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1 **Comparing the life cycle costs of using harvest residue as feedstock for small- and**
2 **large-scale bioenergy systems (Part II)**

3
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11
12 **Abstract**

13
14 In part II of our two-part study, we estimate the nominal electricity generation and
15 greenhouse gas (GHG) mitigation costs of using harvest residue from a hardwood forest
16 in Ontario, Canada to fuel (1) a small-scale (250 kW_e) combined heat and power wood
17 chip gasification unit and (2) a large-scale (211 MW_e) coal-fired generating station
18 retrofitted to combust wood pellets. Under favorable operational and regulatory
19 conditions, generation costs are similar: 14.1 and 14.9 cents per kWh (c/kWh) for the
20 small- and large-scale facilities, respectively. However, GHG mitigation costs are
21 considerably higher for the large-scale system: \$159/tonne of CO₂ eq., compared to \$111
22 for the small-scale counterpart. Generation costs increase substantially under existing
23 conditions, reaching: (1) 25.5 c/kWh for the small-scale system, due to a regulation

mandating the continual presence of an operating engineer; and (2) 22.5 c/kWh for the large-scale system due to insufficient biomass supply, which reduces plant capacity factor from 34% to 8%. Limited inflation adjustment (50%) of feed-in tariff rates boosts these costs by 7%-11%. Results indicate that policy generalizations based on scale require careful consideration of the range of operational/regulatory conditions in the jurisdiction of interest. Further, if GHG mitigation is prioritized, small-scale systems may be more cost-effective.

Highlights

- Generation costs for two forest bioenergy systems of different scales are estimated
- Nominal electricity costs are 14.1 to 28.3 cents/kWh for the small-scale plant
- Nominal electricity costs are 14.9 to 24.2 cents/kWh for the large-scale plant
- GHG mitigation costs from displacing coal and LPG are \$111-\$281/tonne of CO₂ eq.
- High sensitivity to cap. factor (large-scale) and labour requirements (small-scale)

Keywords

bioenergy; biomass; GHG mitigation; harvest residue; life cycle costing; scale

1

2 **1 Introduction**

3

4 The high cost of producing electricity from biomass is widely considered to be a
5 primary impediment to increasing bioenergy supply and realizing associated economic
6 and environmental benefits [1, 2, 3]. To overcome this economic barrier, many
7 governments offer subsidies to encourage investment in bioenergy technologies.
8 However, effective policy design is challenged by the considerable variation in bioenergy
9 generation costs resulting from numerous operational and regulatory conditions that are
10 specific to individual projects and jurisdictions, including conversion efficiency, fuel
11 supply and subsequent capacity factor, financing costs, expected returns, and differing
12 regulatory requirements [4]. Yet, there is one cost consideration that consistently
13 determines the level of subsidization: bioenergy production costs, outside of the cost of
14 feedstock, tend to decrease with scale, or the rated capacity of the system (e.g., [5, 6, 7]).
15 Thus, supply-side subsidy programs often provide greater financial support for smaller-
16 scale projects within a given technology class.

17 Feed-in tariff (FIT) programs, which offer fixed payment rates for the production
18 of renewable electricity, demonstrate considerable inter-jurisdictional variability in the
19 number of technology classes, scales, and related provisions that are taken into account.
20 In a comparison of the FIT programs of Ontario (Canada) and Germany, Mabee *et al.* [8]
21 noted that the Ontario program differentiates between two bioenergy scales, whereas the
22 German program differentiates between four scales. A number of provisions (“adders”)
23 are available through the German program for specific aspects of bioenergy projects that

1 result in desirable auxiliary benefits (e.g., waste heat utilization) [8]. There are also
2 differences in the treatment of the contract over time: in Ontario, an annual FIT rate
3 escalation is present, but not fully indexed to inflation [8], whereas the FIT rate for
4 bioenergy facilities under the German program does not change throughout the lifetime
5 of the contract [9]. These program details can have important consequences for attracting
6 investment in bioenergy capacity. Studies have shown that the rates offered for bioenergy
7 are often misaligned with actual generation costs, including those of Ontario's FIT
8 program [4]. The Ontario FIT rate for bioenergy projects smaller than 500 kW_e has
9 recently been increased from 13.8 to 15.6 cents/kWh (c/kWh), whereas projects larger
10 than 500 kW_e are now ineligible for FIT subsidies, which have been replaced with a
11 bidding/auction mechanism for large projects [10, 11]. Previously, bioenergy projects
12 larger than 10 MW_e commanded a FIT of 13.0 c/kWh [11]. Relative to scale, German
13 FITs for biomass technologies have differed to a much greater extent, starting at 0.08
14 €/kWh for a plant ≤ 20 MW_e, and reaching 0.12 to 0.22 €/kWh for small-scale plants 150
15 kW_e and under [8].

16 Most bioenergy subsidization initiatives acknowledge that generation costs, and
17 subsidy requirements per unit of electricity generated, decrease as the rated electrical
18 capacity of bioenergy facilities increases. However, unlike fossil fuel-based electricity
19 generation projects, fuel procurement costs for bioenergy systems rise rapidly with scale,
20 a function of the relatively low spatial distribution density, energy density, and bulk
21 density of biomass [7, 12, 13]. These unfavorable properties of biomass have constrained
22 the scales of bioenergy facilities in North America since the 1980s to an average of
23 approximately 20 MW_e [14]. With the exception of a few recent co-firing projects in

1 northwestern Europe, supply constraints have reduced co-firing rates to an average of
2 2.8% [15]. In Ontario, initial plans to retrofit coal-fired generating stations to combust
3 wood pellets included a provision that all wood pellet inputs must be derived from in-
4 province biomass supplies. This further constrains biomass supply opportunities and has
5 limited the capacity factor (the ratio of actual output to potential output, based on the
6 nameplate capacity of the facility) of a retrofitted coal-fired generating station in the
7 province to 8% [16].

8 As bioenergy sectors grow, low cost biomass supplies such as sawmill residue
9 will become fully utilized, requiring procurement of higher cost biomass sources [17, 18].
10 The contribution of forest-origin biomass (including roundwood and harvest residue), to
11 total biomass supply is expected to increase in jurisdictions with active forest sectors, as
12 has been observed in Finland and Sweden [19]. Harvest residue (stem tops, branches, and
13 small-diameter unmerchantable trees) is the lowest cost source of biomass that can be
14 procured from forest operations because the fixed costs of the machinery used in these
15 operations are already borne by the recovered merchantable roundwood, and there are
16 usually no alternative economic uses for the residue. However, the amount of residue
17 generated per hectare is equivalent to only a small portion of roundwood production,
18 requiring a larger theoretical procurement radius relative to roundwood, for a given
19 facility scale. Hence, with harvest residue as the main supply source, small-scale systems
20 (e.g., <500 kW_e), when appropriately sited, could have lower generation costs than large-
21 scale systems because the lower annual biomass demand can maintain procurement costs
22 within acceptable limits. Given the additional GHG benefits of utilizing harvest residue
23 for energy [20, 21], future iterations of bioenergy subsidy programs would benefit from a

1 better understanding of the relative costs of small- and large-scale bioenergy facilities
2 utilizing harvest residue as the main fuel source.

3 In addition to biomass supply constraints, there are additional context-sensitive
4 factors that can also serve to reduce the subsidy requirements of small-scale systems
5 relative to large-scale systems. Small-scale combined heat and power (CHP) facilities
6 that are co-located with industrial facilities or district heating networks can have potential
7 revenue advantages relative to large-scale facilities, which tend to lack proximal heat
8 demand [22]. For example, costs of electricity generation fall from 18 to 11 c/kWh when
9 taking into account the economic value of heat recovered in small-scale biomass
10 gasification CHP systems [23]. With regard to GHG mitigation costs, large-scale systems
11 tend to have higher supply chain emissions, such as those from additional feedstock
12 transportation and processing [24, 25, 26]. While electricity generation costs may still be
13 larger for small-scale systems, GHG mitigation costs can drop below those of larger-scale
14 systems due to the improved GHG savings. When considering the potential revenues on
15 carbon markets, the relative subsidy amount required for small-scale systems may further
16 decrease. Conversely, small-scale systems may have larger subsidy requirements in
17 jurisdictions like Ontario, which has a regulation mandating the continual presence of an
18 operating engineer [27], even though unnecessary for certain system designs [4, 28].

19 In this paper, part II of a two-part study (Part I: [29]), we compare the life cycle
20 costs of using harvest residue procured from a hardwood forest in Ontario in a small- and
21 a large-scale bioenergy facility. The small-scale bioenergy facility is a hypothetical wood
22 chip-fuelled combined heat and power (CHP) gasification system (250 kW_e unit) (System
23 1), whereas the large-scale bioenergy facility is a coal-fired generating station retrofitted

1 to combust wood pellets that is currently operational in Ontario (211 MWe unit) (System
2 2). Our analysis estimates the cost of electricity production, and hence the FIT rates that
3 would be necessary to allow bioenergy to compete with lower cost electricity from coal
4 and other fossil fuels. GHG mitigation costs are also estimated in order to assess which
5 system meets this policy objective at lower cost. The sensitivity of the results to capacity
6 factor, operating expenses, and FIT escalation rates is explored for each system through
7 the use of two scenarios representative of different operational and regulatory conditions
8 in the province. Results are further qualified using sensitivity analysis, and discussed in
9 relation to Ontario's FIT policy.

11 **2 Methods**

13 **2.1 Study area, scenarios, and system boundary**

15 As in Part I of our study which pertains only to life cycle GHG emissions and
16 impacts, the life cycle costing (LCC) is based on the use of harvest residue collected from
17 the Haliburton Forest and Wildlife Reserve (HFWR), a privately-owned forest located in
18 the Great Lakes-Saint Lawrence forest region of southern Ontario. The residue would be
19 collected via the modification of a conventional single-tree selection operation, producing
20 an average of 1.9 dry tonnes of biomass per hectare (dt/ha) in the form of small-diameter
21 roundwood [30]. The collected residue would be processed and supplied to either (1) a
22 hypothetical 250 kWe CHP gasification facility installed at the HFWR sawmill using
23 wood chips as fuel (System 1); or (2) an existing 211 MWe coal-fired generating station

1 in Atikokan, Ontario retrofitted to combust wood pellets, generating electricity only
2 (System 2).

3 Each system is evaluated under two scenarios that are differentiated on the basis
4 of key parameters related to operational and regulatory conditions. One scenario
5 represents favourable conditions (S1a and S2a) from a bioenergy project cost perspective,
6 and the other represents current conditions in Ontario (S1b and S2b). Differences
7 between S1a and S1b relate to operation and maintenance (O&M) costs, whereas
8 capacity factor, which is itself a function of the total annual biomass supply (further
9 described in Section 3), differs between S2a and S2b. To account for the possibility that
10 FIT escalation rates are adjusted, the scenarios modelled under favourable conditions
11 (S1a and S2a) include an escalation rate that is equivalent to the Consumer Price Index
12 (CPI) inflation rate (3%/year as in Moore *et al.*, [4]), whereas the scenarios modelled
13 under current conditions (S1b and S2b) include an escalation rate that is equivalent to
14 half of the CPI inflation rate (1.5%/year). Thus, the favourable operational and regulatory
15 conditions, relative to existing conditions, incorporate the following assumptions: (1) the
16 removal of the requirement that an operating engineer must be present at all times while
17 the bioenergy facility is in operation (see Section 2.3.5); (2) an increase in the capacity
18 factor of the large-scale system from 8% to 34% [16, 26]; and (3) an increase in the feed-
19 in tariff (FIT) escalation rate to fully compensate for cost inflation.

20 The system boundary of the LCC includes the following life cycle stages: harvest
21 residue collection, transportation, processing into wood chips or pellets, gasification /
22 combustion, and ash waste management. Whereas capital costs are included in the LCC
23 inventory for the 250 kW_e CHP facility (System 1), the design and installation expenses

associated with the Atikokan coal-fired generating station (System 2), built in the 1980s, are considered sunk costs [26], and are therefore outside of the system boundary. However, those associated with modifying the facility to use wood pellets are included. The savings from the displacement of electricity and/or heat from conventional sources are taken into account when estimating GHG mitigation costs. The electricity displaced by both systems is assumed to be derived from the combustion of coal, as in Zhang *et al.* [26]. Similar to Danon *et al.* [31], we assume that heat recovered from the CHP facility is allocated to a wood kiln. The savings from displaced liquefied petroleum gas (LPG) for heat production in System 1 are based upon the amount currently used for the drying of lumber at HFWR.

2.2 Life cycle costing and net present value models

Our LCC model evaluates the financial expenses within the system boundary, including capital and equipment procurement, labour, equipment operation and maintenance (O&M), financing, taxes, and returns to capital investment. A 20 year project life is assumed for both bioenergy systems. For the small-scale CHP facility, this estimate is the midpoint of the 25 year assumption of Dornburg and Faaij [6], and the 15 year assumption of Wood and Rowley [32]. The 20 year estimate for the Atikokan facility using 100% wood pellets is from Zhang *et al.* [26]. An 8% nominal interest rate for project financing is selected due to its widespread adoption for forest bioenergy projects (e.g., [33]). As in Moore *et al.* [4], it is assumed that 60% of the capital costs of the gasification/combustion equipment and infrastructure are debt financed (we assume a

20 year loan with monthly payments, and an 8% interest rate), with the remaining 40% equity financed. The internal rate of return (IRR) is assumed to be 9% (annual return) over the 20 year project life, equal to the weighted average cost of capital, which takes into account the 10.5% expected return on equity of Ontario Power Generation [34]. The annual depreciation rate is set at 5% (straight line method), based on the 20 year projected lives of the projects. A 32% corporate tax rate for Ontario, Canada is used, based on 2010 figures [35, 36]. Nominal life cycle costs are expressed per one kWh of electricity generated, with year one costs in 2010 Canadian dollars.

Gross after-tax costs in project year t (C_t) encompass the costs of residue collection (N_t), residue and/or wood pellet transportation (T_t), processing (P_t), energy conversion via gasification/producer gas combustion or wood pellet combustion (E_t), and taxes (X_t):

$$C_t = N_t + T_t + P_t + E_t + X_t \quad (1)$$

The net present value (NPV) of the two bioenergy facilities is calculated using a standard NPV equation, as depicted in Equation 2. In order for the project to break even over the project life span (y), the NPV of the profit is generally equal to zero. In this case, an NPV of zero would result in a 9% IRR.

$$NPV_y = \sum_{t=1}^y (R_t - C_t) / (1 + d)^t \quad (2)$$

In Equation 2, R_t represents the revenue in project year t , and d is the discount rate, which is equal to the 9% IRR. The project revenue is equal to the quantity of electricity

generated, multiplied by the contract price per kWh of electricity supplied to the grid.
For S1a and S2a, the contract price is escalated by the projected 3% annual CPI growth.
For S1b and S2b, this contract price is escalated by 50% of the annual CPI growth, in
keeping with FIT policy [10].

Annual taxes are equal to the tax rate (Z) multiplied by the net annual before-tax
revenues, minus depreciation (D_t) of the processing and energy conversion capital:

$$X_t = Z \cdot (R_t - N_t - T_t - P_t - E_t - D_t) \quad (3)$$

2.3 Life cycle stages

2.3.1 Collection of harvest residue during forest operations

Forest operations at HFWR consist of the following sequential activities: felling
and delimbing of trees in the forest stand, extraction of the felled and delimbed trees to
landing (“skidding”), and separation of extracted trees into products (“slashing”).
Products – which include sawlogs, firewood, and small-diameter roundwood (harvest
residue) – are subsequently transported to their destination for processing. Since the tree
felling and skidding processes would be unaffected by the additional collection of
residue, they are excluded from the LCC system boundary. The following equation is
employed to isolate the costs of residue collection from those of harvesting conventional
roundwood:

1

$$N_t = \frac{U \cdot I \cdot H \cdot A}{M} + S \cdot W \quad (4)$$

3
4

5 where N_t represents the total cost of collecting the residue over one operating year; U is
6 the expense per productive machine hour of chainsaw use (\$42.60/PMH); I is the
7 percentage increase in time (10.8%) required for delimbing and topping, based on
8 observations at HFWR from Wolf [30]; H is the conventional annual harvest of wood at
9 HFWR, measured in dry tonnes (19,468 dt), based on the tonnage collected during the
10 2010-2011 harvest year; A is the percentage of the harvest area from which residue is
11 collected, assumed to be 2/3 (66.7%) of annual operating area based on consultation with
12 a forest engineer [37]; M is the dry mass of wood cut by chainsaw per PMH (4.8
13 dt/PMH); S is the expense of processing the wood by the slasher, per dry tonne of
14 biomass (\$5.74/dt); and W is the dry mass of wood residue collected (1,183 dt).

15 The additional cost of collecting the residue is calculated to be \$16.21/dt, or
16 \$19,172/yr, excluding cost inflation (Table 1). In order to convert between cubic meters
17 of wood and dry tonnes of wood, density measurements for sugar maple (*Acer saccharum*
18 - the most commonly harvested tree species at HFWR) from Alemdag [38] are used (616
19 kg/m³ dry, 875 kg/m³ dry and stacked).

20

21 **2.3.2 Transportation of harvest residue to wood processing site**

22

23 Shipping the residue to the gasification/wood processing site is estimated to cost
24 \$18.84/dt. This cost is based on the difference between the cost of shipping (1) all of the

1 merchantable wood harvested in the 2010-2011 harvest season, and (2) the merchantable
2 wood combined with the wood residue. It is assumed that the average capacity of a
3 logging truck is reduced by 40% when shipping only wood residue instead of
4 conventional roundwood, as in Wolf [30].

5 The cost of transporting the wood residue from the harvest sites to the
6 gasification/wood processing site assumes the use of three self-loading logging trucks at
7 HFWR, which take two trips per day [39], and travel an average one-way distance of 27.3
8 km [40]. Each haul includes roundwood destined for the HFWR sawmill, firewood, as
9 well as harvest residue. The portions of the trip distance that are travelled on paved and
10 gravel roads of different grades, each of which is associated with a different truck fuel
11 consumption rate, are based on [41].

12 Costing parameters, including insurance, maintenance and fuel cost, as well as
13 wage per scheduled machine hour (SMH), were supplied by P. Schleifenbaum [42].
14 Generic assumptions pertaining to the purchase price, lifespan, utilization rate, average
15 fuel consumption (varying with road type and truck load), and salvage value of the truck,
16 as well as operating hours per year, are based on estimates from FPInnovations [43],
17 intended to depict harvesting operations in mixed forests in Ontario (Table 2).

18 19 **2.3.3 Wood biomass processing at gasification and pelletization sites**

20
21 The residue chipping costs for the small-scale gasification scenario total \$6.08/dt.
22 The capital cost of the chipping equipment is excluded from this estimate because the
23 wood chipper was already present and used in the HFWR sawmill. Thus, the chipping

cost addresses only electricity use (\$1.02/dt) and maintenance (\$5.06/dt), and is based on the actual costs at HFWR [44] (Table 3).

The wood drying cost for Scenario 1 (\$2.36/dt) is based on (1) the estimated electricity used to dry the chips (0.025 kWh/kg water evaporated) [45], (2) the price of electricity used at HFWR (9 c/kWh), and (3) the capital, operating and maintenance costs of a rotating drum kiln with a 15 year lifespan, using the same 60/40 debt/equity ratio assumed for the gasification and combustion infrastructure [46] (Table 3). It is assumed that the heat used for drying the wood to a 15% moisture content (from 45%, based on [39]) is derived from the exhaust gases from the combustion of the producer gas in the gas engine.

The pelletization process required for the large-scale system is estimated to cost \$53.58/dt of residue input, and uses 15% of the biomass to supply heat for the drying of the wood [26]. Residue pelletization costs are based upon KPMG's [33] estimated pellet manufacturing and administration costs for a 100,000 t/yr facility in Ontario. The financing cost per t of pellet is calculated by estimating the fraction of the annualized 20 year loan payment that would be associated with the annual harvest residue inputs from HFWR, and dividing the resulting cost by the annual tonnage of pellets that would be produced from HFWR residue (Table 3).

2.3.4 Transportation of wood pellets to retrofitted coal-fired generating station

The shipping costs of wood pellets to the Atikokan facility (\$71.89/dt harvested) are based on the 254 km trucking distance to Toronto [47], and the 1,635 km distance to

Atikokan/Marmion Lake by rail [48]. These distances are relatively short when compared with the average shipping distance to the largest markets for Canadian pellets, which are in Europe [49]. As in Gan [7] and Searcy *et al.* [50], trucking costs are based on the number of tonne-km travelled. Calculations are undertaken using the following information: the operating cost per km for a 5 axle semi unit van in Ontario with an annual utilization of 160,000 km, assuming a 10% profit margin for the trucking company (\$1.59/km, based on [51]); the estimated round trip distance shipped; the expected number of trips by truck (26.5); and a 40 tonne truck capacity. This gives a cost of \$735 per truck, or 7.9 cents per tkm to transport the pellets between Haliburton and Toronto.

Rail shipping costs for the wood pellets are based on the use of 100 tonne capacity railcars [52] and a \$5,904 per railcar cost estimate from CN Rail [53]. This estimate is derived from the carload price calculator on the CN Rail website, assuming an origin of Toronto, a destination of Marmion Lake, Ontario, and wood pellets as the cargo (commodity number 2411701). A private covered hopper car with a capacity of between 4,500 and 5,150 cubic feet would be used.

2.3.5 Electricity and heat generation at CHP gasification facility (System 1)

The modelled CHP gasification facility, as described in Part I of the study [29], includes a fixed-bed, down-draft gasifier and a cogeneration gas engine which combusts the producer gas that is assumed to have an energy content of 5.2 MJ/Nm³ (LHV) [45]. Each kg of dry wood chips generates 2.4 Nm³ of producer gas during gasification [45].

1 Thus, the energy conversion efficiency of the gasifier is 64.5% from dry wood chips to
2 producer gas [29], taking into account the heat inputs of the gasification reaction (0.933
3 MJ of heat per Nm³ of producer gas generated) [45]. The electrical efficiency of producer
4 gas combustion is 40%, resulting in a net electrical efficiency of 25% for the entire
5 system [29]. Although a 75% heat exchanger efficiency is assumed, the amount used is
6 considerably less: equal to the requirements for wood chip drying, the gasification
7 process, and the drying of lumber in the existing HFWR kiln. The net heat efficiency,
8 including only the heat allocated to the lumber kiln, is 3% of the energy content of the
9 biomass fuel [29].

10 For both scenarios (S1a and S1b), a \$6,000/kW_e estimate depicts the overall
11 capital costs for the gasifier, the producer gas cleaning and combustion infrastructure, and
12 the electricity generation and heat recovery equipment. This estimate is near the midpoint
13 of the range estimated by IRENA [54] of US\$5,570/kW_e-\$6,545/kW_e for a CHP gasifier.
14 Although the \$6,000/kW_e estimate is outside of the \$3,000/kW_e-\$4,000/kW_e cost range
15 provided in an IEA [55] report for a CHP biomass gasification and engine system, the
16 IEA [55] does not make clear if its capital cost range includes installation. We assume
17 that the small-scale system generates 1.60×10^6 kWh of electricity and displaces 6.80×10^2
18 GJ of heat from LPG used to dry lumber at HFWR each year [29].

19 The cost of operating and maintaining a small-scale CHP gasifier is greatly
20 affected by the potential need for an operating engineer at all times while the unit is in
21 operation. With an automated system, Taljan *et al.* [28] based the operating cost for a 2
22 MW_e wood chip combustion facility on 400 annual hours of labour at 30 Euros/hr. If a
23 similar set of assumptions is adopted for Scenario 1 (substituting a \$30/hr wage, as in

[56]), the annual operating cost estimate would be equivalent to approximately 1.0% of the capital costs. For the Province of Ontario, however, there is reason to believe that the annual hours of labour will be far higher due to Ontario Regulation 219/01 which states that operation engineers must always be present during the operation of boilers used for heat and/or electricity production [27]. It is expected that gasification-based heat and electricity generation systems would be subject to the same regulation. This would require approximately 6570 hours of labour per year, raising annual operating costs to 16.2% of the overall capital costs. Scenario 1a uses the 1.0% estimate, reflecting the absence of a requirement for the continual presence of an operating engineer, while S1b uses the estimate of 16.2%, based on the mandatory operating engineer regulation as it currently exists in Ontario.

Annual maintenance and administrative costs are assumed to be 2%, and 0.7% of capital costs, respectively [28]. This brings the operation, maintenance, and administration costs of S1a to 3.7% of capital costs, and those of S1b to 18.9%. The estimate for S1a is within the range suggested by Beke *et al.* [57], and Dornburg and Faaij [6] (2001), which claim O&M costs ranging from 3% to 7% of project costs for wood chip cogeneration facilities. However, the estimate for S1b is far higher due to the presence of the operating engineer regulation.

In order to estimate the net cost of electricity from both System 1 scenarios, the savings from the displacement of LPG are taken into account. Approximately 680 GJ of LPG are used annually for the drying of lumber at HFWR, with the LPG cost in Haliburton at 55.8 cents/litre [39]. The quantity of heat supplied by the LPG is 8.1% of the net recovered heat remaining after allocating a quantity sufficient for the gasification

1 reaction and for drying the wood chip fuel [29]. With the installation of the CHP
2 gasification facility, we assume that the current LPG gas engine associated with the kiln
3 is no longer used. Exhaust gases from the new producer gas engine are substituted as the
4 heat source for the existing lumber kiln. The sensitivity analysis (Section 6) addresses the
5 net costs if all of the unused recovered heat is used for wood drying, thus displacing
6 3.31×10^5 litres (8.37×10^3 GJ) of LPG.

8 **2.3.6 Electricity generation at retrofitted coal-fired generating station (System 2)**

9
10 The cost of the infrastructure modifications at Atikokan is \$806/KW_e, based on
11 the \$170 million cost of the modifications and the 211 MW_e capacity of the Atikokan
12 facility [16]. The annual O&M cost for the Atikokan facility is \$21,700 (including fixed
13 and variable costs attributed to the proposed percentage of fuel inputs from HFWR),
14 based on estimates supplied by Zhang [58] and Zhang *et al.* [26]. Note that the costs of
15 solid waste management are included here in the reported O&M costs. The cost per kWh
16 of electricity generated is based on a projected capacity factor of 34% [26] for Scenario
17 2a, and the existing capacity factor of 8% for Scenario 2b. The harvest residue-derived
18 wood pellets from HFWR supplied to Atikokan would comprise a very small portion of
19 the annual wood pellet supply of the facility. Using the 31.6% net electrical efficiency of
20 the Atikokan facility, approximately 1.71×10^6 kWh of electricity would be generated
21 annually from the combustion of the pellets produced from HFWR harvest residue [29].
22 As 15% of the harvest residue would be used to dry the remaining biomass to the

required moisture content for the Atikokan facility [29], the net electrical efficiency relative to the initial energy content of the harvest residue is 26.9%.

2.3.7 Displaced coal and LPG

In order to estimate GHG mitigation costs from replacing coal, the default cost of electricity from coal is based on the assumption that the Atikokan generating station would continue to burn coal indefinitely. The low 2.9 c/kWh estimate is based on the default cost assumptions by Zhang *et al.* [26] for the Atikokan facility, and includes only the O&M and fuel costs, while assuming that the capital costs have already been paid off. The prices of displaced coal-fired electricity and LPG are assumed to increase by 3% annually. The GHG intensities of coal (1.14 kg CO₂ eq./kWh) and LPG (0.0348 CO₂ eq. kg/kWh of electricity generated by S1) are derived from the *US-EI* database [59], as cited in Cleary and Caspersen [29].

3 Results and discussion

3.1 Electricity generation costs

Under the favourable operational and regulatory conditions depicted in S1a and S2a, the average nominal generation costs of the small-scale and large-scale systems are 14.1 and 14.9 c/kWh, respectively. When one takes into account the avoided costs of

1 displaced LPG that would have been used for the drying of lumber in the HFWR kiln, the
2 cost per kWh for the small-scale system decreases to 13.2 c/kWh (S1a). However, under
3 existing conditions, the generation costs increase by 62% for the large-scale operation
4 (24.2 c/kWh - S2b) and 101% for the small-scale operation (28.3 c/kWh - S1b) (Figure
5 1). The partial inflation adjustment of the FIT rates (1.5% annually) is responsible for
6 18%-20% of these cost increases. The remaining 80%-82% of the cost increases are
7 attributable to the more stringent regulations pertaining to the presence of a process
8 engineer on site (S1b), and to wood pellet supply limits (S2b).

9 The small-scale of the gasification system inflates the capital and operating costs
10 of the facility. Under the conditions depicted in S1a, capital and O&M costs are
11 responsible for 72% of the cost of electricity, compared to only 20% of the costs
12 associated with the large-scale system in S2a. Under current regulatory conditions, the
13 relative share of capital and O&M costs in total generation cost further increases to 86%,
14 with O&M costs contributing to 42% of the total generation cost. In both scenarios,
15 transportation and wood processing costs per kWh are much higher for the large-scale
16 wood pellet combustion system, contributing between 53% and 71% of generation costs
17 compared to the 9% to 16% range for the small-scale system. Harvest residue collection
18 is responsible for 10% or less of the generation costs. Annual corporate taxes are often
19 avoided entirely because capital depreciation tends to exceed profits throughout the 20
20 year project lives of both systems.

21 22 **3.2 GHG mitigation costs** 23

Timing-adjusted life cycle GHG emissions of the small- and large-scale systems considered here were estimated in Part I of this study [29]. Electricity generated from both systems would be responsible for much lower average non-biogenic GHG emissions than electricity from coal (1,143 g CO₂ eq./kWh), with the small-scale system contributing 38 g/kWh and the large-scale system contributing 134 g/kWh (assuming a 100 year time horizon to calculate global warming potential) [29]. The biomass transportation and processing (chipping of residue and conversion to wood pellets) stages of the life cycle are primarily responsible for the greater emissions from the large-scale system [29]. In addition to these fossil fuel-derived emissions, harvest residue utilization results in supplemental emissions because the biogenic gasification/combustion (stack) emissions are greater than those which would have taken place through natural decomposition under aerobic conditions [29]. However, the net annual biogenic emissions from residue utilization decrease over time, until they eventually become negligible [29]. When displacing coal and LPG, net GHG mitigation ensues after 4 to 7 years [29]. Additional detail pertaining to the calculation of net GHG emissions from the two bioenergy systems is available in Cleary and Caspersen [29].

The GHG mitigation costs, which take into account the bioenergy costs as well as the avoided costs of the displaced coal-fired electricity and LPG, are lower for the small-scale facility under both scenarios. Using a 100 year time horizon for calculating global warming potential, the cost of GHG mitigation under favourable conditions is \$111/t CO₂ eq. for the small-scale system (S1a) and \$159/t for the large-scale system (S2a). However, costs rise substantially under current conditions, reaching \$265/t for the small-scale system (S1b) and \$281/t for the large-scale system (S2b) (Figure 2).

3.3 Sensitivity analysis

This sensitivity analysis addresses the effects of altering a number of the LCC model parameters within plausible ranges to ascertain the extent to which variable operational and regulatory conditions affect generation and mitigation costs. Two parameters are varied for System 1: (1) gasification infrastructure costs; and (2) the recovered heat utilized for the drying of lumber. Three parameters are altered for System 2: (1) wood pellet shipping distance; (2) the combustion of wood residue for pellet drying; and (3) the cost of the coal-based electricity, which affects GHG mitigation costs.

For System 1, gasification infrastructure costs are highly uncertain, exemplified by Wood and Rowley's [32] estimate of \$3000/kW_e to \$7000/kW_e. The initial cost estimate of 14.1 c/kWh for S1a with a capital cost of \$6000/kW_e would decrease to 9.6 c/kWh with a \$3000/kW_e assumption, and increase to 16.8 c/kWh with a \$7000/kW_e assumption. Capital costs also rise considerably if the rated electrical capacity of the bioenergy system falls below 250 kW_e [60]. With regard to the sensitivity of System 1 costs to heat recovery, there is approximately twelve times the heat available for the drying of lumber than there is kiln capacity at HFWR. If HFWR had sufficient kiln capacity to use all of the recovered heat, the net cost of electricity from the small-scale system would fall by 11.5 c/kWh to 2.6 c/kWh (excluding the cost of the additional kiln capacity) due to the displaced LPG. This substantial reduction in costs partly reflects the relatively high price of LPG, and the lack of access to lower priced natural gas (in terms of MJ of energy supplied) at HFWR.

For System 2, approximately 35% to 45% of the estimated generation cost is attributable to transportation costs. Pellets for this facility could be available from sources that are within closer proximity (e.g., [26], which modelled an average distance of 1,350 km, instead of 1,822 km). If the wood pellet combustion facility had been located in Sault Ste Marie, Ontario instead of Atikokan, the 37% reduction in pellet shipping distance by rail from 1,635 km (Toronto to Marmion Lake/Atikokan) to 1,024 km (Toronto to Sault Ste Marie) would decrease rail shipping costs by only 20%. The overall reduction in the generation cost of the large-scale system would be 0.7-0.8 c/kWh. Likewise, the generation cost would only decrease by 0.6-0.7 c/kWh if none of the collected residue needed to be used for pellet drying at the pellet plant(s). Finally, the GHG mitigation costs assessed in Section 3.2 take into account the previous cost of electricity from coal combustion at Atikokan (2.9 c/kWh). However, considerable refurbishment costs might have been necessary for the facility to continue generating electricity from coal combustion for an additional 20 years. When using an 8 c/kWh estimate for the displaced electricity from a new or refurbished coal-fired generating station (e.g., [61]), GHG mitigation costs fall to \$56 and \$91/t CO₂ eq. for S1a and S2a, respectively. In comparison, the costs of S1b are reduced to \$210, while those of S2b fall to \$214/t CO₂ eq.

4 Discussion

Our results indicate that the differences in the generation costs for the two systems under favourable policy conditions (S1a and S2a) are negligible, at under 1 cent.

1 However, the current operational and regulatory constraints in Ontario increase the cost
2 of small-scale electricity generation to a much greater extent than electricity from its
3 large-scale counterpart. The co-production of electricity and heat in the small-scale CHP
4 system, and electricity generation in the retrofitted coal-fired generating station, are only
5 profitable under operational and regulatory conditions that do not currently exist in
6 Ontario. The current 15.6 c/kWh FIT for bioenergy facilities <500 kW_e in Ontario is
7 adequate compensation for undertaking the evaluated small-scale CHP project if the
8 regulation requiring the continuous presence of an operating engineer is eliminated
9 (while retaining sufficient regulation to ensure safe operation of the equipment) and
10 capital costs remain below ~\$7,000/kW_e. However, electricity generation costs from the
11 retrofitted coal-fired generating station are estimated at 24.2 c/kWh under current
12 operational conditions where the capacity factor of the facility is 8%. This bioenergy
13 production option is unprofitable under current subsidy regimes, assuming that the
14 province allocates a subsidy amount under the new bidding/auction mechanism that is
15 similar to that allocated under the past and present FIT program (i.e., in the range of 13-
16 16 c/kWh). If sufficient low-cost harvest residue is procured to raise the capacity factor
17 of the facility to 34%, subsidy levels equal to 14.9 c/kWh or higher could provide
18 adequate compensation to support bioenergy production at the large-scale plant.

19 Our results confirmed the relatively insignificant contribution of harvest residue
20 collection to the total costs of bioenergy systems (e.g., [12]). For the small-scale system,
21 it is the capital and operating costs that predominate, whereas the capital, processing and
22 transportation costs are responsible for most of the costs of the large-scale system. O&M
23 costs contribute to the majority of total costs under regulatory conditions mandating the

1 presence of an engineer (S1b), which substantially increases labour costs. In contrast, for
2 the retrofitted coal-fired generating station now fueled with wood pellets, the majority of
3 total generation costs are related to the upstream activities of transportation and
4 pelletization. Given the wood pellet supply constraints that the facility is currently
5 experiencing (S2b), which has reduced the capacity factor from 34% to 8%, the share of
6 capital costs in the total generation cost increases by a factor of two relative to S2a.

7 The sensitivity analysis provided additional insight into the sensitivity of the
8 generation costs of the small-scale system to capital costs and heat utilization. Generation
9 costs for S1a rise by up to 2.7 c/kWh from an increase in the assumed capital cost, and
10 fall by up to 11.5 c/kWh when assuming that all of the recovered heat from the
11 gasification reaction is used to displace LPG. The generation costs of the large-scale
12 system, on the other hand, are relatively insensitive to the varied parameters
13 (transportation distance and residue use for drying). Instead, the single most important
14 factor contributing to the generation costs of the large-scale system is not a life cycle
15 activity *per se* but rather related to the absolute limits of cost-effective wood pellet
16 supply.

17 An intermediate-scale CHP facility (between 2-10 MW_e) could also be a
18 promising option which would reduce the labour cost of the operating engineer relative to
19 the amount of electricity and heat generated at the bioenergy facility. As labour and
20 capital costs per kWh tend to decrease with scale, an intermediate-scale plant could
21 provide cost benefits relative to the small-scale CHP system addressed in our study.
22 However, biomass transportation costs would increase due to the larger biomass
23 procurement area required. The costs of biomass shipment by rail, per km, have also been

1 shown to decrease with distance (Section 3.3). Nevertheless, the savings from lower
2 operating costs (i.e., associated with the operating engineer) would likely exceed the
3 increased transportation costs. The presence of a substantial nearby heat sink such as a
4 pellet plant would also reduce the net costs of an intermediate-scale plant. Further
5 research on the costs of bioenergy production from intermediate-scale facilities could
6 prove insightful.

7 The costs of GHG mitigation from displacing coal are higher for the large-scale
8 generating station due to the substantial quantity of GHG emissions during fuel shipping
9 and processing. The GHG balance of the small-scale CHP system is much better due to
10 the shorter total transportation distance and an improved conversion efficiency resulting
11 from heat utilization. However, there is currently insufficient justification for investing in
12 either forest bioenergy system solely on the basis of GHG emission avoidance because
13 there is no dedicated carbon tax or carbon pricing in Ontario at present. Only 12% of
14 annual global GHG emissions are subject to a carbon price, which range from under
15 \$1(U.S.)/tonne CO₂ eq. in Mexico to \$168 in Sweden [62]. Further, most of the prices in
16 existing carbon pricing systems are below \$35/t [62], which are insufficient for both the
17 small- and large-scale bioenergy projects.

19 **5 Conclusions**

21 The contrasting results for electricity generation and GHG mitigation costs
22 relative to scale have important implications for future iterations of bioenergy policies
23 that aim to encourage investment and realize attendant benefits at minimal fiscal cost. If

the stated priority of Ontario's FIT program is to increase bioenergy production, the rates offered should be similar for both the large- and small-scale systems under the favourable operational and regulatory conditions explored here. If the primary objective of the bioenergy policy is instead to reduce GHG emissions, it may be most cost-effective to prioritize smaller-scale CHP systems (~250 kW_e) over large-scale electricity-only systems requiring long-distance fuel shipping because more GHGs are mitigated per unit of government funds invested, particularly when significant local heat demand is available. Results also highlight the need for broader consideration of regulatory requirements and proximate fuel availability when designing supply-side policies and programs focused on increasing bioenergy production from facilities of different scales.

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