

Biomass gasification for green ammonia production in kraft mills

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ABSTRACT: As the global energy sector transitions toward net-zero emissions, kraft pulp mills present a compelling opportunity to produce green fuels and achieve net-negative emissions by capturing biogenic carbon, helping offset hard-to-abate sectors. This study explores the techno-economics of integrating biomass gasification for green ammonia production within kraft mills, using KraftSIM modeling to evaluate ammonia production, steam balance, emissions, and utility impacts. The proposed design enables energy and water system integration with the existing mill and allows for a gradual scale-up without disrupting the chemistry and operation of the recovery cycle.

Across five scenarios representing different biomass gasification rates ranging from 100 to 1000 bone-dry metric tons per day (BDMT/d), the process yields ammonia at approximately 0.51 metric tons per bone-dry metric ton (t/BDMT), while generating significant low- and medium-pressure steam and hot water that offset mill utility demands. The incineration of pressure swing adsorption tail gas and ammonia plant purge gas in the power boiler reduces biomass combustion and enhances power boiler efficiency. Economic analysis suggests a net revenue potential of approximately CA\$380/BDMT, which could increase with the implementation of biogenic carbon pricing. Overall profitability is strongly influenced by biomass procurement costs, electricity prices, and prevailing green fuel and chemical market premium. This work outlines a practical, near-term decarbonization pathway for kraft mills by coupling green fuel production with potential opportunities for carbon removal.

Application: This study modeled the integration of biomass-derived ammonia synthesis into a kraft mill using CADSIM Plus. Green ammonia production was estimated based on feedstock characteristics, gasification performance, water-gas shift conversion, and pressure swing adsorption efficiency. Integration of the ammonia and kraft mill energy systems shifted steam requirements across pressure levels, creating opportunities for heat recovery and improved overall energy efficiency.

As the world continues to move toward a net-zero future, sectors capable of achieving net-negative emissions will become critically important to offset hard-to-abate sectors like agriculture, long-haul transport, and aviation. Kraft pulp mills are uniquely positioned to become net-negative through the capture of biogenic emissions released during normal mill operations. This context presents a compelling business case for transforming biomass and black liquor, which are traditionally used for steam and green power generation, into higher-value outputs by valorizing hydrogen and carbon separately. Specifically, the co-production of green ammonia (NH₃) and the capture of concentrated biogenic carbon dioxide present an opportunity to produce green fertilizers and marine fuels, serve as a hydrogen carrier for energy transport of a carbon-free fuel, and generate potential revenue through carbon removal [1-4]. Thus, a “net-zero optimal” kraft mill of the future could be envisioned as one where chemical recovery and utility systems are centered on black liquor gasification, integrated syngas processing with heat recovery, heat pumps, and carbon capture and storage. Such a configuration could enable multiple revenue streams through the production of pulp, green ammonia, and biogenic carbon dioxide. In this role, kraft mills could serve

as anchor sites within regional energy systems, providing on-demand, grid-supporting services and facilitating greater integration of renewable energy [4].

Green ammonia is increasingly recognized as a key energy carrier in a net-zero economy, with smaller modular ammonia plants located near consumption centers potentially becoming economically attractive. In favorable renewable-energy regions, green ammonia could achieve cost parity with fossil-based ammonia as early as 2030 [5]. Continued research, technology development, and policies supporting sustainable biomass sourcing are expected to further strengthen the role of green ammonia in the transition toward a low-carbon, bio-based economy [5].

Biomass gasification is among the most promising thermochemical pathways to support this transition. Compared with alternative biomass conversion technologies such as pyrolysis, gasification can produce syngas with substantially higher hydrogen concentrations and yields, typically ranging from 30–80 vol% hydrogen depending on feedstock, catalyst selection, and operating conditions [4]. Beyond hydrogen production, biomass gasification can reduce waste disposal costs, alleviate biomass handling challenges, and minimize greenhouse gas emissions associated with biomass decomposition or open-field burning, particularly

RECOVERY CYCLE

when coupled with carbon capture [5]. The production of a concentrated biogenic carbon dioxide stream further makes biomass gasification one of the few hydrogen production pathways capable of achieving net-negative emissions [3].

Kraft mills are uniquely positioned to leverage these advantages through the integration of biomass gasification utilizing both internally generated residues and potentially externally-sourced woody and forestry wastes. Such an approach could convert low-value biomass streams into green ammonia while supporting circular economy objectives through the utilization of by-products generated by neighboring industries [5]. Internally available biomass resources may also reduce exposure to feedstock procurement costs and competition from other biomass-consuming sectors [4]. Continued research focused on scale-up, commercial deployment, syngas cleanup, catalyst development, and kraft mill integration strategies will be essential to address the remaining technical challenges, particularly those associated with tar and sulfur contaminants present in biomass-derived syngas [4].

Previous studies have demonstrated the potential benefits of biomass gasification integration within kraft mills. Andersson and Lundgren reported that gasification integration could improve overall mill energy efficiency by approximately 10% while providing a consistent hydrogen supply for ammonia production [4,6]. Similarly, Tang et al. demonstrated that waste pulp could be effectively converted into hydrogen-rich syngas through gasification using low-cost electroplating sludge-derived carriers, highlighting an attractive pathway for simultaneous waste utilization and hydrogen production [5,7]. Despite these promising findings, relatively few studies have rigorously evaluated the full integration of biomass gasification within kraft mills for green ammonia production [3].

The International Energy Agency (IEA) identified biomass gasification as one of the leading commercial-scale pathways for low-carbon hydrogen production, reporting representative hydrogen yields of approximately 100 kg hydrogen per bone-dry metric ton (BDMT) of biomass gasified, corresponding to a biomass-to-hydrogen efficiency of roughly 67% on a higher heating value (HHV) basis [3]. Reported efficiencies range from approximately 35%–75%, depending on technology configuration and underlying assumptions [3]. The IEA estimated hydrogen production costs in the range of CA\$4–6/kg hydrogen and approximately CA\$3.5–5.5/kg hydrogen when carbon capture opportunities are considered [3]. These costs are considered competitive with conventional steam methane reforming and potentially competitive with future renewable electrolysis pathways. The IEA further assigned biomass gasification for hydrogen production a technology readiness level (TRL) of approximately 6–7, indicating that the individual process components are largely proven, while large-scale integrated commercial deployment remains the primary challenge [3].

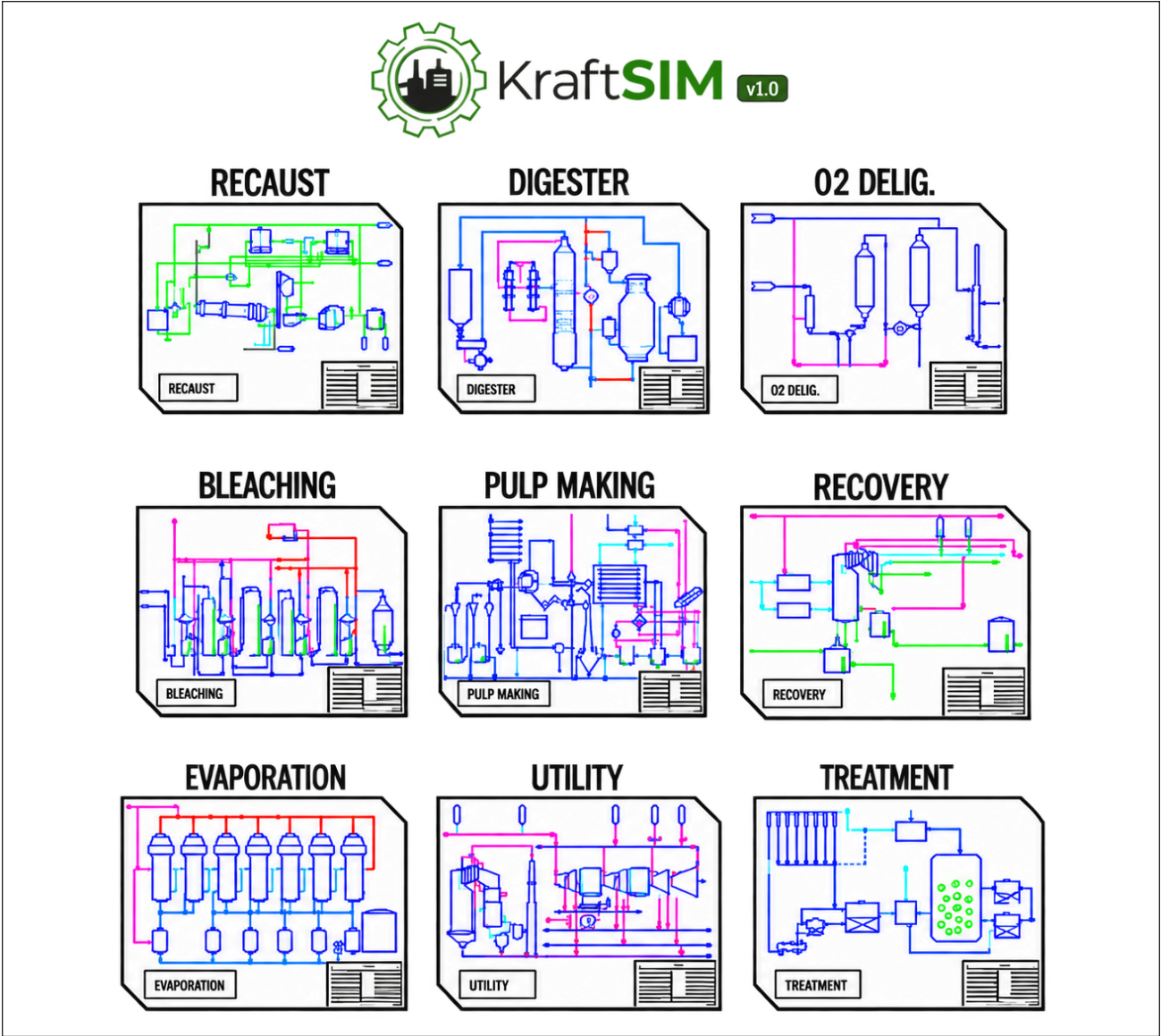
Although numerous studies have examined state-of-the-art hydrogen production and biomass gasification technologies, few have evaluated the detailed integration of biomass gasification for hydrogen and subsequent green ammonia production within a fully interconnected kraft mill. This study addresses that gap by investigating biomass gasification integration for green ammonia production within a kraft mill without carbon capture infrastructure, representing a more accessible deployment pathway that could be implemented as early as 2030 without major technical or market barriers. The proposed configuration maintains the integrity of the existing recovery cycle, avoiding disruption to pulp production and chemical recovery operations while eliminating the complexity associated with carbon dioxide transportation and storage infrastructure, which could be integrated later [3,5]. The novelty of this work lies in its application of KraftSIM, a free publicly-available modeling tool hosted by Natural Resources Canada and developed in CADSIM Plus Version 3.4.14 (Aurel Systems; Burnaby, BC, Canada), to represent an average Canadian kraft mill as a fully integrated and interconnected system, enabling the evaluation of cross-departmental energy, utility, and emissions interactions. This mill-wide perspective establishes a pathway for the incremental transition of kraft mills toward a biorefinery model in which green fuels and, ultimately, negative emissions become integral components of core mill operations.

METHODS

A set of models including a biomass dryer, gasifier, syngas cleaning and conditioning train, and ammonia synthesis plant were developed to assess the techno-economics of integrating green ammonia production within kraft mills. In particular, the models helped evaluate heat recovery opportunities and the net utility impacts across the mill. Simulations were conducted using KraftSIM, which is designed to evaluate the integration of emerging technologies, alternative product pathways, and carbon capture within kraft mills by capturing both departmental and mill-wide energy interactions [8]. The base case model (prior to biomass gasification integration) consists of nine interconnected departmental drawings, illustrated in **Fig. 1**, representing a Canadian northern bleached softwood kraft (NBSK) market pulp mill operating under average chemistry, efficiency, and technology assumptions. The model was then modified to incorporate a biomass gasifier within the utility drawing, along with two additional drawings for syngas processing and ammonia production, as described in the following sections.

Scenarios

This study evaluates ammonia production, steam balances, biomass firing in the power boiler, emissions, electricity demand, and economic performance across a range of gasification rates in bone-dry metric tons per day (BDMT/d), as outlined in **Table I**. The BC (SW1) scenario represents



1. KraftSIM base case departmental drawings [9,10].

the base case kraft mill, producing 1,035 air-dry metric tons per day (ADMT/d) of bleached softwood market pulp without biomass gasification. All other scenarios integrate biomass gasification into this base case without altering recovery cycle operations, maintaining constant pulp production rates, kappa numbers, white liquor chemistry, and dilution factors. In all scenarios, high-pressure (HP 59 barg) steam production from the power boiler was fixed at a minimum of 120 metric tons per hour (t/h) to maximize biomass availability for gasification. This constraint was managed by adjusting the condensing turbine load, allowing power generation to fluctuate to maintain overall steam balance.

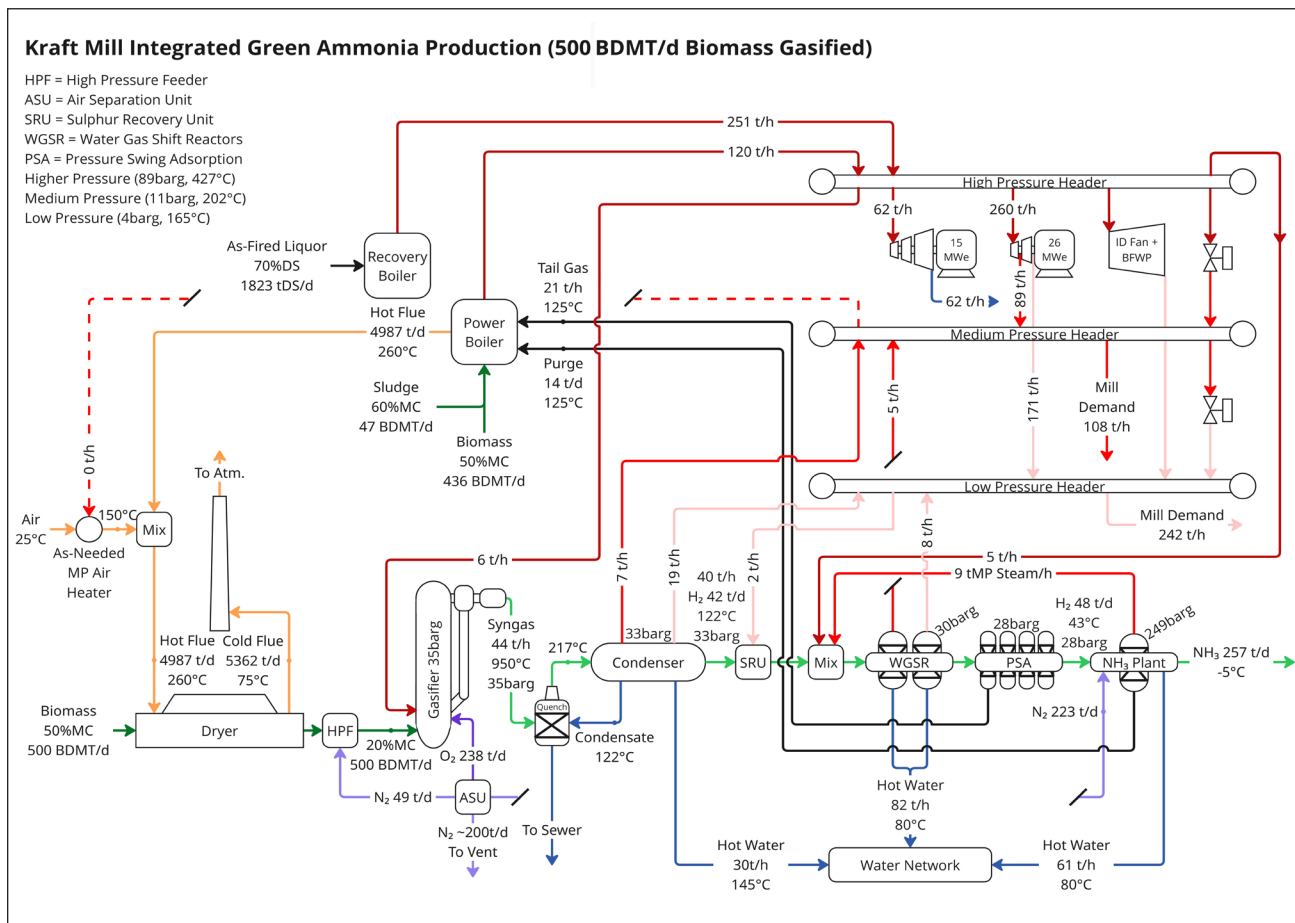
Process flow description
Figure 2 illustrates the process flow from biomass drying to final ammonia production, fully integrated with the kraft mill's steam and water systems. Representative results for

Scenario	BDMT/d Gasified
BC (SW1)	0
BMGS100	100
BMGS250	250
BMGS500	500
BMGS750	750
BMGS1000	1000

BC: base case; SW1: softwood; BMGS: biomass gasification case; BDMT/d: bone-dry metric tons per day.

I. Scenario description.

RECOVERY CYCLE



2. Process flow diagram of green ammonia production in kraft mills. Results are shown for 500 bone-dry metric tons per day (BDMT/d) biomass gasification case (BMGS500).

the 500 BDMT/d biomass gasification case (BMGS500) are included for context.

Biomass drying and pressurization

Wet biomass at 50% moisture content (MC) was dried to 20% MC via direct contact with power boiler flue gases at 260°C, supplemented by hot air at 150°C when necessary. The dried biomass was then pressurized to 35 barg using high-purity nitrogen from the air separation unit (ASU) at a loading rate of 0.0797 metric tons nitrogen gas per BDMT of biomass gasified ($t_{N_2}/BDMT_{GS}$) [1].

Biomass gasification and heat recovery

Dried biomass was gasified in a pressurized oxygen-blown circulating fluidized bed gasifier [1,2]. The high-pressure (HP) steam reduced to 35 barg was injected at 0.277 metric tons steam (t_{Steam})/ $BDMT_{GS}$ to help fluidize the pressurized bed (35 barg) and promote the water-gas shift reaction ($CO + H_2O \rightleftharpoons CO_2 + H_2$), enhancing hydrogen production in the syngas. High-purity 35 barg oxygen from the ASU was supplied at 0.476 $t_{O_2}/BDMT_{GS}$. The resulting hot 35 barg raw syngas exited the gasifier at 950°C, was quenched to 217°C using syngas condensate, and further

cooled to 122°C in a 33 barg condenser where the majority of water vapor was condensed.

This staged cooling process enabled heat recovery and generation of medium-pressure (MP 11 barg) and low-pressure (LP 4 barg) steam at rates of approximately 0.35 $tMP/BDMT_{GS}$ and 0.92 $tLP/BDMT_{GS}$, respectively, as well as 145°C hot water (HW) at 1.5 $tHW/BDMT_{GS}$. The compositions and component yields of both raw and cooled syngas are summarized in **Table II**.

Sulfur removal

All sulfur-containing gases, primarily hydrogen sulfide (H_2S) and carbonyl sulfide (COS), were removed using the Rectisol process — modeled as a sulfur recovery unit (SRU) black box — to safeguard downstream catalysts [1]. The process requires approximately 0.11 $tLP/BDMT_{GS}$ for the regeneration of the methanol-based solvent. In addition to sulfur removal, Rectisol also captures carbon dioxide (CO_2) present in the syngas, which is subsequently vented to the atmosphere.

Syngas shifting and heat recovery

Desulfurized syngas at 31 barg was blended with HP steam that was partly generated in a waste heat boiler in the am-

Component	Raw 950°C Syngas at 35 barg			Cooled 122°C Syngas at 33 barg		
	vol%	wt%	t/BDMT _{GS}	vol%	wt%	t/BDMT _{GS}
H ₂	40.0	4.0	0.085	44.4	4.4	0.085
CO ₂	25.0	55.0	1.15	27.8	60.5	1.15
H ₂ O	15.7	14.1	0.30	6.3	5.6	0.11
CO	14.1	19.8	0.42	15.7	21.8	0.42
CH ₄	1.0	0.8	0.017	1.1	0.9	0.017
H ₂ S+COS	0.006	0.01	0.00022	0.007	0.01	0.00022
N ₂ +Ar	4.2	6.3	0.13	4.7	6.8	0.13

H₂: hydrogen gas; CO₂: carbon dioxide; H₂O: water; CO: carbon monoxide; CH₄: methane; H₂S: hydrogen sulfide; COS: carbonyl sulfide; N₂: nitrogen gas; Ar: argon; t/BDMT_{GS}: metric tons per bone-dry metric ton of biomass gasified.

II. Syngas composition [1,2,11-13].

monia plant at a rate of 0.69 tHP/BDMT_{GS} at the inlet of the 30 barg water-gas shift reactors (WGSRs). This maintains a water/carbon monoxide (H₂O/CO) molar ratio of 3.0 in the syngas, thereby maximizing hydrogen yield [11,14].

Similar to the syngas cooling stage, additional heat recovery from the WGSR product streams yielded approximately 0.22 tMP/BDMT_{GS} and 0.38 tLP/BDMT_{GS} of steam, along with 80°C hot water at a rate of 3.9 tHW/BDMT_{GS}. The WGSR temperatures, pressures, and corresponding carbon monoxide conversion rates are summarized in **Table III**.

Hydrogen purification and tail gas incineration

Shifted syngas at 29 barg was cooled to 43°C, condensing 99% of the water vapor, which was removed via a knockout unit and directed to effluent treatment. The resulting dry shifted syngas, containing 69 vol% hydrogen, was processed through a 28 barg pressure swing adsorption (PSA) unit to isolate high-purity hydrogen (99.9 vol%) with a recovery rate of 85% [11]. The purified 28 barg hydrogen was then sent to the ammonia plant. The PSA tail gases — rich in carbon dioxide (58 vol%) — were preheated to 125°C using hot WGSR product streams and routed to the power boiler for incineration of residual combustibles, including hydrogen, methane, and carbon monoxide.

Ammonia synthesis and heat recovery

Hydrogen from the PSA unit was blended with nitrogen from the ASU at a rate of 0.44 tN₂/BDMT_{GS} to maintain an hydrogen gas/nitrogen gas (H₂/N₂) molar ratio of 3. This mixture was compressed from 28 barg to 249 barg, raising its temperature from 42°C to 342°C before entering the ammonia synthesis loop. The fresh feed was combined with a hot recycle stream at 452°C, and the combined stream entered the ammonia synthesis reactor at 415°C. This entry

Reactor	Inlet, °C	Outlet, °C	Vessel, barg	CO Conversion Rate
High temperature	320	450	30	85%
Low temperature	200	270	29	75%
Combined	—	—	—	95%

III. Water-gas shift reactor operation [11,16] (CO: carbon monoxide).

temperature was selected to ensure that the exothermic ammonia synthesis reaction ($\text{N}_2 + 3\text{H}_2 \rightleftharpoons 2\text{NH}_3$) reaches an optimal outlet temperature of approximately 550°C, balancing increased reaction kinetics with declining ammonia equilibrium concentrations at higher temperatures [15,16].

Roughly 46% of the hot product gases, comprising 20 vol% ammonia, were used to generate 0.43 tHP/BDMT_{GS} (31 barg saturated, not suitable for turbines) steam for the WGSRs, while the rest reheated the recycle stream. Heat integration is optimized to maximize HP steam recovery and maintain a stable reactor inlet of 415°C. The recombined product stream was then cooled to -5°C using cold water followed by ammonia refrigeration, producing 80°C hot water at 2.9 tHW/BDMT_{GS}. At this point, ammonia was condensed and separated (1.4 vol% remaining in the gas phase) using a knockout unit, with the liquid product pumped and sold [15,16]. A purge stream equal to 5% of the incoming fresh feed was used to remove inert gases such as carbon dioxide, steam, and argon. This rate was conservatively set to account for all intermediate losses across the ammonia production process. The purge was then preheated to 125°C and directed to the power boiler for incineration [17].

Table IV presents the specific electricity consumption for each process load associated with green ammonia pro-

RECOVERY CYCLE

Load	kWe/(BDMT _{GS} /d)
Ammonia plant	9.9
ASU	5.8
SRU	2.2
PSA	1.4
Dryer	1.2
ASU: air separation unit; SRU: sulfur recovery unit; PSA: pressure swing adsorption; kWe/(BDMT _{GS} /d): kilowatt electric per bone-dry metric ton of biomass gasified.	

IV. Green ammonia electrical load [1].

duction. Of these, the compressors and refrigeration unit within the ammonia synthesis plant accounted for the largest share of electrical demand.

RESULTS AND DISCUSSION

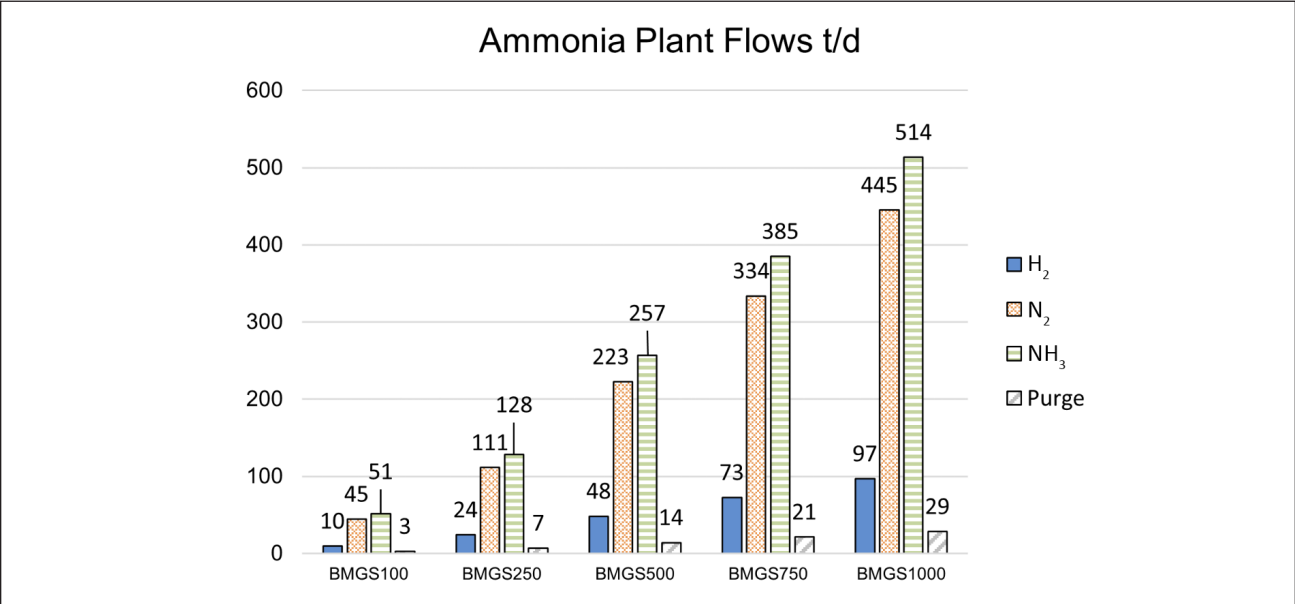
Each scenario was run in KraftSIM and tuned to where all measured variables were at setpoint and reached a steady state. All scenarios resulted in ammonia production proportional to biomass input. Hydrogen was supplied to the ammonia plant at a fixed rate of roughly 0.097 t/BDMT_{GS} of biomass gasified, and ammonia was produced at approximately 0.51 t/BDMT_{GS}. The high yield reflects a hydrogen-rich raw syngas (40 vol%) and a 95% conversion of carbon monoxide across the WGSRs. **Figure 3** shows the mass flow rates of hydrogen and nitrogen fed to the plant, the resulting ammonia production, and the purge stream directed to the power boiler for incineration.

In green ammonia production, the gasifier and WGSRs

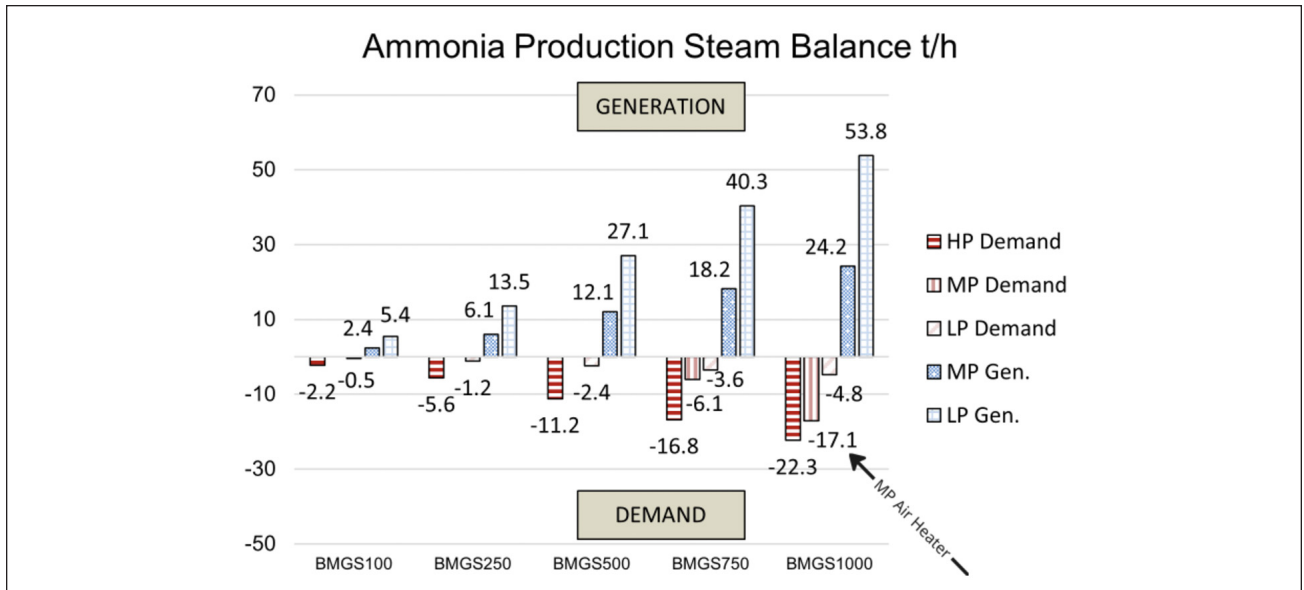
consume HP steam, but significant quantities of LP and MP steam are generated by recovering heat from cooling the syngas and other hot product streams. **Figure 4** provides the total steam generation and demand mass flow rates at the various pressures. There is a net HP steam demand of about 0.53 tHP/BDMT_{GS} and a net generation of roughly 1.18 tLP/BDMT_{GS} along with 0.17–0.58 tMP/BDMT_{GS}. The lower end of the net MP generation occurred when wet biomass (50% MC) cannot be dried to 20% MC using waste heat alone (e.g., from the power boiler flue gas). In such cases (gasifying more than 600 BDMT/d, additional MP steam is consumed to generate hot air for supplemental drying.

In addition to net LP and MP steam generation, the process delivered significant quantities of hot water at two temperature levels, both of which help reduce LP steam demand. Specifically, hot syngas cooling produced 145°C water at approximately 1.5 tHW/BDMT_{GS}, which was utilized to preheat boiler feedwater, thereby offsetting the LP steam required by the deaerator. Furthermore, an additional stream of hot water was recovered at 80°C — exceeding the temperature requirements of the hottest end user (bleach wash at 75°C) — at a rate of roughly 6.8 tHW/BDMT_{GS}. This hot water was directed to a hot water tank that supplies various mill processes, resulting in LP steam savings for pulp and bleach washing and tank heating, as shown in **Fig. 5a**.

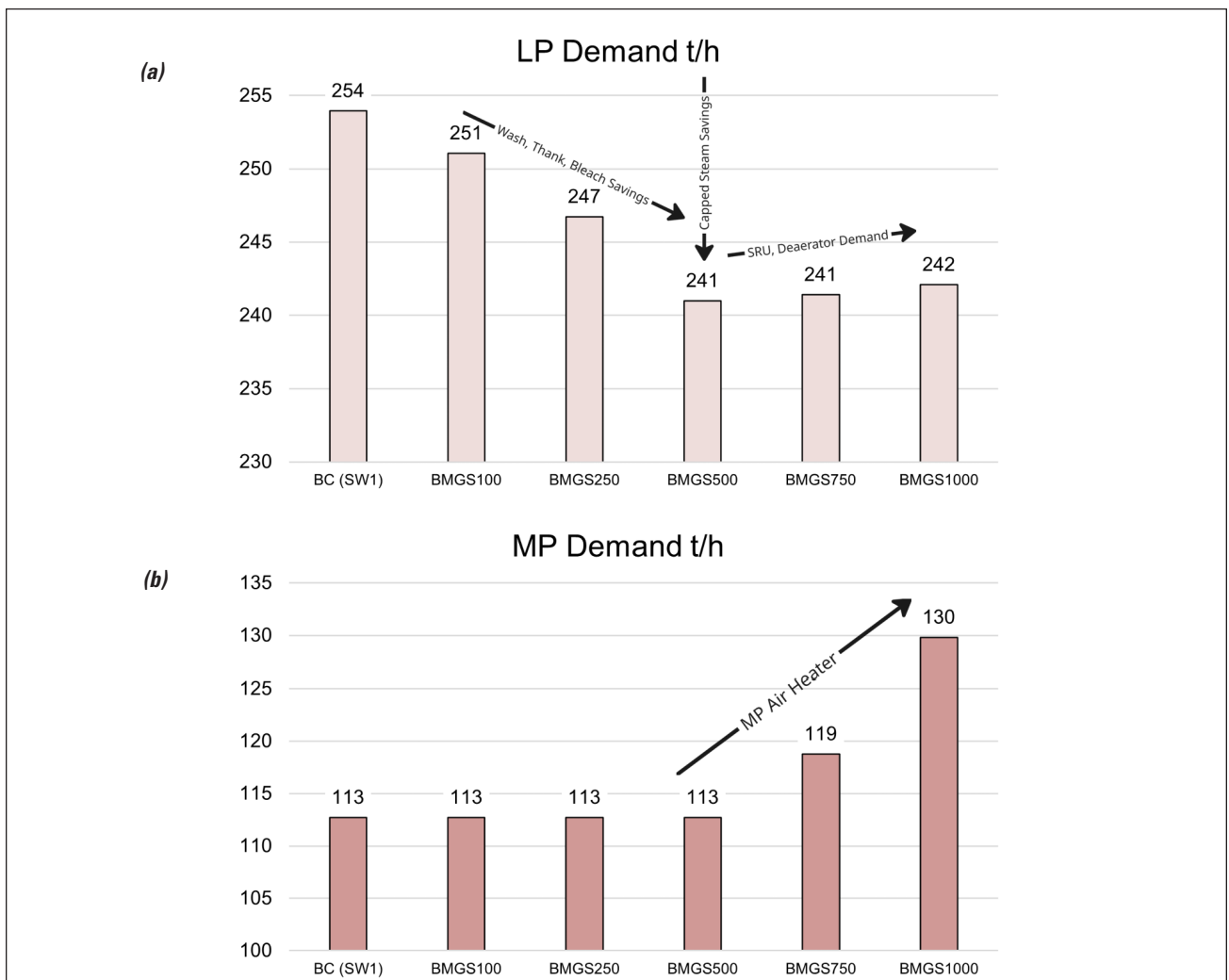
However, steam savings plateaued once tank temperatures exceeded the requirements of their end-use applications. For instance, tank temperatures rose from 60°C in the base case to approximately 73°C at gasification rates of 500 BDMT/d or higher, surpassing the 70°C operating requirement of the decker shower. As a result, additional hot water production no longer offset steam demand. Beyond



3. Ammonia (NH) production (t/d: metric tons per day; H₂: hydrogen gas; N₂: nitrogen gas).

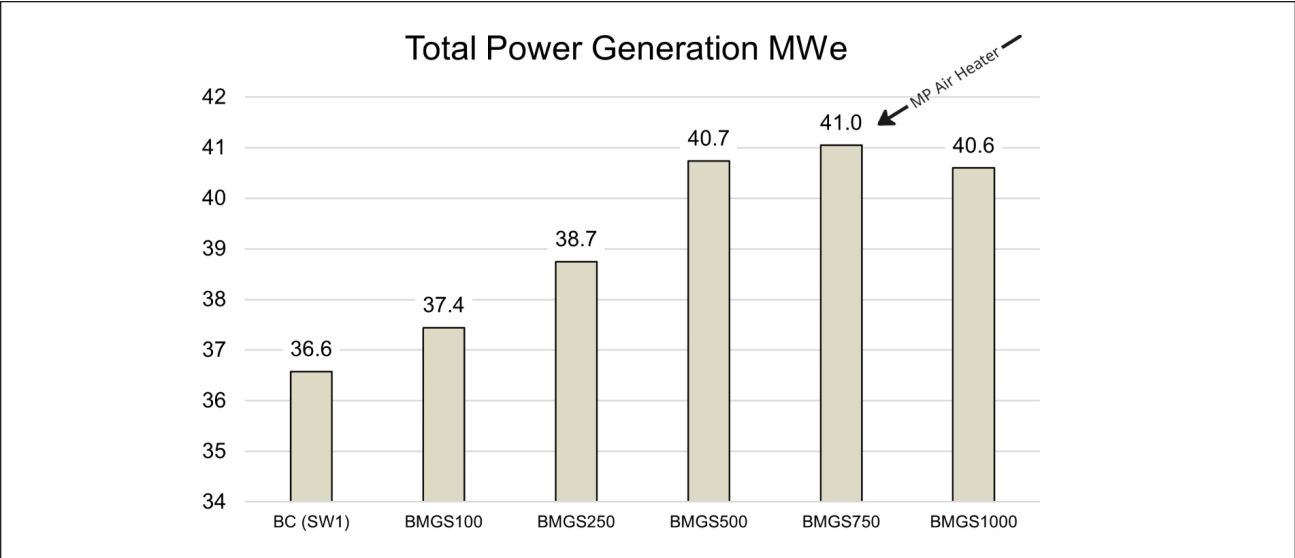


4. Ammonia production steam balance (t/h: metric tons per hour; BMGS: biomass gasification case; HP: high pressure; MP: medium pressure; LP: low pressure).

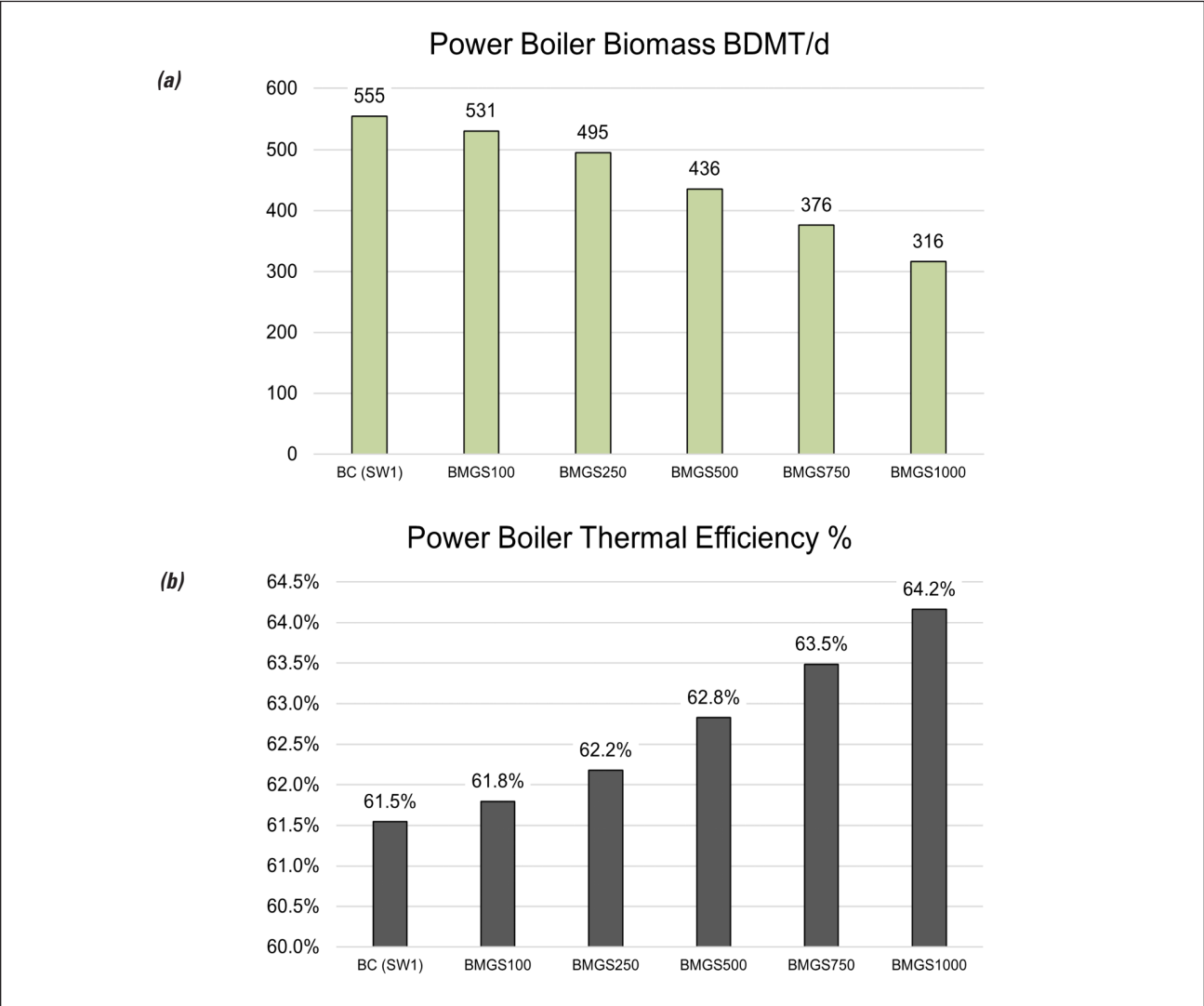


5. (a) Mill low-pressure (LP) steam demand and (b) medium-pressure (MP) steam demand in metric tons per hour (t/h).

RECOVERY CYCLE



6. Total power generation (MWe: megawatt electricity).



7. (a) Power boiler biomass (BDMT/d) and (b) thermal efficiency (%).

this point, LP steam demand continued to increase, driven by rising requirements from the deaerator and sulfur recovery unit (SRU). Additional water network optimization — such as evaluating series and parallel heat exchanger configurations and refining water return temperature targets — could further reduce overall LP steam consumption across the mill. Meanwhile, MP steam demand remained steady until supplemental drying was required; when gasification exceeded 600 BDMT/d, an additional 2.6 tMP/BDMT_{GS} was consumed for each metric ton beyond this threshold, as depicted in Fig. 5b.

Across all scenarios, HP steam production from the power boiler was held at a minimum of 120 t/h to maximize biomass availability for gasification. This constraint was managed by adjusting the condensing turbine load, enabling power generation to fluctuate to maintain steam balance across the mill. Alternatively, if turbine loads are fixed, adjustments in wet biomass firing would be required to preserve this balance.

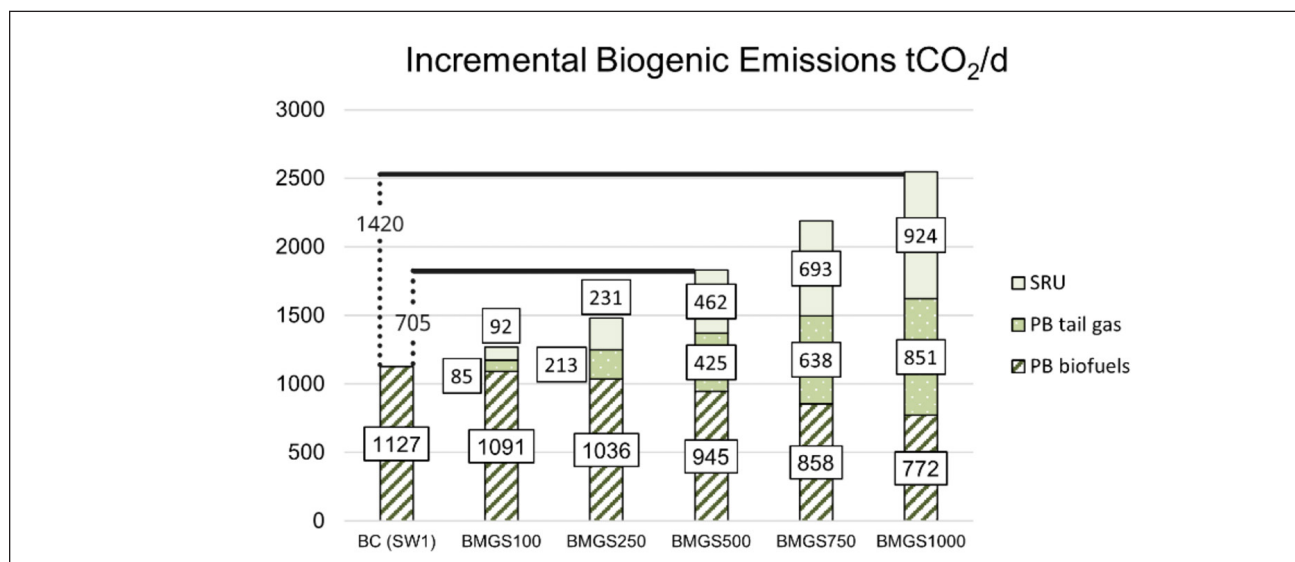
As gasification rates increased, more MP and LP steam was recovered from the ammonia production line, reducing the mill's dependence on the back-pressure turbine and allowing greater steam flow to the condensing turbine, thereby boosting power generation. The nonlinearity observed beyond 500 BDMT/d in Fig. 6 is attributed to the activation of MP steam demand for biomass drying, which begins at gasification rates above 600 BDMT/d. Before this inflection point, power generation increased approximately linearly at a rate of 8.6 kilowatt electric (kWe)/(BDMT_{GS}/d). Ultimately, the realized impact on power generation will depend on the specific configuration and flexibility of each mill's utility system.

The need to incinerate hydrogen, carbon monoxide, and methane contained in hot (125°C) PSA tail gases and in the ammonia purge stream provides the opportunity to com-

bust them in the power boiler, resulting in biomass savings. Biomass fuel savings in the power boiler are linearly generated at approximately 0.24 BDMT_{Combusted}/BDMT_{GS}, as shown in Fig. 7a. Furthermore, as less wet biomass is required to sustain 120 tHP/h steam generation, less moisture was introduced with the fuel, resulting in improved thermal efficiency, as illustrated in Fig. 7b.

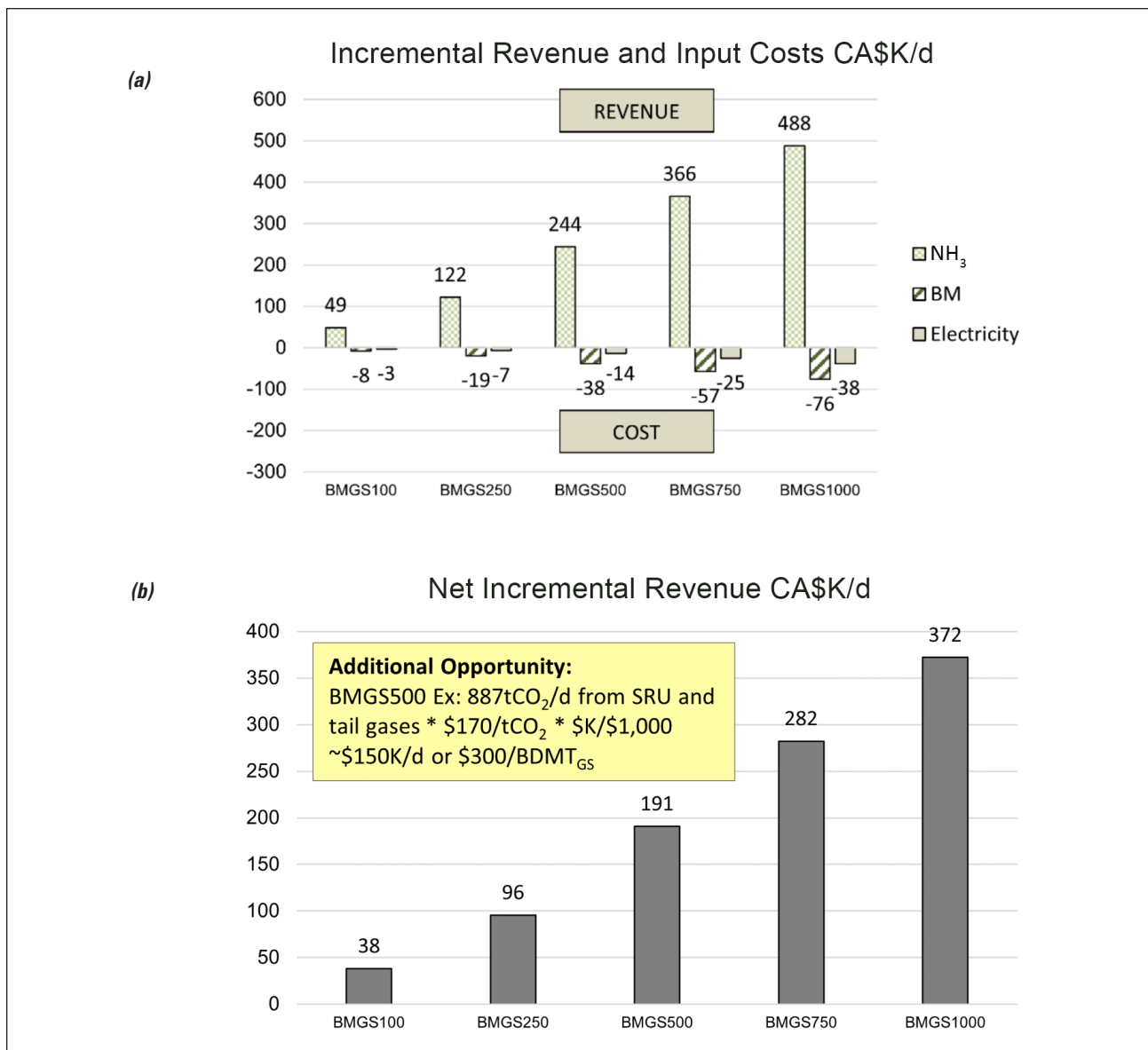
Integrating biomass gasification into the kraft mill did not affect the chemistry, efficiency, or operation of the recovery cycle. Consequently, recovery boiler emissions remained steady at 2201 tCO₂/day (biogenic), with lime kiln emissions unchanged at 178 tCO₂/day (biogenic) and 62 tCO₂/day (fossil). Additional biogenic emissions arose from the gasification process, approximately 0.92 tCO₂/BDMT_{GS} from the SRU and 0.85 tCO₂/BDMT_{GS} from PSA tail gas (pre-combustion). The latter results from the water-gas shift conversion of carbon monoxide to dioxide. As illustrated in Fig. 8, increasing the use of PSA tail gas in the power boiler significantly reduced emissions from biofuel (biomass, sludge, tail gas combustibles) combustion, declining from 10.91 to 0.77 tCO₂/BDMT_{GS}. However, total incremental biogenic emissions rose at a consistent rate of 1.41 tCO₂/BDMT_{GS} due to fixed raw syngas composition, WGSR chemistry, and gas separation performance. Notably, the high carbon dioxide concentrations in the SRU (99 vol%) and PSA tail gas (58 vol%) offered strong potential for biogenic carbon capture and pipeline transport, enabling full valorization of the biomass-derived hydrogen and carbon.

The primary variable input costs for producing green ammonia in a kraft mill are biomass procurement and electricity purchases. To provide conservative estimates, it was assumed that the biomass required for gasification is externally procured at CA\$100/BDMT, and electricity is purchased at CA\$95/MWh [18,19], reflecting a mill op-



8. Incremental biogenic emissions (tCO₂/d: metric tons carbon dioxide per day).

RECOVERY CYCLE



9. (a) Revenue and input cost changes and (b) net incremental revenue in thousands of Canadian dollars per day (CA\$/d).

erating without surplus power for export. A projected green ammonia sales price of CA\$950/tNH₃ was used to estimate revenue [2]. **Figure 9** illustrates the changes in revenue and input costs across the different gasification scenarios. The net incremental revenue (Fig. 9b) accounts only for biomass and electricity costs against ammonia sales revenue and excludes equipment amortization, labor, or auxiliary expenditures. On average, the net incremental revenue is approximately CA\$380/BDMT_{GS}. Furthermore, if biogenic emissions from the SRU and PSA tail gas are captured and valorized at a Canadian carbon price of CA\$170/tCO₂ (2030 legislated fossil emission price), an additional revenue of roughly CA\$300/BDMT_{GS} could be realized [20], offset by the cost of isolation, transportation, and storage.

CONCLUSIONS

This study modeled the integration of ammonia synthesis from gasified biomass into a kraft mill using CADSIM Plus. Green ammonia production was estimated at approximately 0.51 tNH₃/BDMT_{GS}, with yields dependent on feedstock characteristics, gasification, water-gas shift (WGS) control, and pressure swing adsorption (PSA) separation efficiency. Within the mill context, ammonia production resulted in net HP steam consumption, while generating MP and LP steam and substantial quantities of hot water. Incineration of PSA tail gas and ammonia purge combustibles in the power boiler enabled biomass savings and improved thermal efficiency.

Hot water recovery provided significant LP steam savings; however, benefits plateaued once tank temperatures exceeded process requirements. Similarly, power genera-

tion initially increased with additional MP and LP steam recovery but declined when biomass drying required supplemental MP steam. While recovery boiler flue gas could supplement drying capacity and mitigate MP steam use, future work is needed to assess associated challenges, such as inorganic dust contamination.

At larger syngas processing capacities, excess hot water production may surpass mill demand, potentially limiting near-term synergies but creating opportunities for future heat pump integration. Continued optimization of heat and water networks could further reduce LP steam demand and manage thermal excess. Another option could include producing hot water at 125°C to support remaining LP steam consumers at large.

Positioned within a 2050 net-zero framework, kraft mills could evolve from traditional energy generation toward the production of high-value green fuels like ammonia, alongside biogenic carbon capture for carbon dioxide removal. Under the current assumptions and excluding annualized capital costs, the modeled configuration shows an incremental revenue potential of approximately CA\$380/BDMT_{GS}. As biomass is often already available on site at kraft mills, upgrading its use from green electricity (CA\$65/BDMT) to green ammonia (CA\$450/BDMT) is particularly attractive. In this context, repurposing biomass from combustion to green chemical production may be justified, although economic viability remains highly dependent on input costs and green fuel market premiums.

The National Renewable Energy Laboratory (NREL) estimated that biomass gasification facilities processing approximately 450–1800 BDMT/d of woody biomass could produce roughly 30–135 tH₂/d equivalent to approximately 170–715 tNH₃/d assuming downstream ammonia synthesis [2,4]. Reported capital costs for the biomass gasification and syngas processing facility ranged from approximately CA\$290–470 million, while a corresponding ammonia synthesis plant would be expected to require approximately CA\$120–375 million depending on production capacity. Collectively, these estimates imply a total installed capital cost of approximately CA\$410–850 million across the reported production range [2,4].

For the largest gasification case evaluated in this study, consisting of 1000 BDMT/d of gasified biomass and producing approximately 100 tH₂/d and 500 tNH₃/d, the estimated capital cost is approximately CA\$360 million for the biomass gasification and hydrogen production facility and CA\$270 million for the ammonia synthesis plant, corresponding to a total installed capital cost of approximately CA\$630 million. Based on the earnings before interest, taxes, depreciation and amortization (EBITDA) of CA\$372,000/d predicted for this scenario, a simple payback period of approximately five years can be estimated, assuming 355 operating days per year. It should be noted that this estimate is preliminary and does not constitute a full techno-economic assessment. A comprehensive analysis incorporating financing, taxation, depreciation, operating

costs, and market uncertainties would be required to accurately evaluate project viability. Furthermore, project economics remain highly sensitive to biomass feedstock costs and the market value of green ammonia.

Black liquor gasification could further complement biomass gasification, enabling higher ammonia outputs and economies of scale. Future research will focus on black liquor gasification integration and its impact on process performance and mill utility systems.

If biogenic carbon pricing is legislated, additional revenue could be captured through carbon dioxide removal from the sulfur recovery unit and shifted syngas streams. Achieving net-zero or net-negative emissions will likely require a phased decarbonization strategy that combines low-risk short-term interventions with transformative long-term changes enabled by policy, markets, and technology maturation.

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ABOUT THE AUTHORS

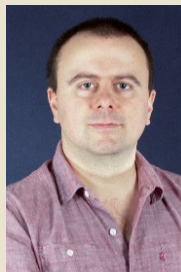
This topic was studied to address current challenges in industrial decarbonization, energy efficiency, and sustainable use of natural resources, while exploring biorefinery concepts and wood valorization pathways that support the transition to a net-zero future.

This research builds on previous work involving process modeling and simulation of kraft mills and the evaluation of process upgrades. It extends that work by exploring the integration of biomass gasification for green ammonia production in KraftSIM and providing insights on the implications of its integration within the interconnected mill system, enabling the evaluation of cross-departmental interactions in energy, utilities, and emissions.

Through this research, we gained insights into the energy and emissions implications of different biomass gasification capacities within a kraft mill, while also improving understanding of heat integration opportunities and supporting the development of industrial solution concepts. A key finding was that ammonia production within the mill resulted in net high-pressure steam consumption while generating medium- and low-pressure steam and significant hot water. Incineration of pressure swing adsorption (PSA) tail gas and ammonia purge



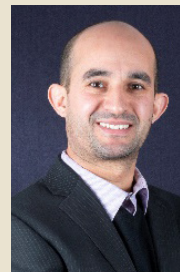
Rogerson



Bernier



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Ghezzaz

streams in the power boiler also enabled biomass savings and improved thermal efficiency.

Mills can benefit from this research by gaining insights into the opportunities for integrating biomass gasification for ammonia production within the kraft process, as well as the associated challenges related to syngas cleaning and handling of PSA tail gas and ammonia purge streams. This knowledge can inform decision-making and help mills develop strategies for producing clean fuels as potential new revenue streams, with limited impact on core mill operation, while contributing to the decarbonization of hard-to-abate industries.

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