TECHNO-ECONOMIC ASSESSMENT OF BIOHYDROGEN PRODUCTION FROM FOREST BIOMASS IN WESTERN CANADA

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ABSTRACT. *Western Canada is the largest hydrocarbon base in Canada. Oil sands, one of its key crude oil resources, are used for production of bitumen, which is further processed to produce crude oil. Bitumen is upgraded before it is sent to the refinery. The upgrading of bitumen requires hydrogen, most of which is currently produced from natural gas. The recent increase in natural gas prices has made it desirable to obtain hydrogen from other sources. Biomass-based fuels are currently receiving much attention, as these fuels are considered carbon neutral and renewable. Hydrogen (biohydrogen) can be produced from biomass using thermo-chemical processes. Western Canada's potential for forest biomass is large. This article explores the option of producing hydrogen for bitumen upgrading from the forest biomass in western Canada. The production of biohydrogen by thermal gasification of whole-tree forest biomass by a stand-alone 2000 dry tonnes per day plant costs \$1.18/kg of H_2 (or \$9.83/GJ of H_2). Capital and operating costs contribute 32% and 26% of the total cost of production, respectively, whereas feedstock delivery cost contributes about 36%. The total cost of delivering biohydrogen by pipeline to a bitumen upgrader located 500 km away from the production plant is \$2.20/kg of H_2 (or \$18.32/GJ of H_2). The current cost of delivered biohydrogen is not competitive with natural gas based hydrogen; it can become competitive only with a long-term natural gas cost of about \$12/GJ. Carbon credits can make biohydrogen competitive. At a natural gas cost of \$5/GJ, the carbon credit required to make biohydrogen competitive with natural gas based hydrogen is about \$140 per tonne of CO_2 equivalent. The economic optimum size (the size at which the cost of production is minimal) for a biohydrogen plant using whole-tree biomass is more than 5000 dry tonnes per day, but a smaller plant could be built to reduce the risk and minimize the capital cost penalty. Most of the economies of scale are exploited by 2000 dry tonnes per day.*

Keywords. *Biohydrogen, Forest biomass, Gasification, Optimal plant size, Production cost, Techno-economic assessment.*

Increase in the atmospheric concentration of greenhouse gases (GHGs) has emerged as one of the most important environmental issues in recent years. The contribution to global warming made by GHG emissions can be effectively mitigated by reducing them at the source. One option is switching to low-emission fuels. If produced and used sustainably, biomass can act as a reservoir of carbon or as a direct substitute for fossil fuels with no or little net contribution to atmospheric buildup of GHGs. Because of various social and environmental benefits, the large potential for biomass in western Canada is considered a key renewable energy resource for the future. Its favorable characteristics have increased interest in biomass-based fuel.

A bioeconomy would consist of various pathways of biomass utilization (e.g., power, liquid fuels, and chemicals). Different products obtained from biomass can be substituted for fossil fuel based products in various energy sectors. For example, bioethanol can replace gasoline in the transportation sector, biopower can replace coal-based power in the electricity sector, and biohydrogen can replace natural gas based hydrogen in the industrial sector as well as fossil fuels in the transportation sector. All these pathways can help in mitigating GHG emissions. Many of these biomass energy technologies are now in different stages of development, demonstration, and commercialization.

Western Canada is one of the largest hydrocarbon bases in North America. In 2007, Canada produced about 438 million barrels of synthetic crude oil and bitumen (CAPP, 2008). Western Canada has a large resource of oil sands (an extremely dense form of petroleum known as bitumen) that is currently being used for bitumen production, which in turn is used for the production of crude oil. Additionally, Canadian oil production was 2.7 million barrels per day in 2007, of which more than 85% was produced in western Canada (CAPP, 2008). Bitumen needs upgrading with hydrogen before it can be used for the production of crude oil. Current oil sands demand for hydrogen is about 2,000 tonnes per day; it is expected that by 2020 this will increase to 14,400 tonnes per day (Deligiannis et al., 2004; Tarun, 2006). Today, most of the hydrogen for bitumen upgrading is produced from natural gas. Alternative sources of hydrogen could be competitive with conventional sources, and there is a need to investigate these. In Alberta, this hydrogen can be partially replaced by biomass-based hydrogen (biohydrogen).

This study presents a techno-economic assessment of western Canada's biohydrogen production using whole-tree biomass. The key objectives of this study are: to estimate the cost of biohydrogen production and delivery from whole-tree

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biomass in western Canada (\$/kg of H_2) using the thermo-chemical conversion process (gasification) to a bitumen upgrader; to estimate the optimum size, i.e., the size of the biohydrogen production plant at which the cost of biohydrogen production is at a minimum; and to estimate the cost of natural gas at which the cost of biohydrogen is competitive with natural gas based hydrogen. This study also estimates the carbon credit (\$/tonne of CO_2 equivalent) required for biohydrogen to be competitive with current natural gas based hydrogen in western Canada. Note that all cost figures in this study are adjusted to the year 2008 and given in U.S. dollars (US\$), unless specified otherwise.

Current Technologies for Biohydrogen Production

Biohydrogen can be produced using thermo-chemical, electrohydrogenesis, and biological processes from a range of forest and agricultural biomass feedstocks. These processes can be subdivided into several categories. Figure 1 gives an overview of the processes that can be used for biohydrogen production from biomass (Cheng and Logan, 2007; Chum and Overend, 2001; Hallenbeck and Benemann, 2002; Hamelinck and Faaij, 2002; Lau et al., 2003; Ni et al., 2006; Simbeck and Chang, 2002; Spath and Dayton, 2003). Among these different processes, gasification (a thermo-chemical process) is more advanced in development and commercialization. This process is used as the basis for the biohydrogen production in this study.

Thermo-Chemical Conversion Process

In thermo-chemical conversion, biomass is chemically converted to a blend of numerous gases using heat. As shown in figure 1, three different thermo-chemical conversion processes can be used for energy production from biomass; however, all of these processes are not efficient in terms of biohydrogen yield and conversion efficiency for biohydrogen production (McKendry, 2002b; Ni et al., 2006). Basically, gasification and pyrolysis are the two thermo-chemical processes with the best potential for biohydrogen production on a commercial scale (Abedi et al., 2002; Babu, 2005; Bridgwater et al., 2002; NETL, 2007; Ni et al., 2006; Williams et al., 1995).

Gasification of Biomass

Gasification is the process of heating biomass to a high temperature using steam in the presence of a limited supply of air or oxygen; this is done in a gasifier (where biomass is gasified) to produce impure syngas (Demirbaş, 2002; Larson et al., 2005; Mahishi et al., 2008; McKendry, 2002c). Biomass feedstock harvested and processed in the forest has a large chip size (>50 mm) and high moisture content (~50%), which make it difficult to gasify without reducing size and drying. The gasification of whole-forest biomass requires a moisture content of approximately 10% to 20% and a feedstock size of about 50 to 80 mm in order to obtain a high heat transfer rate between the heat transfer medium and the biomass feedstock (McKendry, 2002c). Upon being transported to the biohydrogen plant, biomass is put through a hammer mill to reduce chip size. This ground feedstock is dried (to a moisture content of up to 12%) in a rotary drum biomass dryer, which is a commonly used piece of equipment for biomass-based feedstock drying (Lau et al., 2003). The energy required for drying is obtained by burning char produced during the gasification process. In this study, feedstock handling and drying contribute 21% of plant's total capital cost.

Gasification of whole-forest biomass is conducted at 870°C in a circulating fluidized bed gasifier where steam acts as a fluidization medium, and synthetic olivine (calcined magnesium silicate) transfers heat (mostly by conduction) into the gasifier (Bridgwater, 1999; Spath et al., 2005). Gasifier exit gases consist mainly of H_2, CO, CO_2, and H_2O (about 85% on a mole basis), and the remaining gases are CH_4, H_2S, NH_3, and long hydrocarbon chain compounds (Hamelinck and Faaij, 2002; Larson et al., 2005; Lau et al., 2003; Spath et al., 2005). This information is based on the National Renewable Energy Laboratory's published report on hydrogen production by gasification of biomass (Spath et al., 2005).

Syngas, produced from biomass gasification, contains particulates, tar, and impurities. Tar cracking, which takes place at around 800°C in the presence of a catalyst, decreases tar concentration and increases the concentration of product gases in the syngas (Larson et al., 2005; Spath et al., 2005). Large particulates are removed by cyclones, and small particulates are removed by ceramic candle filters. The remaining ammonia and tars are cleaned by a water scrubber, which also reduces the syngas temperature (Hamelinck and Faaij, 2002; Larson et al., 2005; Spath et al., 2005). Several technologies for gas cleaning are used in oil refining, syngas production, steam methane reforming, and ammonia and urea plants. This study used the LO-CAT gas cleaning process (Gas

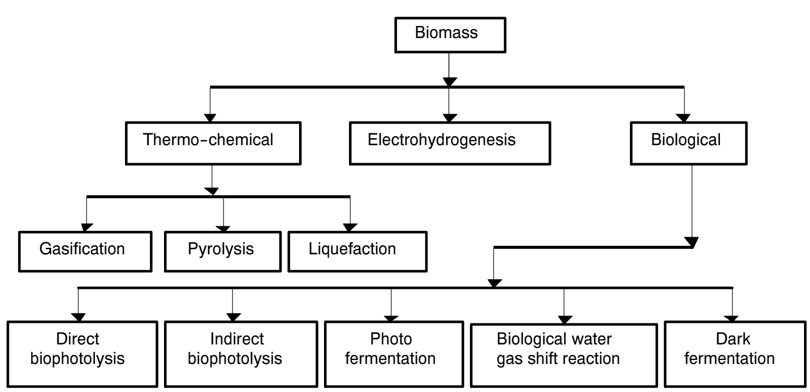

Figure 1. Biohydrogen production processes.

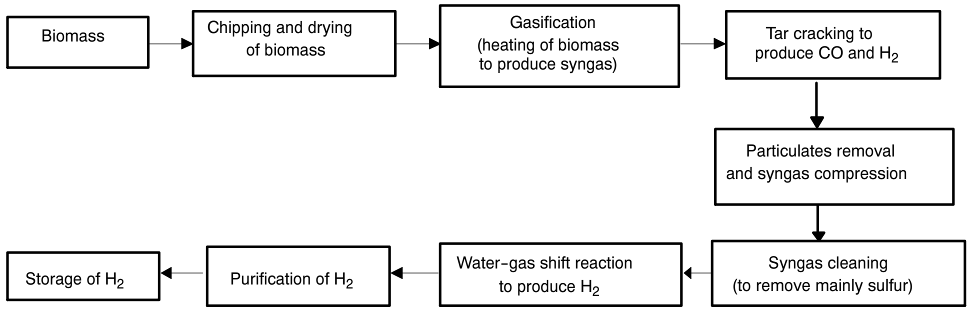

Figure 2. Hydrogen production from whole-forest biomass by gasification.

Technology Products, 2008) followed by a ZnO bed for removal of sulfur from syngas (Spath et al., 2005). In this study, the capital cost of equipment for gas clean up and compression constituted 17% of the total capital cost.

The yield of hydrogen from biomass gasification can be increased by dual water-gas shift reactors at around 350°C for high-temperature shift reactors and 260°C for low-temperature shift reactors (Hamelinck and Faaij, 2002; McKendry, 2002c). The water-gas shift reaction increases hydrogen to 55% in the syngas, which finally passes through the pressure swing adsorption (PSA) unit, where all the gases except hydrogen are adsorbed. Finally, the hydrogen gas is compressed to about 7 MPa for pipeline transportation to the bitumen upgrading plant. Figure 2 shows the various steps of hydrogen production from whole-forest biomass using a gasification process derived from several studies (Hamelinck and Faaij, 2002; IEA, 2006; Lau et al., 2003; Ni et al., 2006; Simbeck and Chang, 2002; Spath et al., 2005; Spath et al., 2003).

Status of the Technology

A range of gasifiers can be used for producing hydrogen from biomass. These gasifiers include: fixed bed updraft and downdraft, bubbling fluidized bed, circulating fluidized bed, and entrained flow gasifiers (Ciferno and Marano, 2002; Henrich and Weirich, 2004; Schingnitz and Mehlhose, 2005; Veringa, 2005; Williams et al., 1995). Details on the characteristics of these gasifiers can be found in the literature (Bridgwater, 2003; Bridgwater, 2007; Ciferno and Marano, 2002; McKendry, 2002c; Schingnitz and Mehlhose, 2005; Veringa, 2005). Although there are a few research-scale biomass gasification projects that generate electricity, presently there is no large-scale commercial biomass gasification plant that produces hydrogen (Babu, 2005; IEA, 2006). One example of a demonstration-scale biomass gasification plant is BIOSYN, Inc., where methanol is produced by a biomass gasification process (Babu, 2005). Another example of an advanced biomass gasification process is the Carbo-V process, a three-stage gasification process for syngas production, developed by CHOREN in Freiberg, Germany (CHOREN, 2007).

Biohydrogen yield depends on the thermo-chemical process and feedstock used for its production. Various other studies have reported yields of biohydrogen using a range of processes (e.g., electrohydrogenesis, synthetic enzymatic pathway, autothermal reforming, and flash volatilization) (Cheng and Logan, 2007; Cortright et al., 2002; Deluga et al., 2004; Salge et al., 2006; Zhang et al., 2007). Table 1 shows the bio-hydrogen yields from gasification of different biomass feedstocks.

Table 1. Biohydrogen yield.

Technology	Feedstock	H_2 Production Rate[a] (kg per dry tonne biomass)
Gasification	Bagasse	78.1
	Switchgrass	84.1
	Nutshell mix	88.3
	Poplar wood chip	83.4
	Rice straw	72.2

[a] Derived from: DOE, 2003; Larson et al., 2005; Lau et al., 2003; Parker, 2007; and Spath et al., 2005.

A range of factors contribute to the overall cost of producing biohydrogen from biomass. The main factors are: type of thermo-chemical conversion process, feedstock for production, capital cost of the plant, biohydrogen yield, delivered feedstock cost, and operation and maintenance costs. These costs vary with the location of the plant. This study is a techno-economic assessment of biohydrogen production in western Canada. All the input data are specific to this location and, wherever required, data are adjusted for this location.

Biohydrogen Production in Western Canada

Large areas of western Canada are covered with boreal forest. The forest in the province of Alberta consists of softwoods and hardwoods. This study is based on using a good biomass yield site that has a combination of spruce and aspen stands (Alberta Energy, 1985; Kumar et al., 2003). The scope of this techno-economic assessment includes felling (cutting) trees, skidding (moving) trees to the roadside, chipping by the roadside, and transporting wood chips to a centralized biohydrogen production plant. The biohydrogen produced is transported to the existing bitumen upgrader by pipeline. Various parameters are considered in estimating the total cost of biohydrogen delivered to the bitumen upgrader. Specific techno-economic cost models based on discounted cash flow analysis are developed for estimating the total cost of delivered biohydrogen. Details on these parameters are given in subsequent sections.

Input Data and Assumptions

Biomass Delivery Cost

The Canadian Forest Service (CFS) and the Forest Engineering Research Institute of Canada (FERIC) have conducted extensive studies on biomass recovery from forests in western Canada. The biomass delivery costs include costs for felling, skidding, chipping, and transportation. These costs are estimated in consultation with researchers and experts

Table 2. Characteristics and costs of biomass procurement and delivery.

Items	Values/Formulae	Comments/Sources
Biomass yield (dry tonnes/ha)	84	Assumed yield based on hardwood and spruce yield in Alberta (Kumar et al., 2003). This yield reflects the average amount of biomass that can be obtained from 80 to 120 year old trees.
Biomass harvesting cost:		Calculated based on biomass harvesting cost (ALPAC, 2006; Dumouchel, 2006; Folkmann, 2006; MacDonald, 1999; MacDonald, 2006).
Felling ($/dry tonne)	3.75	
Skidding ($/dry tonne)	3.11	
Biomass chipping cost ($/dry tonne)	3.84	Calculated for Morbark 50/48A whole-tree chipper (ALPAC, 2006; MacDonald, 2006; Morbark, 2004).
Chip loading, unloading, and transportation cost ($/m^3)	$0.9056 \times (2.30 + 0.0257D)$	*D* is the round-trip transportation distance between in-bush chipping and a centralized biohydrogen production plant (Kumar et al., 2003).
Cost of road construction ($/ha)	$[0.9056 + (453/VT)] \times$ average gross yield (m^3/ha)	*VT* is the mean merchantable volume, where *T* is the number of merchantable stems per hectare, and *V* is the volume per merchantable stem. *VT* is assumed to be 185.4 m^3/ha for Canadian boreal forest (Kumar et al., 2003).
Cost of silviculture ($/ha)	181	This cost is attributed to prepare the land for next cycle of forest growth (Kumar et al., 2003).
Ash disposal cost:		Ash produced from gasification is transported and spread within a radius of 50 km (Zundel et al., 1996).
Ash hauling cost ($/dry tonne/km)	0.18	
Ash disposal cost ($/dry tonne/ha)	25.22	
Tortuosity factor	1.27	Increases feedstock transportation distance for geographical condition such as swamps, hills, and lakes in the biomass site (Overend, 1982).

using an review of the extensive literature (ALPAC, 2006; Dumouchel, 2006; Hall et al., 2001; Hankin et al., 1995; Hudson, 1995; Hudson and Mitchell, 1992; Kumar et al., 2003; LeDoux and Huyler, 2001; Lieffers, 2006; McKendry, 2002a; Mellgren, 1990; Perlack et al., 1996; Puttock, 1995; Silversides and Moodie, 1985; Zundel, 1986; Zundel and Lebel, 1992; Zundel et al., 1996). Details on each of the cost components in biomass delivery are given below in table 2.

Tree biomass is cut by a feller buncher, which is equipment commonly used in western Canada. The forwarder or grapple skidder is used to skid the tree to the road side, where it is chipped by a Morbark chipper (Kumar et al., 2003; MacDonald, 1999; MacDonald, 2006; Morbark, 2004). The biomass is transported to the production plant by B-train chip vans after the chipping operation. The delivery costs also include road construction and silviculture costs. The plant is assumed to be in a remote location, so there would be costs for the construction of primary and secondary roads. These costs are included in this analysis. Silviculture costs include the cost of preparing the land after harvesting wood. In addition to these costs, the study also includes a royalty payment of $4.8/dry tonne to the province of Alberta, which is an average value for the royalty charged by the province (Kumar et al., 2003). The biomass delivery cost assumptions are shown in table 2.

Biomass Fuel Properties

The techno-economic model developed for calculating the cost of producing hydrogen from biomass makes several assumptions on fuel properties. The moisture content, density, and ash content are different for hardwood and softwood. In this study, we have assumed an average value for each of the properties. Table 3 shows the feedstock properties assumed in this study.

Capital Cost and Scale Factor

Biomass gasification is the basis of biohydrogen production technology. The base-case size of a biohydrogen plant is assumed to be 2000 dry tonnes per day, which is equal to the size studied by the National Renewable Energy Laboratory (NREL) and other researchers (Simbeck and Chang, 2002; Spath et al., 2005).

The capital cost of the production plant was obtained primarily from an extensive literature review and from consultation with experts (Curtis et al., 2003; Hamelinck and Faaij, 2002; Hamelinck et al., 2005; Kreutz et al., 2005; Larson et al., 2005; Lau et al., 2003; Mann, 1995; NAE et al., 2004; Padró and Putsche, 1999; Parker, 2007; Spath et al., 2005; Tijmensen, 2000). The capital cost of individual equipment for the 2000 dry tonnes per day plant is derived from these studies using their respective scale factors. The range for the scale factor is 0.33 to 1 for different equipment. The capital cost of the plant includes the purchase price of each piece of equipment, engineering fees, installation costs, plant construction, and contingency budgeting. Using the capital costs and scale factors of various equipment for a 2000 dry tonnes per day plant, an overall scale factor for the capital cost of the plant is calculated as 0.76. In this study, the maximum unit size of the gasifier is considered to be 1000 dry tonnes per day. Thus, a 2000 dry tonnes per day plant has two 1000 dry tonnes per day gasifiers. Accordingly, capital costs are estimated for various plant sizes using scale factors (for

Table 3. Fuel properties.

Characteristics	Whole-Forest Biomass	Comments/Sources
Moisture content (%, wet basis)	50	Feedstock moisture content during transportation (Kumar et al., 2003; Spath et al., 2005).
Fuel density during transportation (kg/m^3)	570	Calculated for 50% moisture content (SImetric, 2007; Simpson, 1993).
Heating value (MJ/dry kg, HHV)	20	Calorific value of whole-tree biomass (Gullett et al., 2003; Kumar et al., 2003).
Percentage of H_2 (%)	6.4	Taken from ultimate analysis of dry western pine (Gullett et al., 2003).
Percentage of ash (%)	1	Ash content (Kumar et al., 2003).

Table 4. Biohydrogen production plant characteristics.

Items	Values	Comments/Sources
Base-case biohydrogen plant size (dry tonnes/day)	2000	Based on literature (Spath et al., 2005).
Capital for biohydrogen production plant using 2000 dry tonnes of biomass per day (million dollars)	178	Derived from (Spath et al., 2005). The capital cost for feedstock handling and drying is about 21% of total plant capital cost.
Plant life (years)	20	Assumed.
Biohydrogen yield (kg H_2 per dry tonne biomass)	83.4	H_2 yield from wood chip biomass (Spath et al., 2005).
Plant operating factor:		These years refer to the first three years of operation of plant (Kumar et al., 2003 and Spath et al., 2005).
Year 1	0.70	
Year 2	0.80	
Year 3 onwards	0.85	
Operating staffing including maintenance staff:		Calculated from Aden et al. (2002) and Spath et al. (2005). It is assumed that if there is an increase or decrease of 1000 dry tonnes per day in the capacity of plant, the number of operating staff changes by 5.
2000 dry tonnes per day	50	
For every change of 1000 dry tonnes per day in capacity of the plant	5	
Administrative staff	4	Assumed to be almost same for all the sizes of plants.
Average labor cost including benefits ($/h)		Salaries have been adjusted for the province of Alberta (Aden et al., 2002; PAQ Services, 2007; Ringer et al., 2006).
Operating staff	40	
Administration staff	64	
Spread of costs during construction (%):		Plant goes into production at the end of year 3 (Ringer et al., 2006; Spath et al., 2005).
Year 1	8	
Year 2	60	
Year 3	32	

instance, cost E_1 = cost E_2 × (size E_1/size E_2)$^{\text{scale factor}}$, where cost E represents the total cost of the equipment). The biohydrogen production plant's construction period is assumed to be three years. Other details on plant characteristics are given in table 4.

Operating Cost

In a biohydrogen plant, the variable operating costs include the cost of natural gas, electricity, catalysts, raw materials, and waste disposal when the biomass gasification process is taken into account (Spath et al., 2005). It is assumed that the variable operating cost changes linearly with plant size. Accordingly, costs are adjusted for different plant sizes. Other costs include employees' remuneration and maintenance costs. Employees' remuneration is estimated at an hourly rate, as given in table 4. Finally, the number of administrative staff is assumed to be the same for different plant sizes. Table 5 shows the general input data for this study.

Synthetic olivine and MgO are used in the gasifier as catalysts to transfer heat to the biomass and continue the fluidization process, respectively, while Fe_2O_3, Cr_2O_3, CuO, and ZnO are used as shift reactor catalysts (Spath et al., 2005). The gasifier bed material and catalysts' costs contribute 38% of the total plant variable operating cost.

Biohydrogen Transportation Cost

Once biohydrogen is produced in a remote location, it needs to be transported from the central production plant to the bitumen upgrader. The transportation method could be classified according to the phase of H_2 fuel as well as the medium used for carrying H_2 (Amos, 1998). Three modes of hydrogen fuel transport are most frequently found in commercial operations in North America (Deligiannis et al., 2004; DOE, 2006a; Yang and Ogden, 2007): compressed gas in a tube trailer transported by truck, liquid hydrogen in a cryogenic tank transported by truck, and compressed gas transmitted through a pipeline. The total transportation cost

Table 5. General input data.

Items	Values	Comments/Sources
Scale factor	0.76	Overall plant scale factor is derived from individual scale factors of different equipment as given in the NREL's report (Spath et al., 2005).
Maximum unit size of gasifier (dry tonnes/day)	1000	Maximum gasifier size for indirectly heated gasification process taken from personal communication and literature (Aden, 2007; Spath et al., 2005; Tijmensen, 2000).
Cost of an additional equal-sized biohydrogen production plant unit (gasifier) relative to the first	0.95	Any additional unit will reduce 5% capital cost of the first unit (Kumar et al., 2003).
Factor to reflect capital cost impact for remote location	1.10	The remote location of the plant will lead to increase capital cost (Kumar et al., 2003).
Annual maintenance cost (% of capital cost)	2	Maintenance cost is assumed as a percentage of capital cost (Hamelinck and Faaij, 2002; Larson et al., 2005; Parker, 2007; Spath et al., 2005).
Labor surcharge for remote location	1.20	Cost of transporting and keeping labor (Kumar et al., 2003).
Aggregate pre-tax return on investment (blend of debt plus equity) - discount rate	10%	
Reclamation cost (% of the capital cost)	20	This is the cost incurred in decommissioning and clearing of land (Kumar et al., 2003).

for these three modes varies with changing transportation rates (i.e., amount transported amount per day) as well as transportation distance. Selection of a transportation method relies on several factors, such as transportation rate (tonnes/day), transportation distance (km), type of hydrogen fuel supply (continuous or intermittent), phase of H_2 (gas or liquid), and infrastructure availability (Amos, 1998). Typically, for a low transportation rate (<600 kg/day) tube trailers could be used, for a medium transportation rate (600 kg/day < flow rate <2.4 tonnes/day) cryogenic tanks could be used, and for a high hydrogen fuel demand (>2.4 tonnes/day) pipeline transportation could be used (Amos, 1998; Deligiannis et al., 2004; DOE, 2006b; Parker, 2005; Simbeck and Chang, 2002; Yang and Ogden, 2007).

Figure 3 illustrates the location of a biohydrogen production plant (point *O*), biomass harvesting area (circle with radius *R*), and bitumen upgrading plant (point *A*). Distance *R* is the maximum distance that whole-forest biomass is transported to the biohydrogen production plant located at the center of the circular area, and $\bar{R}$ is the average biomass transportation distance. Finally, hydrogen is transported a distance *X* from the biohydrogen production plant to the bitumen upgrading plant (point *A*). In this study, the average transportation distance of biomass (wood chips) is 18 km (i.e., the value of $\bar{R}$), and the average transportation distance of biohydrogen (i.e., the value of *X*) is 500 km. Biomass transportation distance also includes the impact of the tortuosity factor, as indicated in table 2.

Figure 4 shows the cost of hydrogen transportation by the three modes (discussed above) for a plant producing 167 tonnes of hydrogen per day. This capacity corresponds to a plant utilizing 2000 dry tonnes of biomass per day. This study is based on this size of plant. In the case of western Canada, the biohydrogen produced would be transported to a bitumen upgrader, where it would be used to upgrade bitumen that is then further refined for crude oil production. Currently, there are four upgraders in western Canada; two of these are located in Fort McMurray (500 km north of Edmonton), Alberta, and one is located in Edmonton, Alberta (CAPP, 2007; Deligiannis et al., 2004). Biohydrogen production from whole-tree biomass in the boreal forest will be at a plant located at a maximum of 500 km from the upgrader. This assumption is made based on the location of the biomass resource and the location of the upgraders in Alberta. From figure 4, it is clear that for biohydrogen transportation at a capacity of 167 tonnes per day and for a distance of 500 km,

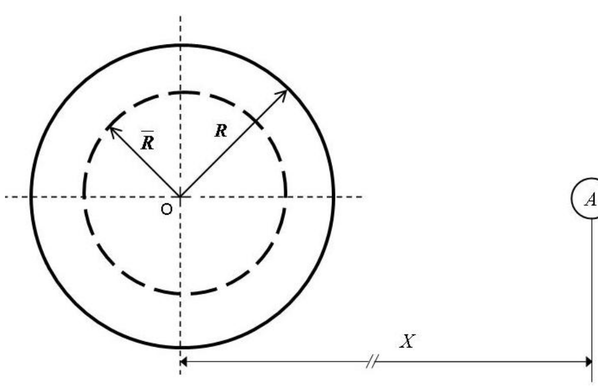

Figure 3. Schematic diagram of biohydrogen plant and hydrogen transportation distance.

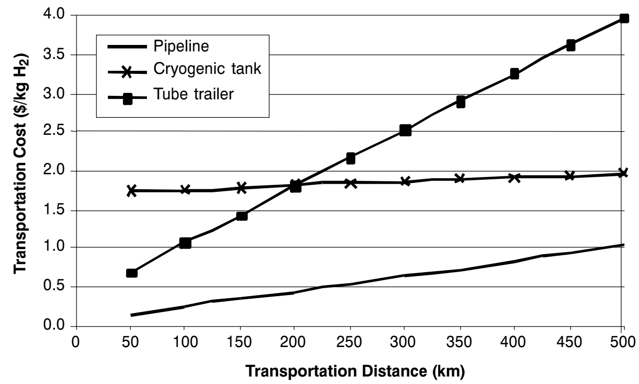

Figure 4. Variation in biohydrogen transportation cost for three transportation modes.

pipelines are the most economical option. Hence, in this study, we have considered pipeline transport as the mode of biohydrogen transportation. This mode can be changed if the transportation distance and capacity change. Based on earlier studies on hydrogen transportation, the pipeline cost is lowest for a large capacity and a long distance (Amos, 1998; Parker, 2007; Simbeck and Chang, 2002). Pipeline transportation of hydrogen for a long distance and large capacity costs the least ($/kg of H_2) due to economy of scale in the capital cost of pipelines (fig. 4). The capital cost of pipelines per unit of throughput decreases as the capacity increases. For tube and cryogenic tank trailers, there is no decrease in transportation cost ($/kg of H_2) as transportation capacity increase. The details on the pipeline size and design parameters for this study are given in the Appendix.

Results and Discussions

Biohydrogen Production Costs

Table 6 shows the breakdown of biohydrogen production costs using whole-tree biomass from the boreal forest in western Canada. These costs are the output of a detailed discounted cash flow analysis based techno-economic assessment model developed in this study using the input parameters explained above. The cost of biohydrogen produced by a plant utilizing 2000 dry tonnes of biomass per day is $1.18/kg of H_2 or $9.83/GJ of H_2 (i.e., $1 per kg of H_2 = $8.32/GJ of H_2). This is based on the lower heating value of H_2 of 120.1 MJ/kg. This cost is an estimation for the third year of operation at an 85% operating factor. Capital and operating costs contribute about 32% and 26% of the total cost of production, respectively. In addition, biomass harvesting and transportation costs are the main components of the total feedstock delivery cost. The total cost of delivering biomass to the biohydrogen plant is $0.43/kg of H_2, which is about 36% of the total production cost. The total cost of delivered biomass is $36/dry tonne, as calculated using the formulae in table 2. Note that the cost of delivered biomass includes a biomass production cost of $15.50/dry tonne.

Optimum Size for a Biohydrogen Plant

Figure 5 shows the cost of biohydrogen at various plant sizes. In this study, the largest gasifier unit processes 1000 dry tonnes of biomass per day. This size is based on a detailed literature review (Aden, 2007; Simbeck and Chang, 2002;

Table 6. H_2 production cost components for base case in 2008 for third year of operation from a plant using 2000 dry tonnes of biomass per day.

Cost Components	Value (\$/kg of H_2)
Capital cost	0.38
Operating cost	0.31
Maintenance cost	0.06
Harvesting cost	0.13
Transportation cost	0.12
Road and infrastructure cost	0.10
Silviculture cost	0.02
Royalty fee	0.06
Ash disposal cost	0.001
Total cost	1.18

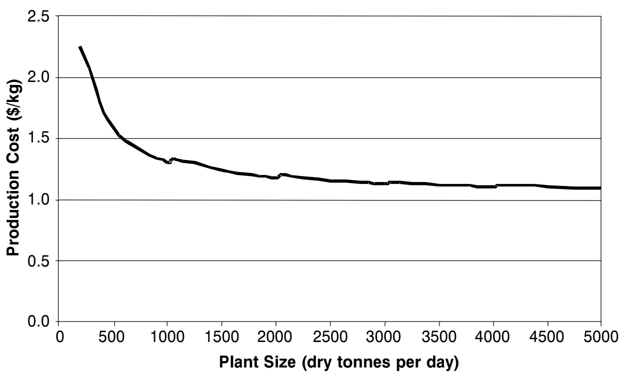

Figure 5. Variation of H_2 production cost with plant size for whole-forest biomass.

Spath et al., 2005). Figure 5 illustrates a few points that are unique to biomass processing facilities. The cost of biohydrogen production decreases as the size of the plant increases. The cost of production decreases about 30% in a size range of 500 to 3000 dry tonnes/day. For a plant size greater than 3000 dry tonnes/day, the curve is flat. There are two competing factors: first, capital cost per unit of biohydrogen production; and, second, the transportation cost of biomass feedstock. The capital cost of biohydrogen production plants per unit of capacity decreases as the size of the plant increases; this is due to the benefits from economy of scale. The cost of transporting biomass to the plant increases with the increase in the size of the plant because the biomass is collected from a larger area, resulting in longer biomass transportation distances. As a result of these two competing factors, there is a plant size at which the total cost of production is lowest. This is the economic optimum size of the plant, which, in this case, is higher than 5000 dry tonnes/day. In the size range of a 500 to 3000 dry tonnes per day plant, the capital cost savings due to economy of scale are much higher than the transportation cost increase. Above 3000 dry tonnes per day, the capital cost benefit due to economy of scale is close to the increase in the transportation cost, resulting in a flat curve.

Since the maximum size of gasifier considered in this study is 1000 dry tonnes/day, multiple units are required for larger plants, resulting in a saw-tooth-shaped curve. For example, a plant having a capacity of 1001 dry tonnes/day would require two units, each with a capacity of 500.5 dry tonnes/day. This results is a sharp rise in biohydrogen production cost from a plant having a capacity of 1001 dry tonnes/day because the capital cost per unit of output is higher for a plant having two units with a capacity of 500.5 dry tonnes/day compared to a plant having one unit with a capacity of 1000 dry tonnes/day.

Cost of Delivered Biohydrogen

As discussed earlier, biohydrogen plants are assumed to be located 500 km away from bitumen upgrading plants. As a result, the total cost of biohydrogen delivered to the upgrader consists of biohydrogen production and biohydrogen transportation costs. The total cost of delivered biohydrogen from a 2000 dry tonnes/day plant is \$2.20/kg of biohydrogen (consisting of a production cost of \$1.18/kg of biohydrogen and a pipeline transportation cost of \$1.02/kg of biohydrogen) for 167 tonnes of biohydrogen transported 500 km by pipeline per day. By increasing the capacity of the plant by 1000 dry tonnes/day (i.e., an increase of capacity from 2000 to 3000 dry tonnes/day), the total cost of delivered biohydrogen decreases by 14% due to the benefits of economy of scale.

Hydrogen Production from Natural Gas

Natural gas, which consists of 25% hydrogen on mass basis, is the preferred feedstock for hydrogen production due to its commercially available conversion process, readily available feedstock, and low feedstock price. In the steam methane reforming process, typically used for commercial hydrogen fuel production, natural gas is heated in the presence of steam to a high temperature and pressure, using a steam-to-carbon ratio of 3:5 and a nickel catalyst (Damen et al., 2006; Longanbach and Rutkowski, 2002). Steam methane reforming is an endothermic process in which the heat of reaction is supplied by the combustion of natural gas (Longanbach and Rutkowski, 2002). Unlike biomass gasification, the steam methane reforming process produces syngas comprised of H_2, CO, CO_2, H_2O, and CH_4, and does not generate any long hydrocarbons or tar. That makes it a simple and inexpensive process compared to the biomass gasification process. Afterward, syngas passes through a water-gas shift reaction, which increases the hydrogen gas concentration. Bulk CO_2 and sulfur compounds are removed through an acid gas removal unit before the syngas is purified in a pressure swing adsorption (PSA) unit. The water-gas shift reaction is accelerated by using an iron-based catalyst, while activated carbon, zeolite, and silica gel act as adsorbing agents in the PSA unit (Longanbach and Rutkowski, 2002; Sircar and Golden, 2000). This is the method of producing hydrogen from natural gas used in this study; the relevant costs and characteristics of the process are given in the Appendix.

Carbon Credits Required for Biohydrogen

Most of the hydrogen in western Canada is produced from natural gas. Natural gas is delivered to bitumen upgraders, and hydrogen is produced on-site. For this study, a techno-economic assessment model was developed to estimate the cost of producing hydrogen from natural gas. The data for this model were derived from an extensive literature review (Deligiannis et al., 2004; Ghafoori and Flynn, 2007; Padró and Putsche, 1999). The model-based cost of delivered hydrogen produced from natural gas at an upgrader is about \$0.96/kg of H_2 for natural gas at a price of \$5/GJ and a hydrogen production plant processing of 427 tonnes/day. This cost is similar to the values reported elsewhere for on-site hydrogen fuel production from natural gas (Ghafoori and Flynn, 2007; Longanbach and Rutkowski, 2002). The cost of producing hydrogen from natural gas depends mainly on the facility size, natural gas price, and location of the plant. The cost of biohydrogen delivered to an upgrader from a plant utilizing 2000 dry tonnes of whole-tree biomass per day is \$2.20/kg of H_2. At this price, it is not currently economical.

One of the key benefits of producing hydrogen from biomass is its carbon neutrality; therefore, carbon credits can make biohydrogen competitive with natural gas based hydrogen. Nonetheless, the price of natural gas would be low for a long-term contract, and if purchased directly from the producer. Estimating the value of carbon credits requires the calculation of life-cycle emissions of greenhouse gases (GHGs) in the production and transportation of both types of hydrogen: that produced from natural gas, and that produced from biomass. Considering the emission characteristics, natural gas based hydrogen has a higher emissions factor than does biomass-based hydrogen. The life-cycle GHG emissions from the production of 1 kg of hydrogen from natural gas are about 11.88 kg CO_2 equivalent (Spath and Mann, 2001). This includes GHG emissions during natural gas production, transportation, conversion to hydrogen, and plant construction and decommissioning. The life-cycle GHG emissions for biohydrogen are 3.12 kg CO_2 equivalent per kg of H_2 (Koroneos et al., 2004; Spath and Mann, 2001). This includes emissions during biomass production, transportation, and plant construction and decommissioning. The GHG emission during the conversion of biomass to hydrogen is considered to be zero; the amount of GHG released during conversion is assumed to be the same as the amount taken up by the tree during its growth (carbon neutral).

The GHG emissions during transportation of biohydrogen 500 km to a bitumen upgrader is 0.50 kg of CO_2 equivalent per kg of H_2. This value was estimated using emissions factors derived from the literature (CASA, 2003; Environment Canada, 2006; GPSA, 1972; Meier and Kulcinski, 2000). The total GHG life-cycle emissions of biohydrogen delivered to a bitumen upgrader is 3.62 kg of CO_2 equivalent per kg of H_2. The total cost of hydrogen delivered to a bitumen upgrader is \$0.96/kg of H_2 for natural gas based hydrogen (at a natural gas price of \$5/GJ) and \$2.20/kg of H_2 for biohydrogen. Using these values, carbon credits were calculated. Figure 6 shows the carbon credit values required for biohydrogen to be competitive with natural gas based hydrogen as a function of natural gas price. It also correlates the production cost of natural gas based hydrogen with the price of natural gas. At a price of \$5/GJ of natural gas, a carbon credit of \$140/tonne CO_2 equivalent is required for biohydrogen to be competitive.

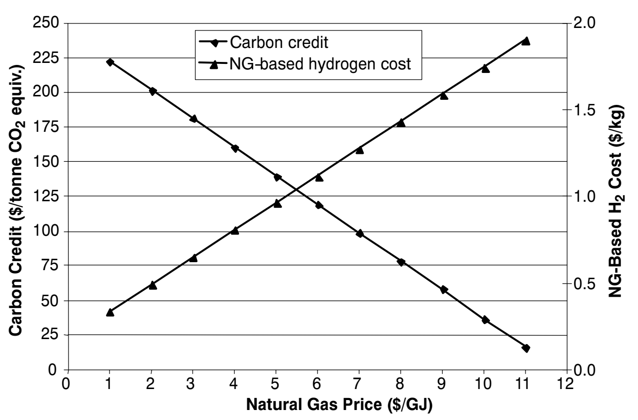

Figure 6. Carbon abatement cost for biomass based hydrogen replacing natural gas based hydrogen.

Table 7. Key sensitivity for H_2 production from whole-tree biomass.

Factor		H_2 Price (\$/kg)	Price Impact (%)
Base case H_2 production cost		1.18	
Capital cost of H_2 plant	10% higher	1.23	+4.2
	10% lower	1.14	-3.4
Operating cost of H_2 plant	10% higher	1.22	+3.4
	10% lower	1.15	-2.5
Feedstock transportation cost	10% higher	1.20	+1.7
	10% lower	1.17	-0.8
H_2 yield from whole-tree biomass	10% higher	1.08	-8.5
	10% lower	1.32	+12
Biomass yield	10% higher	1.17	-0.8
	10% lower	1.20	+1.7
Biomass harvesting cost	10% higher	1.20	+1.7
	10% lower	1.17	-0.8
Ash disposal at zero cost		1.17	-0.8
Pretax return on capital cost is 12% rather than 10%		1.24	+5.6

Sensitivities

The major sensitivities of H_2 production from whole-forest biomass are shown in table 7. Among the different parameters of the sensitivity analysis, the hydrogen yield from biomass has the most significant influence on the hydrogen production cost (8.5% to 12%). Capital cost and operating costs have a similar impact on production cost (about 3% to 4%), and other factors listed in table 7 have little impact on the production cost for the same percentage of change. As a result, the cost of biohydrogen production could be decreased by increasing the hydrogen yield from biomass through improved production processes.

Conclusion

Using gasification technology, hydrogen can be produced from forest biomass (whole-tree biomass) in western Canada at a cost of \$1.18/kg (or \$9.83/GJ of H_2). The cost of feedstock delivery and the capital cost are the two major components of the total production cost, contributing about 36% and 32%, respectively. The economic optimum size (the size at which the cost of production is at a minimum) for a hydrogen production plant based on whole-tree biomass is greater than 5000 dry tonnes per day; however, in practice, smaller plants could be built to reduce the risk and minimize capital penalty. Most of the economies of scale are exploited by 2000 dry tonnes per day.

The cost of biohydrogen transportation has a significant impact on the total delivered fuel cost. For 500 km of pipeline transportation, the total cost of delivered biohydrogen is \$2.20/kg (or \$18.32/GJ of H_2), of which about 50% is for the pipeline transportation of the hydrogen. The cost of delivered biohydrogen could be lowered by optimizing the size of the biohydrogen production plant and its location between the biomass resource and the bitumen upgrader.

In western Canada today, biohydrogen from whole-tree biomass is not competitive with current natural gas based hydrogen. Carbon credits could improve the competitiveness of biohydrogen. At a natural gas price of $5/GJ, a carbon credit of $140/tonne of CO_2 equivalent could make biomass-based hydrogen competitive. There is a huge demand for hydrogen in western Canada, especially for upgrading bitumen since bitumen production is increasing rapidly. In future, biohydrogen could play a significant role in the oil sands industry.

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Appendix

The designed pipeline nominal diameter is 0.254 m (10 in.). Hydrogen gas pressure is approximately 2.4 MPa at the end of purification process in a biomass-based hydrogen fuel production plant. In this study, hydrogen gas is compressed to about 7 MPa with a two-stage reciprocating compressor for pipeline transmission (Spath et al., 2005). Table A1 lists pipeline characteristics and costs. Table A2 presents the capital and production cost of hydrogen from natural gas.

Table A1. Parameters for pipeline transport of hydrogen.

Items	Values/ Formulae	Comments/Sources
Pipeline nominal diameter (m)	0.254	Diameter is calculated using Panhandle B equation, and nominal diameter is selected from an engineering data handbook (GPSA, 1972; Schroeder, 2001).
Hydrogen gas velocity in the pipe (m/s)	7.1	H_2 gas velocity inside the pipeline.
Average frictional pressure loss (kPa/km)	4	Hydrogen gas pressure loss during pipeline gas transmission for the specific hydrogen gas velocity and pipeline diameter (Mohitpour et al., 2007).
Pipeline inlet pressure (MPa)	7	Allowable maximum pipeline operating pressure (DOE, 2006a; GPSA, 1972).
Pipeline outlet pressure (MPa)	4.8	H_2 gas pressure at the end of pipeline.
Pipeline length (km)	500	Assumed for the province of Alberta considering biomass recourse location and upgrader location (Ghafoori and Flynn, 2007).
Compressor power (MW)	3.44	Reciprocating compressor with each stage compression ratio 1.7 to compress 2.4 MPa to about 7 MPa for pipeline transmission (Mohitpour et al., 2007; Spath et al., 2005).
Pipeline capital cost ($/km)	$1869D^2$	Pipeline material cost, which depends on pipeline diameter (*D* is the pipeline diameter in inches) (Yang and Ogden, 2007).
Pipeline installation and ROW cost ($/km)	600,000	Pipeline average installation and right-of-way (ROW) cost for urban area (Yang and Ogden, 2007).
Pipeline fixed operating cost (% of pipeline capital cost)	5	(Yang and Ogden, 2007).
Compressor base size (kW)	10	(Yang and Ogden, 2007).
Compressor base size capital cost ($)	15,000	Compression package cost, which includes compressor, intercooler, and knockout vessel (Spath et al., 2005; Yang and Ogden, 2007).
Compressor scale factor	0.9	(Yang and Ogden, 2007).
Compressor operating and maintenance cost (% of compressor capital cost)	5	(Yang and Ogden, 2007).
Electricity price ($/kWh)	0.07	Assumed electricity price for the province of Alberta.
H_2 loss (% of total transmission)	1	Hydrogen loss during compression and pipeline transmission (DOE, 2006a).

Table A2. Parameters for natural gas based hydrogen production plant.

Items	Values for Natural Gas Based Hydrogen Production Plant	Comments/Sources
Plant size	100,000 N-m^3/h	This is the volume of natural gas at normal pressure and temperature.
Hydrogen production rate	427 tonnes/day	
Natural gas consumption rate	0.172 GJ/kg of H_2	Natural gas consumption rate is 3.27 time of hydrogen on mass basis (Ghafoori and Flynn, 2007; Spath and Mann, 2001).
Natural gas price	$5/GJ	Natural gas would be purchased for long-term contract basis.
Capital cost (million $)	134	(Ghafoori and Flynn, 2007; Longanbach and Rutkowski, 2002; Spath et al., 2005).
Hydrogen production cost ($/kg)	0.96	Levelized production cost of hydrogen.