumed that WWTP residuals would be co-fired with bark in a 20:80 ratio. Based on this ratio, a boiler efficiency was calculated. Increasing the share of residuals in the mix burned would have decreased the boiler efficiency, while decreasing their share would have increased the efficiency. The effect of boiler efficiency on the results was discussed immediately above. The relationship between the share of WWTP residuals burned and boiler efficiency is also uncertain. The best available information was used.

Because paper recycling residuals are made up of a mix of materials that have characteristics similar to WWTP residuals (negative effect on boiler efficiency compared to woody biomass residuals) and plastic (positive effect on boiler efficiency compared to woody biomass residuals), it was assumed that paper recycling residuals would be burned in boilers with the same efficiency as woody biomass residuals at a given water content. Boiler efficiencies for these kinds of material are not known, however. The effect of boiler efficiency on the results was discussed above. Also, OCC rejects were considered to be representative of paper recycling residuals in general. In cases where, for instance, the plastic fraction of other paper recycling residuals is outside the range studied in this study, results would be slightly different. However, a broad range of characteristics was examined in this study to account for these potential variances.

The best available data for energy production using fossil fuels were used. These data were deemed representative of average US conditions. No sensitivity analyses were performed on that part of the modeling. As a consequence, the results of the study cannot be generalized to a broader set of conditions regarding energy production from fossil fuels. Also, it was assumed that the difference in energy requirements for air emissions control would not vary significantly from one fuel to another. If this were not the case, and in particular if the energy penalty for emissions control were lower for natural gas than for biomass, the benefits calculated for scenarios involving natural gas would be reduced. This is not, however, expected to be significant.

The results are very sensitive to landfill and waste decomposition characteristics and these characteristics are very uncertain. Sensitivity analyses were performed to address this issue. Results appear to be robust within the ranges assessed for those characteristics with the exception of woody mill residuals for which very different results can be obtained depending on the assumption made regarding the fraction of carbon that is non-degradable under anaerobic conditions. In this study, a value of 77% was used, obtained from the U.S. EPA GHG Inventory (2014a, Table 7.50). IPCC recommends using a default value of 50% and specifies that waste-specific information can be used instead but emphasizes that “[t]he reported degradabilities especially for wood, vary over a wide range and [are] yet quite inconclusive” (IPCC 2006b, Chapter 3, pp. 3.13-3.14). Table 8.1 compares the results using the two values. The results show that the selected value has significant effect on the results. Some studies have reported higher fractions of non-degradable carbon in wood than 77%

(Wang et al. 2011). Assuming a higher non-degradable fraction would significantly reduce the estimated benefits of using this material for energy.

Table 8.1 Comparison of Results Obtained for Woody Mill Residuals Using the EPA and IPCC Values for Fraction of Carbon Non-Degradable Under Anaerobic Conditions and Effect for Industry Average Results

Indicator	Unit	Fraction of Non-Degradable Carbon Under Anaerobic Conditions (FCCND)			
		Including Fossil Fuel Substitution (Cradle-to-Final Energy)		Excluding Fossil Fuel Substitution (Gate-to-Gate)	
		77% (EPA)	50% (IPCC)	77% (EPA)	50% (IPCC)
Woody mill residuals differential GHGI	kg CO_2E/GJ	-116	-295	-8.5	-187
Weighted average differential GHGI	kg CO_2E/GJ	-158	-228	-4.6	-74.2
Break-even time (woody mill residuals)	years	1.2	0.5	19.5	6.6
Weighted average break-even time	years	0.5	0.2	7.6	2.6
Break-even year for ongoing practice (woody mill residuals)	-	2012	2013	1979	2003
Industry-average benefit	million tonnes CO_2E/yr	181	261	5.3	84.9

In addition, the analysis of the timing of emissions depends heavily on landfill characteristics. In the absence of information more specific to forest products manufacturing residuals, U.S. EPA decay rates for municipal landfills were used. These decay rates were derived for a mix of wastes, i.e., not only for woody materials which may degrade more slowly. Therefore, the lower decay rates used in the scenarios are probably more representative of woody materials. Even considering this, the break-even times were short, with the exception of paper recycling residuals that contain a fraction of plastic.

Finally, the results of the assessment of ongoing practice are valid only in the context of two main assumptions: 1) assuming the same quantity and type of energy produced in every year, 2) assuming the same alternative fates and fossil fuels displaced in every year.

9.0 CONCLUSIONS

In this study, the GHG and fossil fuel-related benefits of using woody manufacturing residuals, recycling residuals, and wastewater treatment plant residuals for energy production within the forest products industry were analyzed using life cycle principles and additional analyses. It was shown that using all types of residuals for energy production produces benefits both in terms of reduced fossil fuel consumption and reduced greenhouse gas emissions. This result is valid across a range of system configuration scenarios (boiler type, assumptions about the displaced fossil fuel, the GHG intensity of the electricity grid, and the level of cogeneration at forest products facilities), residual characteristics (e.g., heating value, moisture content), and whether or not the benefits from fossil fuel substitution are considered. These findings hold true whether biogenic CO_2 is included in the analysis or excluded by giving it an emission factor of zero (equivalent to what is sometimes called “carbon neutrality”). The

benefits occur without affecting the amount of wood harvested or the amount of wood products produced.

It takes 0 to 1.2 years before the cumulative emissions impacts from the biomass energy systems are lower than those in the corresponding non-use systems. Even ignoring the benefits of displacing fossil fuel and limiting the analysis to biogenic emissions, the cumulative emissions impacts from the biomass energy systems associated with producing 1 GJ of energy are lower than those from the non-use systems in 0 to 19.5 years, depending on the residual.

These results were developed by comparing the GHG emissions from systems using manufacturing residuals for energy in the forest products industry to the emissions from alternative systems producing the same amount of energy from fossil fuels while disposing of the residuals by landfilling or a combination of landfilling and incineration. In cases where it is assumed that the alternative to burning manufacturing residuals for energy is incineration, the break-even times for all residuals are zero, whether or not fossil fuel substitution is considered. Where the alternative is assumed to be landfilling, the results can be sensitive to the parameter value describing the extent to which residuals decompose in mill landfills, a parameter with large uncertainty. The impact is especially significant for woody mill residuals.

When considered as an ongoing practice (e.g., ongoing production of 1 GJ energy per year), and when the benefits of displaced fossil fuels are considered, the typical cumulative impact of residuals used for energy in the industry becomes less than that of disposing of the residuals in less than two years. If the benefits of displaced fossil fuels are ignored, the typical cumulative impact of using the residuals becomes smaller than the impact associated with disposing of the residuals in less than 35 years for all of the residuals examined. In all cases, even ignoring the benefits of displaced fossil fuels, the ongoing use of the residuals predates, by a considerable period, the date when the practice would have needed to begin in order for the current use of manufacturing residuals to be showing net benefits.

The emissions benefits of using manufacturing residuals for energy in the forest products industry are large. Given current practice, the use of manufacturing residuals including black liquor in the industry for one year avoids the emission of approximately 181 million tonnes CO_2E, equal to approximately three times the annual direct emissions associated with the combustion of fossil fuels in the forest products industry.

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APPENDIX A

ACRONYMS AND NOMENCLATURE

General Acronyms and Nomenclature:

AF&PA:	American Forest and Paper Association
AWC:	American Wood Council
BC:	Base case
BDmT:	Bone-dry metric tonne
Bio:	Biomass
BioCO_2:	Biogenic CO_2
Biogenic GHGs:	Biogenic CO_2 as well as CH_4 produced from decomposing biomass and CH_4 and N_2O produced in biomass combustion
Biomass energy system:	Product system in which the biomass residuals are used for energy production
Break-even time:	Number of years required for the cumulative emissions from the non-use system to equal the cumulative emissions from the biomass energy system
CHP:	Combined heat and power
CORRIM:	Consortium for Research on Renewable Industrial Materials
CO_2:	Carbon dioxide
CO_2E:	CO_2 equivalents, i.e., measure for describing how much global warming a given type and amount of greenhouse gas may cause, using the functionally equivalent amount or concentration of carbon dioxide (CO_2) as the reference
Cradle-to-final energy analysis:	A cradle-to-final energy analysis can be defined as a specific LCA applied to the production of energy. It generally includes the extraction and production of fuels, their transportation and their combustion to produce energy.
Differential GHGs:	Absolute difference in releases of GHGs, including biogenic CO_2 emissions and removals
Eff:	Efficiency
EPA:	Environmental Protection Agency
FF:	Fossil fuel

Non-use system:	Product system in which the fossil fuels are used for energy production and in which an alternative fate for the biomass residuals is considered or in which only the alternative fate of the biomass residuals is considered
Gate-to-gate analysis:	A gate-to-gate analysis can be described as a partial LCA looking at only one value-added process in the entire production chain
GHG:	Greenhouse gas
GJ:	Gigajoule (1 GJ = 0.948 MMBtu)
GWP:	Global warming potential
HHV:	Higher heating value
H&P:	Heat and power
ISO:	International Organization for Standardization
LCA:	Life cycle assessment
LCI:	Life cycle inventory
LCIA:	Life cycle impact assessment
LHV:	Lower heating value
MSW:	Municipal solid waste
NG:	Natural gas
N/Av.:	Not available
OCC:	Old corrugated containers
OECD:	Organisation for Economic Co-operation and Development
Relative FF CON:	Relative difference in fossil fuel consumption of the biomass energy system compared to the non-use system
Relative Non-Bio CO_2 GHGs:	Relative difference in GHGs, <u>not including biogenic CO_2</u>, of the biomass energy system compared to the non-use system
Removals:	Sequestration or absorption of CO_2 from the atmosphere by the trees
US:	United States
WWTP:	Wastewater treatment plant

System Configuration Scenarios Nomenclature:

Alternative Fate Scenarios

MR1: Landfilling

MR2: Incineration

Boiler Type Scenarios

FB: Fluidized bed boiler

SB: Stoker boiler

Fossil Fuel Scenarios

A: Heat from coal

B: Heat from natural gas

C: US-average electricity

D: Electricity from coal

E: Fossil fuel scenario, electricity from natural gas combined cycle

Size Reduction Scenarios

SR0: Size reduction scenario, no size reduction

SR1: Size reduction scenario, mobile chipper

SR2: Size reduction scenario, stationary chipper

General Nomenclature:

CC: Biogenic carbon content

E_{DC}: Usable energy from direct combustion

E_{Turb}: Steam to turbine

F_{CCND}: Non-degradable carbon content under anaerobic conditions

F_{CH4CB}: Fraction of methane captured and burned

F_{CH4OX}: Fraction of methane oxidized in landfill covers

k: Decay rate

L: Losses

MCF: Methane correction factor

P: Power to process

Q_R: Quantity of residuals required to produced 1 GJ of usable energy

SHP: High pressure steam to process

SMP/LP: Extraction steam to process

WC_R: Water content of residuals

APPENDIX B

REPORT REVISIONS SINCE ORIGINAL PUBLICATION

This is the third version of this report. The first version was published in October 2013. A revised version was published in May 2014 to correct some of the data and make some clarifications to the text. NCASI found that the values describing the composition of biomass energy presented in Table 6.14 were calculated using the wrong method. These numbers affected the various weighted averages calculated throughout the report. In addition, NCASI calculated the total greenhouse gases avoided by the industry's use of woody mill residuals and black liquor to be 110 million tonnes CO_2E for woody mill residuals and 218 million tonnes CO_2E for combined woody mill residuals and black liquor. It was not clear in the report that other residuals were not included in this estimate. If the estimate had included other residuals, the avoided emissions benefit would have been slightly larger. Also, the report text was clarified in a few places. These changes did not affect the general conclusions of the report.

In July 2014, NCASI determined that the calculations pertaining to woody mill residuals were in error due to the use of an incorrect value for the fraction of carbon that degrades in landfills under anaerobic conditions. Specifically, NCASI used a value of 55% for this parameter while it had intended to use 77%, the value used by the United States Environmental Protection Agency in its Inventory of U.S. Greenhouse Gas Emissions and Sinks. NCASI has recalculated all of the results involving woody mill residuals and recomputed all industry-average numbers. The table below lists the changes in results and where they occur in the report. The table only identifies places where the changes involve calculations based on dynamic radiative forcing. The numbers calculated with the Intergovernmental Panel on Climate Change (IPCC) 100-year global warming potentials (GWPs) were also updated but this is not shown in the table. Note that the text of the report was also modified in several places (not listed here) to reflect the changes in these results. NCASI also provided more details concerning the available information on the decay rates of various manufacturing residuals and the fraction of non-degradable carbon in wood. In addition, a sensitivity analysis using the default value from IPCC (i.e., 50% of the carbon non-degradable under anaerobic conditions), also used by EPA in its greenhouse gas reporting rule, was added. (Table 8.1 was added to Section 8.2.2.) Note that many results presented in Table 8.1 were not in the original report.

In the table below, where a value is presented, for instance, in Section ES.6 in the new report, that result is typically presented in Section ES.5 in the previous version of the report. So, where “ES.6” is listed in the table, it pertains to the new version only and, for the previous version, should be “ES.5.” Note also that in some places information was removed from, or added to, a section compared to the previous version of the report.

Indicator	Unit	Including Fossil Fuel Substitution (Cradle-to-Final Energy)			Excluding Fossil Fuel Substitution (Gate-to-Gate)		
		Previous Version of the Report	**This Version of the Report**	**Places in the Report Where the Change Was Made**	**Previous Version of the Report**	**This Version of the Report**	**Places in the Report Where the Change Was Made**
Woody mill residuals differential GHGI	kg CO_2E/GJ	-261	-116	Abstract, Table ES.1 and relative text, Section 6.1.1.1	-154	-8.5	Table ES.5 and relative text, Abstract, Table 7.1 and relative text
Weighted average differential GHGI	kg CO_2E/GJ	-215	-158	Table ES.1 and relative text, Table 6.10	-61.4	-4.6	Table ES.5 and relative text, Table 7.1 and relative text
Woody mill residuals relative GHGI	%	-99.1	-98.7	Table ES.2 and relative text, Section 6.1.1.2	Not calculated in the report		
Weighted average mill residuals relative GHGI	%	-93.9	-93.7	Table ES.2 and relative text, Table 6.10			
Break-even time (woody mill residuals)	years	0.6	1.2	Abstract, Table ES.3 and relative text, ES.6, Figure 6.3, Section 6.1.1.3, Section 9.0	7.4	19.5	Abstract, ES.1 Table ES.5 and relative text, ES.6, Table 7.1 and relative text, Section 9.0
Weighted average break-even time	years	0.2	0.5	ES.4.3, Table 6.10, Section 9.0	2.9	7.6	Table ES.5 and relative text, Table 7.1 and relative text, Section 9.0
Break-even year for ongoing practice (woody mill residuals)	-	Unchanged*			1998†	1979†	Table ES.6 and relative text, Table 7.2
Industry-average benefit	million tonnes CO_2E/yr	218	181	President's Note, ES.1, ES.4.1, ES.6, 6.7, 9.0	The number was added to the text as it was not there previously.		

*The number of years to break-even changed from 1.3 to 1.9 but the year did not necessitate updating. †The number of years was also updated from 16.2 to 34.5.

Other analysis pertaining to woody mill residuals were also updated, including

- the contribution analysis depicted in Figure 6.1;
- the explanation of the timing of emissions in Figure 6.2, Table 6.1, Figure 6.3, Table 6.2, and Figure 6.4,
- the perturbation analyses in Figure 6.6, the sensitivity analyses in Table 6.3;
- the system configuration scenarios in Table 6.4;
- the comparison of the residuals in Figure 6.15;
- the industry-wide benefits from using woody mill residuals only (110 MT CO_2 E removed from the report); and
- the weighted average results in Table 6.10.

In addition, the following changes were also made to the report.

- The text of the abstract, executive summary conclusion, and conclusion were modified to better reflect the limitations of the study.
- A "Significance of Findings" section was added to the executive summary.
- The benefits from using black liquor were recalculated using dynamic radiative forcing. The number went from -182 to -184 kg CO_2E/GJ.
- The analyses on ongoing practices for all residuals type were recalculated using the radiative forcing curves instead of CO_2E curves, leading to some changes when excluding fossil fuel substitution (Table ES.6):
    - wastewater treatment plant (WWTP) residuals went from 2001 to 2004; and
    - paper recycling residuals went from 1997 to 2001.
- The weighted averages and annual values were removed from the ongoing practices tables.
- Some values derived from the literature were corrected and/or clarified and some choices made for the base case and sensitivity analyses for the different manufacturing residuals studied in this report were clarified by adding text in Tables 5.2, 5.3, 5.5, 5.6, and 5.7.
- The choice of the decay rates for all residuals was better justified.
- The equations for calculating emissions from landfill were clarified.

Grouping Montana and Idaho with surrounding states for biogenic accounting

National Council for Air and Stream Improvement *

May 8, 2014

Background

EPA plans to release a new version of its accounting framework for biogenic CO2 emissions from stationary sources during the first half of 2014. It is expected that the new framework will include a procedure for calculating Biogenic Accounting Factors (BAFs) that is based, in part, on forest conditions in regions of the United States.

Regions should consist of states that are related ecologically and where similar levels of forest management are taking place. For example, the following 4 regions result in reasonable state groupings for analysis purposes (Fig 1):

- North: CT, DL, IL, IN, IA, KS, MA, ME, MD, MI, MN, MO, NE, NH, NJ, NY, ND, OH, PA, RI, SD, VT, WV, WI
- South: AL, AR, FL, GA, KY, LA, NC, OK, SC, MS, TN, TX, VA
- SouthWest: AZ, CO, NV, NM, UT
- PacifCoastNW: CA, OR, WA, ID, MT

*http://www.ncasi.org/

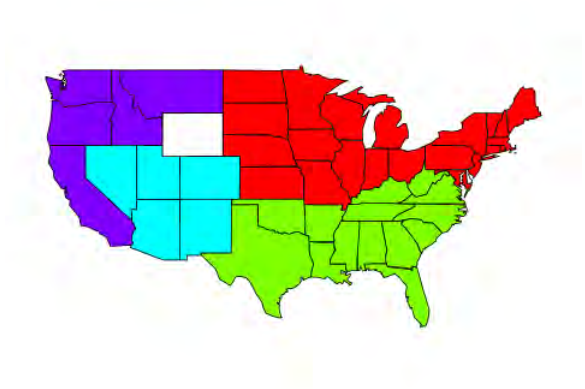

Figure 1: Analysis regions

FIA does not yet have sufficient annual inventory data (Anonymous , 2012) for WY for that state to be included in the analysis. FIA data for AK are generally limited to coastal areas and were not included. MT and ID are grouped with the Pacific Coast states, because they have similar levels of industrial forest activity and share ecological characteristics (Fig 2). We support this grouping with data from the FIA timber products output (TPO) survey and Bailey's (Bailey , 1983) ecological provinces.

Grouping Strategy

We propose grouping states into four regions (Figure 1). The North and South regions closely correspond to FIA regions. The other two regions differ from FIA regions in that we have assigned Montana and Idaho to the Pacific Coast NW region rather than the South West. We have proposed this grouping because Montana and Idaho both have significant forestry taking place unlike the South West. Furthermore, our analysis shows the South West is the only region with recent per acre mean above ground biomass (AGB) decline which is likely due to drought, insects, diseases, and fire rather than forest harvesting. Placing Montana and Idaho in the South West region would tend to diminish and obscure the South West AGB decline.

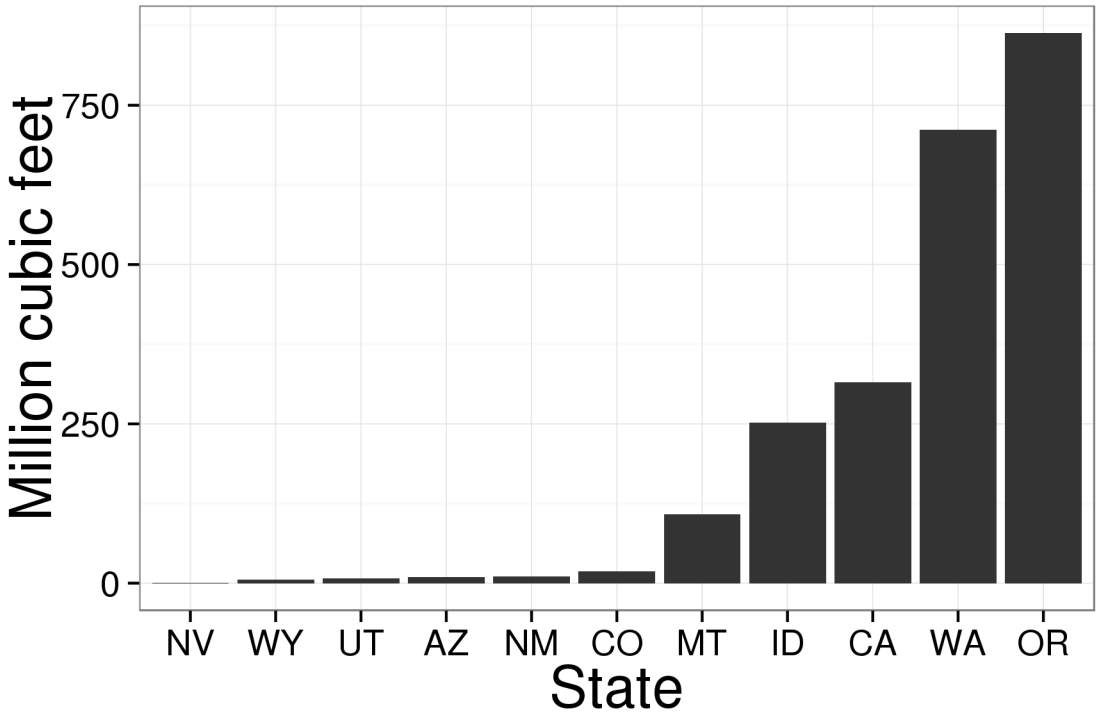

Figure 2: FIA Timber Product Output removals data (excluding firewood)

Support for grouping ID and MT with the Pacific Coast states

Harvest removals data from the FIA TPO database suggest (Fig 2) that ID and MT fit better with CA, OR and WA than with the SouthWest states. Removals from ID and MT are at levels more similar to CA, OR, and WA than to the SouthWest states.

Bailey's eco-provinces also lend some support for grouping ID and MT with the Pacific Coast states. In particular, ID and MT are similar ecologically to western WA and OR (Fig 3). FIA forested plots are colored according to Bailey's province (Fig 3), which shows more province overlap with OR and WA than with neighboring SouthWest states.

The timberland acreage by Bailey's province and state (Tab 1) allows for closer scrutiny of the relationship between MT, ID and surrounding states. Most of the timberland acreage in MT and ID is in Bailey provinces M332 "Middle Rocky Mountain Steppe–Coniferous Forest–Alpine Meadow Province" and M333 "Northern Rocky Mountain Forest-Steppe–Coniferous

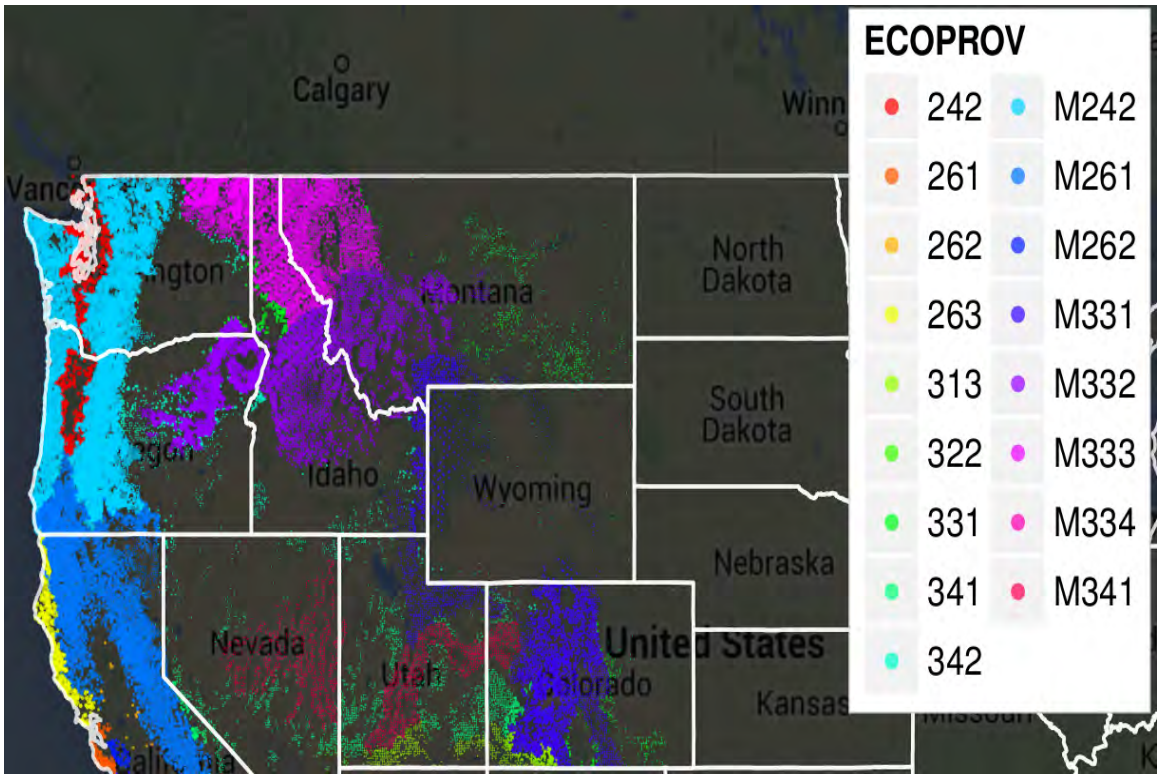

Figure 3: FIA plots colored by Baileys eco-province.

Forest–Alpine Meadow Province". Table (1) indicates that provinces M332 and M333 also have significant acreage in OR and WA. ID and MT also have some timberland acreage in province 331 "Great Plains-Palouse Dry Steppe Province" which is shared with OR and WA, but also with CO and WY. There is also some acreage in M331 "Southern Rocky Mountain Steppe–OpenWoodland–Coniferous Forest–Alpine Meadow Province" that is not shared with OR or WA. Regardless, ID and MT have more timberland acreage in provinces that are found in WA and OR than with any other states.

A map of AGB also supports grouping ID and MT with CA, OR and WA. The greener areas (Fig 4) indicate more per acre AGB. Generally, MT and ID have higher levels of per acre AGB than the other SouthWest states. CO may be an exception and WY has too little FIA annual inventory data available yet to make a definitive statement.

Prov	CA	CO	ID	MT	NV	OR	UT	WA	WY	All
242						616		1540		2156
261	237									237
262	7									7
263	2104					29				2134
313		513					37			551
322					7					7
331		226	559	2275		5		55	414	3534
341	163	320			45		214			742
342	6	12	611		53	314	28	317	216	1556
M242						15358		13041		28399
M261	14323				90	3355				17769
M262	221									221
M331		9644	1486	1264			1819		4342	18555
M332			8304	8668		5776		321		23069
M333			5936	7403				3935		17274
M334									447	447
All	17061	10858	16896	19609	295	25454	3767	19209	5419	118566

Table 1: Timberland acres (x1000) by state and Bailey's province.

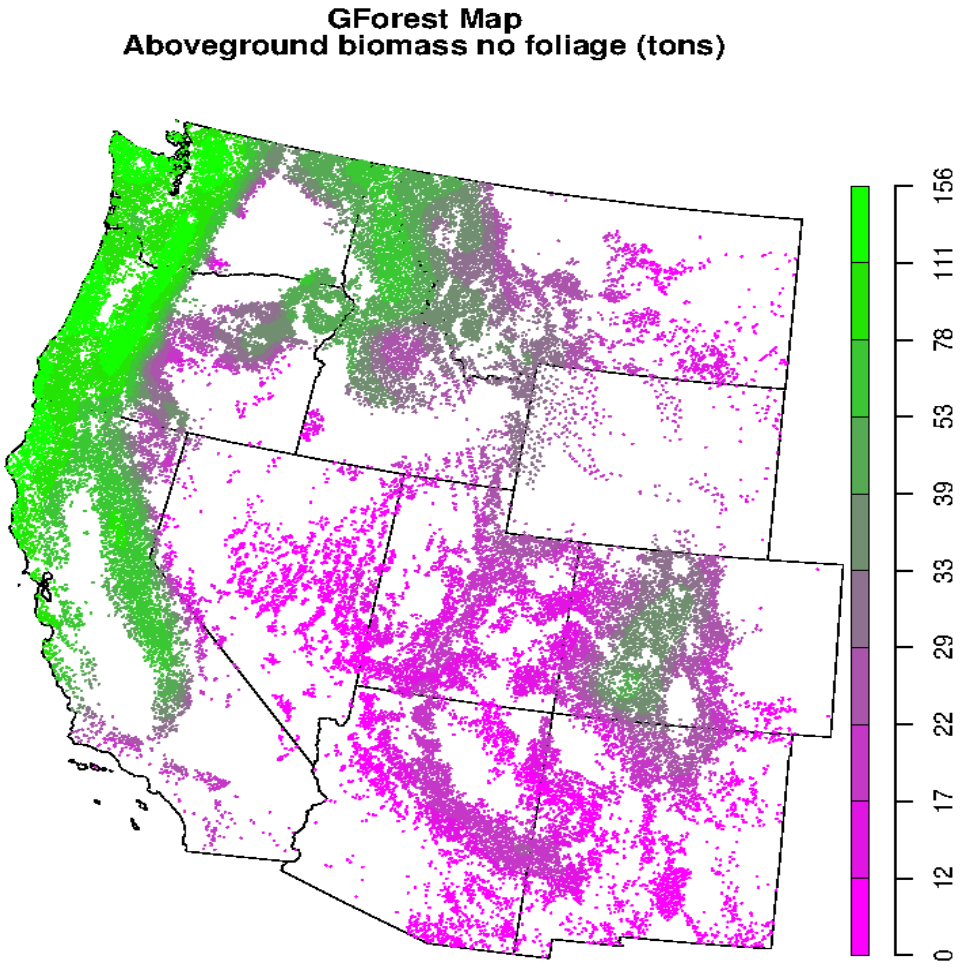

Figure 4: FIA plot locations colored according to above ground biomass. A loess smoothing procedure is applied to enhance AGB spatial patterns.

Conclusions

The lower 48 states could be grouped by a number of criterion for biogenic accounting purposes. We chose to keep most of the states within their FIA designated regions. Our southern region is the same as FIA's southern region, and our northern region is nearly the same. However, we created a PacificCoastNW and a SouthWest region that differ somewhat from FIA regions. In particular, we grouped MT and ID with CA, OR and WA, because they have similar levels of industrial forest activity and share many ecological characteristics. Also, the SouthWest region shows recent AGB declines that are likely due to fires, insects and diseases rather than harvesting. Therefore, it seems reasonable to separate the SouthWest region to facilitate further analysis.

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