Life Cycle Emissions and Cost of Producing Electricity from Coal, Natural Gas, and Wood Pellets in Ontario, Canada

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The use of coal is responsible for $^1/_5$ of global greenhouse gas (GHG) emissions. Substitution of coal with biomass fuels is one of a limited set of near-term options to significantly reduce these emissions. We investigate, on a life cycle basis, 100% wood pellet firing and cofiring with coal in two coal generating stations (GS) in Ontario, Canada. GHG and criteria air pollutant emissions are compared with current coal and hypothetical natural gas combined cycle (NGCC) facilities. 100% pellet utilization provides the greatest GHG benefit on a kilowatt-hour basis, reducing emissions by 91% and 78% relative to coal and NGCC systems, respectively. Compared to coal, using 100% pellets reduces NO_x emissions by 40−47% and SO_x emissions by 76−81%. At $160/metric ton of pellets and $7/GJ natural gas, either cofiring or NGCC provides the most cost-effective GHG mitigation ($70 and $47/metric ton of CO_2 equivalent, respectively). The differences in coal price, electricity generation cost, and emissions at the two GS are responsible for the different options being preferred. A sensitivity analysis on fuel costs reveals considerable overlap in results for all options. A lower pellet price ($100/metric ton) results in a mitigation cost of $34/metric ton of CO_2 equivalent for 10% cofiring at one of the GS. The study results suggest that biomass utilization in coal GS should be considered for its potential to cost-effectively mitigate GHGs from coal-based electricity in the near term.

Introduction

"One of the most significant challenges in addressing global climate change is reducing greenhouse gas (GHG) emissions resulting from the use of coal" (*1*), currently responsible for $^1/_5$ of global emissions. Given the heavy dependence of many countries on coal-fired electricity generation [coal provides 50% of electricity in the US, 80% in China (*1*), and 40% on average worldwide (*2*)], abatement of GHG emissions from this sector will be challenging but critical to meet targets. While carbon capture and storage (CCS) will be needed to make large GHG reductions from coal generation, commercial projects are required to demonstrate the integration of these technologies at large scale and to better understand the technical performance and financial costs (*3*). In the next decade or so, there are few opportunities to make significant GHG emissions reductions from coal electricity generation.

One near-term option that can reduce GHG emissions and be utilized to meet renewable portfolio standards is the combustion of sustainably produced biomass in coal generating stations (GS). In contrast to many other renewable generation options, biomass firing does not have the drawback of being intermittent and is applicable to areas without significant wind, solar, or hydropower resources. Biomass cofiring, where coal and biomass are fired simultaneously, generally has a higher fuel cost than coal-only generation but is a favorable option as it requires low capital expenditure by using existing facilities and is applicable for virtually all types of utility coal boilers. Biomass cofiring has been shown to reduce SO_x and NO_x emissions and to result in net GHG emissions reductions (*4*). The technology has been utilized commercially in Europe, the United States, and other countries but not to our knowledge in Canada. There are no major technical obstacles to cofiring, although it could pose logistical and operational challenges, primarily due to differences in coal and biomass properties. There is far less experience with 100% biomass-fired generation (often termed "repowering") in prior coal GS, although it has been successfully implemented in Europe (Electrobel, Belgium) and in the United States (Schiller Station, NH) and there are plans for additional GS (e.g., FirstEnergy, Southern Company). There is not a "standard retrofit" for repowering, with a range of reported and planned modifications, from changes to handling systems and coal boilers to full replacement with a biomass boiler (see Supporting Information).

The Ontario government has committed to eliminating the use of coal for electricity production by December 31, 2014. In 2007, the province obtained 18% of its electricity from coal (coal capacity is 6400 MW, 19% of total generation capacity), resulting in ~28 million metric tons of CO_2 equivalent, or 15% of the province's total GHG emissions (*5*−*7*). The government has a plan for reducing emissions by 2020, with the largest component of reductions (29%) expected from actions in the electricity sector (*8*). Ontario's electricity generation capacity is expected to evolve by the year 2025 from the current mix to one that meets the government's supply mix directive (see Supporting Information). A doubling of renewable capacity and expansion of conservation are planned, although exact plans are not finalized (*9*). While there are initiatives to increase renewable generation (i.e., Ontario's Green Energy Act 2009, which includes a feed-in tariff program), expansion of hydro capacity is constrained by limited remaining resource availability. Ontario Power Generation (OPG), which operates four coal-fired GS, is investigating biomass firing in these stations as one action toward addressing some of the above issues. This study examines the life cycle (LC) GHG emissions and costs of biomass options for these GS.

In the United States and Canada (as well as other countries), the potential for biomass utilization is substantial

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due to abundant resources (*10*). The net benefits of using biomass will depend upon the activities throughout the LC of biomass production and combustion, particularly the biomass properties, fossil energy inputs, fertilizer use (if employed) and related N_2O emissions, and impacts associated with land use change. As is well-documented for biofuels (*11*), GHG emissions and other performance metrics can vary significantly depending on the LC attributes. Additionally, the LC performance of the displaced energy system is important in determining net benefits of biomass. OPG is focusing on pelletized biomass for use in the coal GS as pelletization dries and densifies input biomass, producing a solid fuel of even proportion that is more easily transported and handled and that has better properties for electricity generation than other forms of biomass. However, pelletization generally results in a higher-cost feedstock and requires energy inputs that may negatively impact the net benefit of biomass use.

Although life cycle assessments (LCA) of GHG emissions associated with electricity from biomass coal cofiring have been completed (*12*–*15*), only Damen and Faaij (*15*) examined wood pellets (hereafter referred to as pellets) and these were produced from mill residues, unlike the present study, which examines dedicated wood harvest for pellet production. There have been studies on electricity generation from biomass use in direct-fired biomass boilers and integrated gasification combined cycle systems (*16, 17*) but the studies did not include economic analyses. Robinson et al. (*4*) estimated the cost-effectiveness (CE) of GHG reduction through cofiring nonpelletized biomass but considered direct, not LC, emissions. Qin et al. (*18*) employed a LC approach and calculated the CE of GHG emissions reductions through cofiring nonpelletized biomass and 100% biomass firing (the latter in a hypothetical stand-alone biomass unit). In Results and Discussion and Supporting Information, we compare our results with those of the literature.

We investigate the use of pellets for cofiring with coal and 100% biomass-fired generation in two of Ontario's coal GS. To our knowledge, this is the first study to analyze 100% biomass usage in a coal GS and to examine dedicated wood harvest for pellet production. Life cycle GHG and selected air pollutant emissions are quantified for biomass as well as reference coal and natural gas electricity generation. The electricity production costs as well as CE of GHG emissions mitigation are also estimated, additional contributions to address gaps in the literature. While site-specific details of the Ontario case are important, insights from the analysis can provide guidance for other jurisdictions.

Methods

Life cycle inventory (LCI) analysis models are developed to quantify the relative changes in selected GHG and air pollutant emissions, for the following Ontario "pathways":

(1) *Reference coal*: production of electricity from coal in two existing coal-fired GS, Nanticoke [3948 MW (net)] and Atikokan [215 MW (net)].

(2) *Reference natural gas*: production of electricity from representative (hypothetical) newly constructed natural gas combined cycle (NGCC) facility (400 MW).

(3) *Pellet cofire*: production of electricity at cofire rates of both 10% and 20% (energy input basis) at Nanticoke and Atikokan.

(4) *100% pellet-fired*: production of electricity from pellets as the sole energy source in one unit at Nanticoke and in the single unit at Atikokan.

Life cycle costing models are also developed to estimate the electricity production cost for the above pathways.

LCI Analysis. All LC activities from resource extraction (e.g., roundwood, coal) and production (e.g., pellet production) through use of the fuel in the electricity GS are included, as well as all transportation stages. "Cradle-to-gate" modules for the required energy and material inputs were developed or obtained from databases. Actual operating data for the coal GS were utilized. As the LCI quantifies the relative change in the metrics when switching from coal-only to pellet combustion or natural-gas-only options, grid electricity distribution and use are identical for all pathways and therefore not included in the system boundary. Material and energy inputs needed for equipment manufacture, facility construction, and labor are not included in the study. Exclusion of these activities is common practice where it is expected that these aspects have far smaller implications than the operations of the facilities (*19*).

Two time frames relevant to the Ontario electricity sector's near-term technologies and regulatory initiatives are selected. The cofiring pathways are relevant to the time frame 2010 to 2014, during the coal phase-out, while those utilizing 100% pellets are relevant post-2014 but could be implemented prior to that time.

The functional unit for the electricity analysis is 1 kWh of electricity produced. The environmental metrics examined are selected GHGs (CO_2, CH_4, N_2O), reported as CO_2 equivalents (CO_2equiv) based on 100-year global warming potentials (*20*), and air pollutant (NO_x and SO_x) emissions. The base assumption in this study is that emissions of CO_2 resulting from the combustion of biomass are entirely balanced by the carbon incorporated during regrowth of the forest during the time period considered. This assumption is in line with the treatment of biobased sources in the literature (for example, refs *21* and *22*), which considers forest biomass (referred to as biofiber) to be carbon-neutral so long as the forest is sustainably managed.

Pellet Production. The pellet production LC activities include biofiber harvesting, forest renewal, forest road construction, biofiber transportation to a pellet facility, pelletization, and pellet delivery to Nanticoke and Atikokan GS (Supporting Information, Figure S-1). As pellet production has not previously occurred in Ontario at the scale presented here, and siting studies are needed to determine locations of harvest, transportation activities, and facility locations, best available data at the time of the study are utilized. A sensitivity analysis was completed on key parameters.

In this study, biofiber for pellet production is supplied by forest management units in the Great Lakes St. Lawrence (GLSL) forest region of Ontario (see Supporting Information). The total harvest volume available for pellets supplied from sustainably managed Crown (public) GLSL forest is ~1.475 million oven dry metric tons (ODT)/year. Allocating this forest biofiber to pellet production would not reduce current harvest quantities for traditional products but instead would create a market for available merchantable logs no longer marketable given the decline in the forest sector. It is not anticipated that there will be any trade-off between traditional products and bioenergy outputs. The present study assumes no additional biomass supply; however, there are other resources in the province and surrounding regions that could be utilized (*23*).

The pelletization process is described in Supporting Information (Figure S-2). Data on electricity and biofiber consumption during pelletization were provided by a northeastern U.S. pellet producer and reflect a state-of-the-art facility (pellet capacity 12 ODT/h). The data obtained from the producer were utilized, with two modifications [to drying energy use (see Supporting Information) and the use of the Ontario grid for grid-based electricity]. As data for pellet production are limited and generally proprietary, the producer's data were verified by comparison with refs *24* and *25*. Pellets are shipped to Atikokan exclusively by rail, while those destined for Nanticoke are shipped by rail to a deepwater port and then transported by vessel. Characteristics of the pellets are based on specifications of the pellet producer and ref *24* and would meet specifications stated by ref *26*. See Supporting Information, Tables S-1 and S-2, for LCI data.

Reference Coal and Natural Gas Pathways. The LCI system boundary for coal-based electricity includes coal mining and processing, transportation, and combustion in the GS. These pathways reflect existing conditions at the GS. Nanticoke GS, located on Lake Erie, has eight 490 MW_e (net) wall-fired natural circulation pulverized coal boilers equipped with low-NO_x burners, two of which are equipped with selective catalytic reduction equipment. The station uses both subbituminous southern Powder River Basin (PRB) coal (84% by weight) and bituminous Central Appalachian U.S. low-sulfur (USLS) coal (16% by weight) (*27*). Atikokan GS, in northwestern Ontario, has one 215 MW_e (net) boiler equipped with low-NO_x burner and uses Canadian lignite coal. The capacity factors and net coal to electricity conversion efficiencies are 55% and 35% for Nanticoke and 34% and 33% for Atikokan (*27*). See Supporting Information, Tables S-3 and S-6.

The natural gas reference pathway is based on a hypothetical NGCC electricity generation facility (53% conversion efficiency) (*28*) located in Ontario, which would receive gas from Alberta. The LCI activities are natural gas recovery, processing, transmission and storage, and use in the facility (Supporting Information, Tables S-4 and S-6). Retrofitting of the coal GS to natural gas boiler or NGCC systems are not considered economically viable alternatives (see Supporting Information).

Pellet Cofire Pathways. Emissions associated with electricity generation from cofiring are estimated on the basis of upstream coal and pellet production and transportation emissions, the amount of each fuel required to produce 1 kWh of electricity, and the emissions from electricity generation. Cofiring at Nanticoke displaces USLS coal initially and then PRB coal after all USLS is displaced (*27*), while cofiring at Atikokan displaces lignite. To implement cofiring at the GS, the fuel delivery and handling systems must be modified by installing additional conveyors, hoppers, and covered storage to handle and store the pellets. Pellets are introduced to the boilers through dedicated silos. Based on tests at the GS, the estimated heat rate degradation due to cofiring is 0.5% for every 10% input of pellets (*27*), resulting in minimal decrease in conversion efficiency. For Nanticoke and Atikokan at 20% cofire, efficiencies are 34.7% and 32.7%, respectively. The issue of efficiency loss is of less concern with pellets because of their low moisture content (5% in this study).

Pellet combustion-related CO_2 emissions are treated as zero as per our base assumption. Pellet cofiring is expected to reduce GS SO_x emissions relative to coal-fired generation because biomass typically contains less sulfur. SO_x emissions reductions are often greater than would be expected from fuel substitution alone because sulfur in coal can react with alkali in biomass to form sulfates (*29*). Reductions in SO_x emissions are estimated on the basis of sulfur contents of the pellets and coals (reductions beyond those associated with fuel substitution are not considered). The effects of cofiring on NO_x emissions are more difficult to quantify due to the complex mechanisms of NO_x formation during combustion. Emissions of NO_x can increase, decrease, or remain the same depending on fuel type, firing and operating conditions, and the change in combustion conditions. We assume cofiring does not yield reductions in NO_x emissions in either of the GS, as tests at Nanticoke reported that NO_x emissions were virtually unchanged from coal-only operation.

100% Pellet-Fired Pathways. According to OPG, modifications expected at both GS to accommodate 100% pellet firing include those to dust and fire suppression equipment, fuel storage (covered) and handling equipment, pulverizers (replacement or modification of classifiers), and primary air systems. Detailed engineering studies will determine if additional modifications are necessary (e.g., to air heater systems and burners). It is assumed that the units would operate year-round on pellets. Atikokan's capacity when operating with pellets is expected to be close to that when operating with coal (*27*). The heat rate degradation at Atikokan is estimated to be 5% for 100% pellet operation compared to coal-only, resulting in an efficiency of 31.4%. Due to several technical issues, the capacity of Nanticoke's unit when operating with pellets is anticipated to be 50% of its capacity when operating with coal. The issues include (1) limited furnace size (as the units were originally designed for bituminous coal with a higher energy density than pellets) and (2) the use of ball-race mills (used to pulverize the fuel); when used with pellets, thick beds of wood dust are generated that result in high pressure differentials that limit their capacity (*27*). The Nanticoke unit's capacity when operating with pellets is estimated at 250 MW_e. The reduction in capacity could be lessened with additional retrofitting. Heat rate degradation is estimated to be about 10% (*27*) resulting in an efficiency of 31.8% (Supporting Information, Table S-6).

No measurements have been made of CH_4 and N_2O emissions for 100% pellet firing at the GS, and therefore data from ref *28* are used to estimate these emissions. Test data for 100% pellet firing at Atikokan are utilized for estimating SO_x and NO_x emissions for both GS, as no tests have been completed at Nanticoke. During testing, SO_2 emissions remained below the detectable level of the analyzer for all firing conditions. We estimate SO_x emissions on the basis of sulfur content of the pellets. A range of NO_x emissions rates is provided by the test data. Data are extrapolated for Nanticoke GS by assuming the same percentage change in emissions (from operation on coal) would occur as at Atikokan. These results are compared with the limited data available in the literature (Supporting Information, Table S-5).

Life Cycle Cost Analysis and Cost-Effectiveness of GHG Emissions Abatement. Life cycle cost models are developed to estimate the cost of electricity generated from coal, pellet, and NGCC systems (see Supporting Information, Table S-6). Capital (including financing), fixed operating and maintenance (O/M), nonfuel variable O/M, and fuel costs are considered. The cost of electricity production from coal at the GS is based on actual operating data, with the capital costs treated as sunk costs. The NGCC system costs are estimated from those of a 400 MW advanced NGCC system (*30*) and estimates in ref *31*. Due to the uncertainty of future natural gas prices, low, average, and high prices based on 2004−2008 prices are examined (see Supporting Information).

Biomass cofiring has not been implemented by OPG and therefore costs are estimated from literature and reviewed by OPG. The capital cost is estimated to be \$225/kW biomass capacity, the midpoint of the range in ref *4*. A delivered cost for pellets, \$160/metric ton, is based on refs *32* and *33*, studies that estimate the pellet production cost from roundwood in the GLSL forest for utilization in OPG's GS.

There is little data publicly available from which to estimate the cost of converting the GS to 100% biomass, as few conversions have been completed and detailed data have not been published. Capital cost estimates in the gray literature for completed retrofits are ~\$125/kW (Electrobel, Belgium) and ~\$1500/kW (Schiller Station, NH) of biomass capacity (calculated from refs *34, 35)*. The cost difference reflects the level of retrofit and facility configuration (see Supporting Information). A retrofit to be completed by FirstEnergy (R.E. Burger GS, OH) (*36*) and expected to cost ~\$640/kW of biomass capacity (assuming no capacity loss, as is claimed by FirstEnergy) matches most closely those

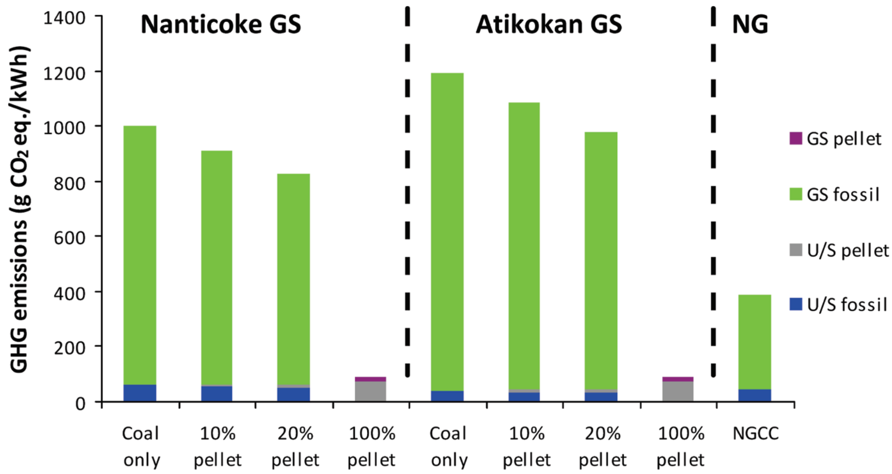

FIGURE 1. Life cycle GHG emissions associated with electricity production through reference, cofiring, and 100% pellet-fired pathways. Sources of emissions are indicated. Upstream (U/S) and GS fossil emissions for coal and cofiring refer to production and combustion of coal, respectively; for NGCC, fossil emissions refer to production and combustion of natural gas. CO_2 emissions resulting from biofiber combustion are not included in the figure due to base assumptions.

planned by OPG. On the basis of the above and discussions with industry experts, we assume the \$640/kW cost for OPG's GS. Due to the uncertainty in the cost, we perform a sensitivity analysis (see Supporting Information).

The CE of LC GHG (CO_2 equivalents) and air pollutant emissions mitigation (dollars per metric ton) relative to the reference (coal) pathways through the switch to the pellets and NGCC are calculated (see Supporting Information). Due to the significant impact of variability/uncertainty in pellet and natural gas prices, ranges of these values are examined.

Results

Pellet Production. The mass of pellets that could be produced annually from the GLSL biofiber supply (unused component of annual allowable cut) is estimated to be 1.25 million ODT (1.475 million ODT less biomass used for drying). Implementing 10% cofiring year-round in both GS would require 76% of the pellet supply, while 20% cofiring would require more pellets than could be produced by the GLSL forest alone under the sustainable management plans, assuming no impact on the wood supply of traditional industries. Utilizing 100% pellets in Atikokan and one unit at Nanticoke would require 83% of the pellets. These calculations assume electricity output from the two GS remains at 2007 levels (Nanticoke 18 210 GWh; Atikokan 652 GWh).

The production of the pellets and their transportation to either GS results in 0.133 metric ton of CO_2equiv/ODT (Supporting Information, Table S-7). A comparison of our results with those of another study is reported in Supporting Information. The forest harvest and pelletization processes are each responsible for the largest fractions (30% each) of the GHG emissions associated with pellet production and transportation. Of the parameters studied, the pellet production emissions were found to be most sensitive to the GHG emissions intensity of forest operations, but these data are generally of high quality and based on actual fuel use, etc., in GLSL operations (see Supporting Information).

Life Cycle Inventory Results for Electricity Generation. Life cycle GHG emissions (those associated with the GS itself and "upstream" activities) are shown in Figure 1. The lowest GHG emissions on a kilowatt-hour basis result from the 100% pellet pathways. Reductions at Nanticoke and Atikokan are 91% and 92%, respectively, compared to the reference coal pathways. The 100% pellet pathway (in both GS) produces 78% less GHG emissions compared to the NGCC. Displacement of coal or natural gas with a biobased resource such as pellets results in a large reduction in emissions based on the assumption that the CO_2 resulting from the combustion of the biobased resource is exactly balanced by carbon incorporated during regrowth of the forest during the time period considered. The small amount of GS emissions (16 g of CO_2equiv/kWh) in the 100% pellet pathways results from emissions of non-CO_2 GHGs. While these results are encouraging, to maintain the current GS capacity factors, biomass resources other than those of the GLSL forest would be required, and in the case of Nanticoke, a more extensive retrofit (e.g., replacement of the coal boiler with a biomass boiler) could be an option. Other sources of electricity or conservation initiatives would be required to balance supply and demand. The implications of these initiatives would depend on the LC emissions intensity of the feedstock/conversion system options utilized.

Compared to the reference coal pathways, the 10% and 20% cofiring rates at both GS result in GHG emissions reductions of 9% and 18%, respectively (values for a 10% cofiring rate in the literature range from 6.3% to 9.9%; see Supporting Information). While cofiring results in lower emissions than coal-only operation, emissions from the NGCC are lower. This is mainly because cofiring involves the combustion of a large amount of coal, which has a higher carbon content than natural gas (25 vs 14 kg of C/GJ). In spite of the emissions benefits of the NGCC, natural gas is a fossil fuel that is limited in supply and subject to price volatility, which are factors of concern if moderate to large portions of electricity were to be generated from this resource.

The upstream emissions associated with production of the fuels are of similar magnitude on a kilowatt-hour basis. With the exception of the 100% pellet pathways, the vast majority of LC emissions occur at the GS (resulting from the combustion of the fuel in the facility).

The GS (facility) emissions of NO_x and SO_x represent the majority of LC emissions for the coal, NGCC, and cofiring pathways (Supporting Information, Figures S-4 and S-5). Compared to coal, both NO_x and SO_x emissions are reduced by using 100% pellets; reductions are 40−47% and 76−81%, respectively. The NGCC pathway also substantially reduces emissions compared to the coal reference. The cofiring pathways reduce SO_x emissions but result in approximately the same NO_x emissions compared to the coal reference.

Cost of Electricity Production. The coal pathways have the lowest cost due to their low fuel costs and sunk capital costs (see Figure 2). Atikokan has higher fixed O/M costs than Nanticoke, resulting in a higher electricity cost (\$42.6 vs \$29.2/MWh). Co-firing at 10% increases the electricity cost

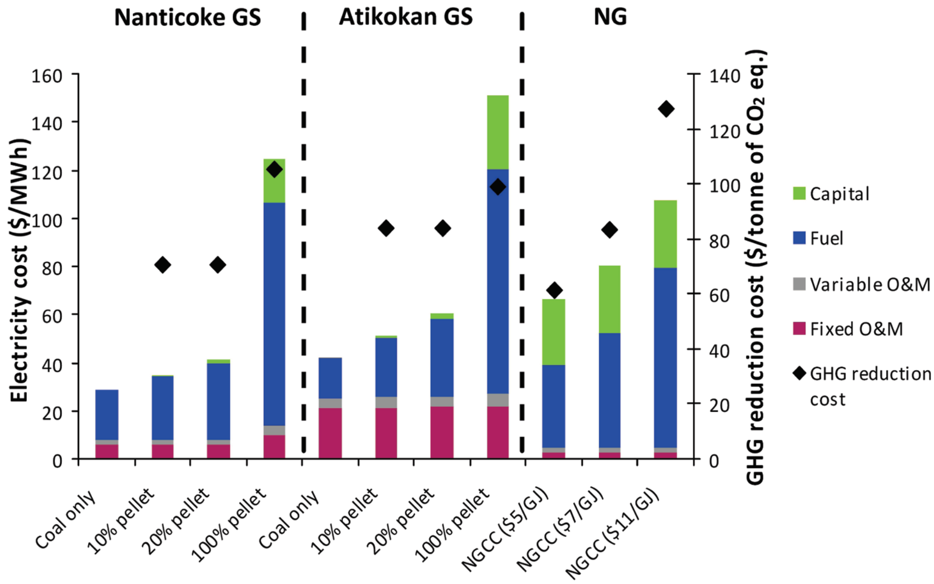

FIGURE 2. Electricity cost (net of taxes, subsidies, and profit margins) and CE of GHG reduction. Bars represent electricity cost (left axis). Reference for NGCC for CE is Nanticoke GS coal-only generation. Reference for cofiring CE is coal-only operation at respective GS.

by 0.6 and 0.9 cents/kWh at Nanticoke and Atikokan. However, even at the lowest natural gas price, the cofire options have lower electricity costs due to their primary reliance on low-cost coal and their lower retrofit cost relative to the capital cost of new NGCC. The 100% pellet pathways result in the highest electricity cost due to the pellet cost and, to a lesser extent, the retrofit cost.

The sensitivity analysis for the Nanticoke 100% pellet pathway shows that the pellet cost assumptions most impact the electricity cost (Supporting Information, Figure S-6). Capital cost is the next most important variable; an increase from $640 to $800/kW increases electricity cost by 4%. Reducing the pellet cost from $160 to $60/metric ton (ref *37* reports a pellet price of $60) lowers the electricity cost by 46%. While a pellet cost this low is unlikely for Ontario, even if the pellets were produced from "waste" feedstock, some biomass (unpelletized) is expected to be available at this cost. Southern Company (*38*) reports that biomass for their Georgia facility will be available at a similar cost as coal, and Walsh (*39*) reports 192 million and 420 million dry metric tons could be available in the United States at <$50/metric ton in 2010 and 2020, respectively. However, additional capital and O/M costs and efficiency loss would be incurred at the GS if unpelletized biomass or low-quality pellets were utilized (these aspects are not considered in the sensitivity analysis).

Cost-Effectiveness of Emissions Mitigation. At the base prices ($160/metric ton pellet; $7/GJ natural gas), implementing cofiring at Nanticoke or switching to a NGCC system at Atikokan are most cost-effective for mitigating GHGs ($70 and $47/metric ton of CO_2equiv, respectively) (Figure 2 and Supporting Information, Figure S-7). The differences in coal price, electricity generation cost, and LC emissions at the two GS are responsible for the different options being preferred. Variation in the LC performance of reference fossil fuel pathways is an aspect that has not received attention in prior studies but is shown as being of importance here. Our use of actual operating data for the coal GS highlights the performance differences.

Cofiring at Atikokan almost doubles the mitigation cost compared to a NGCC, whereas displacing Nanticoke with a NGCC has a higher cost than cofiring. Converting the GS to 100% pellet operation are the most costly options. Although the biomass and NGCC pathways reduce LC SO_x emissions and the 100% pellet and NGCC pathways reduce NO_x emissions, the mitigation costs are very high in comparison with market prices for these emissions (Supporting Information, Table S-10).

The costs of GHG mitigation for the biomass and NGCC pathways are highly dependent on fuel costs. The mitigation costs resulting from varying pellet prices ($60−$200/metric ton) and natural gas prices ($5−$11/GJ) are shown in Supporting Information, Figure S-7. Lower pellet prices of $125 and $100/metric ton result in mitigation costs of $49 and $34/metric ton of CO_2equiv, respectively, for 10% cofiring at Nanticoke. While the cofiring and NGCC pathways are generally more cost-effective than 100% pellet firing, ranges of results overlap for all pathways. In order for GHG reduction to be equally cost-effective for the 100% pellet and NGCC pathways (natural gas $7/GJ), the delivered pellet price must be <$128 and <$65/metric ton for Nanticoke and Atikokan, respectively. At a pellet price of $160/metric ton, the natural gas price must be at least $9/GJ (Nanticoke) and $13/GJ (Atikokan) in order for the 100% pellet and NGCC options to be equally cost-effective. It is not unrealistic that prices at these levels could occur in the near future (*40*). No costs have been included in our analysis for regulation of fossil-based GHG emissions under a carbon tax or cap-and-trade scheme although both the U.S. and Canadian governments have policies to implement such schemes. If implemented, the mitigation costs for the NGCC and cofiring scenarios would increase (options would be less cost-effective for reducing GHGs) while the 100% pellet option would have little increase in cost (only that associated with upstream fossil fuel use).

The costs in the present study are considerably higher than those in the literature, primarily due to the high biomass price (Supporting Information, Table S-12). Assuming a low and likely unrealistic pellet price of $60/metric ton, in line with prices of unpelletized biomass examined in other studies, results in $10 and $31/metric ton of CO_2equiv at Nanticoke and Atikokan, respectively, for both cofiring rates, similar to the other studies' results. 100% pellet firing results in $42 and $46/metric ton of CO_2equiv at the GS. Comparison with mitigation costs reported in BIOCAP (*41*) of $52 and $374/metric ton of CO_2equiv for small-scale wind and solar, respectively, in Ontario shows that biomass utilization in coal GS can be competitive with other options, depending on the scenario and, importantly, the biomass cost.

Discussion

Although Canada is one of the world leaders in pellet production, the mass of pellets that could be produced from the GLSL forest would almost double the country's production of 1.34 million ODT/year (*42*). Pellet-generated electricity would provide 2.5 TWh/year of renewable electricity, 1.6% of Ontario's total electricity supply, and reduce GHG emissions by 2.1 million metric tons of CO_2equiv [7% reduction in the province's electricity generation emissions (based on 2007 generation)]. This puts into perspective the magnitude of electricity consumption relative to the availability of the GLSL biomass resource. A combination of conservation, efficiency improvement, and renewables would be needed to make significant progress in reducing electricity sector emissions. It was beyond the scope of this study to examine all potential generation options and to determine the "preferred" mix. Alternatives should be explored on the basis of techno-economic, environmental, social, risk, and institutional perspectives.

Although a case study, our analysis provides guidance for other jurisdictions. The results suggest that electricity produced from biomass in existing coal GS should be considered, along with other alternatives, as a means of achieving near-term GHG reductions. The GS characteristics as well as the fuel costs were found to significantly impact the electricity costs and relative CE of GHG mitigation. There are technical and cost trade-offs associated with the use of roundwood versus "wastes"/residues for pellet production and as well between pelletized and unpelletized biomass. Local studies are needed to understand coal GS characteristics, supply of biomass resources, and infrastructure issues. The following simplistic calculations do not reflect the local nature of these aspects or a host of other issues but are provided for perspective. If 10% cofiring were to be implemented in all coal GS in the United States and Canada (60% capacity factor assumed), electricity generation from biomass could contribute approximately 4% of annual generation of the two countries (185 of 4660 TWh), reducing GHG emissions by 170 million metric tons/year, ~5% of emissions from the two countries' electricity sectors (*7, 43*). This would require ~2000 PJ/year [~100 million metric tons (dry)] of biomass, a large amount but within inventory amounts in ref *39*.

With biomass, as with any resource, large-scale implementation must be done cautiously. Benefits will be achieved only if policies are enacted that steer biofuels in the "right direction" and if environmentally sustainable practices are employed throughout the LC (*44*). The Intergovernmental Panel on Climate Change recognizes the potential contribution of forests in reducing GHG emissions through maintaining or increasing forest carbon storage as well as sustainably producing fiber, timber, and energy products (*21*). Displacement of coal with biomass results in considerable reductions in CO_2 emissions in large part due to the base assumption regarding forest carbon. Increasing harvest for pellet production, while still within sustainable harvest limits, will impact the quantity of carbon stored in the forest. A full accounting of the GHG balance of biomass use should include resulting changes in forest carbon (*45*): further modeling examining forest carbon is recommended.

In addition to the issues examined, additional considerations (other environmental, public perception, technological, and regulatory aspects) must be studied prior to implementation. There are nonbiomass options to meet renewable energy and GHG reduction goals, and other biomass uses that should be considered. Several low-carbon renewable electricity generation technologies, all with their own merits and disadvantages, are being implemented. Even if these achieve much higher penetration in the near future, they would in most cases still represent a modest portion of peak demand. Hydro is the exception in a small number of countries but there are limited sites. Biomass utilization in coal GS can follow load and be integrated into the existing grid, while other renewables will require new infrastructure. There is promise of carbon capture and storage but uncertainty with regard to its performance, cost, public acceptance, and time frame for implementation. Biomass utilization in coal GS should be considered for its potential to mitigate GHGs from the electricity sector in the near term. Climate change is a critical issue, and delaying the implementation of abatement measures will be costly.

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Supporting Information Available

Details on electricity generation in Ontario, conversion of coal generating stations to biomass, methods, and additional results and discussion. This information is available free of charge via the Internet at http://pubs.acs.org/.

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