



BIOMASS AND NATURAL GAS AS CO-FEEDSTOCKS FOR PRODUCTION OF FUEL FOR FUEL-CELL VEHICLES

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Abstract Prospects are examined for utilizing renewable energy crops as a source of liquid fuel to mitigate greenhouse gas emissions from mobile sources and reduce dependence on imported petroleum. Fuel-cell vehicles would provide a promising technology for coping with the environmental and economic effects of an expanding vehicle fleet and a decreasing petroleum supply. Fueled with methanol or hydrogen derived from biomass, fuel cells can also effectively address the problem of CO₂ emissions from that fleet. The extent to which this combination might affect petroleum displacement depends on the amount of biomass that could be produced and the efficiency of its conversion to a fuel compatible with fuel cells. Reduction of net CO₂ emissions by the best current bio-fuel technology will be limited by biomass supply. Biomass conversion efficiency, petroleum displacement and overall net CO₂ emission reduction can be improved, and the cost of fuel minimized, by use of natural gas as a co-feedstock. The extra hydrogen provided by natural gas allows these improvements by eliminating the partial shift of CO to CO₂ that is otherwise necessary; elimination of that step and additional *in situ* leveraging of fuel yield by conventional reforming reactions also reduce the production cost. A thermochemical process utilizing both biomass and natural gas as co-feedstocks is compared with other options for methanol production and CO₂ mitigation using either biomass or natural gas alone. Use of natural gas as co-feedstock makes possible the additional environmental advantage of utilizing waste methane from landfills and waste-water treatment facilities, as well as the carbonaceous solid wastes and sludge from those facilities, for conversion to clean transportation fuel. Greenhouse gas emissions from these important municipal sources can thus be concurrently reduced, together with landfill disposal requirements. Published by Elsevier Science Ltd

Keywords Greenhouse gas; biomass; fuel cells; methanol; hydrogen; natural gas

1. INTRODUCTION

The risks associated with eventual climate changes due to anthropogenic greenhouse gas emissions have been cited by the EPA Science Advisory Board (SAB) as one of the highest priority issues facing the Agency.¹ The main sources of the principal anthropogenic greenhouse gas, carbon dioxide (CO₂), are fossil-based power generation and transport. These two sources are approximately equal in magnitude and account for about two-thirds of the total U.S.A. emissions. Use of renewable energy to displace fossil fuels is a leading option for reducing net emission of CO₂. Of the renewable energy sources, only biomass can be converted to a liquid fuel to displace fossil fuels in the transportation sector. For that reason, and the fact that petroleum fuels are responsible for increasing national economic and environmental burdens, apart from the global warming issue, the prospects for utilizing biomass for

production of transportation fuel in particular need careful examination. Although the magnitude and effects of increased future global temperatures are debated, the costs of current petroleum dependence are already demonstrably real and severe.² The risk of inaction on the global warming question must also be considered and, if alternative fuels derived from biomass could reduce both risks substantially, they would provide a strong "no regrets" approach to the climate change issue whatever the final outcome of the debate. As stated by the SAB:¹ "Some risks are potentially so serious, and the time for recovery so long, that risk reduction actions should be viewed as a kind of insurance premium and initiated in the face of incomplete and uncertain data... Preemptive actions are especially justifiable if they lead to unrelated but immediate and substantial benefits, such as improved ambient air quality and reduced U.S. dependence on imported oil."

The Climate Change Action Plan (CCAP) of 1993, which commits the U.S.A. to the goal of reducing greenhouse gas emissions to their 1990 levels by the year 2000, outlines two mitigation strategies to achieve that goal: a natural gas strategy; and a renewable energy strategy (which includes biomass). Natural gas provides more energy per unit of CO_2 emission (14 kg C GJ^{-1}) than coal (25 kg C GJ^{-1}) or oil (about 20 GJ^{-1}) and the EPA was directed by the CCAP to encourage the use of natural gas in vehicle fleets under the provisions of the Clean Air Act. In the long term (beyond the year 2000), the EPA Administrator's strategy will emphasize measures to reduce greenhouse gas (CO_2) emissions from cars and light trucks and the Agency has established working groups to examine technology, R and D, and other policies that will implement that strategy. These strategies for mobile sources supplement the objectives of the Energy Policy Act of 1992, which aims to improve national energy security and the national economy; that Act has the specific goal of displacing 30% of U.S.A. petroleum requirements with alternative fuels by the year 2010, and half of that alternative fuel is to be derived from domestic resources. The Energy Policy Act also identifies greenhouse gas emissions as one factor to be assessed in the development of alternative transportation fuels.

This paper summarizes an analysis of methods by which the long-term national goals for energy security and environmental protection might be achieved, given the assumption that natural gas and biomass are the principal energy sources to be utilized for that purpose. It will be shown that these dual goals may be achieved most efficiently if biomass and natural gas are not utilized separately or directly, but are converted to a single fuel that is compatible with fuel cells to displace petroleum in the transportation sector.

2. THE SUPPLY ISSUE

If biomass is to be considered a practical alternative energy source, one must first ask how much biomass might be produced in the U.S.A. for that purpose. An assessment of the potential for energy crop production¹ indicates that: (i) the total U.S.A. land area that is suitable for perennial energy crops, such as short-rotation woody crops, but not suitable for conventional crops, is 15.4 million ha; (ii) the

total excess cropland that is suitable for energy crops and could be converted to that use without affecting domestic and export food production is about 16.2 million ha; and (iii) on the total 31.6 million ha of suitable land, about 13.5 Mg of dry biomass could be produced per ha year⁻¹. Assuming 10% loss in harvest, 7.4 EJ year^{-1} (7.0 quads) of biomass energy could thus be produced. A more recent assessment² estimates the total production of wood and grass crops at 5.8 EJ year^{-1} (5.5 quads) for the target year 2020. The extent to which either of these projections might be realized depends on the price that could be obtained per tonne of biomass produced and the crop yield per ha year⁻¹, because the amount of suitable land that will be dedicated to energy crop production depends on the economic return to the producer.

To achieve 5.8 EJ year^{-1} of biomass energy production in the year 2020 will require an improvement of current wood crop yields by a factor of 2.3. If that improvement is realized as anticipated,³ the projected cost of woody biomass production will be $\text{US\$1.66 GJ}^{-1}$ ($\text{US\$1.75/million Btu}$)⁴ in 1993 US\$; with a 40-km transport cost added, the delivered cost is $\text{US\$1.74 GJ}^{-1}$ ($\text{US\$1.84/million Btu}$). The most promising herbaceous energy crop, switchgrass, is estimated to cost $\text{US\$1.7–US\$2.8 GJ}^{-1}$ to produce, excluding transport.⁵ If used for electric power production to displace coal, biomass would have to compete with coal on the basis of energy content. The delivered cost of contract coal is currently $\text{US\$1.14–US\$1.5 GJ}^{-1}$. Added to the constraint imposed by the cost differential is the fact that a major portion of the land suitable for energy crop production will be too distant from any potential energy conversion plant site for that area to be utilizable from a logistical standpoint. If economic factors are the only incentive for energy crop production, it is therefore unlikely that the displacement of coal by biomass could approach the 5.8 EJ year^{-1} potential. If the target fuel price for electric power production is $\text{US\$1.33 GJ}^{-1}$, the projected displacement of coal by biomass is only about $0.53 \text{ EJ year}^{-1}$ (0.5 quad).⁴ In order to obtain 5.8 EJ year^{-1} displacement of a coal containing 78% carbon and 30.2 MJ kg^{-1} , an "insurance premium" of $\text{US\$0.42 GJ}^{-1}$ ($\text{US\$0.44/million Btu}$) is required or about $\text{US\$4.4/tonne}$ of CO_2 emission reduction from stationary sources.

An alternative to using the available biomass to displace coal for electric power production is to convert biomass to transportation fuel for petroleum displacement. The choice between these alternatives needs to consider: (1) the relative energy displacement potential of a given biomass supply; (2) the relative value of the displaced fuel per unit of energy delivered; (3) whether the displaced fuel is from domestic or foreign sources, as it affects indigenous job creation and the national balance of payments; (4) the prospects for integration with other energy sources, preferably domestic, to leverage economic and environmental benefits; and (5) the relative efficiency of utilization of the energy delivered as it affects the cost of achieving the potential benefits, including CO₂ emission reduction.

3. BIOMASS AS A SOURCE OF TRANSPORTATION FUEL

The U.S.A. transportation sector now consumes 16.9 EJ year⁻¹ of petroleum fuels, and by the year 2020 will need 23 EJ year⁻¹. Half of the current petroleum requirement is imported, accounting for 75% of the trade deficit. In terms of production cost, the best current technology for conversion of biomass to liquid transportation fuel is the Battelle Columbus Laboratory (BCL) process for methanol production⁶ and the enzymatic hydrolysis process for ethanol production.⁷ Of the biomass energy, 50–60% is lost in conversion to ethanol and 39% is lost when converted to methanol by the BCL route. One might, therefore, expect to displace less than 3.5 EJ year⁻¹ of petroleum with alcohols produced from the 5.8 EJ of maximum available biomass. Marrison and Larson⁸ project the cost of alcohol production from biomass in the year 2020 to be US\$12.4 and US\$11.2 GJ⁻¹ (higher heating value, HHV) for the minimum cost of methanol and ethanol, respectively, in the North Central area of the U.S.A., where the major portion of land suitable for energy crops is located.

Given the limits of biomass production and the economics of conversion to useful energy, the benefits to climate change must be couched in terms of cost per unit of CO₂ emission reduction for the alternative options for biomass utilization. If it will cost US\$4.4/tonne to reduce CO₂ emissions from stationary sources, will it cost more to reduce emissions

from mobile sources? Taking the BCL process as an example for the latter case, the biomass cost accounts for about 38% of the methanol production cost. In terms of farm-gate price, the US\$12.4 GJ⁻¹ production cost could sustain an average biomass cost of US\$61/tonne or US\$3.2 GJ⁻¹ (US\$3.36/million Btu). This price would justify economically the full 5.8 EJ year⁻¹ of biomass production and produce 3.5 EJ year⁻¹ (HHV) of methanol. The first requirement for establishment of a viable bio-fuel industry would, therefore, be satisfied with enough price elasticity to provide a strong incentive for the producer. The current production cost of gasoline, US\$4.5 GJ⁻¹ HHV (US\$0.60/gal), is expected to increase to US\$6.8 GJ⁻¹ by the year 2010. Projecting to the year 2010, the cost differential for displacing 3.5 EJ year⁻¹ of gasoline by the BCL process would be about US\$3.00 GJ⁻¹, taking into account the relative efficiencies of methanol and gasoline in internal combustion engines (ICE), or US\$0.106 l⁻¹ (US\$0.40/gal) of gasoline displaced, or \$45/tonne of CO₂ avoided. This comparison suggests that greater benefit will derive from coal displacement in terms of both cost and CO₂ reduction. That conclusion, however, is limited to the technologies assumed; if the options are broadened to include fuel and vehicle technologies that will be considered beyond those assumed, use of biomass for petroleum displacement in the transportation sector is seen to offer superior dividends.

3.1. *Impact of fuel-cell vehicle technology*

In view of the national effort now in place under the Partnership for a New Generation of Vehicles (PNGV) to develop fuel-cell technology for transport, the implications of that technology for fossil fuel displacement and greenhouse gas mitigation need to be taken into account. Urban transit buses powered by hydrogen fuel cells are currently undergoing test for service in Chicago and Vancouver (three in each city); commercial introduction is planned for 1999 by Ballard Power Systems Inc. Georgetown University is conducting a demonstration program for the Department of Transportation of buses powered by methanol fuel cells in the Washington, DC area, with the objective of commercializing a 12-m model. In May of this year a fuel-cell van was demonstrated in Berlin by Daimler-Benz as part of a program to develop fuel-cell cars. Many other programs are underway to optimize fuel-cell

systems for transportation applications and have exceeded most goals of the PNGV well ahead of schedule. Conceptual designs of fuel-cell cars for the U.S. market are being developed by General Motors Corporation for methanol fuel and by Ford Motor Company for hydrogen fuel.

Fuel cells, more than any other factor, have the potential to reduce petroleum consumption and greenhouse gas emissions by the vehicle fleet. Use of methanol as the hydrogen source for fuel-cell vehicles (FCVs) has the advantage of relative ease of on-board conversion to hydrogen and a much higher energy density than compressed hydrogen gas, which is ultimately required by fuel cells. Assuming the Federal Urban Driving cycle, FCVs are expected to achieve 2.5 times greater fuel efficiency than gasoline in ICE vehicles.⁹ Assessments based on the European City Driving cycle suggest a methanol-FCV advantage of 3.1 relative to gasoline ICE passenger cars.¹⁰ Also important is the fact that natural gas is the conventional feedstock for methanol production and can be used as a co-feedstock to increase the conversion efficiency of biomass, greatly leveraging alcohol production with a corresponding reduction of production cost. The combination of biomass and natural gas is particularly effective because a thermochemical process for methanol production can be re-configured to produce hydrogen directly should it become the primary transportation fuel of the future. In that case, the potential for petroleum displacement and reduction of greenhouse gas emissions would be further enhanced due to the increased efficiency of FCVs using hydrogen fuel.

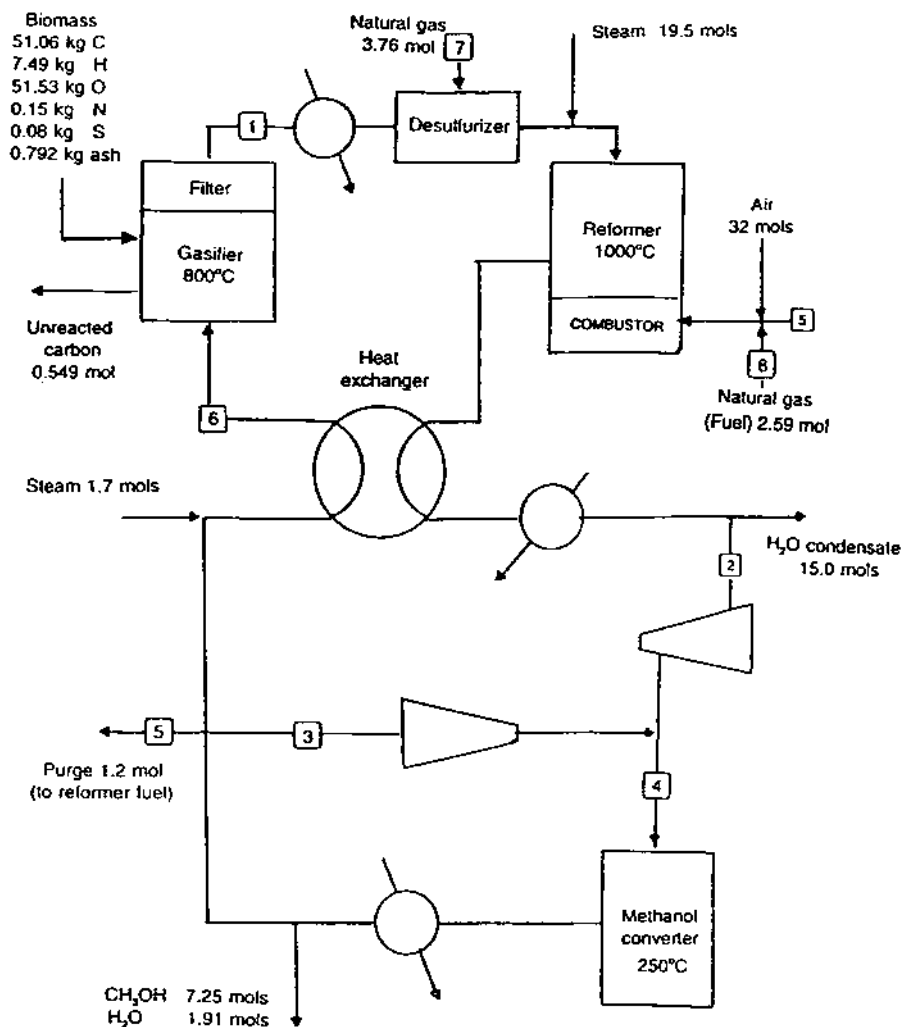
With an estimated resource base of 4×10^{14} m³, the U.S.A. has an abundant supply of natural gas. The supply is, nevertheless, finite and has many valuable uses, of which transportation fuel is but one. Given a policy to utilize natural gas to displace petroleum in the transportation sector, either to reduce greenhouse gas emissions or to increase energy security, its long-term availability for achieving both goals will be leveraged if biomass can also be used in a manner that will complement natural gas as transportation fuel. The incompatibility of natural gas with the existing vehicle refueling infrastructure is a major barrier to its direct utilization. Conversion of natural gas and biomass to a single liquid fuel that can employ

the existing infrastructure to serve fuel-cell vehicles will, therefore, improve the prospects for maximum petroleum displacement by these alternative sources of energy.

4. COST AND BENEFITS OF FUEL PRODUCED FROM BIOMASS AND NATURAL GAS

4.1. *Production technology*

In an effort to evaluate biomass for production of transportation fuel and reduce greenhouse gas emissions from mobile sources, the EPA has investigated various options for conversion to alcohol. These evaluations, carried out with the Aspen Plus process simulator,¹¹ have focused on methanol production for the reasons outlined above. The options studied include operation with, and without, natural gas addition. Figure 1 is a simplified flowsheet resulting from that evaluation. This thermochemical process, conceived at Brookhaven National Laboratory,¹² takes advantage of the extra hydrogen provided by natural gas to increase the efficiency of biomass conversion in three ways: (i) at equilibrium conditions, it would allow complete conversion of the carbon in biomass to a synthesis gas; (ii) the gasifier design would not require an external biomass combustor or internal partial oxidation of the biomass in order to generate the energy needed for gasification: excess hydrogen from the methanol reactor is recycled to the gasifier through a heat exchanger that returns high temperature sensible heat from the reformer effluent which, combined with the exothermic heat of reaction of the hydrogen with biomass, is sufficient to satisfy the gasification enthalpy requirements; and (iii) because of the extra hydrogen and the recycle of unconverted CO and CO₂ to the gasifier, no shift reactor is required for methanol production and a lower methanol synthesis pressure can be considered. In theory, this process can achieve 69% thermal efficiency with no imported electric power and produce 72.5 kg mols of methanol per tonne of dry biomass using 37.6 kg mols of natural gas as process co-feedstock and 25.9 mols of natural gas as reformer fuel. EPA's evaluation of this process, called hynol, indicates that it might achieve 20% greater CO₂ emission reduction when the methanol is used in fuel-cell vehicles than the alternative option of converting biomass to methanol by the BCL process and converting



	Stream composition, kg mols							
	Stream 1	Stream 2	Stream 3	Stream 4	Stream 5	Stream 6	Stream 7	Stream 8
H ₂ O	3.18	0.166	0.161	0.327	0.0006	1.71	0	0
H ₂	6.18	25.94	190.1	216.0	0.9333	8.52	0	0
CO	1.73	6.49	17.5	24.0	0.0860	0.785	0	0
CO ₂	0.959	2.36	11.23	13.59	0.0551	0.503	0.0075	0.005
CH ₄	2.62	0.238	4.75	4.99	0.0233	0.213	3.561	2.56
C ₂ H ₆	0	0	0	0	0	0	0.1053	0.074
N ₂	0.826	0.91	18.3	19.2	0.0899	0.820	0.086	0.062
CH ₃ OH	0	0	2.34	2.34	0.0115	0.105	0	0
SUM	15.49	36.1	244	280	1.20	12.65	3.76	2.59
Deg. C	800	50	40	250	40	954	25	62
Atm	29	22.3	30.5	36.0	13.3	29.5	28	1.5

Fig. 1. Process configuration for methanol production from woody biomass and natural gas. Basis: 100 kg dry biomass with 10 wt% moisture.

Table 1. Cost estimate for methanol production by the hynol process. Basis: 7870 tonne day⁻¹ (biomass) plant, 4.129 × 10⁶ GJ day⁻¹ methanol production, biomass delivered @ US\$61 tonne⁻¹, natural gas @ US\$2.37 GJ⁻¹

Component	Cost (US\$million)
Plant facilities investment	
Feed preparation	39.3
Gasifier	305
Ceramic heat exchanger	102
Gasifier feed compressor	114
Reformer	173.4
Methanol synthesis	595.8
Utilities, auxiliaries	81.4
Total plant facilities investment (PFI)	1411
Total capital investment @ 125% of PFI	1760
Operating cost per day	
Biomass	0.480
Natural gas	1.00
O and M	0.258
Catalysts	0.00239
Purchased energy	0
Total operating cost	1.740
Methanol production cost = US\$6.97 GJ ⁻¹ (US\$0.479/gal)	

the natural gas to methanol by the conventional steam reforming route.

4.2. Cost

Table 1 summarizes the projected cost of methanol production by the hynol process. This estimate assumes a plant size of 7870 tonnes day⁻¹ of biomass, which is the optimum size determined by a balance between the economy of scale afforded by large plant size and the delivered cost of biomass that increases with plant size due to transport from increasingly remote supply regions;⁸ the corresponding biomass cost of US\$61/tonne is assumed for that plant size. Natural gas is taken to be US\$2.37 GJ⁻¹ (US\$2.5/million Btu). The gasifier cost is based on the Fluor/EPRI estimate for the Texaco gasifier,¹³ re-sized for relative gas throughputs and indexed to 1994 US\$. Other equipment costs are based on Princeton data,⁹ re-sized for throughput, and scaled-up using the same exponent, 0.70, for all plant facilities except the methanol converter, which uses an exponent of 0.66. The projected methanol production cost is US\$6.97 GJ⁻¹ (US\$0.48/gal) based on a discounted cash flow rate-of-return of 10% after taxes and after adjusting for inflation. The following economics are assumed:

- 15-year depreciation period with constant annual expenses

- Capital recovery factor of 15.45%
- 13% after-tax rate of return, including 2.7% inflation rate
- 26% corporate income tax rate

Figure 2 compares the fuel production costs of methanol and gasoline on a basis of cents per vehicle mile. Methanol, produced from natural gas and biomass by the hynol process, is shown as a function of natural gas price (which has recently ranged from US\$1.3 to US\$2.8 GJ⁻¹). The comparison shows that the current low cost of gasoline used in conventional vehicles can be reduced substantially by methanol used in fuel-cell vehicles. Not only will the environmental benefits be obtained at no net cost, but a national economic gain will be realized by displacement of imported petroleum from which the gasoline is produced.

If methanol is produced at a cost of US\$0.48/gal and used in vehicles powered by IC engines instead of fuel cells, the cost to the consumer will still be competitive with gasoline. Assuming those vehicles are designed specifically for neat methanol, the volumetric equivalence ratio of methanol/gasoline is 1.57 as determined by the EPA Office of Mobile Sources.¹⁴ When the costs of taxes (@ US\$0.12/gal), distribution (@ US\$0.06/gal) and

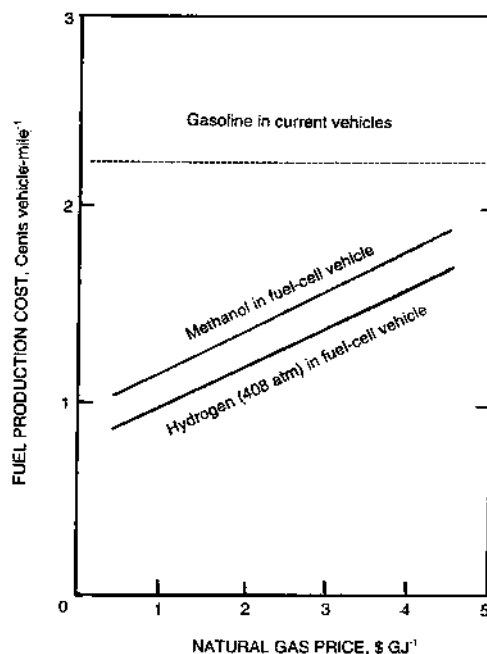


Fig. 2. Relative fuel costs for light duty vehicles. Gasoline @ 4.5 GJ⁻¹ (US\$0.60 gal⁻¹) used in ICE vehicles; methanol or hydrogen produced in 7870 tonne day⁻¹ hynol plant from biomass @ US\$61 tonne⁻¹, and natural gas @ US\$2.37 GJ⁻¹. Federal urban driving cycle assumed.

mark-up (at US\$0.08/gal) are added to the methanol production cost, the equivalent gasoline selling price is US\$1.16/gal. The environmental benefits of petroleum displacement would still be obtained at no net cost if used in IC engines, either during the interim period of fuel-cell development and commercialization, or as an alternative to that technology.

The U.S.A. currently imports 51% of the petroleum consumed at a cost of about US\$50 billion year⁻¹. Seventy-five per cent of this petroleum is consumed by the transportation sector. The imported oil required to produce half of the current annual gasoline consumption (23×10^{10} l) has a value of about US\$34 billion year⁻¹. At a crude price of US\$21.9 bbl⁻¹, the economic benefit of displacing imported petroleum with methanol produced at US\$6.97 GJ⁻¹ is a cost saving of US\$4.28 GJ⁻¹ of gasoline displaced. This saving represents a direct return to the public, but does not include the "hidden" or "external" costs² of that petroleum, much of which would also be reduced. Such costs do not enter the usual accounting of fuel price: it is a debit otherwise bequeathed to future generations, together with global warming. Considering that diesel fuel—which accounts for another 7×10^{10} l of imported fuel—is also displaceable, one could argue that the overall annual benefit to the national economy would exceed US\$100 billion if these fuel imports were displaced with an alternative fuel produced domestically and used in fuel-cell vehicles to reduce the external as well as the apparent fuel costs. That saving (or cost, depending on the course taken) will increase with the proportion of imported petroleum.

4.3. CO₂ emission reduction

As indicated by the data of Fig. 1, natural gas accounts for 75% of the energy input to the hynol process. The process does not, therefore, achieve maximum reduction of greenhouse gas emissions by elimination of fossil fuel. The optimum ratio of natural gas to biomass derives from consideration not only of the CO₂ emission of an individual vehicle, but also that of the vehicle fleet. If biomass comprises the sole energy input to the fuel of a given vehicle, the net CO₂ emission from that vehicle is effectively eliminated, but the cumulative effect on global warming depends on the size of the vehicle fleet

for which fuel can be provided. As increasing amounts of natural gas are used to leverage the quantity of petroleum fuel displaced, fossil carbon emission will also increase, although at a lesser rate than the carbon that would have been emitted from the displaced petroleum. Given a strategy of utilizing biomass and natural gas as energy sources for transport, and assuming that FCVs will play a primary role in any future effort to maximize the reduction of greenhouse gas emissions from mobile sources, two options for accomplishing that goal are possible: (1) production of an alternative fuel from biomass alone, with natural gas used in a separate process to produce a fuel compatible with FCVs (a process such as steam reforming of natural gas to produce methanol); or (2) a single process such as hynol that would utilize both feedstocks to produce a fuel for FCVs. The best choice between these options depends on the amount of biomass available for conversion to transportation fuel.

Figure 3 indicates the relative effect of these options on the overall net CO₂ emission. Option (1) of Fig. 3 assumes 1 tonne of biomass is converted to 14.77 mols of methanol by the BCL process and varying amounts of natural gas are converted to methanol in a separate conventional steam-reforming process at a yield of 0.782 mol methanol per mol of natural gas.¹⁵ Option (2) is seen to be favored for any amount of natural gas exceeding 12 mols per tonne of biomass. When biomass is the limiting feedstock, and fuel cost is also to be considered, option (2) will yield maximum relative advantage at the combination of 25% biomass and 75% natural gas as energy mix (closed symbol), which yields 20% more overall reduction of net CO₂ emission from the vehicle fleet than could be obtained by using the same resources for fuel production in separate processes. This result is due to the increased total yield of methanol from the feedstocks, made possible by improved thermal efficiency of biomass conversion when natural gas is a co-feedstock, as discussed under section 4.1.

It is also informative to compare a third option which would utilize only biomass as the energy source for alternative transportation fuel, thus avoiding all net greenhouse gas emissions from the vehicle fleet using that fuel. Consider the limiting case, in which the entire 5.8 EJ of biomass were converted to methanol by the BCL process. If that methanol were used

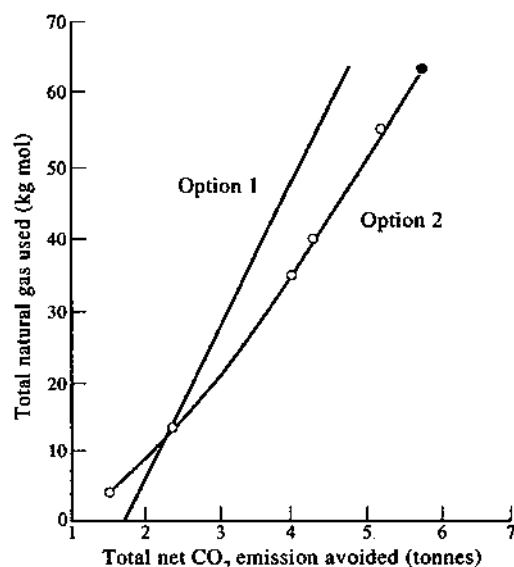


Fig. 3. Comparison of options for utilization of biomass and natural gas for reduction of CO₂ emissions from the vehicle fleet. Methanol produced in separate processes by option (1) or by a single, combined process by option (2). Basis: 1 tonne biomass and fuel cell vehicles in federal urban driving cycle. Symbols denote simulation results, closed symbol corresponds to Fig. 1.

in FCVs, 24.7×10^{10} l (8.67 EJ) of gasoline could be displaced and essentially all of the CO₂ emissions (5.9×10^8 tonnes), which would have resulted from the gasoline use, would be avoided; at an incremental cost of US\$3.00 GJ⁻¹ of gasoline displaced. If, on the other hand, biomass is used in a process designed to accept natural gas as co-feedstock, only 4.0 EJ of biomass could displace the entire 23 EJ of petroleum that will be needed in the year 2020. In doing so, the net CO₂ emission reduction would be 1.17×10^9 tonnes, or twice as much as the total CO₂ emission reduction achievable if the entire 5.8 EJ of biomass were converted to methanol by the BCL process with no natural gas as co-feedstock and the effective cost, relative to the gasoline displaced, would be zero. By contrast, if 4.0 EJ of biomass were used to displace an equal amount of coal in stationary sources, the CO₂ emission reduction potential would be 3.8×10^8 tonnes, or about one-third of the net CO₂ reduction that could be achieved by petroleum displacement.

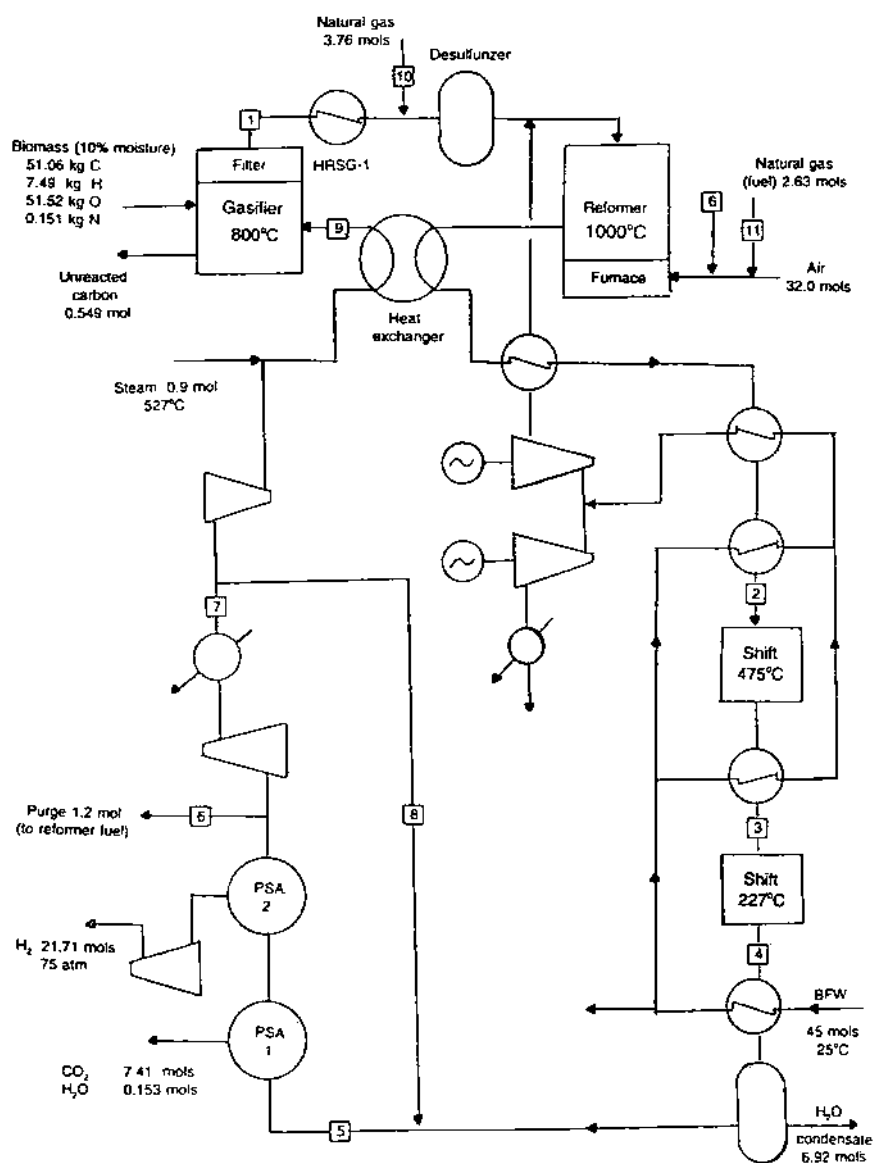
4.4. Hydrogen production

With modification, thermochemical processes provide the option of producing hydrogen^{6,9}

instead of, or in addition to, methanol. Hydrogen production can be leveraged in the same way with natural gas as a biomass-to-methanol process. Petroleum displacement and CO₂ emission reduction will be further increased as well as the economic and environmental benefits of that displacement. Figure 4 shows a re-configuration of the hynol process to produce hydrogen. The same feedstocks are utilized as for methanol in Fig. 1, but the methanol converter is replaced with shift converters and pressure swing adsorbers (PSA). Like the methanol simulation, a steam/carbon ratio of 2.5 is provided in the reformer feed stream. In this case, slightly less natural gas is required as fuel for the reformer, and a hydrogen yield of 217 kg mols is obtained per tonne of biomass. The energy ratio (yield of hydrogen, HHV, to all natural gas and biomass inputs) is 81.7%. Figure 4 assumes that the hydrogen will be stored on the vehicle as metal hydride, for which a pressure of 75 atm is adequate. The thermal efficiency, which takes into account 909 kWh of imported electric power that is required to produce the hydrogen and compress it to 75 atm is 73%. In FCVs, assuming the Federal Urban Driving Cycle and a three-fold increase of fuel economy relative to gasoline used in conventional vehicles,⁹ 217 mols of hydrogen will displace 1300 gal of gasoline with a net CO₂ emission reduction of 8.35 tonnes. The net emission reduction per vehicle utilizing that hydrogen is 71% compared with 67% for methanol.

The production cost of hydrogen, estimated in Table 2, is US\$6.6 GJ⁻¹. Because of the lower energy loss in conversion of the feedstocks to hydrogen, relative to methanol, the higher efficiency of hydrogen in fuel cells, and its lower production cost, the overall effect on petroleum displacement and the economic benefit of that displacement are maximized. Hydrogen storage on-board is the main drawback of hydrogen vehicles and the higher energy density of methanol (1.583×10^7 J l⁻¹, LHV) and relative ease of on-board reforming to hydrogen remain its primary advantage over compressed hydrogen gas (3.8×10^6 J l⁻¹ at 408 atm). Methanol is also more adaptable to the existing refueling infrastructure, and FCVs are initially expected to operate on methanol mainly for that reason even though the problems of methanol integration to that infrastructure are not trivial.

The use of compressed natural gas as fuel in ICE vehicles suggests that compressed gaseous



	Stream composition, kg mols										
	Stream 1	Stream 2	Stream 3	Stream 4	Stream 5	Stream 6	Stream 7	Stream 8	Stream 9	Stream 10	Stream 11
H ₂ O	2.292	12.64	9.51	7.07	0.154	0	0	0	0.900	0	0
H ₂	5.67	25.23	28.37	30.82	55.81	1.0367	33.07	24.95	8.072	0	0
CO	1.142	5.92	2.79	0.349	1.305	0.0396	1.265	0.956	0.309	0	0
CO ₂	0.498	1.84	4.97	7.41	7.41	0	0	0	0	0.0075	0.0052
CH ₄	2.63	0.287	0.287	0.287	1.073	0.0326	1.041	0.787	0.254	3.551	2.49
C ₂ H ₆	0	0	0	0	0	0	0	0	0	0.1053	0.0736
N ₂	0.721	0.807	0.807	0.807	3.04	0.0917	2.93	2.21	0.715	0.0865	0.0605
SUM	12.96	46.74	46.74	46.74	68.8	1.20	38.3	28.95	10.25	3.76	2.63
Deg. C	800	400	164	227	40	40	40	40	956	180	25
Atm	29	22.8	21.3	20.8	20.3	1.5	20.8	20.8	29.5	28.5	1.5

Fig. 4. Process configuration for hydrogen production from biomass and natural gas. Basis: 100 kg dry biomass with 10 wt% moisture.

Table 2. Cost estimate for hydrogen production by the hynol process. Basis: 7870 tonne day⁻¹ (biomass) plant, 4.88 × 10⁶ GJ day⁻¹ hydrogen production, biomass delivered at US\$61 tonne⁻¹, natural gas at US\$2.37 GJ⁻¹

Component	Cost (US\$million)
Plant facilities investment	
Feed preparation	39.3
Gasifier	255
Ceramic heat exchanger	84.9
Gasifier feed compressor	42.7
Reformer	175.7
Shift reactors	35.7
Pressure swing adsorbers	167.9
PSA recycle compressor	548
Hydrogen compressor	45.4
Utilities, auxiliaries	63.5
Total plant facilities investment (PFI)	1458
Total capital investment at 125% of PFI	1823
Operating cost per day	
Biomass	0.480
Natural gas	0.993
O and M	0.266
Catalysts	0.0325
Purchased energy	0.267
Total operating cost	2.038
Hydrogen production cost = US\$6.58 GJ ⁻¹	

fuels may become acceptable as range limitations, distribution problems and long refueling times are overcome. The range barrier would not apply to compressed hydrogen used in fuel-cell vehicles, which would approach the range capability of gasoline in ICE vehicles, especially with newly developed carbon-graphite composite tanks. If hydrogen is to be utilized as a compressed gas, an additional 374 kWh of imported electricity is required for compression from 75 to 408 atm; the thermal efficiency of the process is then 65.5%, the CO₂ emission reduction is 69.5% (FCVs, FUD cycle), and the cost is US\$7.1 GJ⁻¹. As indicated in Fig. 2, vehicles powered by hydrogen fuel cells will operate at a cost per vehicle mile that is less than half that of gasoline, given the current gasoline production cost, the current natural gas price and the projected cost of biomass.

4.5. Ambient air quality

Motor vehicles using petroleum fuels are responsible for 80% of the total U.S.A. emissions of CO and 45% of the anthropogenic emissions of NO_x and volatile organic compounds (VOC).¹⁶ A methanol-FCV is expected to emit 99% less CO, 83% less NO_x, 87% less VOC than gasoline-ICE vehicle¹⁰, while eliminating essentially all vehicle particulate emissions. Hydrogen FCVs would be even more effective in reducing criteria pollutants from

urban air; a problem that has so far prevented compliance with EPA air quality standards in many U.S. cities. The ozone reduction potential of FCVs is significantly greater than ICE vehicles fueled directly with natural gas.¹⁰

4.6. Waste reduction

Municipalities produce carbonaceous wastes that are suitable feedstocks, when used in conjunction with natural gas, for production of methanol or hydrogen. These include wastewater treatment sludge and digester gas, landfill gas and carbonaceous landfill solids, greenwaste and rubber tires. All of these potential feedstocks are presenting serious disposal problems in terms of cost, space and environmental impact. The carbon content of most of these landfilled wastes eventually enters the atmosphere as methane; a much more efficient absorber of solar radiation than CO₂. The sludge produced in the treatment of waste-water prior to discharge to the environment, as required by the Clean Water Act, amounts to 26 kg per person per year. The U.S.A. total is expected to reach 12 million dry tonnes year⁻¹ by the year 2000.¹⁷ Process analyses show that all of these wastes, both solid and gas, could be used in any proportion to energy crops for conversion to clean transportation fuels.

Because the capital cost of gasification processes such as described here is sensitive to plant size, operations that include municipal wastes as feedstock would be most cost-effective if used to supplement dedicated energy crops and natural gas as co-feedstocks in large plants. Table 4 summarizes process simulations that consider the use of sewage sludge and digester gas to supplement woody biomass and natural gas in varying proportions for methanol production. The base case corresponds to the plant shown in Fig. 1 in which no sludge is added. Sewage sludge composition is taken to be 31.66 wt% C, 4.53% H, 4.02% N, 1.51% S, 17.78% O and 40.5% ash with a HHV of 3054 kcal kg⁻¹ and a heat of formation of 984 kcal kg⁻¹; the composition of anaerobic digester gas is taken to be 65 mol% CH₄ and 35% CO₂. Digester gas is assumed to be available in a ratio of 14.9 kg mol tonne⁻¹ of dry sludge. The total carbon fed to the gasifier and the amount of natural gas used as process feedstock are the same for all simulations. The results show that the yield of methanol per unit of woody biomass increases with the addition of sludge and digester gas; this, together with the

negative cost of that sludge, can reduce the cost of methanol substantially if a large amount of sludge is available.

5. CONCLUSIONS

- Biomass will have difficulty displacing domestic coal if it must compete solely on a basis of cost per unit of energy content. If commercial factors are the only consideration, the difference between biomass production cost and its value as a boiler fuel will offer little incentive for production of dedicated energy crops on a scale sufficient to significantly affect coal displacement.
- The higher value of transportation fuels, per unit of energy content, will provide greater incentive for establishment of energy crop production on a scale needed for a viable bio-fuels industry. The unit cost of bio-fuels produced from biomass alone, however, is still too high to compete with currently priced gasoline produced from petroleum.
- The cost of alcohol production from biomass can be reduced, and the alcohol yield increased, by use of natural gas as a co-feedstock in a thermochemical process. This might be accomplished with a thermal efficiency as high as 69–73% and a production cost of US\$7.0 GJ⁻¹ for fuel methanol or US\$6.6 GJ⁻¹ for hydrogen using biomass delivered at US\$3.2 GJ⁻¹.
- Because vehicles powered by fuel cells using methanol or hydrogen are expected to operate at 2.5 to 3 times higher thermal efficiency than gasoline vehicles now in use, the fuel cost per vehicle mile will be competitive with the current gasoline cost. Pronounced benefits can also be expected in terms of displacement of petroleum imports, energy security and increased economic returns for domestic agriculture.
- If fuel cell vehicles use methanol or hydrogen derived partially from biomass with natural gas as a co-feedstock, the net emission of CO₂ can be reduced by as much as 71% relative to conventional vehicles. The cumulative net CO₂ emission reduction from U.S. highway vehicles would exceed that obtainable by direct use of biomass and natural gas independently, either for production of transportation fuel or electric power.
- Reduction of urban pollution due to CO, NO_x, VOC and particulates, in addition to maximum gross greenhouse gas emissions, can be expected for fuel-cell vehicles using fuels derived from biomass and natural gas. These reductions may be obtained at no cost relative to current fuel costs for light duty vehicles.
- Use of carbonaceous wastes, both solid and gaseous, can be converted to clean fuels

Table 3. Notes to process flowsheets and cost estimates

O and M cost is assumed to be 6% of plant facilities investment
Total capital investment is assumed to be 125% of plant facilities investment and includes contingencies, fees, start-up, land and working capital
Costs are in US\$ as at 1991
Plant operating factor is 90%
Scale-up exponents are 0.7 for all equipment except the methanol system which is 0.66
Steam/carbon ratio is 2.5 in the reformer feed stream, all carbon species included
Isentropic turbine efficiency is 75% and generator efficiency is 95%
Polytropic compressor efficiency is 85% with inter-stage cooling to 40 °C
Approach to equilibrium is -10K in reformer, +12K in methanol converter, +20K in each shift reactor. Carbon conversion in the gasifier is assumed to be 87%
Imported electricity is valued at 5 cents/kWh
Unreacted carbon from the gasifier is burned to produce electric power
Natural gas used for reformer fuel is expanded to 1.5 atm through a turbine/generator
Flue gases are discharged at 120 °C
Biomass is dried from 50% moisture to 10% moisture before gasification using low pressure steam generated within the process
Pressure swing adsorption uses zeolite molecular sieves with a one-pass retention of 86% of all constituents other than hydrogen
Gasifier effluent is desulfurized at 330 °C with zinc oxide or zinc titanate
Pressure drops include 2.7 atm for reformer, 2.5 atm for methanol converter and 0.5 atm for gasifier and each heat exchanger
Energy balances include distillation of methanol to 99.3 wt%, power for reformer and combustor ID fans, drier fan and lock hopper

Table 4. Summary of process simulations using municipal wastewater sludge and digester gas as co-feedstocks with woody biomass and natural gas for methanol production

	No sludge base case	Low sludge	Intermediate sludge	High sludge	Sludge only
Woody biomass feed (kg)	111.7	97.4	84	56.3	0
Sludge feed (dry) (kg)	0	20	40	80	161.3
Digester gas feed (kg mol)	0	0.30	0.60	1.20	2.42
Natural gas to process (kg mols)	3.76	3.76	3.76	3.76	3.76
Natural gas for reformer fuel (kg mol)	2.70	2.88	3.05	3.30	3.82
Methanol produced (kg mol)	7.25	7.52	7.83	8.31	9.37
Steam to reformer (kg mol)	19.5	20.8	21.7	24.5	29.1
Gasifier loop throughput (kg mol)	51.1	54.0	56.1	63.1	74.7
Methanol loop throughput (kg mol)	244	252	263	276	306
Ratio of total throughputs to methanol product (mols/mol)	40.7	40.7	40.7	40.8	40.6
H ₂ S in gasifier effluent (ppm)	89	678	1154	2054	3570
Equilibrium H ₂ S/CaS in gasifier (ppm)	1840	1660	1480	1310	1020
Ash from gasifier (including carbon) (kg)	0.95	8.1	16.9	32.9	65.3
Electric power import (Whr/kg methano)	0	9.1	80.5	61.0	67.7
Mol methanol/mol natural gas	1.122	1.133	1.150	1.177	1.236
kg methanol/kg (NG + biomass)	1.079	1.182	1.299	1.571	2.472

for fuel-cell vehicles, thus avoiding other greenhouse emissions, especially methane, from municipal landfills and water-treatment facilities.

- Assuming the successful development of fuel-cell technology for transport, the dual national goals for mitigation of greenhouse gas emissions and energy security—as embodied in the Climate Change Action Plan and the Energy Policy Act—could be achieved by production of a fuel from both natural gas and biomass for fuel-cell vehicles.

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