An Economic Analysis of Various Hydrogen Fuelling Pathways from a Canadian Perspective

a report for

Natural Resources Canada

by the

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Executive Summary

This study provides an economic comparison of hydrogen to gasoline and diesel as a transportation fuel. In addition, it examines the impact of including indirect costs or benefits, referred to as externalities, and various government policy options on the comparison.

A lifecycle analysis approach, which includes the full costs associated with the manufacturing, distribution and operation of the vehicle, was used in conducting this comparison.

Nine methods for producing hydrogen, or " fuelling pathways", are examined in this study. Five of the pathways assume that the hydrogen is mass-produced at a central location, and is then distributed to fuelling stations via pipeline. The remaining pathways assume that the hydrogen is produced at the fuelling station itself, or "on-site", and therefore there is no need to distribute the hydrogen.

For the base case scenario, the most competitive light-duty vehicle pathway involves decentralized production of hydrogen using a methanol reformer, for which the total costs per kilometre were $24 per month higher than gasoline. For the heavy-duty vehicles, the most competitive pathway was also the decentralized methanol reformer, with costs $528 per month higher than diesel.

However, it was shown that the following factors could make hydrogen a competitive product for some of the pathways: decreasing the hydrogen pathways' associated vehicle costs, setting the purchase price of a fuel cell vehicle equal to it's internal combustion engine or combustion ignition engine counterpart, or decreasing the maintenance costs and increasing the life of the vehicle. This was more effective than a significant reduction in the costs for the production machinery and equipment or decreased primary energy purchase prices.

Incorporating the externalities associated with the pathways in Part 2 of the study reinforced the degree to which vehicle acquisition and other non-fuel related costs affect the total costs. Externalities that decreased the costs for some of the hydrogen pathways were countered by externalities that increased the operating costs for the hydrogen fuel cell vehicle.

The results in Part 3 were consistent with those in Parts 1 and 2. In particular, policy options that directly decreased the costs of operating a hydrogen fuel-cell vehicle resulted in hydrogen pathways that are competitive with gasoline and diesel. For example, a provincial sales tax exemption on the purchase price of a hydrogen fuel-cell vehicle, in conjunction with excise tax exemptions for hydrogen, yielded four competitive light-duty vehicle hydrogen pathways, and one competitive heavy-duty vehicle pathway.

A combination of emissions taxes and the sales and excise tax exemptions cited above yields multiple hydrogen pathways that are competitive with, if not cheaper than, gasoline or diesel. It also provides an incentive to minimize emissions in the production of hydrogen.

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Introduction

The purpose of this study is to examine how hydrogen compares economically to petroleum based products, namely gasoline and diesel, as a transportation fuel. Other aspects of this study include internalizing the costs of externalities such as emissions and considering whether government policy options could improve the economics of hydrogen.

The purpose of this study is not to determine the price of hydrogen and compare it to the price of gasoline. Since market places currently exist for both goods, the prices are known quantities. In examining how government policy may affect the price of a good, it is important to understand the various cost components of that good, which is one of the components of this study.

Furthermore, simply looking at the price of the fuel ignores the differences that exist in the dispensing and consumption of the fuel. A lifecycle approach is used throughout the analysis. Such an approach is also sometimes referred to as a "well-to-wheel", or a "source-to-service" approach. This approach examines the costs associated with the extraction, production, distribution and storage, dispensing and consumption of the fuels. Including all these factors will provide a total dollar cost per kilometre driven, for each of the fuel, fuel source or production method, and vehicle combinations, or "fuelling pathways", which will be the main point of comparison for this study.

Nine methods for producing hydrogen are examined in this study. Five of the pathways assume that the hydrogen is mass-produced at a central location, and is then distributed to fuelling stations via pipeline[1]. The remaining pathways assume that the hydrogen is produced at the fuelling station itself, or "on-site", and therefore there is no need to distribute the hydrogen.

The report is divided into three parts. Part 1 is designed to analyze, compare, and contrast the costs associated with the use of hydrogen fuelled, fuel cell based light-duty vehicles (cars and light-trucks), and heavy-duty mass-transit vehicles (buses), versus the costs associated with their conventional petroleum fuelled counterparts (Internal Combustion Engine ("ICE") based light-duty, and heavy-duty Compression-Ignition Engine ("CIE") mass-transit vehicles[2]).

In addition to the direct financial costs outlined in Part 1, each of the fuelling pathways has associated indirect costs or benefits, referred to as externalities, or social costs/benefits. These costs/benefits are borne by society as a whole when these products are produced and consumed, but are not captured in the pricing for the products. Examples of such costs include air or water pollution.

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[1] Distribution by pipeline is just one possible option, and is possibly the most expensive in the short run. Other options include compressed gas trucks, and liquefied gas trucks. The focus of this study is primarily on the production costs. As such, a pipeline distribution system was chosen, because this will help "frame" the costs, between production pathways not requiring any distribution infrastructure (the four decentralized pathways), and those using a relatively expensive distribution network.

[2] Other heavy-duty vehicles, such as large transport trucks were not considered in our analysis since this is not considered an early or mid-market for fuel cell applications.

Part 2 considers the impact of internalizing these external costs on the relative costs of hydrogen and electricity.

Finally, Part 3 examines a mix of policy options available to the government, and analyzes their effectiveness in improving the economics of hydrogen based fuel pathways.

Part 1: Comparing the Cost Components of Using Hydrogen vs. Gasoline or Diesel for Transportation Services

This part of the study focuses on comparing and contrasting the cost components associated with the hydrogen-based pathways to the gasoline and diesel-based pathways.

In order to conduct this analysis, cost and performance profiles are determined for:

- the nine fuelling pathways
- a light-duty vehicle fuel cell vehicle (FCV) (car and light-duty truck)
- a heavy-duty mass-transit fuel cell bus
- a light-duty vehicle with a gasoline ICE (car and light-truck)
- a heavy-duty mass-transit bus with a diesel CIE.

These profiles are constructed based on statistical data and information from the industry, where available, and from literature estimates. Great reliance is placed on literature estimates, because participants in the industry are reluctant to disclose their cost profiles, as this could put them at a competitive disadvantage.

With these profiles, and with an assumption on the size of the fleet of vehicles to be supported, a breakdown of the cost components per kilometre driven using gasoline, diesel or hydrogen can be determined and compared.

1-1) Methodology and Approach for Part 1

1-1.1) The Energy System

The philosophy behind the methodology used in this study is that any analysis of energy requires a review of the full *energy system*.

Any energy system may be represented by five links, from sources to the services that require the input of energy. These five links are depicted in Figure 1 below. In placing the "service" link at the start of the chain, we are assuming that the consumers demand for the service drives the need for the source (or fuel).

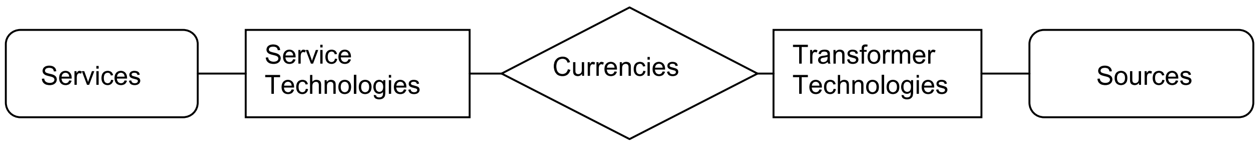

Figure 1: Architecture of the energy system.

To make the nomenclature of this five-link architecture clear, Figure 2 gives examples of what is covered under each of the headings in Figure 1.

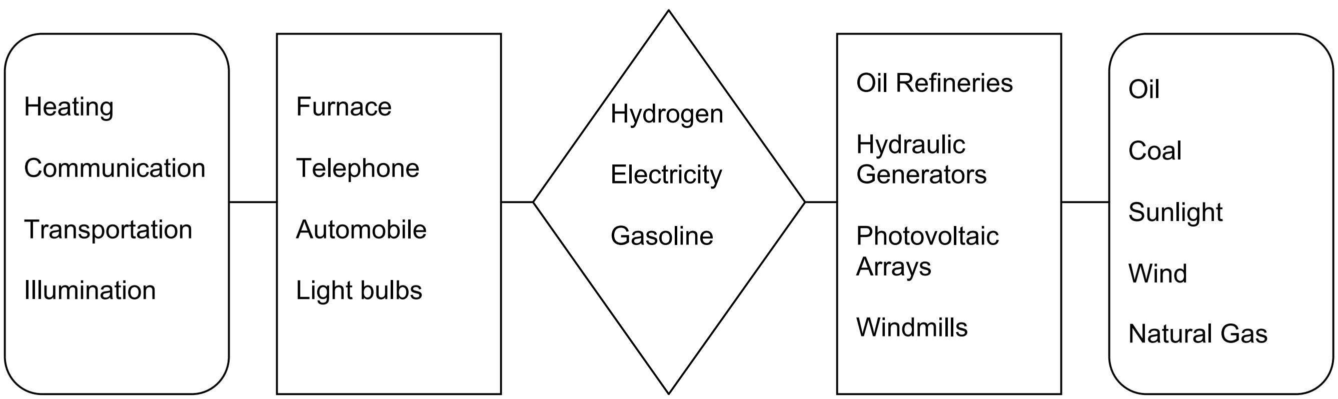

Figure 2: Examples of components of the energy system.

In conducting this study, our approach is not to simply compare the production costs of a given 'currency', e.g. gasoline vs. diesel vs. hydrogen. While such a study could be conducted, and figures comparing the production cost per unit of energy (e.g. $/Joules or BTUs) of hydrogen, gasoline, and diesel could be obtained, this would not provide a comprehensive answer. The question that really needs to be answered is "How does hydrogen compare to gasoline or diesel as a means of providing transportation services?" The response to this question must consider the following: the amount of energy required by hydrogen-powered vehicles and gasoline/diesel-powered vehicles, the cost differences between those vehicles, as well as the costs associated with production and distribution.

Such an approach, when looking at transportation services specifically, is commonly referred to as a full lifecycle, or sometimes as a "well-to-wheel" study.

This approach also permits the comparison and contrast of the relative strengths and weaknesses of each fuelling pathway, on a lifecycle basis, at each point along the energy system. This is essential when considering policy options: it identifies points in the chain of a particular pathway where possible policy support measures might be best and most effectively used. For example, if a hydrogen pathway is competitive with a gasoline or diesel pathway in every stage but the transformer technology, policy supports for R&D into improved transformer technology may be a more effective and targeted option than incentives for the purchase of alternatively fuelled vehicles.

1-1.2) Conducting the Cost Analysis

The cost assessment modelling is broken into two components. The first component is a "well-to-tank" model, which analyses the costs from fuel source to readily distributable fuel currency. The second component is a "tank-to-wheel" model, which analyses the costs associated with using the fuel to provide transportation services.

The "well-to-tank" component is based on the Ernst & Young Tax Policy Services group's Inter-Jurisdictional Tax Competitiveness Tool (InTaCT). InTaCT is designed to measure the tax implications of a new investment, in a given jurisdiction, over the economic life of that investment. InTaCT performs this analysis by looking at the income statement and balance sheet of a given investment, such as an investment into a Hydrogen production facility, and then applying various taxes, such as income tax, capital tax, sales and excise taxes, etc., to determine the total tax burden for that investment. Once the tax burden has been calculated, InTaCT provides the after tax rate of return for that investment project, for use in comparing across investments in a given jurisdiction, or for comparing a given investment in various taxing jurisdictions.

In this exercise, we are not interested in the after-tax rate of return for the investment per se; rather we want to determine the product price (hydrogen, gasoline, or diesel). To accommodate this objective, the model has been modified to take the after-tax rate of return as a given, and then generate the corresponding price required to generate that rate of return. This methodology, assessing the product price using a fixed after-tax rate of return across production methods, is similar to that used in other lifecycle studies[3].

The "tank-to-wheel" component is a spreadsheet that analyses the capital and operating costs for the various vehicles being modeled. This component applies the fuel prices as determined in the "well-to-tank" component in order to determine the total cost per kilometre driven for each vehicle type, using fuel from each of the available pathways.

1-1.3) The Pathways

The costs associated with providing both light-duty and heavy-duty mass transportation services are determined using eleven[4] different fuelling pathways. Four of these pathways involve producing hydrogen, as the energy 'currency', at decentralized production facilities, i.e. at the fuelling station. Five of the pathways involve producing

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[3] See, for example, Thomas, et al (2001)

[4] While there are 11 different methods for providing the fuel currency, there are only ten pathways for producing personal transportation services, and ten pathways for producing the mass transportation services. There are nine common methods for producing hydrogen, and then one unique pathway using crude oil as the source.

hydrogen at centralized production facilities. The remaining two pathways involve the production of gasoline, for light-duty transportation, and diesel, for heavy-duty applications.

Figure 3 presents the energy system grid tracing for these various fuelling pathways[5].

Figure 3 The fuelling pathways

Services	**Service Technology**	**Currency**	**Transformer Technology**	**Source**
Light-duty Vehicles	ICE Automobile	Gasoline	Oil Refinery	Crude Oil
Heavy-duty Vehicles	CIE Bus	Diesel		
Light-duty Vehicles	Light-duty fuel cell vehicle	Hydrogen	Centralized Electrolysis	Electricity from Nuclear Power Plant
				Electricity from Coal-Fired Power Plant
				Electricity from Wind Generator
Heavy-duty fuel cell vehicles (Buses)	Hydrogen Fuel-Cell Urban Transit Bus			Electricity from Hydro Generator
			Centralized Steam Methane Reformer	Natural Gas
			Decentralized Electrolysis	Electricity 'Off the Grid'
			Decentralized Steam Methane Reformer	Natural Gas
			Decentralized Methanol Reformer	Methanol
			Decentralized Gasoline Reformer	Gasoline

The currency, or fuel, production methods are described briefly below.

Method 1 & 2) Centralized production of gasoline and diesel at an oil refinery

These two methods represent the current conventional sources for fuel for light-duty and heavy-duty vehicles. As such, they serve as the benchmark in this study.

Oil refineries use crude oil as a source to produce a number of petroleum products. The breakdown of the different products varies around the world depending on the demand. For example, in Europe, where diesel is a more prevalent fuel, 36% of the refinery output

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[5] These pathways are in no way meant to represent the full range of pathways available, nor are they meant to represent NRCan or Ernst & Young's views on the most appropriate pathways. Many other feasible pathways exist, such as pathways that use on-board means of reformation.

is diesel, and only 20% is gasoline, whereas in North America only 23% of the output is diesel, and 41% is gasoline[6].

Crude oil is generally delivered to the refinery by pipeline. Once the crude oil has been refined into gasoline and diesel fuel, the gasoline and diesel is transported via pipeline to various regional distribution centres, and then transported by truck to individual fuelling stations.

Method 3, 4, 5 & 6) Centralized hydrogen production using electrolysis with electricity from a nuclear power plant, a coal-fired generator, a wind powered generator and a hydroelectric generator

In these four methods, hydrogen is produced using electrolysis. Electrolysis involves breaking water into hydrogen and oxygen using electricity, e.g.

$$H_2O + \text{electricity} \Rightarrow H_2 + \_O_2 \qquad (1)$$

This is, in essence, the inverse process undergone in a fuel cell, where hydrogen and oxygen are the inputs, and water and electricity the outputs. Efficiency levels for the electrolysis process itself are fairly high, usually cited to be in the 70-75% range. Further efficiency losses occur, of course, during compression, distribution, feedstock preparation, etc.

In each of these methods, the hydrogen is produced on site using an electrolyser and then distributed out to fuelling stations by pipeline.

Operationally speaking, one of the advantages of this production method is that it allows the operator of the electrolyser to use energy generated at peak efficiency and around the clock. For example, the operator of a coal-fired generator, or a hydro-generating station can have the plant “following load”, that is cycling its production capacity up and down based on load demand.

However, supplementing the plant with the capacity to produce hydrogen enables the plant operator to maintain constant production levels by switching to hydrogen production when demand on the grid drops off. This hydrogen can also assist the operator to meet electricity demand during peak times, by converting some of the stored hydrogen back into electricity through the use of an on-site stationary fuel-cell[7].

Similar advantages are available to solar or wind powered generator operators. Production from these electricity sources is not necessarily in sync with demand cycles. Supplementing the operation with hydrogen production would allow the operator to take advantage of the full generating capacity of the site, even if production exceeds current demand from the grid. And, having stores of hydrogen available would also allow the operator to supplement their supply of electricity to the grid, when demand exceeds current generating capacity.

Even a base load generator, such as a nuclear generating station, could supplement its operations with hydrogen production. This would allow the plant operator to choose

[6] According to the International Energy Agency, Monthly Oil Survey, January 2002.

[7] The impact that this behaviour can have on the rate of return for these generator operators is beyond the scope of this study, and has not been included in the analysis.

whether to sell their electricity to the grid, or to use it to produce hydrogen. For example, when the price for electricity falls during off-peak hours, the operator may choose to produce hydrogen instead of supplying the grid. The operator would therefore be able to optimize their revenue stream.

One of the disadvantages of electrolysis often cited[8] is that it can be a relativity expensive production method due to the high price of the feedstock, electricity, as compared to methods that use lower cost feedstock, such as fossil fuels. This will be further explored in the costing analysis section of this report.

Method 7) Centralized hydrogen production using a steam methane reformer

Steam methane reforming is currently the most common method used for producing hydrogen, accounting for more than half of total production[9]. Natural gas, which in most regions is about 99% methane, accounts for the majority of feedstock to this process. The basic process involves combining methane and water vapour (steam) at high temperature and pressure. This creates the reaction as shown by,

$$CH_4 + H_2O + \text{energy} \Rightarrow 3H_2 + CO \qquad (2)$$

A further step in the process combines the carbon monoxide from the first stage with steam again, further enriching the hydrogen yield.

$$CO + H_2O + \text{energy} \Rightarrow H_2 + CO_2 \qquad (3)$$

Steam methane reforming is a well-developed technology, and as such is an efficient method for producing hydrogen. Efficiency levels for the reformation process alone are typically in the 70-75% range, similar to that for the electrolysis process. Efficiency losses will occur in transmission, distribution, etc.

Method 8) Decentralized hydrogen production using electricity 'off the grid'

Like methods 3 to 6, inclusive, this method uses electricity to decompose water into hydrogen and oxygen. In this method, however, the hydrogen is produced on-site at the fuelling station. The electricity used in producing the hydrogen is acquired from the "grid". As such, it comes from a mixture of sources. For the purposes of this report, Canada's electricity mix is assumed to consist of: 17.0% coal, 1.7% gas boiler, 1.2% gas turbine, 21.3% nuclear and 58.8% hydro. This primarily comes into play in Part 2 of the study, when the externalities, such as greenhouse gas emissions, associated with each production pathway are evaluated.

The operational advantage of this decentralized method is that there is no need to create a hydrogen distribution infrastructure.

Method 9) Decentralized hydrogen production using a steam methane reformer

Like method 7 above, this method uses a steam methane reformer to produce hydrogen. In this method, the hydrogen is produced at the fuelling station.

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[8] Padro (1999)
[9] Kruse (2002), Padro (1999)

One advantage of method over method 7 is that natural gas has a higher energy density than hydrogen, which means that natural gas contains more energy per volume than hydrogen at similar temperatures and pressure. This makes natural gas a more efficient means of transporting energy to the fuelling station.

For example, at 1 atmospheric pressure and 15 degrees Celsius, hydrogen contains 10,050 kJ/m^3, whereas methane contains 32,560 kJ/m^3 [10]. Furthermore, like method 8, this method can take advantage of an existing natural gas distribution network to acquire its feedstock fuel.

Method 10) Decentralized hydrogen production using a methanol reformer

Method 10 also uses a reformer process to produce hydrogen at the fuelling station. Liquid fuel is the feedstock for the process. As with the steam methane reformer, a two-step process is involved. The first step involves breaking up the methanol,

$$CH_3OH + heat \Rightarrow CO + 2H_2 \qquad (4)$$

and then the carbon monoxide produced is combined with steam,

$$CO + H_2O + heat \Rightarrow H_2 + CO_2, \qquad (5)$$

producing carbon dioxide and additional hydrogen.

Like the steam methane reformer, the advantage to this process is that methanol has a higher volumetric energy density than hydrogen (15,800,100 kJ/m^3 for methanol, as compared to 8,491,000 kJ/m^3 for hydrogen when in a liquid state), and, as such, is a more efficient means of transporting energy to the fuelling station.

One difference between this method and method 9 above is that an existing distribution infrastructure exists for supplying the fuelling station with natural gas, while a new distribution infrastructure may be required for methanol[11].

11) Decentralized hydrogen production using a gasoline reformer

The final method is the reformation of gasoline. There are no commercial gasoline reformers currently available, but several companies[12] have Naphtha reformers. The process involved in this method is similar to the steam methane reforming process, where the stock fuel is combined with steam at a high temperature and passed through a catalyst to produce hydrogen. Using octane as a surrogate for gasoline, the reaction would be as follows

$$C_8H_{18} + 8H_2O + heat \Rightarrow 8CO + 17H_2 \qquad (6)$$

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[10] It should be noted, however, that hydrogen has a much greater energy/weight ratio than other fuel sources. For example, the lower heating value (LHV) of hydrogen (at 25^{o}C and 1 atm) is 119.93.86 kJ/g, while that for methane is 50.02 kJ/g, and gasoline's is 44.5 kJ/g.

[11] While the current gasoline distribution infrastructure could be retro-fitted for distribution of methanol, this gasoline distribution network would still need to distribute gasoline for use in ICE vehicles until such time as alternate fuel vehicles become the predominant form of light-duty vehicle.

[12] See Levelton Engineering (2002)

A secondary reaction is used to combine the carbon monoxide with more steam to produce additional hydrogen and carbon dioxide.

$$8CO + 8H_2O + heat \Rightarrow 8CO_2 + 8H_2 \qquad (7)$$

This method presents two operational advantages. First, like natural gas and methanol, gasoline has a higher volumetric energy density than gaseous hydrogen, (31,150,000 kJ/m^3). Second, there is an existing distribution network in place to supply the gasoline to the refuelling station.

1-2) Building the Model

The model used in this study has three basic components. The overall fuel requirement for the fleet of vehicles is determined in the first component. The second "well-to-tank" component uses the information obtained in the first component to determine the production capacity needs for the production equipment. The final component, "tank-to-wheel", uses the price of the fuel determined in the "well-to-tank" component to determine the total cost per kilometre associated with any given fuelling pathway.

There have been many studies published over the last ten to fifteen years on the potential costs of hydrogen as a motor vehicle fuel, and the costs for FCVs. However, many of the earlier studies had to derive their cost estimates without much source information. As a result, many estimates were used.

In this study, the performance characteristics of the production equipment or vehicles being modelled are based on statistical information or actual performance specifications where such data is available. Estimates from the literature are then used to supplement this data. Where possible, this study uses data from the literature that is based on direct cost information. For example, Thomas (2001), and Myers (2002) estimate the costs of small, decentralized hydrogen production and distribution systems, based on cost quotes from various manufacturers, using a method referred to as Design For Manufacturing and Assembly ("DFMA") costing approach. DFMA directly pieces together the costs of obtaining and assembling the necessary components for the machinery and equipment in question. Such a source provides greater confidence than sources that rely on other literature estimates, or estimates based on general cost statistics.

Fuel prices are derived from industry sources, such as the Ontario Independent Electricity Marketing Operator, or from Statistics Canada.

1-2.1) Establishing the Fuel Requirements

A few basic inputs are required to determine the total fuel requirements for the production equipment to be modelled. These include the following:

- The fuel efficiency and fuel tank capacity for the gasoline and diesel fuelled vehicles
- The fuel efficiency and fuel tank capacity for the FCVs
- Average annual distance driven
- The overall size of the fleet

The fuel efficiency for the light-duty ICE vehicle and FCV has been supplied by Natural Resources Canada ("NRCan"). Average annual kilometres driven by a light-duty vehicle is determined from the Canadian Vehicle Survey. The average annual kilometres driven by the light-duty FCV is assumed to be equal to the light-duty ICE vehicle.

Using the above data and the assumed size of the fleet of light-duty vehicles the total light-duty vehicle fleet fuel requirements can be determined. This data is displayed in Table 1.

Table 1 Light-duty vehicle fleet fuel requirements

	Light-duty ICE Vehicle	Light-duty FCV
Fuel Efficiency	0.1118 l/km	0.1558 Nm^3/km
Energy Consumption	3.4831 MJ/km	1.8868 MJ/km
Average Annual Mileage	16,700 km	16,700 km
Fleet Size	5,000	5,000
Annual Fuel Requirements (volume)	9,336,710 litres	13,006,231 Nm^3
Annual Fuel Requirements (energy)	290,838,507 MJ	157,543,820 MJ

Similar calculations are performed to determine the fuel requirements for the heavy-duty mass-transit vehicle fleet. Mileage for the mass-transit vehicle is based on various, consistent, sources providing a range of 3.5 to 4.5 miles per gallon.

The fuel consumption factor for the mass-transit FCV is set at a level one and a half times the fuel efficiency of the diesel vehicle. Although sources have indicated a potential fuel efficiency level of ten miles per gallon[13] for mass-transit FCVs, this would be roughly two and a half times the fuel economy of a traditional diesel fuelled bus. Considering that the fuel efficiency for the light-duty FCV being modelled is roughly twice that for a gasoline ICE, and considering that diesel engines are more efficient than gasoline engines, it is doubtful that there are greater efficiencies to be gained moving from a diesel engine to a FCV as compared to moving from a gasoline engine to a FCV. The inverse is in fact more likely.

Operating conditions for mass-transit vehicles can vary significantly between regions. Influencing factors include the amount of stopping and starting required, the topographic features of the region and ambient temperature. As such, there are no figures that are truly representative of conditions in municipalities across Canada. Since average data would not be representative of any given municipality, in this study the operating parameters of the heavy-duty vehicle is based on the actual operational data for a mass-transit vehicle from a selected municipality.

Average annual distance driven data for the mass-transit CIE is based on operational data from the Toronto Transit Commission (TTC), and it was assumed the mass-transit FCV would be required to cover the same distance. Table 2 presents the data for the mass-transit vehicle fleet.

Table 2 Mass-transit vehicle fleet fuel requirements

	Heavy-duty CIE Buses	Heavy-duty fuel cell Buses
Fuel Efficiency	0.5877 l/km	1.0169 Nm^3/km
Energy Consumption	18.4759 MJ/km	12.3172 MJ/km
Average Annual Mileage	70,000 km	70,000 km
Fleet Size	500	500
Annual Fuel Requirements (volume)	20,570,652 litres	35,590,279 Nm^3
Annual Fuel Requirements (energy)	646,654,908 MJ	431,103,272 MJ

[13] See, for example, the Diesel Technology Forum "Comparison of Transit Bus Fuel Options".

Once the annual fuel requirements were calculated, the parameters for the fuelling stations were determined. For the light-duty vehicles fuelling station, the starting point was to provide a figure for the fuel tank capacity for both vehicles. The fuel tank capacity was determined by calculating the amount of fuel necessary to provide a range of approximately 475kms[14]. The average fuel consumed per day was calculated based on this number and the average daily kilometres driven. This in turn, determines the number of days a vehicle can go between refuelling.

Data on the average amount of fuel that a fuel station for ICE vehicles currently processes a year was obtained from Imperial Oil annual reports. This figure, and the number of days a light-duty ICE vehicle goes between refuelling, were used to determine the number of light-duty ICE vehicles supported by a fuelling station, and the average amount of fuel processed hourly by the station. For the light-duty fuel cell vehicle fuelling station, it was assumed that the station supports the same number of vehicles as an ICE fuelling station. This determined the annual capacity of the station, and the average amount of fuel processed per hour. Data for the light personal vehicle fuelling stations is presented in Table 3.

Table 3 Light-duty vehicle fleet fuelling stations

	ICE	HFC
Vehicle Range	475 km	475 km
Fuel Tank Capacity (volume)[15]	53 litres	74 Nm^3
Fuel Tank Capacity (energy)	1,654 MJ	896 MJ
Fuel Consumed per Day (volume)	5 litres	7 Nm^3
Fuel Consumed per Day (energy)	159 MJ	86 MJ
Days Between Refuelling	10	10
Fuel Station's Annual Capacity (volume)	4,500,000 litres	6,268,593 Nm^3
Fuel Station's Annual Capacity (energy)	140,175,000 MJ	75,931,159 MJ
Avg Fuel Processed per Day (volume)	12,329 litres	10,195 Nm^3
Avg Fuel Processed per Day (energy)	384,048 MJ	123,492 MJ
Number of Vehicles Refuelled Daily[16]	232	232
Number of Vehicles Supported per Station	2,410	2,410
Total Number of Stations Required	2	2
Number of Fuel Pumps per Station	8	8

Similar calculations were performed for the mass-transit vehicle fuelling stations.

In the case of the mass-transit vehicle, the fuel tank capacity was set to 450 litres, based on the characteristics of typical diesel urban transit buses which have fuel tank

[14] Combined city and highway driving. Other studies have used a target figure of 600kms range, but this is typically based on highway driving alone. This range is based on current ICE vehicle design parameters.
[15] Note that this does not describe the actual physical size of the fuel tank, as the hydrogen will be stored in a compressed or liquefied state in the vehicle
[16] Given that both the ICE vehicles and the HFC vehicles travel the same average distance, and have the same range on a tank of fuel, the days between refuelling, and the number of vehicles refuelling daily will be the same.

capacities ranging from 100-150 gallons.[17] It was assumed that a single fuelling station would support twenty mass-transit vehicles. With these two additional data points, and the light-duty vehicle characteristics cited in Table 3 above, the rest of the parameters for the fuelling station could be determined. Data for the heavy-duty vehicles fuelling stations is presented in Table 4.

Table 4 Heavy-duty vehicle fleet fuelling stations

	Heavy-duty CIE	Heavy-duty FCV
Vehicle Range	766 km	766 km
Fuel Tank Capacity (volume)	450 litres	779 Nm^3
Fuel Tank Capacity (energy)	14,018 MJ	9,431 MJ
Fuel Consumed per Day (volume)	113 litres	195 Nm^3
Fuel Consumed per Day (energy)	3,511 MJ	2,362 MJ
Days Between Refuelling	4	4
Fuel Station's Annual Capacity (volume)	10,285,326 litres	17,795,140 Nm^3
Fuel Station's Annual Capacity (energy)	320,387,908 MJ	215,551,636 MJ
Avg Fuel Processed per Day (volume)	28,179 litres	48,754 Nm^3
Avg Fuel Processed per Day (energy)	877,775 MJ	590,552 MJ
Number of Vehicles Refuelled Daily	63	63
Number of Vehicles Supported per Station	250	250
Total Number of Stations Required	2	2
Number of Fuel Pumps per Station	2	2

1-2.2) The Well-to-Tank Component

The construction of the well-to-tank model for the gasoline and diesel fuel pathways is different from that of the hydrogen pathways: the selling price for the fuel and its rate of return are taken as given. The hydrogen fuel pathways take the cost structure as given; the selling price of hydrogen and the rates of return are variables determined by the model.

The price of gasoline is taken as fixed, as it is assumed that this is a well established market, therefore any investment project would have to be able to sell at market prices. The rate of return for gasoline and diesel is also set as a fixed parameter, as it is used to establish the benchmark for comparing the rate of return for the hydrogen production investment projects. Given these two fixed parameters, the various cost components of gasoline are input into the model as fixed percentages of the selling price. This methodology may have implications later on in the analysis where the impact of pipeline costs is being considered.

For the hydrogen pathways, the cost structure and performance characteristics are fixed in relation to the amount of hydrogen being produced. With the cost profiles established, the model then determines the selling price of hydrogen to either yield a given rate of return, or determines the rate of return using a price for hydrogen which yields the same cost/kilometre driven as gasoline.

[17] For example, an Orion VII low floor diesel bus has a fuel tank capacity of 125 US gallons, or 473 litres.

The various costs associated with production for the fuelling pathways include the following:

- Production equipment costs
- Supply equipment costs (pipelines, etc.)
- Fuelling station equipment costs
- Primary energy costs
- Other energy and other significant input (e.g. water) costs
- Maintenance and overhead costs
- Interest costs

The production costs unique to specific pathways are discussed below.

Depreciation rates for accounting purposes are specified for each class of equipment, yielding the annualized costs for the production, supply, and refuelling equipment. The maintenance costs are then assumed to be equal to 10% of the annualized capital costs.

Interest expenses are based on an assumed interest rate of 5%, and using a debt to equity ratio of three to two[18]. This debt to equity ratio is assumed to be constant over all the fuel pathways.

The costs associated with the fuelling stations include fuel pumps and on-site storage capacity at the fuelling station[19]. For the light-duty FCV fuelling stations, at an average daily flow rate of 514 litres of gasoline per hour it would take approximately 6 minutes to fill the tank of a car[20]. As such, it is assumed that each fuelling station will require a storage tank able to hold a days worth of fuel production[21].

The fuelling station costs will differ between the gasoline and diesel stations as compared to the hydrogen stations. For example, the hydrogen station storage tanks will require significant compression. In addition, the hydrogen based fuel dispenser must be able to handle the highly compressed fuel. These costs are discussed below.

Land and building costs are not included for the refuelling stations for a few reasons. First, these costs would be highly sensitive to the location of the station. Second, these costs would likely not be significantly different for an investment in a hydrogen station or a petroleum station. Third, at least during the initial take-up period, it is likely that these refuelling stations would not be new locations, but would be added to existing locations, with the necessary supporting infrastructure. Similarly, land and supporting buildings and structure (e.g. offices) are excluded from the costs for the production machinery and equipment.

Commodity and energy prices used in the model are presented in Table 5 below.

[18] This is roughly equivalent to the debt to equity ratio for Imperial Oil Canada, as reported in their 2002 Annual Report.
[19] See Table 5
[20] This is an artefact of the method used to calculate the fuelling needs, as the station was designed to fuel 232 cars in a period of one day, or 24 hours, or one car every 6 minutes.
[21] Thomas (2001) conducted an analysis on dispensing and storage requirements, and determined that storage requirements were only 40% of daily maximum production. Additional storage capacity is used in this study to err on the side of caution.

Table 5 Commodity and energy prices in the model

	Price	Source
Electricity	5.624 ¢/kWh	Ontario Independent Electricity Marketing Operator
Gasoline – Retail Price (before sales and excise taxes)	44.7 ¢/litre	MJ Ervin
Gasoline – Wholesale Price	39.3 ¢/litre	MJ Ervin
Diesel – Retail Price (before sales and excise taxes)	46.9 ¢/litre	MJ Ervin
Methanol	23.0 ¢/litre	Methanex
Natural Gas	27.74 ¢/m^3	Statistics Canada
Water	0.32 ¢/m^3	Environment Canada

Methods 1 & 2) Centralized production of gasoline and diesel at an oil refinery

Data for the gasoline and diesel production methods were obtained from the US Department of Energy, Energy Information Administration *Weekly Petroleum Status Report* (historical data file) and *Petroleum Marketing Monthly*, the Canadian Association of Petroleum Producers' *Monthly Crude Oil Report*, and MJ Ervin & Associates' *Fuel Facts Price Monitor* (various issues), and *Canadian Retail Petroleum Markets Study*.

It was assumed that the cost structure for the gasoline and diesel production methods would be identical, because a single refinery would be used to produce both fuels[22]. However, different cost structures will exist for the associated supply chains and fuelling stations.

The cost differences for the supply chains will reflect the fact that a similar number of fuel stations must be supplied (21 for gasoline, and 25 for diesel), but only one quarter the amount of fuel is being transported to the diesel fuelling stations. The supply chain being modelled assumes a 100 to 200 kilometre pipeline to a central distribution point, with truck transport from the central distribution point to the individual fuelling stations. Since the majority of the supply costs are pipeline related, the absolute supply costs for the two chains are similar. The result is a higher supply cost per litre of fuel for the diesel production method.

The Conference Board of Canada report *The Final Fifteen Feet of Hose* (2001), contains data on the capital costs for various size service stations. Based on this data, the cost for the capital equipment for each gasoline fuelling station was set at $140,000[23], with $60,000 allocated to storage tanks, and $80,000 for dispensing equipment.

Table 6 outlines the cost structures for the gasoline and diesel production methods.

[22] The gasoline to diesel ratio for this oil refinery would be higher than the average for a North American operation, at four to one, instead of the global average two to one.

[23] Using the "site B" data for equipment capital costs of $240,000, and then reducing the number to only include that equipment used in refuelling, i.e. excluding the equipment used in the convenience store and fast-food establishment on site.

Table 6 Gasoline and diesel production cost structure ($/MJ fuel produced)

	Gasoline	Diesel
Primary Energy Input Costs	$0.0097	$0.0088
Other Energy Costs	$0.0009	$0.0009
Maintenance, Overhead and Labour Costs	$0.0010	$0.0028
Production Equipment Costs	$0.0008	$0.0007
Supply Costs	$0.0003	$0.0003
Fuelling Station Costs	$0.0001	$0.0000
Interest Expenses	$0.0006	$0.0006
Total Costs per MJ of Fuel, Before Income Tax	**$0.0134**	**$0.0141**

Methods 3, 4, 5 & 6) Centralized hydrogen production using electrolysis with electricity from a nuclear power plant, a coal-fired generator, a wind powered generator and a hydroelectric generator

It is assumed that the methods for producing hydrogen at a centralized location using electrolysis will generally have the same cost structure. However, these methods will differ is in the externalities associated with the method of production, to be examined in Part 2 of this study.

In reality, these methods would have some differences in cost structure. For example, the distance of some of these electricity sources from urban centres can vary significantly, which would affect the cost of the pipeline required to supply the hydrogen.

In addition, the internal cost of producing the electricity for the electrolysis will vary from source to source. Therefore, the internal charge for consuming electricity for the hydrogen production process would also vary from source to source. It will be assumed, however, that the price paid for the electricity consumed in the electrolysis process will be the common market rate in each of these processes, reflecting the opportunity cost of selling the electricity used to the grid[24].

The centralized hydrogen production processes requires approximately 10,800 Nm^3 of hydrogen per hour to supply both the light-duty and heavy-duty FCVs is. One of the advantages often cited for electrolysis is that it can be easily scaled up or down to suit the needed production volumes. Scaling up production is achieved by simply adding on additional modular electrolysis units. As such, capital costs associated with electrolysis are usually considered linear in relation to production volumes. Literature estimates for the capital costs for industrial electrolysers are in the range of US$250/kW to US$1,000/kW. For the base case in this study a figure of US$600/kW is used[25]. Sensitivity analysis on this assumption is also conducted.

In analyzing the main inputs into the production process, the model uses performance data supplied by Natural Resources Canada, indicating 4.9kWh of electricity consumed per Nm^3 of hydrogen produced. In addition, data from Norsk Hydro Electrolysers AS, indicates consumption of roughly 1 litre of water per Nm^3 of hydrogen produced.

[24] This is likely a highly contentious assumption. Sensitivity analysis on the price of electricity will be conducted which should indicate how important this assumption might be in terms of influencing the advantage or disadvantage of these pathways over gasoline and diesel.
[25] This is consistent with Mann, MK, et al (1999)

Literature estimates of hydrogen pipeline costs suggest a cost range of around $220,000 to $870,000 per kilometre[26] depending on whether the pipeline is passing through rural or urban areas. Approximately 100 kilometres of pipeline will be required to feed the fuelling stations in this study. An average price per kilometre of $600,000 is assumed.

For the hydrogen fuelling stations, the cost of on-site storage is a significant cost component. Various literature estimates[27] place the cost of compressed gas storage tanks in the range of US$300 to US$650 per kilogram of hydrogen. For fuelling stations supplied by pipeline, the pipeline system can somewhat reduce the need for on-site storage. However, Ogden (1999) concluded that such "pipeline packing" would only contain about 7% of the daily fuel requirements, therefore largely inconsequential.

In addition to the compressed gas storage tanks, the fuelling station will require a compressor, and fuel dispensing equipment. Data for the costs of these items was obtained from Myers (2002), assuming a linear growth in costs from their costs estimates based on lower daily hydrogen supply needs.

Table 9 below presents the cost structure for the four centralized electrolysis methods, and the cost structure for the centralized steam methane reformer.

Method 7) Centralized hydrogen production using a steam methane reformer

Literature estimates for production equipment costs for production of hydrogen, using a centralized steam methane reformer, vary.

However, most of the literature suggests that the cost for steam methane reforming is not linear in relation to production volumes, and is more cost efficient at higher levels of production. Simbeck and Chang (2002), for example, cites capital costs of US$3.00 per standard cubic feet ("scf") of methane reformed per day for a reformer producing 1,000 kilograms of hydrogen per day, but those costs drop to only US$0.75 per scf of methane reformed per day for a reformer producing 100,000 kilograms of hydrogen per day. They contend that these figures are consistent with figures that Air Products had provided for an earlier study for the U.S. Department of Energy.

Myers, et al (2002) performed a thorough analysis of the potential costs associated with producing hydrogen using a small (52 Nm^3 hydrogen per hour) on-site steam methane reformer. The capital costs for the reformer equipment were determined to be approximately US$0.39 per Nm^3 of hydrogen produced. However, the two steam methane reformer plants modelled in this study, the large decentralized plant, and the small on-site plane, are both significantly larger (roughly 5,500 Nm^3 hydrogen per hour for the large plant, and 700 Nm^3 of hydrogen per hour for the small plant). Myers provides a method for scaling the capital costs up for larger production plants[28]. This method suggests that the capital costs for a steam methane reformer producing 700 Nm^3 of hydrogen per hour would be approximately US$0.10 per Nm^3 of hydrogen produced per year, and for a steam methane reformer producing 5,500 Nm^3 of hydrogen per hour would be approximately US$0.05 per Nm^3 of hydrogen produced per year. These cost figures fall well below the Simbeck and Chiang figures. Using the Simbeck

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[26] Amos (1998), Ogden (1999)
[27] Thomas (2001), Myers (2002).
[28] *Cost-scaled up = Cost-original x (Capacity-scaled up / Capacity-original)^scale exponent,* where scale exponent = 0.60 for the reformer.

and Chiang cost estimates, the small reformer would have capital costs of US$1.38 per Nm^3 of hydrogen produced per year, and the large reformer would have capital costs of US$0.35 per Nm^3 of hydrogen produced per year. The Simbeck and Chiang estimates will be used for the base case in this study and sensitivity analysis will be conducted applying the Myers estimates. As the decentralized fuelling pathways for the heavy-duty vehicles requires significantly more fuel than the decentralized fuelling pathways for the light-duty vehicles, a reduced capital cost of US$2.00 per standard cubic feet ("scf") of methane reformed per day will be used.

According to Myers et al. (2002) energy consumption would be approximately $0.46m^3$ of natural gas, and 0.28kWh of electricity being consumed per Nm^3 of hydrogen produced. The costs for the pipeline and fuelling infrastructure are assumed to be the same as for the centralized electrolysis pathways.

Table 7, below, compares the cost structures for the centralized steam methane reformer and electrolysis production processes.

Table 7 Centralized hydrogen production cost structure ($/MJ fuel produced)

	Electrolysis	Steam Methane Reformer
Primary Energy Input Costs	$0.0228	$0.0105
Other Energy Costs	$0.0009	$0.0021
Maintenance, Overhead and Labour Costs	$0.0020	$0.0017
Production Equipment Costs	$0.0019	$0.0020
Supply Costs	$0.0051	$0.0051
Fuelling Station Costs	$0.0013	$0.0013
Interest Expenses	$0.0046	$0.0047
Total Costs per MJ of Fuel, Before Income Tax	**$0.0385**	**$0.0275**

Method 8) Decentralized hydrogen production using electricity 'off the grid'

The cost structure for the smaller decentralized electrolysers was kept largely the same as for the centralized electrolysers. A significant difference, of course, is that there are no capital costs associated with hydrogen distribution pipelines.

As suggested above, capital costs for electrolysers are generally considered to be linear in relation to production volumes. Given this, the same $/kW capital cost figure is used for this scaled down electrolyser as was used in the larger models in methods 3-6. Although the capital costs for the production equipment might be slightly higher on a per kW basis, this higher capital cost would be offset by the need for additional compression equipment in the decentralized investment, in order to feed the pipeline. The decentralized pathways use the same cost structures for the fuelling stations as were used for the centralized pathways. However, since there are two different types of fuelling stations modelled in this study (heavy-duty vehicle fuelling stations, and light-duty fuelling stations), two separate cost profiles must be developed[29].

[29] The difference between the two fuelling stations is the number of fuel dispensers, and the size of the storage facilities.

The results for the decentralized pathways are presented in Table 8, for the light-duty vehicle fuelling station, and Table 9, for the heavy-duty fuelling station.

Method 9) Decentralized hydrogen production using a steam methane reformer

For the smaller decentralized steam methane reformer, the capital cost for the reformer is based on the small steam methane reformer specified in Simbeck and Chiang (2002). The capital costs for the reformer are $1.38 per Nm^3 of hydrogen produced, and the energy consumption is 0.46m^3 of natural gas, and 0.28kWh of electricity per Nm^3 of hydrogen produced.

Method 10) Decentralized hydrogen production using a methanol reformer

Data for this method was obtained from analysis performed by (S&T)^2 Consultants Inc. for Methanex. The capital costs for the reformer are $0.21 per Nm^3 of hydrogen produced. This method requires the installation of a storage tank for the methanol to be used in the reformation process[30]. The addition of this storage tank increases the capital costs of the reformation equipment to $0.22 per Nm^3 of hydrogen produced. The process consumes 0.83 litres of methanol per Nm^3 of hydrogen produced, and 0.45 kWh of electricity.

Method 11) Decentralized hydrogen production using a gasoline reformer

Very little information exists in the literature on capital costs associated with a gasoline reformer. The capital cost for the steam methane reformer can be used as a proxy[31], as the two processes are similar in complexity. Operating costs for the gasoline reformer are based on the Levelton (2002) study, which suggest gasoline consumption at a rate of 0.51 kg of gasoline per Nm^3 of hydrogen produced, and 0.33 kWh of electricity.

Table 8 Decentralized hydrogen production cost structure ($/MJ fuel produced), at a light-duty vehicle refuelling station

	Electrolysis	Steam Methane Reforming	Methanol Reforming	Gasoline Reforming
Primary Energy Input Costs	$0.0228	$0.0105	$0.0158	$0.0238
Other Energy Costs	$0.0009	$0.0021	$0.0029	$0.0024
Maintenance, Overhead and Labour Costs	$0.0012	$0.0019	$0.0009	$0.0022
Production Equipment Costs	$0.0019	$0.0081	$0.0010	$0.0081
Supply Costs	$0.0000	$0.0000	$0.0000	$0.0000
Fuelling Station Costs	$0.0015	$0.0015	$0.0016	$0.0016
Interest Expenses	$0.0016	$0.0053	$0.0011	$0.0054
Total Costs per MJ of Fuel, Before Income Tax	**$0.0299**	**$0.0296**	**$0.0234**	**$0.0435**

[30] It is assumed that the methanol is being supplied by truck, rather than a pipeline.
[31] No additional storage tank for the delivered feedstock fuel is added in this case, as the reformer is assumed to be installed at an existing fuel station, which already has gasoline storage facilities.

Table 9 Decentralized hydrogen production cost structure ($/MJ fuel produced), at a heavy-duty mass-transit vehicle refuelling station

	Electrolysis	Steam Methane Reforming	Methanol Reforming	Gasoline Reforming
Primary Energy Input Costs	$0.0228	$0.0105	$0.0158	$0.0238
Other Energy Costs	$0.0009	$0.0021	$0.0029	$0.0024
Maintenance, Overhead and Labour Costs	$0.0011	$0.0014	$0.0008	$0.0017
Production Equipment Costs	$0.0019	$0.0054	$0.0010	$0.0054
Supply Costs	$0.0000	$0.0000	$0.0000	$0.0000
Fuelling Station Costs	$0.0012	$0.0012	$0.0012	$0.0012
Interest Expenses	$0.0015	$0.0036	$0.0010	$0.0036
Total Costs per MJ of Fuel, Before Income Tax	**$0.0294**	**$0.0243**	**$0.0228**	**$0.0381**

1-2.3) Calculating Income Taxes

The income tax implications for each of the fuelling pathway investment projects are assessed based on the tax consequences of a new investment by an existing firm once that investment reaches maturity. This relies on a number of assumptions. Specifically, maturity of the investment implies that the investment is fully operational, and producing expected levels of output. It also implies that there are no un-utilized tax losses, which are common for a new start-up firm.

In addition, by assuming that this is an investment by an existing firm, and not a brand new investment into the jurisdiction, we can assume that certain base deductions that have thresholds (e.g. the $10,000,000 deduction for the Large Corporations Tax) have already been used by the existing operations of the firm.

Furthermore, the tax costs are the average annual tax liabilities over the life of the investment, assumed to be 20 years for this study. This provides the average value of the tax deductions for capital investments. This is achieved by calculating the average effective tax depreciation rate, determined for each property class, for the twenty-year period[32]. This average effective rate is then used in place of the statutory rate to calculate the depreciation deduction.

The book depreciation and tax depreciation rates for each class of equipment are presented in Table 10, below.

With the tax structure in place, the after tax rate of return for the investment is determined in one of two ways. The first method is by choosing a price for the hydrogen that would to yield a target rate of return. The second method is to determine a price for the hydrogen that would make hydrogen competitive with gasoline, in terms of $/kilometre driven, and then determining the rate of return based on that sale price.

[32] It can be shown that over time the effective rate of tax depreciation approaches the rate of replacement. In this study we are assuming that capital is replaced at the rate of book depreciation. So, over the twenty-year period, the average effective rate of depreciation for tax purposes approaches the replacement rate.

Table 10 Accounting and tax depreciation treatment of capital assets

Equipment Type	Expected Life (book depreciation)	Tax Treatment	
		Capital Cost Allowance ("CCA") Class	CCA Rate
Production Machinery and Equipment	20 years	Class 43	30%
Pipelines	20 years	Class 1	4%
Vehicles	10 years	Class 10	30%
Gas and Water Storage Tanks	10 years	Class 6	10%
Compressors	10 years	Class 8	20%
Fuel Dispensers	10 years	Class 8	20%

1-2.4) The Tank-to-Wheel Component

The tank to wheel component includes the following exogenously specified cost components and vehicle performance variables:

- Vehicle purchase price
- Annual maintenance charges
- Interest rate for vehicle financing
- Expected vehicle lifetime
- Kilometres driven per year
- Fuel consumed per kilometre

Other vehicle operating costs, such as insurance, are not included in the model, as they are not expected to differ between the two classes of vehicles, and would therefore have no impact on the absolute cost differential[33].

Fuel costs for the vehicles are then determined endogenously, based on the fuel prices as determined in the well-to-tank component, and the exogenously specified vehicle performance variables.

1) Light Personal Internal Combustion Engine Vehicle

The model for the light-duty ICE vehicle is primarily based on data from the Statistics Canada *Canadian Vehicle Survey* (2001)[34]. As such, the data will reflect the performance characteristics of an average light-duty vehicle currently on the road, and not the improved performance characteristics of the latest model vehicles. This is consistent with the experiment of analysing the impact of replacing current vehicle stock with FCVs.

Data on the purchase price for light-duty vehicles is from Statistics Canada's *New Motor Vehicle Sales* (April 2003). Operating and maintenance costs and the financing interest rate are from the Canadian Automobile Association's *Driving Costs* (2003).

Data for the light-duty ICE vehicle is displayed, and contrasted to the light-FCV, in Table 11 below.

[33] Bevilacqua Knight Inc. (2001)
[34] The 2002 survey data has recently been released, and the study will be updated based on this newer data.

2) Light Personal Hydrogen Fuel Cell Vehicle

The purchase price for a mass-produced light-duty FCV is assumed to be 15% higher than that for an equivalent ICE vehicle. This is based on literature analysis of the mass production costs for alternative fuel vehicles[35], and is consistent with statements from various vehicle manufacturers regarding their target cost difference.

Many proponents of FCVs claim that these vehicles will have lower maintenance costs, and longer lifetimes, primarily because fewer mechanical parts are involved. However, there is no current data to support or refute these claims given the limited numbers of these vehicles currently in operation. Therefore, for the purposes of this study the annual maintenance costs and expected lifetime for the vehicle have been set equal to those for the ICE vehicle.

Financing charges and annual kilometres driven are also set equal to those for the ICE vehicle, as these variables are not dependant on the technology in use. The FCV's fuel consumption data is from NRCan, as specified above in section 1-2.1 where the vehicle fuel requirements were identified.

Table 11 displays the data for the light personal HFC vehicle, and contrasts it to the data for the ICE vehicle.

Table 11 Data for the light-duty ICE vehicles and FCVs.

	ICE vehicle	FCV
Vehicle purchase price	$24,800	$28,520
Annual maintenance and insurance costs	$795	$795
Interest rate for financing	6.50%	6.50%
Expected lifetime	14 years	14 years
Annual financing costs	$438	504
Kilometres driven per year	16,700	16,700
Costs per km, Excluding Fuel	**$0.2877**	**$0.3075**

3) Heavy-duty Mass-Transit CIE Vehicle

The model for the mass-transit CIE vehicle is mainly based on data from Orion Bus Industries, and from the Toronto Transit Commission (TTC)[36]. Orion Bus Industries provided the average purchase price, and average expected life. The TTC provided average annual kilometres driven. Maintenance costs were assumed to be equal to vehicle depreciation, and the fuel consumption per kilometre is based on various, consistent sources.

Data for the mass-transit CIE vehicle is displayed, and compared to the FCV, in Table 12 below.

4) Mass-Transit Hydrogen Fuel Cell Vehicle

The purchase price for a mass-produced mass-transit FCV was assumed to be 15% higher than for an equivalent CIE vehicle, based on the price premium used for the light-

[35] Thomas et al (2000)

[36] The Canadian Urban Transit Associations' (CUTA) *Transit Stats* was consulted, but it did not provide operational data by vehicle type. Further input from CUTA may be forthcoming.

duty FCV. The expected lifetime, annual kilometres driven, and maintenance costs were all assumed to be equal to the CIE vehicle.

The mass-transit FCV modelled here is derived from the performance specifications for the light-duty FCV. The light-duty FCV had almost double the efficiency of the gasoline ICE vehicle, so it is assumed here that, since diesel engines are typically already more efficient than gasoline engines, the efficiency gains of the heavy-duty FCV over the diesel CIE vehicle would be roughly one and a half.

Table 12 displays the data for the mass transit vehicle and compares it to the data for the CIE vehicle.

Table 12 Data for the mass-transit CIE vehicles and FCVs.

	CIE vehicle	FCV
Vehicle purchase price	$450,000	$517,500
Annual maintenance costs	$25,000	$25,000
Interest rate for financing	5.00%	5.00%
Expected lifetime	18 years	18 years
Annual financing costs	$6,097	$7,011
Kilometres driven per year	70,000	70,000
Costs per km, Excluding Fuel	**$0.8014**	**$0.8680**

1-3) Comparing Results for Part 1

1-3.1) Base Case Results

With the model fully specified, the first experiment is to determine the selling price for hydrogen, for each of the hydrogen pathways, which would yield an after tax rate of return equal to that for gasoline and diesel. The results from this experiment are displayed in Table 13 for the light-duty vehicle and Table 14 for the heavy-duty mass-transit vehicle.

Table 13 Results for light-duty vehicle (rate of return=gasoline)

		Pre-tax Retail price of fuel (per MJ)	MJ of fuel consumed per km	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from gasoline**
Centralized	Gasoline	$0.0143	3.4831	$0.0500	$0.2877	**$0.3377**	**$0**
	Electrolysis	$0.0470	1.8868	$0.0887	$0.3075	**$0.3962**	**$81**
	Steam Methane Reformer	$0.0360	1.8868	$0.0679	$0.3075	**$0.3755**	**$53**
Decentralized	Electrolysis	$0.0323	1.8868	$0.0609	$0.3075	**$0.3685**	**$43**
	Steam Methane Reformer	$0.0369	1.8868	$0.0697	$0.3075	**$0.3772**	**$55**
	Methanol Reforming	$0.0252	1.8868	$0.0475	$0.3075	**$0.3550**	**$24**
	Gasoline Reforming	$0.0509	1.8868	$0.0961	$0.3075	**$0.4036**	**$92**

Table 14 Results for heavy-duty vehicle (rate of return=diesel)

		Pre-tax Retail price of fuel (per MJ)	MJ of fuel consumed per km	Fuel costs per KM	Other costs per km	**Total Costs per km**	**$/month difference from diesel**
Centralized	Diesel	$0.0149	18.4759	$0.2756	$0.8014	**$1.0770**	**$0**
	Electrolysis	$0.0470	12.3172	$0.5787	$0.8680	**$1.4468**	**$2,157**
	Steam Methane Reformer	$0.0360	12.3172	$0.4436	$0.8680	**$1.3116**	**$1,368**
Decentralized	Electrolysis	$0.0316	12.3172	$0.3891	$0.8680	**$1.2571**	**$1,050**
	Steam Methane Reformer	$0.0293	12.3172	$0.3608	$0.8680	**$1.2288**	**$885**
	Methanol Reforming	$0.0243	12.3172	$0.2995	$0.8680	**$1.1675**	**$528**
	Gasoline Reforming	$0.0431	12.3172	$0.5310	$0.8680	**$1.3990**	**$1,878**

Examining the results in Tables 13 and 14 reveals that the most competitive hydrogen fuel pathway for the light duty vehicles would be the decentralized methanol reformer, followed by the decentralized electrolysis. For the heavy-duty vehicle pathways, the decentralized steam methane reformer is second to the decentralized methanol reformer, coming in at a lower cost than the centralized steam methane reformer, in contrast to the results for the light-duty vehicle. This switch in rankings between the light-duty and heavy-duty pathways for the steam methane reformer occurs because the decentralized steam methane reformer providing fuel into the pathway ending with the heavy-duty vehicles has a higher output requirement. Therefore it is more efficient than the decentralized steam methane reformer providing fuel into the pathway ending with the light-duty vehicles.

The centralized steam methane reformer is still more efficient than the decentralized steam methane reformer at the heavy-duty refuelling station. However, the efficiency advantage in this case is insufficient to compensate for the additional capital costs required for the pipeline distribution infrastructure. With the small fleet sizes supported by the pipeline distribution the cost per vehicle creates a significant disadvantage for the centralized pathways.

The most important factor contributing to the cost disadvantage for the light-duty vehicle hydrogen fuelling pathways, as compared to the gasoline pathway, is the "other costs" associated with the vehicle, not the fuel costs. The "other costs per km" contribute 70-80% of the total costs. This holds true for the heavy-duty vehicle fuelling pathways, although to a lesser degree, with other costs accounting for 60-75% of the total costs. As a result, when determining the economic advantages or disadvantages of the technology the acquisition and maintenance cost differences between FCVs and traditional vehicles will be as important, if not more important, than the cost differences between the fuels.

The cost advantage displayed by the decentralized methanol reformer pathway over the other hydrogen pathways is due to a number of reasons. For example, in comparing the hydrogen pathways (see Tables 7, 8 and 9), it is evident that the methanol reformer has an advantage in terms of the capital costs for the reformer equipment, and has relatively low costs for the primary energy input.

In interpreting any of the results in this study a sensitivity factor of $20 per month for the light-duty vehicles, and a slightly greater $100 per month for the heavy-duty vehicles. This translates to roughly $0.015 per km in costs. With these criteria, it can be seen that for the light-duty vehicle pathways, even the most competitive production method, the decentralized methanol reformer, remains just outside the sensitivity range, while none of the heavy-duty hydrogen pathways are close to being within the range.

1-3.2) Experiment 1: Determining Rate of Return if Total Costs set Equal to Gasoline

An alternative experiment was conducted to provide a means of understanding how significant the cost differentials are between the various hydrogen pathways, and the gasoline and diesel pathways.

In this experiment, a price for hydrogen is determined which would yield the same total cost per km as gasoline or diesel, and then the after tax rates of return are compared. This involves setting the total cost per kilometre equal across all the pathways, and then comparing the impacts on the after tax rates of return for the production methods.

The results from this experiment are shown in Tables 15 and 16.

Table 15 Results for light-duty vehicle (total costs per km=gasoline)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total Costs per km**	**Rate of Return on Equity**	**Rate of Return on Capital Employed**
Centralized	Gasoline	$0.0143	$0.0500	$0.2877	**$0.3377**	**10.00%**	**4.00%**
	Electrolysis	$0.0160	$0.0302	$0.3075	**$0.3377**	**-35.47%**	**-14.19%**
	Steam Methane Reformer	$0.0160	$0.0302	$0.3075	**$0.3377**	**-17.71%**	**-7.08%**
Decentralized	Electrolysis	$0.0160	$0.0302	$0.3075	**$0.3377**	**-62.13%**	**-24.85%**
	Steam Methane Reformer	$0.0160	$0.0302	$0.3075	**$0.3377**	**-18.36%**	**-7.35%**
	Methanol Reforming	$0.0160	$0.0302	$0.3075	**$0.3377**	**-48.53%**	**-19.41%**
	Gasoline Reforming	$0.0160	$0.0302	$0.3075	**$0.3377**	**-37.25%**	**-14.90%**

Table 16 Results for heavy-duty vehicle (total costs per km=diesel)

		Pre-tax Retail price of fuel (per MJ)	Fuel costs per KM	Other costs per km	**Total Costs per km**	**Rate of Return on Equity**	**Rate of Return on Capital Employed**
Centralized	Diesel	$0.0149	$0.2756	$0.8014	**$1.0770**	**10.00%**	**4.00%**
	Electrolysis	$0.0170	$0.2090	$0.8680	**$1.0770**	**-33.91%**	**-13.56%**
	Steam Methane Reformer	$0.0170	$0.2090	$0.8680	**$1.0770**	**-16.16%**	**-6.47%**
Decentralized	Electrolysis	$0.0170	$0.2090	$0.8680	**$1.0770**	**-59.34%**	**-23.74%**
	Steam Methane Reformer	$0.0170	$0.2090	$0.8680	**$1.0770**	**-14.56%**	**-5.83%**
	Methanol Reforming	$0.0170	$0.2090	$0.8680	**$1.0770**	**-43.02%**	**-17.21%**
	Gasoline Reforming	$0.0170	$0.2090	$0.8680	**$1.0770**	**-42.55%**	**-17.02%**

Tables 15 and 16 clearly show that the model is highly sensitive, for both light and heavy-duty vehicles, to variances in the price of the fuel sold. Small changes in those prices have a very large impact on the after tax rates of return. For example, to affect a $0.0585 decrease in the total costs per km for the light-duty vehicle centralized electrolysis pathways (moving total costs down from $0.3962/km to $0.3377/km), the after tax rate of return on equity drops from 10% to -35.47%.

Even for the most competitive alternative fuelling pathway, the decentralized methanol reformer, the drop in fuel price necessary to become competitive with gasoline reduces the rate of return on equity to -18.36%.

1-3.3) Experiment 2: Varying the Price of Electricity

Tables 9, 10 and 11 reveal that primary energy input is one of the most significant cost factors. It comprises approximately 63% of the production costs for the centralized electrolysis pathways and 75% of the production costs for the on-site gasoline reforming.

To test the sensitivity of the model to the price of energy inputs, a second counter-factual experiment is conducted in which the average “off-peak” price for electricity in Ontario is used in the production of hydrogen in place of the overall average electricity price.

It should be noted that this experiment does not correspond with using the off-peak excess capacity of an electrical generating station to generate hydrogen. To model off-peak production would require the hydrogen generating equipment to either produce hydrogen at a much faster rate than in the base case or have a much higher production capacity, either of which would require additional capital investment.

For the purposes of this experiment, the average off-peak price is used as an indicator of a feasible lower electricity price. The off-peak electricity price used is $0.0436/kWh (versus the overall average price being used of $0.05624/kWh), based on the Ontario Independent Electricity Marketing Operator published average off-peak rates.

The experiment is conducted yielding rates of return for hydrogen equal to the rates of return for gasoline or diesel. The results of this experiment are shown in Tables 17 and 18, below.

Comparing Tables 17 and 18 to Tables 13 and 14, the most significant impact is, not unexpectedly, on the electrolysis pathways. The cost reduction is still not sufficient to make the electrolysis pathways competitive with the gasoline and diesel pathways, the closest competitive pathway being the light-duty vehicle decentralized methanol reformer, which still remains just outside the sensitivity range.

Table 17 Results for light-duty vehicle (reduced electricity prices)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from gasoline**	Base case results	**% Change**
Centralized	Gasoline	$0.0143	$0.0500	$0.2877	**$0.3377**	**$0**	$0.3377	**0.00%**
	Electrolysis	$0.0415	$0.0784	$0.3075	**$0.3859**	**$67**	$0.3962	**-2.59%**
	Steam Methane Reformer	$0.0355	$0.0670	$0.3075	**$0.3746**	**$51**	$0.3755	**-0.25%**
Decentralized	Electrolysis	$0.0268	$0.0506	$0.3075	**$0.3582**	**$29**	$0.3685	**-2.79%**
	Steam Methane Reformer	$0.0364	$0.0688	$0.3075	**$0.3763**	**$54**	$0.3772	**-0.25%**
	Methanol Reforming	$0.0245	$0.0462	$0.3075	**$0.3538**	**$22**	$0.3550	**-0.36%**
	Gasoline Reforming	$0.0504	$0.0950	$0.3075	**$0.4026**	**$90**	$0.4036	**-0.25%**

Table 18 Results for heavy-duty vehicle (reduced electricity prices)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from diesel**	Base case results	**% change**
Centralized	Diesel	$0.0149	$0.2756	$0.8014	**$1.0770**	**$0**	$1.0770	**0.00%**
	Electrolysis	$0.0415	$0.5117	$0.8680	**$1.3797**	**$1,766**	$1.4468	**-4.64%**
	Steam Methane Reformer	$0.0355	$0.4375	$0.8680	**$1.3055**	**$1,333**	$1.3116	**-0.46%**
Decentralized	Electrolysis	$0.0261	$0.3220	$0.8680	**$1.1900**	**$659**	$1.2571	**-5.34%**
	Steam Methane Reformer	$0.0288	$0.3547	$0.8680	**$1.2227**	**$850**	$1.2288	**-0.49%**
	Methanol Reforming	$0.0236	$0.2912	$0.8680	**$1.1592**	**$480**	$1.1675	**-0.71%**
	Gasoline Reforming	$0.0426	$0.5243	$0.8680	**$1.3923**	**$1,839**	$1.3990	**-0.48%**

Further manipulation of the model reveals that the price for electricity would have to be reduced to $0.0183/kWh for the light-vehicle decentralized electrolysis pathway to be cost competitive with gasoline, and maintain a rate of return equal to that for gasoline.

1-3.4) Experiment 3: Varying the Fleet Size

In order to determine the sensitivity of the pipeline costs for the centralized pathways to the size of the vehicle fleet an experiment was conducted where the size of the light-duty fleet of vehicles was increased from 5,000 to 500,000.

These results are displayed in Table 19.

Table 19 Results for light-duty vehicle (fleet size=500,000)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from gasoline**	Base case results	**% Change**
Centralized	Gasoline	$0.0143	$0.0500	$0.2877	**$0.3377**	**$0**	$0.3377	**0.00%**
	Electrolysis	$0.0328	$0.0619	$0.3075	**$0.3695**	**$44**	$0.3962	**-6.75%**
	Steam Methane Reformer	$0.0218	$0.0412	$0.3075	**$0.3488**	**$15**	$0.3755	**-7.12%**
Decentralized	Electrolysis	$0.0323	$0.0609	$0.3075	**$0.3685**	**$43**	$0.3685	**0.00%**
	Steam Methane Reformer	$0.0369	$0.0697	$0.3075	**$0.3772**	**$55**	$0.3772	**0.00%**
	Methanol Reforming	$0.0252	$0.0475	$0.3075	**$0.3550**	**$24**	$0.3550	**0.00%**
	Gasoline Reforming	$0.0509	$0.0961	$0.3075	**$0.4036**	**$92**	$0.4036	**0.00%**

Expanding the size of the fleet does lead to a significant reduction in the costs for the centralized production pathways. The total costs per km for the centralized steam methane reformer drops below all the decentralized pathways, as the cost advantages of the better efficiencies at higher levels of production outweigh the cost disadvantages of having to establish a distribution network. However, total costs per km are still higher than that for gasoline due to the significantly higher “other costs”.

1-3.5) Experiment 4: Varying the Capital Costs

As mentioned above, literature estimates for the capital costs of the hydrogen production equipment vary significantly. Tables 20 and 21, show the impact of reducing the capital costs for the production equipment by 50% to test the sensitivity of the results to variances in these estimates.

Table 20 Results for light-duty vehicle (reduced capital costs for production equipment)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from gasoline**	Base case results	**% Change**
Centralized	Gasoline	$0.0143	$0.0500	$0.2877	**$0.3377**	**$0**	$0.3377	**0.00%**
	Electrolysis	$0.0445	$0.0840	$0.3075	**$0.3915**	**$75**	$0.3962	**-1.18%**
	Steam Methane Reformer	$0.0334	$0.0630	$0.3075	**$0.3706**	**$46**	$0.3755	**-1.31%**
Decentralized	Electrolysis	$0.0298	$0.0562	$0.3075	**$0.3638**	**$36**	$0.3685	**-1.27%**
	Steam Methane Reformer	$0.0265	$0.0500	$0.3075	**$0.3576**	**$28**	$0.3772	**-5.21%**
	Methanol Reforming	$0.0238	$0.0450	$0.3075	**$0.3525**	**$21**	$0.3550	**-0.71%**
	Gasoline Reforming	$0.0405	$0.0764	$0.3075	**$0.3840**	**$64**	$0.4036	**-4.87%**

Table 21 Results for heavy-duty vehicle (reduced capital costs for production equipment)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from diesel**	Base case results	**% change**
Centralized	Diesel	$0.0149	$0.2756	$0.8014	**$1.0770**	**$0**	$1.0770	**0.00%**
	Electrolysis	$0.0445	$0.5482	$0.8680	**$1.4162**	**$1,979**	$1.4468	**-2.11%**
	Steam Methane Reformer	$0.0334	$0.4115	$0.8680	**$1.2795**	**$1,181**	$1.3116	**-2.45%**
Decentralized	Electrolysis	$0.0291	$0.3585	$0.8680	**$1.2265**	**$872**	$1.2571	**-2.43%**
	Steam Methane Reformer	$0.0223	$0.2752	$0.8680	**$1.1433**	**$386**	$1.2288	**-6.96%**
	Methanol Reforming	$0.0230	$0.2830	$0.8680	**$1.1510**	**$432**	$1.1675	**-1.41%**
	Gasoline Reforming	$0.0362	$0.4455	$0.8680	**$1.3135**	**$1,379**	$1.3990	**-6.11%**

Comparing the results in Tables 20 and 21 with the results from the base case in Tables 13 and 14, it is evident that a 50% reduction in the capital costs of the production equipment does not have a large impact on the overall results, although the light-duty vehicle decentralized methanol reformer does almost get within the sensitivity range, and so could be considered competitive. This is in part due to the fact that this equipment is being written off over a twenty-year period, the assumed life of the production machinery and equipment.

The pathways that see the largest decrease in costs are those that have the largest proportion of production equipment capital costs, namely the decentralized steam methane reformer and gasoline reformer.

1-3.6) Experiment 5: Varying the Vehicle Costs

The final experiment involved varying the other costs associated with the vehicles acquisition and operation. This experiment actually involves two different sets of model runs.

The first model run eliminates the price differential between a hydrogen fuel cell vehicle and a conventional vehicle. In the base case model, the price differential between the conventional vehicles and the hydrogen fuel cell based vehicles was assumed to be 15%.

Tables 22 and 23, below, show the results of removing the cost differential.

Table 22 Results for light-duty vehicle (decreased vehicle purchase costs)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from gasoline**	Base case results	**% Change**
Centralized	Gasoline	$0.0143	$0.0500	$0.2877	**$0.3377**	**$0**	$0.3377	**0.00%**
	Electrolysis	$0.0470	$0.0887	$0.2877	**$0.3763**	**$54**	$0.3962	**-5.01%**
	Steam Methane Reformer	$0.0360	$0.0679	$0.2877	**$0.3556**	**$25**	$0.3755	**-5.29%**
Decentralized	Electrolysis	$0.0323	$0.0609	$0.2877	**$0.3486**	**$15**	$0.3685	**-5.39%**
	Steam Methane Reformer	$0.0369	$0.0697	$0.2877	**$0.3574**	**$27**	$0.3772	**-5.26%**
	Methanol Reforming	$0.0252	$0.0475	$0.2877	**$0.3352**	**-$3**	$0.3550	**-5.59%**
	Gasoline Reforming	$0.0509	$0.0961	$0.2877	**$0.3838**	**$64**	$0.4036	**-4.92%**

The results are fairly consistent across all the pathways, with a drop in the vehicle purchase price of around 15% leading to a decrease in the total costs per kilometre of around 5%. This is in contrast to the reduction in the production equipment costs, where a 50% reduction in the acquisition costs resulted in reductions in the total costs per kilometre of only around 2% for most of the pathways.

Table 23 Results for heavy-duty vehicle (decreased vehicle purchase costs)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from diesel**	Base case results	**% change**
Centralized	Diesel	$0.0149	$0.2756	$0.8014	**$1.0770**	**$0**	$1.0770	**0.00%**
	Electrolysis	$0.0470	$0.5787	$0.8014	**$1.3801**	**$1,768**	$1.4468	**-4.61%**
	Steam Methane Reformer	$0.0360	$0.4436	$0.8014	**$1.2450**	**$980**	$1.3116	**-5.08%**
Decentralized	Electrolysis	$0.0316	$0.3891	$0.8014	**$1.1904**	**$662**	$1.2571	**-5.30%**
	Steam Methane Reformer	$0.0293	$0.3608	$0.8014	**$1.1622**	**$497**	$1.2288	**-5.42%**
	Methanol Reforming	$0.0243	$0.2995	$0.8014	**$1.1009**	**$139**	$1.1675	**-5.71%**
	Gasoline Reforming	$0.0431	$0.5310	$0.8014	**$1.3324**	**$1,490**	$1.3990	**-4.76%**

In one of the pathways, the decentralized methanol reforming for light-duty vehicles, this results in a total cost per km that is lower than that for the corresponding conventional fuelling pathway. In addition, the light-duty vehicle decentralized steam methane reformer comes well within the sensitivity range, with the centralized steam methane reformer falling just outside the sensitivity range.

As an alternative means of determining the sensitivity of the results to the vehicle acquisition and operation cost profile assumptions, the model was also run assuming an increased average lifetime for fuel-cell vehicles, and assuming reduced annual maintenance costs for the fuel cell vehicles.

As mentioned above, proponents of fuel cell based vehicles argue that these vehicles could have longer expected lifetimes, and lower maintenance costs than their conventionally fuelled counterparts. They reason that this would be the result of, amongst other things, fewer mechanical components within the vehicle.

Tables 24 and 25, below, provide the results of the model being run assuming that fuel-cell vehicles expected life, for both light and heavy duty vehicles, is two years longer, and maintenance costs are only 90% of the base case assumptions. These assumptions provide almost identical results to the decreased acquisition cost for the vehicle, for the light duty vehicle. There is a slightly larger decrease for the heavy-duty vehicle, which is sufficient to bring one of the decentralized pathways, the methanol reformer, within the competitive range.

Table 24 Results for light-duty vehicle (decreased vehicle maintenance and increased life)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from gasoline**	Base case results	**% Change**
Centralized	Gasoline	$0.0143	$0.0500	$0.2877	**$0.3377**	**$0**	$0.3377	**0.00%**
	Electrolysis	$0.0470	$0.0887	$0.2878	**$0.3764**	**$54**	$0.3962	**-4.99%**
	Steam Methane Reformer	$0.0360	$0.0679	$0.2878	**$0.3557**	**$25**	$0.3755	**-5.26%**
Decentralized	Electrolysis	$0.0323	$0.0609	$0.2878	**$0.3487**	**$15**	$0.3685	**-5.36%**
	Steam Methane Reformer	$0.0369	$0.0697	$0.2878	**$0.3575**	**$28**	$0.3772	**-5.24%**
	Methanol Reforming	$0.0252	$0.0475	$0.2878	**$0.3353**	**-$3**	$0.3550	**-5.56%**
	Gasoline Reforming	$0.0509	$0.0961	$0.2878	**$0.3839**	**$64**	$0.4036	**-4.89%**

Table 25 Results for heavy-duty vehicle (decreased vehicle maintenance and increased life)

		Pre-tax retail price of fuel (per MJ)	Fuel costs per km	Other costs per km	**Total costs per km**	**$/month difference from diesel**	Base case results	**% Change**
Centralized	Diesel	$0.0149	$0.2756	$0.8014	**$1.0770**	**$0**	$1.0770	**0.00%**
	Electrolysis	$0.0470	$0.5787	$0.7919	**$1.3706**	**$1,713**	$1.4468	**-5.26%**
	Steam Methane Reformer	$0.0360	$0.4436	$0.7919	**$1.2355**	**$924**	$1.3116	**-5.80%**
Decentralized	Electrolysis	$0.0316	$0.3891	$0.7919	**$1.1810**	**$606**	$1.2571	**-6.05%**
	Steam Methane Reformer	$0.0293	$0.3608	$0.7919	**$1.1527**	**$441**	$1.2288	**-6.19%**
	Methanol Reforming	$0.0243	$0.2995	$0.7919	**$1.0914**	**$84**	$1.1675	**-6.52%**
	Gasoline Reforming	$0.0431	$0.5310	$0.7919	**$1.3229**	**$1,434**	$1.3990	**-5.44%**

The implications of the sensitivity of the results to the various cost components of the pathways, is further examined in Part 3 of the report, in order to determine methods that could efficiently and effectively bridge the cost gaps between the petroleum and hydrogen pathways.

Part 2: Accounting for the Externalities Associated With Using Hydrogen vs. Gasoline or Diesel for Transportation Services

In addition to the direct financial costs outlined in Part 1 of this study, each of the fuelling pathways would have indirect costs or benefits, referred to as externalities, or other social costs and benefits. These costs and benefits are borne by society as a whole when the products are produced and consumed, but are not captured in the product pricing. Examples of such costs include air or water pollution.

These costs and benefits are typically associated with the consumption or production of "public goods". Such goods are available for society to consume, but typically do not have an associated price, or are priced below their value to society. Public goods include the air, waterways, and a safe environment in which to live. Although public goods are available at no cost, or at a cost below their social value, their use or consumption in production is not without cost to society. For example, a production process that disposes unwanted by-products, such as carbon dioxide, or nitrous oxides, into the air may be reducing the value of that air to the rest of society.

Part 2 of this study expands on Part 1, refining the costing model used into a "full-cost accounting" model. This expanded model will capture some of the externalities associated with each of the pathways. Specifically, this study will focus on capturing the following associated externalities:

- Greenhouse gas emissions
- Other airborne emissions
- Safety issues
- Use of other public goods (e.g. water, land, feedstock)
- Socio-economic impacts (e.g. employment)

2-1) Methodology and Approach for Part 2

There is an obvious, and inherent, difficulty in attempting to assess the cost for non-market goods, or goods that have no explicit price. Several methods are used to determine a cost for these non-market goods: assessment of the damage costs, assessment of revealed preferences (or "hedonic method"), assessment of stated preferences (or "contingent valuation"), assessment of control or prevention costs, assessment of compensation rates, or, using permit trading prices. Each of these methods is described briefly below.

An assessment of the damage costs associated with an externality considers the economic losses attributable to the production or consumption of a good. Economic losses would include the following costs: health-care services, lost productivity due to injured workers, and lost public resources. For example, in evaluating the costs of air pollution, studies consider these costs: of providing health care services to those affected by air pollution; and lost GDP due to reduced productivity caused by people becoming sick due to air pollution. Since the linkage between the cause (e.g. air pollution) and the effect (e.g. illness) is not always clear and uncontroversial, this method is highly subjective.

The revealed preference method attempts to infer the cost associated with an externality based on market reaction to the presence of the externality. For example, the value of houses near a source of air or water pollution can be compared to comparable houses in an area free of air and water pollution. Of course, it is necessary to isolate other factors that may influence the market prices of the goods in question. For example, the houses near the air or water pollution might have better access to public transportation and sources of employment than the houses with no proximal pollution sources.

The stated preference methodology involves actually polling individuals as to the value they place on certain public goods, such as clean air. Of course, the results of such a method are highly dependant upon the design of the survey. For example asking the question "Do you think the government should spend $x to clean the air?", may produce a different response from "Do you think the government should raise your taxes y% to generate $x to clean the air?".

Assessing the control or prevention costs involves an evaluation of the cost to control or eliminate the impact on the public good. For example the cost to capture and sequester carbon dioxide emissions could be used to assess the cost to society of greenhouse gas emissions. This method does not examine the costs to society; therefore it only serves as a proxy for the actual cost to society. It does, however, provide a maximum limit to the costs to society: if the actual damage costs exceed the control or prevention costs, then the control or prevention costs represent the maximum cost to deal with the problem.

Assessment of compensation rates uses damage awards from court cases to assess the cost to society of a certain act. For example, if a community wins a lawsuit against a source of pollution, and is awarded damages, the dollar value of those damages can be used as a valuation for the cost to society of that particular pollutant.

Finally, where the government has established a marketplace for trading emissions permits, the market price could be used as an estimate for the societal costs for that emission. This is dependant on whether the government has constrained the total number of permits on the market at an appropriate level. An appropriate level would be one where the marginal benefit of any further reduction in the number of permits would be less than the marginal cost increase in the price of the permits.

Each of these methods has pros and cons. Therefore, when assessing each of the fuelling pathways consideration needs to be given to the method which is most applicable, and for which methods the most reliable data is available.

In this study, the approach used to account for the externalities associated with any given pathway is to internalize those costs. That is it will be assumed that the externalities result in a direct cost to the agent responsible for the activity generating a given externality.

In determining the costs associated with a given fuelling pathway, this study will focus on the externalities that are direct results of the activities in that pathway (e.g. the fuel production, distribution, storage, and consumption). Many studies also attempt to capture the externalities indirectly associated with the activity, or, more specifically, the externalities generated by the inputs to the activity in question. For example, many studies examining the externalities associated with the vehicular consumption of fuel will also include the externalities associated with the production of the tires and other components of the vehicle.

Since this study assumes that the costs associated with the generation of an externality are borne directly by the agent responsible for that generation, it would be inappropriate to assign the externality of the production of a tire, for example, to the operation of a vehicle. Rather, that externality would be borne by the manufacturer of the tire. The tire manufacturer would probably attempt to recover their increased costs through increased prices for their tires, thus indirectly affecting the costs associated with the operation of a vehicle. However, many factors, such as the competitiveness of the tire market and the openness of the economy, would affect their ability to do so. For example, if tire manufacturers from a different country, who can sell their products in Canada, were not required to internalize the costs of their associated externalities, tire manufacturers in Canada would be constrained in their ability to pass along the increased prices to consumers.

A full General Equilibrium model of the economy is required to properly capture the degree to which the externalities borne by the producers of the inputs into an activity would be reflected in higher input costs for that activity. That is beyond the scope of this study.

Alternatively, overall cost impacts could be captured through cost multipliers. However, the determination of appropriate cost multipliers would require the use of either a General Equilibrium model, or independent studies of each of the markets for the inputs into the activities captured in this study. Either method is beyond the scope of this study. In effect, by ignoring the indirect cost impacts associated with the externalities generated by the inputs into these activities, the assumption is that the overall multiplier for each pathway is the same. Therefore there is no impact on the relative prices for each pathway.

Finally, only those externalities that may have different cost implications for different pathways will be captured in this study.

2-2) Building Full-Cost Accounting into the Model

This section covers the implications of each of the six categories of externalities listed above for each of the pathways.

As with Part 1 of the study, these costs are broken down into two components: (1) those costs generated during the source-to-currency, or well-to-tank, portion of the pathway, which will be borne by the producer, and will be reflected in the price of the fuel, and (2) those costs generated during the currency-to-service, or tank-to-wheel, portion of the pathway, which will be borne by the operator of the vehicle.

For the well-to-tank sections, the externalities associated with the fuel production, storage and distribution will be evaluated and compared. These additional costs are treated as a tax-deductible expense for the business, as is common with many fines and charges. As such, the impact on the retail price will be somewhat mitigated by the offsetting income tax deduction.

For the tank-to-wheel sections, the focus is on the externalities associated with the operation of the vehicle.

2-2.1) The Costs Associated with Greenhouse Gas Emissions

For costing the impact of greenhouse gases this study will convert all the greenhouse gases being examined, Carbon Dioxide (CO_2), Methane (CH_4), and Nitrous Oxide (N_20) into CO_2 equivalents, using the equivalence factors listed in Table 24 below.

Table 26 Carbon dioxide equivalence

	CO_2 Equivalence
Carbon Dioxide	1
Methane	21
Nitrous Oxide	310

Using these equivalence factors a common price can be associated.

For the purposes of this study, the base price for greenhouse gases is set at the Canadian government target value, \$15 per tonne, as identified in the government's Kyoto Protocol commitments. Literature estimates for the costs associated with greenhouse gases can range anywhere from \$6 to \$300 per tonne[37]. Given this broad range, alternative experiments are also conducted using a price per tonne of \$50, to evaluate how the results are affected by changes in price level.

Levels of greenhouse gas emissions for each of the pathways were determined using Natural Resources Canada's GHGenius model. This model estimates lifecycle emissions for a number of fuelling pathways, including all the pathways covered in this study. The text box on the following page provides a further description of this model.

[37] See OECD Nuclear Energy Agency, 2001, for example.

Table 27 below depicts both the level of greenhouse gases, in CO_2 equivalents, for each of the production methods, and the proportion of total costs these emissions would represent if the producing company were required to pay a $15 per tonne charge.

Natural Resource Canada's GHGenius model

GHGenius is a model developed for Natural Resources Canada to estimate greenhouse gas emissions from various fuelling pathways. The model covers over 100 transportation fuelling pathways, with various light-duty and heavy-duty vehicle profiles, and is capable of estimating emissions for any given year between 2000 and 2050.

Although GHGenius was primarily designed to calculate the emissions of greenhouse gases, it is also capable of estimating the emissions of other contaminants.

For gasoline or diesel engines these other emissions are determined using simple algorithms that have been designed to mimic the emissions that would be predicted by the Environmental Protection Agency's ("EPA") Mobile6 model. The emissions of alternative fuels are generally calculated based on a relative emission factor to gasoline or diesel that has been inputted into the model.

The emissions that are desired for GHGenius are the average emissions of a vehicle produced in the target year over the life of the vehicle. This is different than the emission results from the Mobile models, which provide an average fleet emission for a specific year.

In GHGenius Hydrogen fuel cell vehicles are assumed to have zero emissions for all of the criteria pollutants except for evaporative emissions. These are calculated based on the emissions lost during refuelling and the purity of the hydrogen. It is possible that there will be traces of methane and carbon dioxide in the hydrogen lost to the atmosphere.

Table 27 Well-to-tank greenhouse gas emissions

Pathway			Level of CO_2 equivalent emissions (grams /MJ output)	% of Total Costs (at $15 per tonne)	Level of CO_2 equivalent emissions (grams / kilometres fuelled)	Costs of Emissions ($/km at $15 per tonne)
Centralized		Gasoline	25.34	2.10%	88.27	$0.0013
		Diesel	27.32	2.53%	504.75	$0.0076
		Electrolysis Using Nuclear	6.12	0.24%	30.41	$0.0005
		Electrolysis Using Coal	453.13	14.93%	2,250.94	$0.0338
		Electrolysis Using Wind	10.93	0.42%	54.28	$0.0008
		Electrolysis Using Hydro	10.93	0.42%	54.28	$0.0008
		Steam Methane Reformer	98.57	5.10%	489.66	$0.0073
Decentralized	Light-Duty Vehicles	Electrolysis using Grid	91.17	4.37%	82.90	$0.0012
		Steam Methane Reformer	98.14	4.73%	89.25	$0.0013
		Methanol Reforming	104.96	6.28%	95.44	$0.0014
		Gasoline Reforming	183.42	5.94%	166.79	$0.0025
	Heavy-Duty Vehicles	Electrolysis using Grid	91.17	4.45%	561.46	$0.0084
		Steam Methane Reformer	98.14	5.71%	604.43	$0.0091
		Methanol Reforming	104.96	6.45%	646.39	$0.0097
		Gasoline Reforming	183.42	6.72%	1,129.61	$0.0169

Table 28, below, shows the level greenhouse gases output that occurs in the production and operation of the various vehicles modelled in this study.

Table 28 also shows the impact of these emissions on the costs to the vehicle operator on a per kilometre basis. It is assumed the vehicle manufacturer is charged for emissions resulting from the production of the vehicle, and that they pass such charge to the consumer in the price of the vehicle. The additional cost is then divided over the total expected lifetime kilometres of the vehicle to determine the per kilometre cost. For the vehicle operation costs, the price of the fuel is assumed to include a surcharge based on average vehicle fuel efficiency, and the resultant emissions, to reflect the costs associated with the fuel emissions.

Table 28 Tank-to-wheel greenhouse gas emissions

	Gasoline Fuelled ICE light-duty vehicle	Hydrogen Fuelled fuel-cell light-duty vehicle	Diesel Fuelled CIE heavy-duty vehicle	Hydrogen Fuelled fuel-cell Heavy-duty vehicle
Total emissions created producing the vehicle (tonnes)	17.72	19.12	95.00	137.34
Emissions created producing the vehicle (grams/km)	75.80	81.80	75.40	109.00
Emissions from vehicle operation (grams/km)	219.16	0.00	1,562.24	0.19
Total emissions (grams/km)	294.96	81.80	1,637.64	109.19
Costs of Emissions[38] ($/km at $15 per tonne)	$0.0044	$0.0012	$0.0246	$0.0016

The impact that these costs have on the relative total costs for each of the pathways is contained in section 2-3, below.

2-2.2) The Costs Associated with Other Airborne Emissions

In addition to the emission of greenhouse gases, each pathway also generates other airborne emissions. These emissions are associated with the creation of smog and other local air quality issues, and include nitrous oxides ("NOx"), sulphur oxides ("SOx"), particulate matter (PM), volatile organic compounds ("VOCs"), and carbon monoxide (CO). This study focuses on the costs associated with NOx, SOx and PM and uses figures from the David Suzuki Foundation report, *Clearing the Air: Air Quality Co-benefits of Reducing Greenhouse Gas Emissions in Canada*, as suggested by Natural Resources Canada. The report estimated costs of $1,300 per tonne of NOx and sulphur dioxide (SO_2, which constitutes the bulk of SOx emissions), and $20,000 per tonne of PM.

These cost estimates are based on an estimation of the health costs associated with each category of emissions and are in line with other estimates. For example, Environment Canada's *Discussion Paper on Meeting the Commitments of the Notice of Intent on Cleaner Vehicles, Engines and Fuels*, cites costs of $750-$1,960 per tonne to reduce sulphur dioxide emissions by 164,000 tonnes per year from 1999 levels. The discussion paper also includes a survey of reduction measures used in other countries, including some explicit sulphur emissions charges. These charges would presumably represent that countries estimate of the social cost attached to those emissions. For example, Denmark applies a charge of $1,950 per tonne for sulphur dioxide emissions, which is reasonably consistent with the $1,300 per tonne figure to be used in this study.

As with the greenhouse gases, emissions levels for each of the pathways were determined using Natural Resources Canada's GHGenius model. Table 29, 30, and 31,

[38] These costs do not include the marginal additional financing costs that would result from the increased vehicle purchase cost. This impact is included in the results presented below in section 2-3.

below, show the levels of emissions for each of the production methods. These tables also reflect the proportion of total costs these emissions would represent if the producing company were required to pay an explicit charge for their emissions at prices set equal to their cost values, as determined by the David Suzuki Foundation report.

These additional costs are treated as a tax-deductible expense for the business, as discussed in the introduction to section 2-2, and so the impact on the retail price will be somewhat offset by the income tax deduction.

Table 29 Well-to-tank NOx Emissions

Pathway			Level of NOx emissions (grams /MJ output)	% of Total Costs (at $1,300 per tonne)	Level of NOx equivalent emissions (grams / kilometres fuelled)	Costs of Emissions ($/km at $1,300 per tonne)
Centralized		Gasoline	0.14	1.00%	0.47	$0.0006
Centralized		Diesel	0.16	1.31%	3.00	$0.0039
Centralized		Electrolysis Using Nuclear	0.05	0.16%	0.24	$0.0003
Centralized		Electrolysis Using Coal	0.67	1.99%	3.33	$0.0043
Centralized		Electrolysis Using Wind	0.00	0.00%	0.01	$0.0000
Centralized		Electrolysis Using Hydro	0.00	0.00%	0.01	$0.0000
Centralized		Steam Methane Reformer	0.12	0.54%	0.58	$0.0007
Decentralized	Light-Duty Vehicles	Electrolysis using Grid	0.14	0.57%	0.12	$0.0002
Decentralized	Light-Duty Vehicles	Steam Methane Reformer	0.11	0.50%	0.10	$0.0001
Decentralized	Light-Duty Vehicles	Methanol Reforming	0.18	1.00%	0.17	$0.0002
Decentralized	Light-Duty Vehicles	Gasoline Reforming	0.32	0.94%	0.29	$0.0004
Decentralized	Heavy-Duty Vehicles	Electrolysis using Grid	0.14	0.58%	0.84	$0.0011
Decentralized	Heavy-Duty Vehicles	Steam Methane Reformer	0.11	0.61%	0.71	$0.0009
Decentralized	Heavy-Duty Vehicles	Methanol Reforming	0.18	1.03%	1.14	$0.0015
Decentralized	Heavy-Duty Vehicles	Gasoline Reforming	0.32	1.07%	1.99	$0.0026

Table 30 Well-to-tank SOx Emissions

Pathway			Level of SOx emissions (grams /MJ output)	% of Total Costs (at $1,300 per tonne)	Level of SOx equivalent emissions (grams / kilometres fuelled)	Costs of Emissions ($/km at $1,300 per tonne)
Centralized		Gasoline	0.03	0.22%	0.10	$0.0001
		Diesel	0.03	0.27%	0.61	$0.0008
		Electrolysis Using Nuclear	0.00	0.01%	0.01	$0.0000
		Electrolysis Using Coal	1.59	4.72%	7.91	$0.0103
		Electrolysis Using Wind	0.00	0.00%	0.00	$0.0000
		Electrolysis Using Hydro	0.00	0.00%	0.00	$0.0000
		Steam Methane Reformer	0.03	0.12%	0.13	$0.0002
Decentralized	Light-Duty Vehicles	Electrolysis using Grid	0.27	1.15%	0.25	$0.0003
		Steam Methane Reformer	0.03	0.11%	0.02	$0.0000
		Methanol Reforming	0.03	0.16%	0.03	$0.0000
		Gasoline Reforming	0.09	0.25%	0.08	$0.0001
	Heavy-Duty Vehicles	Electrolysis using Grid	0.27	1.17%	1.68	$0.0022
		Steam Methane Reformer	0.03	0.13%	0.16	$0.0002
		Methanol Reforming	0.03	0.17%	0.19	$0.0002
		Gasoline Reforming	0.09	0.28%	0.53	$0.0007

Table 31 Well-to-tank PM Emissions

Pathway			Level of PM emissions (grams /MJ output)	% of Total Costs (at $20,000 per tonne)	Level of PM equivalent emissions (grams / kilometres fuelled)	Costs of Emissions ($/km at $20,000 per tonne)
Centralized		Gasoline	0.01	0.73%	0.02	$0.0004
		Diesel	0.01	0.87%	0.13	$0.0026
		Electrolysis Using Nuclear	0.00	0.07%	0.01	$0.0001
		Electrolysis Using Coal	0.11	5.00%	0.54	$0.0109
		Electrolysis Using Wind	0.00	0.00%	0.00	$0.0000
		Electrolysis Using Hydro	0.00	0.00%	0.00	$0.0000
		Steam Methane Reformer	0.01	0.71%	0.05	$0.0010
Decentralized	Light-Duty Vehicles	Electrolysis using Grid	0.02	1.28%	0.02	$0.0004
		Steam Methane Reformer	0.01	0.66%	0.01	$0.0002
		Methanol Reforming	0.01	0.88%	0.01	$0.0002
		Gasoline Reforming	0.02	0.87%	0.02	$0.0004
	Heavy-Duty Vehicles	Electrolysis using Grid	0.02	1.30%	0.12	$0.0024
		Steam Methane Reformer	0.01	0.80%	0.06	$0.0012
		Methanol Reforming	0.01	0.90%	0.06	$0.0013
		Gasoline Reforming	0.02	0.99%	0.12	$0.0024

Table 32 shows the level of output of each of the emissions in the production and operation of the various vehicles modelled in this study. Table 32 also shows the impact of these emissions on the costs to the vehicle operator if the following occurred: the vehicle manufacturer were charged for the emissions produced in manufacturing the vehicle, which they then passed along fully to the purchaser; and, if the fuel price included a surcharge reflecting the costs associated with the fuel emissions.

Table 32 Tank-to-wheel other airborne emissions

	Gasoline Fuelled ICE light-duty vehicle	Hydrogen Fuelled fuel-cell light-duty vehicle	Diesel Fuelled CIE heavy-duty vehicle	Hydrogen Fuelled fuel-cell Heavy-duty vehicle
NOx Emissions created producing the vehicle (tonnes)	0.04	0.04	0.24	0.36
Total NOx emissions created producing the vehicle (grams/km)	0.16	0.17	0.19	0.28
NOx Emissions emitted during vehicle operation (grams/km)	0.19	0.00	16.87	0.00
Total NOx emissions (grams/km)	0.35	0.17	17.06	0.28
Costs of NOx Emissions ($/km at $1,200 per tonne)	$0.0005	$0.0002	$0.0222	$0.0004
SOx Emissions created producing the vehicle (tonnes)	0.04	0.05	0.22	0.40
Total SOx emissions created producing the vehicle (grams/km)	0.19	0.23	0.17	0.32
SOx Emissions emitted during vehicle operation (grams/km)	0.02	0.00	0.16	0.00
Total SOx emissions (grams/km)	0.21	0.23	0.33	0.32
Costs of SOx Emissions ($/km at $1,200 per tonne)	$0.0003	$0.0003	$0.0004	$0.0004
Total PM Emissions created producing the vehicle (tonnes)	0.03	0.03	0.31	0.38
PM emissions created producing the vehicle (grams/km)	0.14	0.14	0.24	0.30
PM Emissions emitted during vehicle operation (grams/km)	0.03	0.00	0.49	0.00
Total PM emissions (grams/km)	0.18	0.14	0.74	0.30
Costs of PM Emissions ($/km at $1,200 per tonne)	$0.0002	$0.0002	$0.0010	$0.0004
Total Costs of other Airborne Emissions	$0.0010	$0.0007	$0.0236	$0.0012

The impact of these costs on the relative total costs for each pathway is contained in section 2-3, below.

2-2.3) The Costs Associated with Safety Issues

2-2.3.1) Well-to-tank Safety Issues

Various production processes may vary in their potential safety to the public. For example, there is probably more public concern over the safety risks involved with nuclear reactors than the other fuel sources in this study, because the consequences of a failure may be more significant than the failure of an oil refinery.

However, the differences in safety risk have, in all likelihood, already been internalized, through two mechanisms. Government regulation of manufacturing industries represents the first mechanism. It should be a fair reflection of the costs to society of the safety risks. The compliance cost of the operation of a nuclear reactor are probably greater than those associated with operating an oil refinery. The insurance market will also have assessed costs associated with the varying degrees of risk inherent in the various industries. Any insurance coverage would reflect the different degrees of risk in their insurance premiums, thereby providing a second mechanism of cost internalization.

As a result, no additional costs are added in the well-to-tank component of the model in association with safety issues.

2.2.3.2) Tank-to-Wheel Safety Issues

As hydrogen fuel-cell vehicles have not yet been introduced to the market place, there is little data comparing the relative safety of these vehicles to current gasoline and diesel-fuelled vehicles. As a result, the argument that government regulations and insurance premiums already capture the potential safety costs cannot be made here.

However most of the literature agrees that the perception that hydrogen is a highly dangerous fuel is not well founded. This perception is largely a result of the notoriety of the Hindenburg incident. The Hindenburg incident was not a result of the hydrogen held within the zeppelin's canopy, but was caused by highly flammable coatings used to seal the canopy. Therefore, this incident does not provide a factual basis for concluding that hydrogen is a highly dangerous fuel.

Some of the properties of hydrogen do create risks that do not exist with gasoline and diesel: it burns with a largely invisible flame, and is more combustible. However, some of its other properties offset those risks: it is lighter than air, and therefore does not pool, and dissipates quickly. These trade-offs lead most of the literature to suggest that hydrogen as a fuel poses no greater a threat to safety than gasoline or diesel.

However, since there may be public concern over the safety of hydrogen as a transportation fuel, insurance companies may charge a premium for such vehicles. As such, the impact of a $500 per year increase in insurance premiums for the operation of a hydrogen-based vehicle is assessed. This isn't strictly an externality, it is simply a potential additional direct cost that has not already been captured in the base case.

The results of this experiment are contained in section 2-3.3 below.

In addition, there may be additional regulatory requirements governing the operation of heavy-duty hydrogen vehicles, which may differ from the regulatory requirements for the operation of a diesel heavy-duty vehicle. For example, as vented hydrogen would tend to float upwards, rather than pool on the floor like diesel, there may be additional ventilation requirements for bus garages. Adapting to a new regulatory environment can be expensive. As such, an additional cost of $1,000,000 per bus garage is added into the model, to capture the possible additional capital requirements and other possible costs associated with complying with a new and different regulatory environment. The results of this experiment are also contained in section 2-3.3.

It should be noted that these figures are used simply to provide an estimate for the possible impact that these factors could have on costs, and are not based on any actual estimates of possible increased insurance premiums or operating costs.

2-2.4) The Costs Associated with the Use of Other Public Goods

Sections 2-2.1 and 2-2.2 focussed on particular costs associated with the use of the air, a public good, as a depository for various emissions. Similar issues can exist for other public goods, like the water and land.

In the pathways being examined, we are assuming that additional land use is marginal, as the investments are all marginal investments of existing operations. Given this, there would not be any significant un-captured costs associated with the use of land.

If, however, we were to assume that the additional electricity generation capacity were necessary to supply the pathways, or additional oil or methane production were required, land use could be an issue. Free markets exist for land, e.g. the real estate market; therefore the price paid for land should generally reflect the value society places on it. However, this might not hold true in all cases. For example, if government lands were granted to an operator of a wind-farm, or hydro-generating station, the price might not reflect the true value of the land. Or the addition of a new hydro-generating station on a waterway could cause flooding of un-associated lands along that waterway.

Water costs are also captured in this model by incorporating the cost of the water used in the production processes. The price used is an average of prices charged by municipalities. Since the pricing of water in Canada has been the subject of much debate the price used in the model may not accurately reflect the true value of the resource. However, a tenfold increase in the price charged for water had insignificant impacts on the final costs to the vehicle operator.

2-2.5) Other Externalities

A transition from petroleum-based fuels to hydrogen would have numerous other impacts on society. Some impacts would be socio-economic in nature, such as a shift in income distribution, or shifts in regional employment levels. Others would be more political-economic in impact, such as increased energy independence.

Many of the socio-economic impacts would be regionally based, and may net out at a national level. For example, it would be anticipated that decreased demand for petroleum based products could lead to a decline in income and employment in regions endowed with petroleum, such as Alberta. However, increased demand for hydrogen, and increased demand for hydrogen production machinery, could lead to increased income and employment in other regions of the country. As such, there might be no net impact on employment and income on a national level.

However, even if the positive and negative impacts did net out on a national level, there still could be costs associated with the transition to a new technology, as old job skills become obsolete, and new ones must be learned. However, it is unlikely that the shift from petroleum-based fuels to hydrogen-based fuels will occur at a significant rate. A slower transition reduces the impact of such costs.

The political-economic impacts of such a transition could include benefits gained from increased energy independence. However, such political gains would be difficult to quantify. This factor is often cited in considering the impacts for the United States of America, but would probably not be as significant for Canada, due to greater domestic energy production in Canada. However, even though Canada is a net exporter of energy, Canada is not insulated from the impact of energy price shocks. The price of oil in Canada is highly responsive to international oil price pressures.

There could actually be some adverse factors for Canada from the use of hydrogen, if the United States were to become more energy independent. Canada benefits from the export of oil to the United States, and so reduction in that demand would affect Canada. Canada also exports other forms of energy to the United States, such as electricity and natural gas, which are used in the production of hydrogen, so the drop in demand for oil could be offset by an increase in demand for these other forms of energy. However, while this might balance out the energy export equation with the United States, this could still lead to regional redistributions of income, away from oil producing regions, and towards electricity and natural gas producing regions.

Some writers have also cited possible increased security benefits, since political involvement in the Middle East could be reduced. Reliable estimates as to the value of these benefits are not available, and it is beyond the scope of this study to attempt to quantify them.

2-3) Comparing Results for Part 2

2-3.1) Impact of Internalizing Greenhouse Gas Emissions Costs

As discussed in section 2-2.1 above, a charge of $15 per tonne for greenhouse gas emissions affects the costs of the fuelling pathways in three areas: the production of the fuel, the production of the vehicle, and in the use of the fuel in the vehicle.

Table 33 contains the results of those impacts on the total costs per kilometre for the light-duty vehicle, for each of the light-duty vehicle pathways. Table 34 contains the results of those impacts for the heavy-duty vehicles. Each of the centralized electrolysis pathways are displayed individually because the differing levels of greenhouse gas emissions produced in generating the electricity leads to different cost structures for each of the pathways.

Table 33 Results for light-duty vehicles (incorporating GHG emissions costs at $15/tonne)

		Pre-tax price of fuel per MJ[39]	Fuel costs per km	Other costs per km[40]	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0202	$0.0703	$0.2891	**$0.3594**	**$0**	$0.3377	**6.42%**
	Electrolysis Using Nuclear	$0.0471	$0.0888	$0.3091	**$0.3979**	**$54**	$0.3962	**0.43%**
	Electrolysis Using Coal	$0.0540	$0.1018	$0.3091	**$0.4109**	**$72**	$0.3962	**3.71%**
	Electrolysis Using Wind	$0.0470	$0.0887	$0.3091	**$0.3978**	**$53**	$0.3962	**0.40%**
	Electrolysis Using Hydro	$0.0472	$0.0890	$0.3091	**$0.3980**	**$54**	$0.3962	**0.47%**
	Steam Methane Reformer	$0.0375	$0.0708	$0.3091	**$0.3799**	**$29**	$0.3755	**1.17%**
Decentralized	Electrolysis using Grid	$0.0337	$0.0636	$0.3091	**$0.3726**	**$18**	$0.3685	**1.13%**
	Steam Methane Reformer	$0.0384	$0.0725	$0.3091	**$0.3816**	**$31**	$0.3772	**1.16%**
	Methanol Reforming	$0.0268	$0.0505	$0.3091	**$0.3596**	**$0**	$0.3550	**1.29%**
	Gasoline Reforming	$0.0537	$0.1014	$0.3091	**$0.4105**	**$71**	$0.4036	**1.70%**

[39] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[40] Includes impacts of emissions charges for vehicle production.

Table 34 Results for heavy-duty vehicles (incorporating GHG emissions costs at $15/tonne)

		Pre-tax price of fuel per MJ[41]	Fuel costs per km	Other costs per km[42]	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0183	$0.3389	$0.8039	**$1.1428**	**$0**	$1.0770	**6.10%**
	Electrolysis Using Nuclear	$0.0471	$0.5799	$0.8728	**$1.4527**	**$1,808**	$1.4468	**0.41%**
	Electrolysis Using Coal	$0.0540	$0.6646	$0.8728	**$1.5374**	**$2,302**	$1.4468	**6.27%**
	Electrolysis Using Wind	$0.0470	$0.5791	$0.8728	**$1.4519**	**$1,803**	$1.4468	**0.36%**
	Electrolysis Using Hydro	$0.0472	$0.5808	$0.8728	**$1.4536**	**$1,813**	$1.4468	**0.47%**
	Steam Methane Reformer	$0.0375	$0.4623	$0.8728	**$1.3351**	**$1,122**	$1.3116	**1.79%**
Decentralized	Electrolysis using Grid	$0.0330	$0.4063	$0.8728	**$1.2791**	**$795**	$1.2571	**1.75%**
	Steam Methane Reformer	$0.0308	$0.3794	$0.8728	**$1.2522**	**$638**	$1.2288	**1.90%**
	Methanol Reforming	$0.0259	$0.3194	$0.8728	**$1.1922**	**$288**	$1.1675	**2.11%**
	Gasoline Reforming	$0.0459	$0.5658	$0.8728	**$1.4386**	**$1,726**	$1.3990	**2.83%**

The results in Tables 33 and 34 are not unexpected: the gasoline and diesel pathways face the most significant impact of incorporating a charge for greenhouse gases. Total costs for both increases by more than 6%, as does the electrolysis pathway that uses coal-fired electrical generation as its source. Total costs increase by over 3% when used in the light-duty vehicles, and over 6% when used in the heavy-duty vehicles.

However, even with this additional charge, the gasoline and diesel pathways remain the lowest cost pathways, although, for the light-duty vehicles, the decentralized electrolysis and methanol reformer do come within the sensitivity range of less than $20 per month cost differential.

As mentioned in sub-section 2-1.1 above, an additional experiment was conducted, using a $50 per tonne charge for greenhouse gas emissions. The results from this experiment are displayed in Tables 35 and 36.

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[41] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.

[42] Includes impacts of emissions charges for vehicle production.

Table 35 Results for light-duty vehicles (incorporating GHG emissions costs at $50/tonne)

		Pre-tax price of fuel per MJ[43]	Fuel costs per km	Other costs per km[44]	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0337	$0.1176	$0.2924	**$0.4100**	**$0**	$0.3377	**21.41%**
	Electrolysis Using Nuclear	$0.0473	$0.0892	$0.3126	**$0.4019**	**-$11**	$0.3962	**1.44%**
	Electrolysis Using Coal	$0.0702	$0.1325	$0.3126	**$0.4451**	**$49**	$0.3962	**12.35%**
	Electrolysis Using Wind	$0.0471	$0.0889	$0.3126	**$0.4015**	**-$12**	$0.3962	**1.34%**
	Electrolysis Using Hydro	$0.0475	$0.0897	$0.3126	**$0.4024**	**-$11**	$0.3962	**1.55%**
	Steam Methane Reformer	$0.0411	$0.0775	$0.3126	**$0.3901**	**-$28**	$0.3755	**3.90%**
Decentralized	Electrolysis using Grid	$0.0370	$0.0697	$0.3126	**$0.3824**	**-$38**	$0.3685	**3.78%**
	Steam Methane Reformer	$0.0420	$0.0792	$0.3126	**$0.3918**	**-$25**	$0.3772	**3.87%**
	Methanol Reforming	$0.0306	$0.0577	$0.3126	**$0.3703**	**-$55**	$0.3550	**4.30%**
	Gasoline Reforming	$0.0603	$0.1138	$0.3126	**$0.4265**	**$23**	$0.4036	**5.66%**

The impact of the increased greenhouse gas charge is fairly linear, with a 333% increase in the charge resulting in cost increases of roughly the same amount. This results in a cost increase of over 20% for the gasoline for light-duty vehicles pathway; therefore this pathway becomes one of the least economical pathways. Only the pathways that use coal-fired electricity and off-board gasoline reforming are less economical.

[43] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.

[44] Includes impacts of emissions charges for vehicle production.

Table 36 Results for heavy-duty vehicles (incorporating GHG emissions costs at $50/tonne)

		Pre-tax price of fuel per MJ[45]	Fuel costs per km	Other costs per km[46]	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0263	$0.4864	$0.8098	**$1.2962**	**$0**	$1.0770	**20.35%**
	Electrolysis Using Nuclear	$0.0473	$0.5826	$0.8840	**$1.4666**	**$994**	$1.4468	**1.37%**
	Electrolysis Using Coal	$0.0702	$0.8649	$0.8840	**$1.7489**	**$2,641**	$1.4468	**20.88%**
	Electrolysis Using Wind	$0.0471	$0.5801	$0.8840	**$1.4640**	**$979**	$1.4468	**1.19%**
	Electrolysis Using Hydro	$0.0475	$0.5857	$0.8840	**$1.4696**	**$1,012**	$1.4468	**1.58%**
	Steam Methane Reformer	$0.0411	$0.5059	$0.8840	**$1.3898**	**$546**	$1.3116	**5.96%**
Decentralized	Electrolysis using Grid	$0.0363	$0.4467	$0.8840	**$1.3306**	**$201**	$1.2571	**5.85%**
	Steam Methane Reformer	$0.0343	$0.4228	$0.8840	**$1.3067**	**$61**	$1.2288	**6.34%**
	Methanol Reforming	$0.0297	$0.3658	$0.8840	**$1.2498**	**-$271**	$1.1675	**7.04%**
	Gasoline Reforming	$0.0525	$0.6469	$0.8840	**$1.5308**	**$1,369**	$1.3990	**9.42%**

For the heavy-duty vehicle pathways an advantage remains with the conventional diesel fuelled vehicle. Only the decentralized methanol reformer is more economical.

In comparing the centralized electrolysis results with the decentralized electrolysis results in tables 33, 34, 35, and 36, it appears that the decentralized electrolysis pathway could be even more competitive with gasoline and diesel, where the process fuelled solely by a cleaner electricity source than the mix of the grid, such as wind or hydraulic power. However, the grid was specifically chosen for the decentralized electrolysis pathway because the actual environmental impact of purchasing electricity off the grid, labelled as having been produced from a single specific source, is somewhat controversial.

It is physically impossible to direct the energy purchased at a given source through the grid to a particular designated user. However, some provinces have programs where a consumer may indicate that they wish to purchase their electricity from a specific source, such as from a wind generator. However allocating the production of “clean” electricity to a specific user does not necessarily change the total mix of electricity production.

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[45] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[46] Includes impacts of emissions charges for vehicle production.

Therefore the electricity purchased by the rest of the consumers would have to be considered much "dirtier". In the end, the cost to society of the marginal demand would have to take into account the direct impact of the electricity allocated to fulfill that demand and the indirect effect of removing that source on the emissions from the rest of the electricity produced. In the end, the results of this direct and indirect effect would be basically the same as the result if the marginal demand were satisfied using the overall general mix of electricity.

2-3.2) Impact of Other Airborne Emissions

As with the greenhouse gas emissions charges, incorporating costs for the NOx, SOx, and PM emissions affects the fuel production costs, vehicle production costs, and vehicle operation costs. The results of incorporating those costs on the total costs per kilometre for the light-duty vehicle are presented in Table 37, and for the heavy-duty vehicle in Table 38.

Table 37 Results for light-duty vehicles (incorporating other airborne emissions costs)

		Pre-tax price of fuel per MJ[47]	Fuel costs per km	Other costs per km[48]	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0190	$0.0663	$0.2918	**$0.3581**	**$0**	$0.3377	**6.04%**
	Electrolysis Using Nuclear	$0.0471	$0.0888	$0.3118	**$0.4006**	**$59**	$0.3962	**1.11%**
	Electrolysis Using Coal	$0.0523	$0.0986	$0.3118	**$0.4104**	**$73**	$0.3962	**3.57%**
	Electrolysis Using Wind	$0.0470	$0.0887	$0.3118	**$0.4004**	**$59**	$0.3962	**1.07%**
	Electrolysis Using Hydro	$0.0470	$0.0887	$0.3118	**$0.4004**	**$59**	$0.3962	**1.07%**
	Steam Methane Reformer	$0.0364	$0.0687	$0.3118	**$0.3805**	**$31**	$0.3755	**1.32%**
Decentralized	Electrolysis using Grid	$0.0332	$0.0627	$0.3118	**$0.3745**	**$23**	$0.3685	**1.63%**
	Steam Methane Reformer	$0.0373	$0.0704	$0.3118	**$0.3822**	**$34**	$0.3772	**1.32%**
	Methanol Reforming	$0.0257	$0.0485	$0.3118	**$0.3602**	**$3**	$0.3550	**1.46%**
	Gasoline Reforming	$0.0519	$0.0978	$0.3118	**$0.4096**	**$72**	$0.4036	**1.49%**

[47] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[48] Includes impacts of emissions charges for vehicle production.

Table 38 Results for heavy-duty vehicles (incorporating other airborne emissions costs)

		Pre-tax price of fuel per MJ[49]	Fuel costs per km	Other costs per km[50]	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0187	$0.3459	$0.8134	**$1.1593**	**$0**	$1.0770	**7.64%**
	Electrolysis Using Nuclear	$0.0471	$0.5799	$0.8895	**$1.4695**	**$1,810**	$1.4468	**1.57%**
	Electrolysis Using Coal	$0.0523	$0.6436	$0.8895	**$1.5331**	**$2,181**	$1.4468	**5.97%**
	Electrolysis Using Wind	$0.0470	$0.5788	$0.8895	**$1.4683**	**$1,803**	$1.4468	**1.49%**
	Electrolysis Using Hydro	$0.0470	$0.5788	$0.8895	**$1.4683**	**$1,803**	$1.4468	**1.49%**
	Steam Methane Reformer	$0.0364	$0.4484	$0.8895	**$1.3379**	**$1,042**	$1.3116	**2.01%**
Decentralized	Electrolysis using Grid	$0.0325	$0.4008	$0.8895	**$1.2903**	**$764**	$1.2571	**2.64%**
	Steam Methane Reformer	$0.0297	$0.3656	$0.8895	**$1.2551**	**$559**	$1.2288	**2.14%**
	Methanol Reforming	$0.0248	$0.3057	$0.8895	**$1.1952**	**$209**	$1.1675	**2.37%**
	Gasoline Reforming	$0.0441	$0.5426	$0.8895	**$1.4322**	**$1,592**	$1.3990	**2.37%**

The results displayed in Tables 37 and 38 are similar to the results for the greenhouse gas emissions at $15 per tonne, as shown in tables 33 and 34 above.

The largest increases are for the gasoline and diesel pathways, as well as the coal-fired electricity based electrolysis process used to fuel the heavy-duty vehicle. And gasoline and diesel remain the most economical pathways.

2-3.3) Impact of Safety Costs

Unlike the greenhouse gas and other airborne emissions, the impact of the safety related costs are more focussed. For the light-duty vehicles the costs affect primarily the operation of the vehicle. The impacts for the heavy-duty vehicles are largely in the fuel distribution costs, which are reflected in the "pre-tax retail price of fuel".

Table 37 contains the impacts for the light-duty vehicles of the $500 increased insurance premium for hydrogen-fuelled vehicles, and Table 38 contains the results of the $1,000,000 additional regulatory cost per garage ($2,000,000 in total) for the heavy-duty vehicle. As the impact of these costs do not vary by hydrogen production method, the

[49] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[50] Includes impacts of emissions charges for vehicle production.

tables in this subsection have again collapsed the centralized electrolysis pathways, as the results are identical for each of them.

The model was run with both of these additional charges incorporated at the same time, as the additional costs to house and fuel the heavy-duty vehicles does impact the light-duty vehicle centralized pathways. The cost structure for the centralized pathways contains the costs to produce and distribute the fuel for both the light and heavy duty vehicles. It is assumed that there is one company producing and distributing the fuel for both the light and heavy-duty vehicles. If their costs go up as a result of having to comply with additional regulations associated with their operations fuelling the heavy-duty vehicles, this may impact the price they charge to light-duty vehicles. Similarly, this would also reduce the potential impact that those regulatory costs would have on the heavy-duty centralized pathway results if applied in isolation, as is the case with the decentralized pathways fuelling the heavy-duty vehicles.

Table 39 Results for light-duty vehicle (incorporating safety costs)

		Pre-tax price of fuel per MJ[51]	Fuel costs per km	Other costs per km[52]	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0143	$0.0500	$0.2877	**$0.3377**	**$0**	$0.3377	**0.00%**
	Electrolysis	$0.0483	$0.0911	$0.3375	**$0.4286**	**$127**	$0.3962	**8.18%**
	Steam Methane Reformer	$0.0373	$0.0704	$0.3375	**$0.4079**	**$98**	$0.3755	**8.63%**
Decentralized	Electrolysis using Grid	$0.0323	$0.0609	$0.3375	**$0.3984**	**$84**	$0.3685	**8.13%**
	Steam Methane Reformer	$0.0369	$0.0697	$0.3375	**$0.4072**	**$97**	$0.3772	**7.94%**
	Methanol Reforming	$0.0252	$0.0475	$0.3375	**$0.3850**	**$66**	$0.3550	**8.43%**
	Gasoline Reforming	$0.0509	$0.0961	$0.3375	**$0.4335**	**$133**	$0.4036	**7.42%**

51 Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.

52 Includes impacts of emissions charges for vehicle production.

Table 40 Results for heavy-duty vehicle (incorporating safety costs)

		Pre-tax price of fuel per MJ[53]	Fuel costs per km	Other costs per km[54]	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0149	$0.2756	$0.8014	**$1.0770**	**$0**	$1.0770	**0.00%**
	Electrolysis	$0.0483	$0.5949	$0.8680	**$1.4629**	**$2,251**	$1.4468	**1.11%**
	Steam Methane Reformer	$0.0373	$0.4597	$0.8680	**$1.3277**	**$1,462**	$1.3116	**1.23%**
Decentralized	Electrolysis using Grid	$0.0334	$0.4111	$0.8680	**$1.2791**	**$1,179**	$1.2571	**1.75%**
	Steam Methane Reformer	$0.0311	$0.3828	$0.8680	**$1.2508**	**$1,014**	$1.2288	**1.79%**
	Methanol Reforming	$0.0261	$0.3215	$0.8680	**$1.1895**	**$656**	$1.1675	**1.88%**
	Gasoline Reforming	$0.0449	$0.5530	$0.8680	**$1.4210**	**$2,007**	$1.3990	**1.57%**

The results for the light-duty vehicles show how significant any difference in annual acquisition and maintenance costs can have on the final results. The $500 per year increase in operating the hydrogen vehicles leads to increases of around 8% in the total costs per kilometre. This is larger than the impact of internalizing greenhouse gas emissions costs or other airborne emissions costs had on the gasoline pathways.

For the heavy-duty vehicles, the total cost increases are less significant, leading to costs of a couple of cents more per kilometre. As suggested above, the impacts on the centralized pathways are less than the impacts on the decentralized pathways, as the increased costs associated with the additional regulatory requirements are partially borne by the light-duty vehicles.

2-3.4) Impact of All Externalities Combined

For this experiment, the impact of including all the costs associated with the externalities cited above is examined. In this initial iteration of the model, the costs for the greenhouse gas emissions are left at their initial value of $15 per tonne.

Table 41 contains the results for the light-duty vehicles, and Table 42 contains the results for the heavy-duty vehicles.

[53] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[54] Includes impacts of emissions charges for vehicle production.

Table 41 Results for light-duty vehicles (all externalities, GHG at $15/tonne)

		Pre-tax price of fuel per MJ[55]	Fuel costs per km	Other costs per km[56]	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0249	$0.0866	$0.2932	**$0.3798**	**$0**	$0.3377	**12.46%**
	Electrolysis Using Nuclear	$0.0485	$0.0915	$0.3432	**$0.4347**	**$76**	$0.3962	**9.72%**
	Electrolysis Using Coal	$0.0605	$0.1142	$0.3432	**$0.4574**	**$108**	$0.3962	**15.46%**
	Electrolysis Using Wind	$0.0483	$0.0912	$0.3432	**$0.4344**	**$76**	$0.3962	**9.65%**
	Electrolysis Using Hydro	$0.0485	$0.0914	$0.3432	**$0.4347**	**$76**	$0.3962	**9.71%**
	Steam Methane Reformer	$0.0392	$0.0740	$0.3432	**$0.4173**	**$52**	$0.3755	**11.12%**
Decentralized	Electrolysis using Grid	$0.0346	$0.0653	$0.3432	**$0.4086**	**$40**	$0.3685	**10.89%**
	Steam Methane Reformer	$0.0388	$0.0733	$0.3432	**$0.4165**	**$51**	$0.3772	**10.41%**
	Methanol Reforming	$0.0273	$0.0515	$0.3432	**$0.3947**	**$21**	$0.3550	**11.18%**
	Gasoline Reforming	$0.0547	$0.1032	$0.3432	**$0.4464**	**$93**	$0.4036	**10.61%**

These results show that the costs are largely linearly cumulative. In other words, the results displayed in Tables 41 and 42 (below) are not significantly different than the values that would be obtained by adding the cost increases from the tables for the greenhouse gas emission, and the tables for the other airborne emissions, and the tables for the safety costs, together. This is to be expected, as there is very little interaction between any of the cost elements.

In examining the resulting cost impacts for the light-duty vehicles, the cost increases are remarkably similar across all the pathways. The advantage that many of the hydrogen based pathways had in terms of emissions, except for the path reliant upon the coal-fired electricity generator, is lost due to the increased insurance costs. As such, gasoline remains the most economic pathway, with the decentralized methanol reformer at the edge of being competitive.

[55] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[56] Includes impacts of emissions charges for vehicle production.

Table 42 Results for heavy-duty vehicles (all externalities, GHG at $15/tonne)

		Pre-tax price of fuel per MJ[57]	Fuel costs per km	Other costs per km[58]	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0221	$0.4092	$0.8159	**$1.2251**	**$0**	$1.0770	**13.75%**
	Electrolysis Using Nuclear	$0.0485	$0.5972	$0.8943	**$1.4915**	**$1,554**	$1.4468	**3.09%**
	Electrolysis Using Coal	$0.0605	$0.7456	$0.8943	**$1.6399**	**$2,420**	$1.4468	**13.35%**
	Electrolysis Using Wind	$0.0483	$0.5953	$0.8943	**$1.4896**	**$1,543**	$1.4468	**2.96%**
	Electrolysis Using Hydro	$0.0485	$0.5970	$0.8943	**$1.4913**	**$1,553**	$1.4468	**3.08%**
	Steam Methane Reformer	$0.0392	$0.4832	$0.8943	**$1.3775**	**$889**	$1.3116	**5.02%**
Decentralized	Electrolysis using Grid	$0.0357	$0.4400	$0.8943	**$1.3343**	**$637**	$1.2571	**6.15%**
	Steam Methane Reformer	$0.0330	$0.4062	$0.8943	**$1.3005**	**$440**	$1.2288	**5.83%**
	Methanol Reforming	$0.0282	$0.3476	$0.8943	**$1.2419**	**$98**	$1.1675	**6.37%**
	Gasoline Reforming	$0.0487	$0.5994	$0.8943	**$1.4937**	**$1,567**	$1.3990	**6.77%**

For the heavy-duty vehicle pathways, the hydrogen-based pathways, except for the path reliant upon the coal-fired electricity generator, still have significantly lower increases than the diesel pathway, but diesel remains the most economic pathway.

2-3.4) Impact of All Externalities Combined, Increased Greenhouse Gas Costs

A further experiment is conducted where all the externalities are included, but the charge for the greenhouse gas emissions is increased to the alternate value of $50 per tonne.

Table 43 contains the results for the light-duty vehicles, and Table 44 contains the results for the heavy-duty vehicles.

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[57] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.

[58] Includes impacts of emissions charges for vehicle production.

Table 43 Results for light-duty vehicles (all externalities, GHG at $50/tonne)

		Pre-tax price of fuel per MJ[59]	Fuel costs per km	Other costs per km[60]	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0384	$0.1339	$0.2965	**$0.4304**	**$0**	$0.3377	**27.45%**
	Electrolysis Using Nuclear	$0.0487	$0.0919	$0.3468	**$0.4387**	**$12**	$0.3962	**10.73%**
	Electrolysis Using Coal	$0.0768	$0.1449	$0.3468	**$0.4917**	**$85**	$0.3962	**24.11%**
	Electrolysis Using Wind	$0.0484	$0.0913	$0.3468	**$0.4381**	**$11**	$0.3962	**10.59%**
	Electrolysis Using Hydro	$0.0489	$0.0922	$0.3468	**$0.4390**	**$12**	$0.3962	**10.80%**
	Steam Methane Reformer	$0.0428	$0.0807	$0.3468	**$0.4275**	**-$4**	$0.3755	**13.85%**
Decentralized	Electrolysis using Grid	$0.0379	$0.0715	$0.3468	**$0.4183**	**-$17**	$0.3685	**13.54%**
	Steam Methane Reformer	$0.0424	$0.0799	$0.3468	**$0.4267**	**-$5**	$0.3772	**13.12%**
	Methanol Reforming	$0.0311	$0.0586	$0.3468	**$0.4054**	**-$35**	$0.3550	**14.19%**
	Gasoline Reforming	$0.0613	$0.1156	$0.3468	**$0.4624**	**$45**	$0.4036	**14.57%**

As expected, for the light duty vehicles total costs in the gasoline pathway increase significantly over the results in Table 41. This experiment results in most of the fuelling pathways being within a couple of cents per kilometre of one another, with the one outlier being the pathway reliant on the coal-fired electricity generator. In this case, all but two of the hydrogen pathways become competitive with gasoline, the exceptions being the coal-fired electrolyser, and the decentralized gasoline reformer.

[59] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[60] Includes impacts of emissions charges for vehicle production.

Table 44 Results for heavy-duty vehicles (all externalities, GHG at $50/tonne)

		Pre-tax price of fuel per MJ[61]	Fuel costs per km	Other costs per km[62]	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0301	$0.5567	$0.8218	**$1.3785**	**$0**	$1.0770	**27.99%**
	Electrolysis Using Nuclear	$0.0487	$0.5999	$0.9055	**$1.5054**	**$740**	$1.4468	**4.05%**
	Electrolysis Using Coal	$0.0768	$0.9459	$0.9055	**$1.8514**	**$2,759**	$1.4468	**27.97%**
	Electrolysis Using Wind	$0.0484	$0.5962	$0.9055	**$1.5017**	**$719**	$1.4468	**3.80%**
	Electrolysis Using Hydro	$0.0489	$0.6018	$0.9055	**$1.5073**	**$751**	$1.4468	**4.18%**
	Steam Methane Reformer	$0.0428	$0.5268	$0.9055	**$1.4323**	**$314**	$1.3116	**9.20%**
Decentralized	Electrolysis using Grid	$0.0390	$0.4803	$0.9055	**$1.3858**	**$43**	$1.2571	**10.24%**
	Steam Methane Reformer	$0.0365	$0.4496	$0.9055	**$1.3551**	**-$137**	$1.2288	**10.27%**
	Methanol Reforming	$0.0320	$0.3940	$0.9055	**$1.2995**	**-$461**	$1.1675	**11.30%**
	Gasoline Reforming	$0.0552	$0.6805	$0.9055	**$1.5859**	**$1,210**	$1.3990	**13.36%**

For the heavy-duty vehicles the results remain scattered. The centralized pathways remain relatively expensive, as does the gasoline reforming pathway, while the other decentralized pathways become competitive, with the steam methane reformer, and methanol reformer actually less expensive than diesel.

2-3.4) Impact of Stacked Alternative Assumptions

A couple of experiments were conducted where some of the alternative assumptions examined in the sensitivity analysis of Part 1 are incorporated into the model containing all the externalities (with greenhouse gas emissions being charged at a rate of $15 per tonne).

For the first of these alternative experiments, the size of the fleet is increased to 500,000 light-duty vehicles (no changes to the heavy-duty vehicle fleet size), in order to remove the penalizing effect of pipeline costs on the centralized pathways for the base case small fleet size.

The results of this experiment are shown in Tables 45 and 46.

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[61] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[62] Includes impacts of emissions charges for vehicle production.

Table 45 Results for light-duty vehicles (all externalities, GHG at $15/tonne, increased fleet)

		Pre-tax price of fuel per MJ[63]	Fuel costs per km	Other costs per km[64]	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0260	$0.0905	$0.2932	**$0.3837**	**$0**	$0.3377	**13.62%**
	Electrolysis Using Nuclear	$0.0331	$0.0624	$0.3432	**$0.4056**	**$30**	$0.3962	**2.38%**
	Electrolysis Using Coal	$0.0451	$0.0851	$0.3432	**$0.4283**	**$62**	$0.3962	**8.11%**
	Electrolysis Using Wind	$0.0329	$0.0621	$0.3432	**$0.4053**	**$30**	$0.3962	**2.30%**
	Electrolysis Using Hydro	$0.0330	$0.0623	$0.3432	**$0.4056**	**$30**	$0.3962	**2.37%**
	Steam Methane Reformer	$0.0238	$0.0449	$0.3432	**$0.3881**	**$6**	$0.3755	**3.37%**
Decentralized	Electrolysis using Grid	$0.0346	$0.0653	$0.3432	**$0.4086**	**$35**	$0.3685	**10.89%**
	Steam Methane Reformer	$0.0388	$0.0733	$0.3432	**$0.4165**	**$46**	$0.3772	**10.41%**
	Methanol Reforming	$0.0273	$0.0515	$0.3432	**$0.3947**	**$15**	$0.3550	**11.18%**
	Gasoline Reforming	$0.0547	$0.1032	$0.3432	**$0.4464**	**$87**	$0.4036	**10.61%**

As in Part 1, with an increased fleet size, the centralized hydrogen pathways become more competitive with the decentralized hydrogen pathways. In fact, the centralized steam methane reformer becomes competitive with gasoline, as shown in Table 45 above, and diesel, as shown in Table 46 below, under these circumstances. The other centralized hydrogen pathways, however, remain uncompetitive.

[63] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[64] Includes impacts of emissions charges for vehicle production.

Table 46 Results for heavy-duty vehicles (all externalities, GHG at $15/tonne, increased fleet)

		Pre-tax price of fuel per MJ[65]	Fuel costs per km	Other costs per km[66]	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0221	$0.4092	$0.8159	**$1.2251**	**$0**	$1.0770	**13.75%**
	Electrolysis Using Nuclear	$0.0331	$0.4071	$0.8943	**$1.3015**	**$446**	$1.4468	**-10.04%**
	Electrolysis Using Coal	$0.0451	$0.5555	$0.8943	**$1.4498**	**$1,311**	$1.4468	**0.21%**
	Electrolysis Using Wind	$0.0329	$0.4052	$0.8943	**$1.2995**	**$434**	$1.4468	**-10.18%**
	Electrolysis Using Hydro	$0.0330	$0.4069	$0.8943	**$1.3012**	**$444**	$1.4468	**-10.06%**
	Steam Methane Reformer	$0.0238	$0.2931	$0.8943	**$1.1875**	**-$219**	$1.3116	**-9.46%**
Decentralized	Electrolysis using Grid	$0.0357	$0.4400	$0.8943	**$1.3343**	**$637**	$1.2571	**6.15%**
	Steam Methane Reformer	$0.0330	$0.4062	$0.8943	**$1.3005**	**$440**	$1.2288	**5.83%**
	Methanol Reforming	$0.0282	$0.3476	$0.8943	**$1.2419**	**$98**	$1.1675	**6.37%**
	Gasoline Reforming	$0.0487	$0.5994	$0.8943	**$1.4937**	**$1,567**	$1.3990	**6.77%**

In addition to the assumptions used in the above experiment, a further experiment was conducted which relaxed some of the other assumptions that are built into the base case.

For this experiment it was assumed that the fuel-cell vehicles have a longer expected life than the conventional vehicles. The maintenance costs were not reduced as was modelled jointly in the base case. Although the rationale for both of these assumptions is the same, i.e. that less mechanical components would lead to less wear and tear, the maintenance costs are not reduced in this study. Although there are reduced mechanical components, and possibly fewer required visits to the garage, those visits might be more costly, at least for the first few years. Mechanics would need to be re-educated, and the automotive systems might require new diagnostic tools.

The lower electricity price was also used for this experiment. This could reflect the ability of the electrolysis producers to cost the price of the electricity used at lower internal costs, as opposed to market rates, or it could reflect the use of off-peak rates[67].

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[65] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[66] Includes impacts of emissions charges for vehicle production.

Finally, for this experiment the additional insurance costs for the light-duty vehicle was also dropped. If the literature is correct in the assertion that hydrogen-fuelled vehicles are no more dangerous to operate than gasoline or diesel fuelled vehicles, then competition among insurance companies should rapidly eliminate any initial premium that insurance companies might impose.

The results for this experiment are presented in Tables 47 and 48.

Table 47 Results for light-duty vehicles (all externalities except insurance, GHG at $15/tonne, reduced price of electricity, extended vehicle life, increased fleet)

		Pre-tax price of fuel per MJ[68]	Fuel costs per km	Other costs per km[69]	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0260	$0.0905	$0.2932	**$0.3837**	**$0**	$0.3377	**13.62%**
Centralized	Electrolysis Using Nuclear	$0.0276	$0.0521	$0.2985	**$0.3506**	**-$46**	$0.3962	**-11.52%**
Centralized	Electrolysis Using Coal	$0.0397	$0.0748	$0.2985	**$0.3733**	**-$14**	$0.3962	**-5.78%**
Centralized	Electrolysis Using Wind	$0.0275	$0.0518	$0.2985	**$0.3503**	**-$46**	$0.3962	**-11.59%**
Centralized	Electrolysis Using Hydro	$0.0276	$0.0521	$0.2985	**$0.3505**	**-$46**	$0.3962	**-11.52%**
Centralized	Steam Methane Reformer	$0.0233	$0.0440	$0.2985	**$0.3425**	**-$57**	$0.3755	**-8.80%**
Decentralized	Electrolysis using Grid	$0.0292	$0.0551	$0.2985	**$0.3536**	**-$42**	$0.3685	**-4.04%**
Decentralized	Steam Methane Reformer	$0.0383	$0.0723	$0.2985	**$0.3708**	**-$18**	$0.3772	**-1.70%**
Decentralized	Methanol Reforming	$0.0266	$0.0502	$0.2985	**$0.3487**	**-$49**	$0.3550	**-1.79%**
Decentralized	Gasoline Reforming	$0.0541	$0.1021	$0.2985	**$0.4006**	**$24**	$0.4036	**-0.74%**

[67] As mentioned above, caution must be used in using this interpretation, as this would require either further capital investment in order to produce the same amount of fuel over a shorter period, or it would require assuming that a smaller fleet size is supported, which might increase the impact of the pipeline costs.
[68] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[69] Includes impacts of emissions charges for vehicle production.

Table 48 Results for heavy-duty vehicles (all externalities except insurance, GHG at $15/tonne, reduced price of electricity, extended vehicle life, increased fleet)

		Pre-tax price of fuel per MJ[70]	Fuel costs per km	Other costs per km[71]	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0221	$0.4092	$0.8159	**$1.2251**	**$0**	$1.0770	**13.75%**
	Electrolysis Using Nuclear	$0.0276	$0.3401	$0.8534	**$1.1935**	**-$184**	$1.4468	**-17.50%**
	Electrolysis Using Coal	$0.0397	$0.4884	$0.8534	**$1.3419**	**$681**	$1.4468	**-7.25%**
	Electrolysis Using Wind	$0.0275	$0.3382	$0.8534	**$1.1916**	**-$195**	$1.4468	**-17.64%**
	Electrolysis Using Hydro	$0.0276	$0.3398	$0.8534	**$1.1933**	**-$186**	$1.4468	**-17.52%**
	Steam Methane Reformer	$0.0233	$0.2871	$0.8534	**$1.1405**	**-$494**	$1.3116	**-13.04%**
Decentralized	Electrolysis using Grid	$0.0303	$0.3730	$0.8534	**$1.2264**	**$8**	$1.2571	**-2.44%**
	Steam Methane Reformer	$0.0325	$0.4001	$0.8534	**$1.2535**	**$166**	$1.2288	**2.01%**
	Methanol Reforming	$0.0275	$0.3393	$0.8534	**$1.1927**	**-$189**	$1.1675	**2.16%**
	Gasoline Reforming	$0.0481	$0.5926	$0.8534	**$1.4461**	**$1,289**	$1.3990	**3.36%**

As these alternative assumptions favour the hydrogen pathways, this experiment yields results for the light-duty vehicles in which almost all the hydrogen pathways are competitive with the gasoline pathway. The one exception is the pathway using the gasoline reformer, due to significant emissions associated with that pathway.

For the heavy-duty vehicle, results of most hydrogen pathways become more economical than the diesel pathway, except for those pathways with high associated emissions, such as the coal-fired electricity, grid-based electricity and gasoline reformer pathway, or those pathways that have low cost-efficiency, such as the decentralized steam-methane reformer.

These results again demonstrate how sensitive the model can be to some of the assumptions used, particularly those around the relative expected life and maintenance costs of the hydrogen vehicles, as compared to conventional vehicles.

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[70] Includes impacts of emissions charges for fuel production and vehicle operation, does not include sales or excise taxes.
[71] Includes impacts of emissions charges for vehicle production.

Part 3: The Impacts of Policy Tools on the Economics of Hydrogen vs. Gasoline or Diesel for Transportation Services

This part of the study analyses the impact of government policy tools on the economic competitiveness of the hydrogen fuelling pathways. It will consider the following:

- government sponsored capital investment,
- favourable tax treatment for hydrogen,
- infrastructure related incentives,
- research & development subsidies,
- zero-emission vehicle mandates, and
- emissions taxes.

Each of these instruments are examined both in terms of their most appropriate application, and how effective they might be.

3.1) Description of the Policy Tools

3.1-1) Emissions Taxes

One policy instrument available to the government is the use of emissions taxes. These are explicit taxes on the production or consumption of a product that attempts to internalize the externalities associated with its production or consumption.

Many parts of the world already use this tool, particularly in the area of greenhouse gases emissions. Typically, these taxes are used in conjunction with production, where it is easier to assess the actual level of emissions in order to determine an appropriate tax rate.

The effectiveness of such a tool in terms of the pathways being examined in this study, is largely captured by Tables 33 through 38 in Part 2 above, as the method used to capture the externalities of the emissions in Part 2 is consistent with the application of a tax. However, a further experiment is included in subsection 3.2-1 below where an emissions tax for greenhouse gases, NOx, SOx, and PM are simultaneously levied on the production of energy. The emissions associated with both the operation and production of the vehicle are excluded. No tax is placed on the operation of the vehicle, as all vehicles will produce different emissions levels based on the model, age, condition, driving profile, etc. of that particular vehicle, and so a single charge based on the fuel being purchased would not capture the exact emissions of that particular vehicle. Such a tax would more appropriately be referred to as an excise tax.

The emissions level of a particular vehicle could be determined, and a tax rate assigned, through various methods. For example, a vehicle specific tax value could be established at periodic emissions tests. However, this would probably not be administratively feasible, and attempts to evade such a tax would ensue.

There is very little difference in the emissions produced in vehicle production. As a result, such a tax would not lead to the choice of a “cleaner” technology path. It could, however, result in lower overall emission levels, if the resulting higher purchase price for vehicles leads to less demand for vehicles

3.1-2) Government Sponsored Capital Investment

Government sponsored capital investment can be implemented in a variety of ways. Public-Private Partnerships, known as PPPs, or P3s, are a popular method for sponsored capital investment. Under this method, the government will invest in a project if matching funds can be found from private investors. Another method can involve 100% up-front government funding of the investment project, and then leasing the completed project to private investors (like the highway 407 project).

This policy instrument usually only comes into play in situations where there is a public need (e.g. reduced commute times), requiring a large capital investment that is unlikely to be undertaken by the private sector (e.g. a highway), but where there is a role in which the private sector can take part (e.g. the management of a toll road).

In the case of the hydrogen pathways, the one area that might fit these criteria would be the establishment of a hydrogen pipeline distribution infrastructure. There are a number of ways that the government could participate in such a capital investment. As described above, the government could match private sector investments in pipeline development, or they could build the pipelines and lease them to the private sector.

Relieving the private sector of much of the cost of establishing a hydrogen pipeline infrastructure, or averaging out the costs over an extended period, would help to make hydrogen more competitive with gasoline and diesel. Hydrogen could be produced centrally, with some cost efficiency advantages over decentralized production, without suffering the cost penalty attached to distributing hydrogen by pipeline, as has been illustrated above. Subsection 3.2-2 below considers the impact on the costs per kilometre of hydrogen produced centrally and distributed by pipeline, if the government were to build the pipeline, and provide a 100 year lease of that pipeline to the industry, using a preferred interest rate.

3.1-3) Favourable Tax Treatment for Hydrogen

The tax system can affect the costs associated with using hydrogen as a fuel in the following places:

- The production of the fuel;
- The distribution of the fuel;
- The production of the vehicle;
- The operation of the vehicle;

The tax instruments available for use include:

- The tax depreciation rates for production and distribution equipment;
- The income tax rate for hydrogen production operations;
- Specific tax credits, or enhanced tax credits, such as research and development tax credits;
- Fuel excise tax rates, and provincial sales taxes, and the Goods and Services Tax.

These instruments are largely technologically neutral, and may be effective in influencing the costs, but would not necessarily be effective in addressing the government's environmental policy objectives. For that purpose, the emissions taxes discussed above would be far more effective.

The results in Part 1 demonstrate that some of the key factors are the distribution costs and vehicle acquisition costs. This suggests that the most effective instruments will be depreciation rates for the distribution equipment, provincial sales taxes on the fuel and the vehicles, and excise taxes. Subsection 3.2-3 below considers the results of enhanced tax depreciation rates for hydrogen pipelines, provincial sales tax exemptions for the purchase of hydrogen-fuelled vehicles, as well as excise tax and provincial sales tax exemptions for the purchase of hydrogen.

It is unlikely that preferential corporate income tax rates would ever be provided for specific industries. Historically, the federal and provincial governments have offered preferential corporate income tax rates for manufacturing and processing ("M&P")

operations, as well as for small business. The recent trend in tax policy has been to eliminate preferential rates, by bringing the general rate down to the M&P rate.

It is equally unlikely that preferential treatment would be provided under the Goods and Services Tax (the "GST"). The federal government has always resisted any exceptional treatment under the GST, striving to keep the tax as broad as possible. However, provincial sales taxes have many commodity specific exemptions. Even provinces that apply the Harmonized Sales Tax (the "HST"), a merged federal and provincial version of the GST, have introduced some specific exceptions for certain commodities.

Depending on the nature of the investments, other possible tax treatments that could be effective in reducing the costs for hydrogen. For example, flow-through shares, an instrument for passing un-utilizable tax losses onto other companies are used in the resource sector to deal with high start-up costs. However, this study assumes that the investments in any given pathway are being undertaken by a large entity that can use any losses generated. Therefore the possible effectiveness of such an instrument cannot be captured here.

3.1-4) Infrastructure Related Incentives

As previously discussed, the development of the distribution infrastructure represents the most significant infrastructure cost for the hydrogen fuelling pathways. The two most effective ways for supporting the development of this infrastructure would be through direct capital investment participation or supportive tax policies. These options have been covered in subsections 3.1-2, and 3.1-3.

3.1-5) Research & Development Subsidies

Research and development could play an important role in making hydrogen costs more competitive with gasoline and diesel. Further research could lead to improved efficiencies of the various hydrogen production technologies, yielding more hydrogen for the same capital investment. It could also reduce the costs of producing, and purchasing, a hydrogen fuel cell powered vehicle, which has been shown to be a very important factor in the cost differentials.

The federal and provincial governments already provide generous support for research and development through the tax system. For example, the federal government already offers a 100% write-off of all current and capital R&D expenditures, and a 20% refundable investment tax credit for qualifying expenditures, referred to as "scientific research and experimental development" ("SRED") expenditures, with the rate increasing up to 35% for small Canadian Controlled Private Corporations ("CCPC").

Combined with provincial incentives, these can have a significant impact on the after-tax cost of R&D expenditures. For example, in the case of a large manufacturing firm, the after-tax cost for an expenditure of $100 on capital equipment can be as low as $51 in Ontario. The table below demonstrates this calculation.

Table 49 After tax cost of an R&D expenditure

	R&D Expenditure	Non-R&D Expenditure
Capital expenditure	$100.00	$100.00
Ontario Sales Tax (R&D exemption)	$0.00	$7.00
Gross Expenditure	$100.00	$107.00
Subtotal	$100.00	$107.00
Federal investment tax credit – 20%	-$20.00	
Subtotal	$80.00	$107.00
Tax Deduction (at the 2003 combined rate for M&P = 33.12%)	-$26.50	-$35.84
Ontario exemption of federal tax credit (at the 2003 Ontario rate for M&P = 11.00%)	-$2.20	
Net After-Tax Cost	$51.30	$71.56

The impact of the tax incentives will vary depending on the type of corporation. In our example, the net after tax cost of $100 in R&D expenditures would be $51.30 for a large manufacturing company, the net after tax cost for a large non-manufacturer would be $46.60, and the net after-tax cost for a medium sized manufacturer would be $46.17.

According to the federal governments 2002 Tax Expenditures and Evaluations estimates, the cost of the SRED credit in 2003 will be approximately $1.4 billion[72].

Given this existing support system for research and development expenditures, the government is unlikely to focus support programs in this area.

3.1-6) Zero-Emission Vehicle Mandates

Imposing a zero-emission vehicle mandate, e.g. a requirement that x% of all vehicles produced in a given year be zero-emission vehicles, would not have a direct impact on the relative cost of hydrogen versus gasoline or diesel. However, it might indirectly impact the costs.

For example, such a mandate could accelerate the development of zero-emission vehicles, resulting in production cost reductions. This approach would only be effective if other areas of North America had similar mandates, because the Canadian market probably does not constitute a great enough share of total production. As a result, vehicles developed to satisfy Canadian regulatory requirements would actually come at high production costs.

Furthermore, this policy instrument is designed to “push” vehicles to the market. It does not provide any incentive for consumers to actually purchase the vehicles. If the cost and infrastructure issues were not addressed, most consumers would be reluctant to purchase the zero-emission vehicles. As such, this policy instrument would have to be implemented in conjunction with some incentives for consumers to purchase the vehicles.

[72] The Ontario government does not provide estimates of the costs of their tax credits.

This policy instrument could be more effective for the heavy-duty vehicles, as these typically are purchased in fleet applications, such as a municipal transit operation, where government regulations can be implemented requiring that a proportion of the fleet be of a particular nature, e.g. low-emissions, or hydrogen fuel-cell in particular.

3.2) Impact of Select Policy Tools

3.2-1) Impact of Emissions Taxes

As discussed above, this sub-section provides the results of implementing emissions charges on the fuel production, without similar charges on the vehicle production or operation. The tax rates are $15 per tonne of carbon equivalent greenhouse gas emissions, $1,300 per tonne of SOx and NOx emissions, and $20,000 per tonne of particulate matter.

The results for the light-duty vehicle pathways are shown in Table 50, and the results for the heavy-duty vehicle pathways are shown in Table 51.

Table 50 Results for light-duty vehicles (fuel production emissions taxes)

		Pre-tax price of fuel per MJ[73]	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0236	$0.0823	$0.2877	**$0.3700**	**$0**	$0.3377	**9.57%**
	Electrolysis Using Nuclear	$0.0472	$0.0890	$0.3075	**$0.3966**	**$37**	$0.3962	**0.09%**
	Electrolysis Using Coal	$0.0592	$0.1117	$0.3075	**$0.4193**	**$69**	$0.3962	**5.83%**
	Electrolysis Using Wind	$0.0470	$0.0887	$0.3075	**$0.3963**	**$37**	$0.3962	**0.02%**
	Electrolysis Using Hydro	$0.0472	$0.0890	$0.3075	**$0.3965**	**$37**	$0.3962	**0.08%**
	Steam Methane Reformer	$0.0379	$0.0715	$0.3075	**$0.3791**	**$13**	$0.3755	**0.96%**
Decentralized	Electrolysis using Grid	$0.0346	$0.0653	$0.3075	**$0.3729**	**$4**	$0.3685	**1.20%**
	Steam Methane Reformer	$0.0388	$0.0733	$0.3075	**$0.3808**	**$15**	$0.3772	**0.95%**
	Methanol Reforming	$0.0273	$0.0515	$0.3075	**$0.3590**	**-$15**	$0.3550	**1.13%**
	Gasoline Reforming	$0.0547	$0.1032	$0.3075	**$0.4107**	**$57**	$0.4036	**1.76%**

[73] Includes impacts of emissions charges for fuel production, does not include sales or excise taxes.

Table 51 Results for heavy-duty vehicles (fuel production emissions taxes)

		Pre-tax price of fuel per MJ[74]	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0191	$0.3537	$0.8014	**$1.1551**	**$0**	$1.0770	**7.25%**
	Electrolysis Using Nuclear	$0.0472	$0.5811	$0.8680	**$1.4491**	**$1,715**	$1.4468	**0.16%**
	Electrolysis Using Coal	$0.0592	$0.7294	$0.8680	**$1.5975**	**$2,581**	$1.4468	**10.42%**
	Electrolysis Using Wind	$0.0470	$0.5792	$0.8680	**$1.4472**	**$1,704**	$1.4468	**0.03%**
	Electrolysis Using Hydro	$0.0472	$0.5808	$0.8680	**$1.4489**	**$1,714**	$1.4468	**0.14%**
	Steam Methane Reformer	$0.0379	$0.4671	$0.8680	**$1.3351**	**$1,050**	$1.3116	**1.79%**
Decentralized	Electrolysis using Grid	$0.0339	$0.4180	$0.8680	**$1.2860**	**$764**	$1.2571	**2.30%**
	Steam Methane Reformer	$0.0312	$0.3842	$0.8680	**$1.2522**	**$566**	$1.2288	**1.90%**
	Methanol Reforming	$0.0264	$0.3256	$0.8680	**$1.1936**	**$225**	$1.1675	**2.23%**
	Gasoline Reforming	$0.0469	$0.5774	$0.8680	**$1.4454**	**$1,693**	$1.3990	**3.31%**

For light-duty vehicles, implementing emissions taxes would make a number of the hydrogen pathways competitive with gasoline. Hydrogen from the centralized and decentralized steam methane reformer, and from the decentralized electrolysis would become competitive with gasoline. Hydrogen produced by the decentralized methanol reformer would become less costly than gasoline. However, for the heavy-duty vehicles none of the hydrogen pathways becomes competitive. Of course, in these simulations the centralized pathways still bear the additional pipeline infrastructure costs, and therefore remain uncompetitive.

This policy instrument yields some competitive results for the hydrogen pathways. In addition, increases the cost of “dirtier” technologies more than “cleaner” technologies. It is the only policy instrument being examined that is effective in this manner. Presumably one of the government’s policy goals in encouraging the adoption of hydrogen fuel cell vehicles is a reduction in emissions

3.2-2) Impact of Government Sponsored Capital Investment

For this experiment, it is assumed that the government builds the distribution pipeline for the centralized producers and leases that pipeline to the hydrogen producers. Extremely

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[74] Includes impacts of emissions charges for fuel production, does not include sales or excise taxes.

generous lease terms are assumed, with payments equal to the mortgage over a 100-year term at 3% interest. The producers would still be required to pay maintenance and operating costs.

This instrument will only affect the costs for the centralized production pathways. Table 52 presents the impact for light-duty vehicles, and Table 53 presents the impact for heavy-duty vehicles.

Table 52 Results for light-duty vehicles (leased pipeline)

		Pre-tax price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0143	$0.0500	$0.2877	**$0.3377**	**$0**	$0.3377	**0.00%**
	Electrolysis Using Nuclear	$0.0351	$0.0662	$0.3075	**$0.3737**	**$50**	$0.3962	**-5.67%**
	Electrolysis Using Coal	$0.0351	$0.0662	$0.3075	**$0.3737**	**$50**	$0.3962	**-5.67%**
	Electrolysis Using Wind	$0.0351	$0.0662	$0.3075	**$0.3737**	**$50**	$0.3962	**-5.67%**
	Electrolysis Using Hydro	$0.0351	$0.0662	$0.3075	**$0.3737**	**$50**	$0.3962	**-5.67%**
	Steam Methane Reformer	$0.0241	$0.0455	$0.3075	**$0.3530**	**$21**	$0.3755	**-5.98%**

Table 53 Results for heavy-duty vehicles (leased pipeline)

		Pre-tax price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0149	$0.2756	$0.8014	**$1.0770**	**$0**	$1.0770	**0.00%**
	Electrolysis Using Nuclear	$0.0351	$0.4321	$0.8680	**$1.3001**	**$1,301**	$1.4468	**-10.14%**
	Electrolysis Using Coal	$0.0351	$0.4321	$0.8680	**$1.3001**	**$1,301**	$1.4468	**-10.14%**
	Electrolysis Using Wind	$0.0351	$0.4321	$0.8680	**$1.3001**	**$1,301**	$1.4468	**-10.14%**
	Electrolysis Using Hydro	$0.0351	$0.4321	$0.8680	**$1.3001**	**$1,301**	$1.4468	**-10.14%**
	Steam Methane Reformer	$0.0241	$0.2970	$0.8680	**$1.1650**	**$513**	$1.3116	**-11.18%**

While this instrument closes the price gap, it still does not create centralized hydrogen production pathways that are competitive with gasoline.

Tables 54 and 55 consider the impact that government investment in the pipeline infrastructure would have if introduced in addition to emissions taxes.

Table 54 Results for light-duty vehicles (leased pipeline, and emissions taxes)

		Pre-tax price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0236	$0.0823	$0.2877	**$0.3700**	**$0**	$0.3377	**9.57%**
	Electrolysis Using Nuclear	$0.0353	$0.0665	$0.3075	**$0.3741**	**$6**	$0.3962	**-5.58%**
	Electrolysis Using Coal	$0.0473	$0.0893	$0.3075	**$0.3968**	**$37**	$0.3962	**0.16%**
	Electrolysis Using Wind	$0.0351	$0.0663	$0.3075	**$0.3738**	**$5**	$0.3962	**-5.65%**
	Electrolysis Using Hydro	$0.0353	$0.0665	$0.3075	**$0.3741**	**$6**	$0.3962	**-5.59%**
	Steam Methane Reformer	$0.0260	$0.0491	$0.3075	**$0.3566**	**-$19**	$0.3755	**-5.02%**

Table 55 Results for heavy-duty vehicles (leased pipeline, and emissions taxes)

		Pre-tax price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0191	$0.3537	$0.8014	**$1.1551**	**$0**	$1.0770	**7.25%**
	Electrolysis Using Nuclear	$0.0353	$0.4344	$0.8680	**$1.3025**	**$860**	$1.4468	**-9.97%**
	Electrolysis Using Coal	$0.0473	$0.5828	$0.8680	**$1.4508**	**$1,725**	$1.4468	**0.28%**
	Electrolysis Using Wind	$0.0351	$0.4325	$0.8680	**$1.3005**	**$848**	$1.4468	**-10.11%**
	Electrolysis Using Hydro	$0.0353	$0.4342	$0.8680	**$1.3022**	**$858**	$1.4468	**-9.99%**
	Steam Methane Reformer	$0.0260	$0.3204	$0.8680	**$1.1885**	**$195**	$1.3116	**-9.39%**

For both the light and heavy-duty pathways, this combination of instruments does help make the cost of hydrogen more competitive. Only the hydrogen produced by the coal-based electrolyser does not become competitive with gasoline. However, this combination is still not effective for the heavy-duty pathways, as none of those pathways become very competitive with diesel.

While this instrument might produce multiple competitive light-duty vehicle pathways, it may not be the most efficient use of government funds.

For consumers to accept hydrogen as a fuelling alternative they would have to feel comfortable with the refuelling infrastructure, i.e. that they can find conveniently located refuelling stations. This means that a rather extensive pipeline infrastructure is required. Whether it is developed in the private sector, the public sector, or some combination, the cost per vehicle supported in the initial years would be extremely high. As such, a large amount of tax dollars would be allocated to support a small number of vehicles during this period.

Furthermore, a centralized production facility with a pipeline distribution system may not ultimately be the most efficient manner of supplying hydrogen. This study has only examined a few of the possible pathways for supplying hydrogen. Specifically, this study did not consider centralized production facilities using either compressed gas or liquefied gas rail and truck distribution systems. In addition, many of the figures that the cost comparisons are based on are from literature estimates, and may not reflect the actual costs of developed technologies.

3.2-3) Impact of Favourable Tax Treatment for Hydrogen

The impacts of preferential tax treatments are modelled in this sub-section, both in isolation and in combination.

The first simulation is the application of an accelerated tax depreciation rate for pipeline equipment, moving pipelines from the capital cost allowance ("CCA") class 1, with a depreciation rate of 4%, into class 43, with a depreciation rate of 30%. The purpose of this experiment is to see how effectively the tax system could reduce the costs of the centralized hydrogen production pathways, comparing the results against the direct government investment in the pipeline. The results are shown in Tables 56 and 57.

Table 56 Results for light-duty vehicles (accelerated depreciation for pipelines, and emissions taxes)

		Pre-Tax price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**% Change**
Centralized	Gasoline	$0.0136	$0.0475	$0.2877	**$0.3352**	**$0**	$0.3377	**-0.74%**
	Electrolysis Using Nuclear	$0.0448	$0.0846	$0.3075	**$0.3921**	**$79**	$0.3962	**-1.03%**
	Electrolysis Using Coal	$0.0448	$0.0846	$0.3075	**$0.3921**	**$79**	$0.3962	**-1.03%**
	Electrolysis Using Wind	$0.0448	$0.0846	$0.3075	**$0.3921**	**$79**	$0.3962	**-1.03%**
	Electrolysis Using Hydro	$0.0448	$0.0846	$0.3075	**$0.3921**	**$79**	$0.3962	**-1.03%**
	Steam Methane Reformer	$0.0338	$0.0639	$0.3075	**$0.3714**	**$50**	$0.3755	**-1.09%**

Table 57 Results for heavy-duty vehicles (accelerated depreciation for pipelines, and emissions taxes)

		Pre-tax price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**% Change**
Centralized	Diesel	$0.0146	$0.2699	$0.8014	**$1.0713**	**$0**	$1.0770	**-0.53%**
	Electrolysis Using Nuclear	$0.0448	$0.5521	$0.8680	**$1.4201**	**$2,035**	$1.4468	**-1.84%**
	Electrolysis Using Coal	$0.0448	$0.5521	$0.8680	**$1.4201**	**$2,035**	$1.4468	**-1.84%**
	Electrolysis Using Wind	$0.0448	$0.5521	$0.8680	**$1.4201**	**$2,035**	$1.4468	**-1.84%**
	Electrolysis Using Hydro	$0.0448	$0.5521	$0.8680	**$1.4201**	**$2,035**	$1.4468	**-1.84%**
	Steam Methane Reformer	$0.0338	$0.4169	$0.8680	**$1.2849**	**$1,246**	$1.3116	**-2.03%**

Comparing tables 56 and 57 to tables 53 and 54, it is evident that this approach does not have the same impact as the direct investment. None of the centralized hydrogen pathways become competitive based on the increased depreciation rate.

These two experiments are not entirely comparable since the costs to the government are much different. In the direct investment case, the government has an initial $60,000,000 outlay, which it slowly recoups over a 100-year period. The cost of accelerated depreciation to the government would be foregone corporate income taxes incurred. Total foregone corporate income taxes (federal and provincial) from the investments in this study would be approximately $6,000,000.

On the other hand, the direct investment is a more targeted approach, in that the government's cost would be just for the hydrogen pipelines it builds. For the accelerated tax depreciation, however, there could be income tax revenue losses from all other businesses with pipelines. This "leakage" from the incentive program could potentially be resolved by only allowing the accelerated depreciation for hydrogen pipelines.

The second favourable tax simulation involves a provincial sales tax exemption for hydrogen fuel-cell vehicle purchases, and a provincial and federal excise tax exemption for hydrogen.

For the purposes of this study a provincial sales tax rate of 8% is used as a representative figure, even though this rate will be misrepresentative of provinces with different rates. It is also assumed that the provincial sales tax does not apply to fuel purchases, even though some provincial sales taxes apply to fuel.

The federal excise tax rates applied are 10¢ per litre for gasoline, and 4¢ per litre for diesel, with hydrogen being treated as exempt for each of the simulations. The provincial excise tax rates applied are based on Ontario rates of 14.7¢ per litre for gasoline, and 14.3¢ per litre for diesel, with hydrogen being treated as exempt[75].

The GST is also introduced into the model at this point, but is assumed to apply to all fuel and vehicle purchases[76].

One advantage of this combination of pathways is that the costs would be very low to start, consisting of the foregone tax revenues on vehicle and fuel purchases. These costs would grow, as take-up of hydrogen vehicles increased. However, once hydrogen vehicles reached a certain level of market penetration, the need for the policy supports would be lessened, and the programs could be phased out or eliminated. Calculating the foregone revenues is not a straightforward task. It would not necessarily be the number of vehicles sold and volume of fuel sold multiplied by the tax rates, because some of those purchases would presumably not have occurred without the policy supports.

Tables 58 and 59 contain the results assuming a provincial sales tax exemption for vehicle purchases.

As shown in Table 58, below, this combination of policy instruments yields a number of competitive hydrogen pathways. The decentralized electrolysis pathway and decentralized methanol reformer pathway have costs lower than gasoline. The centralized and decentralized steam methane reformer pathways become competitive.

[75] The Ontario Fuel Tax Act applies a levy on all fuels, but defines fuels as “any gas or liquid that may be used for the purpose of generating power by internal combustion”. As such, hydrogen used in a fuel-cell powered vehicle would already be exempt under this definition. Hydrogen used in a hydrogen combustion engine based vehicle would be taxable.
A similar definition is used in some of the other provinces, while some have more general definitions that might capture hydrogen as a fuel. In any event, it is likely that most provinces will need to review their sales and excise tax legislation with the introduction of this new technology.

[76] For the heavy-duty vehicles it is assumed that a municipality is making the purchase, and so they would qualify for the municipal GST rebate on their purchases. This will yield different tax inclusive prices for the centralized production of hydrogen for the light-duty and heavy-duty vehicles.

Table 58 Results for light-duty vehicle (vehicle PST exempt, hydrogen excise tax exempt)

		Tax inclusive price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**Percentage Change**
Centralized	Gasoline	$0.0238	$0.0830	$0.3075	**$0.3906**	**$0**	$0.3377	**15.67%**
	Electrolysis Using Nuclear	$0.0503	$0.0949	$0.3182	**$0.4131**	**$31**	$0.3962	**4.25%**
	Electrolysis Using Coal	$0.0503	$0.0949	$0.3182	**$0.4131**	**$31**	$0.3962	**4.25%**
	Electrolysis Using Wind	$0.0503	$0.0949	$0.3182	**$0.4131**	**$31**	$0.3962	**4.25%**
	Electrolysis Using Hydro	$0.0503	$0.0949	$0.3182	**$0.4131**	**$31**	$0.3962	**4.25%**
	Steam Methane Reformer	$0.0385	$0.0727	$0.3182	**$0.3909**	**$0**	$0.3755	**4.10%**
Decentralized	Electrolysis using Grid	$0.0345	$0.0652	$0.3182	**$0.3834**	**-$10**	$0.3685	**4.05%**
	Steam Methane Reformer	$0.0395	$0.0746	$0.3182	**$0.3928**	**$3**	$0.3772	**4.12%**
	Methanol Reforming	$0.0269	$0.0508	$0.3182	**$0.3690**	**-$30**	$0.3550	**3.94%**
	Gasoline Reforming	$0.0545	$0.1028	$0.3182	**$0.4210**	**$42**	$0.4036	**4.31%**

Table 59, below, shows that this combination of instruments is less effective for the heavy-duty vehicles. None of the hydrogen pathways drop below the costs of the diesel pathway. One notable impact of the inclusion of these taxes, for the hydrogen pathways, the pathways with the lowest costs experience higher relative cost increases. Because the GST is applied to the purchase of the vehicle, which is a flat amount across all the pathways, it represents a higher proportion of total costs in the lower cost pathways.

Table 59 Results for heavy-duty vehicle (vehicle PST exempt, hydrogen excise tax exempt)

		Tax inclusive price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**Percentage Change**
Centralized	Diesel	$0.0214	$0.3947	$0.8895	**$1.2842**	**$0**	$1.0770	**19.24%**
	Electrolysis Using Nuclear	$0.0484	$0.5961	$0.9805	**$1.5766**	**$1,706**	$1.4468	**8.98%**
	Electrolysis Using Coal	$0.0484	$0.5961	$0.9805	**$1.5766**	**$1,706**	$1.4468	**8.98%**
	Electrolysis Using Wind	$0.0484	$0.5961	$0.9805	**$1.5766**	**$1,706**	$1.4468	**8.98%**
	Electrolysis Using Hydro	$0.0484	$0.5961	$0.9805	**$1.5766**	**$1,706**	$1.4468	**8.98%**
	Steam Methane Reformer	$0.0371	$0.4569	$0.9805	**$1.4374**	**$894**	$1.3116	**9.59%**
Decentralized	Electrolysis using Grid	$0.0325	$0.4007	$0.9805	**$1.3812**	**$566**	$1.2571	**9.88%**
	Steam Methane Reformer	$0.0302	$0.3716	$0.9805	**$1.3521**	**$396**	$1.2288	**10.04%**
	Methanol Reforming	$0.0250	$0.3085	$0.9805	**$1.2890**	**$28**	$1.1675	**10.41%**
	Gasoline Reforming	$0.0444	$0.5469	$0.9805	**$1.5275**	**$1,419**	$1.3990	**9.18%**

Another advantage of such a combination of instruments would be that the revenues raised from the imposition of the emissions tax would help offset the foregone revenues from the sales and excise tax exemptions. Although, presumably, if the emissions taxes are effective then the revenues from the program should fall over time as producers switch to cleaner production methods. This would be in contrast to the cost of the sales and excise tax expenditures, which would grow over time, as more consumers switch to hydrogen fuelled vehicles. However, the need for the sales and excise tax exemptions would also decline over time, once hydrogen fuel cell vehicles become established in the marketplace, so the sales and excise tax exemptions could be cancelled, or phased out. Although dropping these incentives might increase the costs to the consumer, presumably, as the market for these vehicles grows, their costs of production should drop, eliminating one of the key factors that contributed to the need for the incentives.

Although the above combination of instruments assists in meeting the policy objective of reducing the differential between the cost of using hydrogen as a fuel versus diesel and gasoline, it does not penalize polluting pathways. As a result, emissions taxes are included with this combination of instruments.

The results from this simulation are presented in Tables 60 and 61 below.

Table 60 Results for light-duty vehicle (vehicle PST exempt, hydrogen excise tax exempt, and emission taxes)

		Tax inclusive price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from gasoline**	Base Case Results	**Percentage Change**
Centralized	Gasoline	$0.0338	$0.1176	$0.3075	**$0.4252**	**$0**	$0.3377	**25.91%**
	Electrolysis Using Nuclear	$0.0505	$0.0952	$0.3182	**$0.4134**	**-$16**	$0.3962	**4.35%**
	Electrolysis Using Coal	$0.0634	$0.1196	$0.3182	**$0.4378**	**$18**	$0.3962	**10.49%**
	Electrolysis Using Wind	$0.0503	$0.0949	$0.3182	**$0.4131**	**-$17**	$0.3962	**4.27%**
	Electrolysis Using Hydro	$0.0505	$0.0952	$0.3182	**$0.4134**	**-$16**	$0.3962	**4.34%**
	Steam Methane Reformer	$0.0406	$0.0766	$0.3182	**$0.3947**	**-$42**	$0.3755	**5.13%**
Decentralized	Electrolysis using Grid	$0.0371	$0.0699	$0.3182	**$0.3881**	**-$52**	$0.3685	**5.34%**
	Steam Methane Reformer	$0.0416	$0.0784	$0.3182	**$0.3966**	**-$40**	$0.3772	**5.13%**
	Methanol Reforming	$0.0292	$0.0551	$0.3182	**$0.3733**	**-$72**	$0.3550	**5.14%**
	Gasoline Reforming	$0.0585	$0.1104	$0.3182	**$0.4286**	**$5**	$0.4036	**6.19%**

This combination of instruments is highly effective in bringing the cost of the light-duty vehicle hydrogen pathways below the costs of gasoline. As shown in Table 60 below, all the hydrogen pathways except for the two “dirtiest” pathways, the gasoline reformer and coal-fired generator based electrolysis, becoming less costly. The two “dirty” pathways are within the competitive range.

It is significant to note that the centralized pathways (except for the coal pathway) are more economical even with the significant cost penalty of the pipeline investment to support a relatively small vehicle fleet.

As shown in Table 61, below, this combination of instruments is not as effective for the heavy-duty pathways. Only one hydrogen pathway, the decentralized methanol reformer, becomes more cost effective than the diesel pathway, and only the decentralized steam methane reformer comes under the sensitivity range of less than $100 per month in additional costs.

Table 61 Results for heavy-duty vehicle (vehicle PST exempt, hydrogen excise tax exempt, and emissions taxes)

		Tax inclusive price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**Percentage Change**
Centralized	Diesel	$0.0257	$0.4751	$0.8895	**$1.3646**	**$0**	$1.0770	**26.70%**
	Electrolysis Using Nuclear	$0.0486	$0.5985	$0.9805	**$1.5790**	**$1,251**	$1.4468	**9.14%**
	Electrolysis Using Coal	$0.0610	$0.7513	$0.9805	**$1.7318**	**$2,142**	$1.4468	**19.70%**
	Electrolysis Using Wind	$0.0484	$0.5965	$0.9805	**$1.5771**	**$1,239**	$1.4468	**9.01%**
	Electrolysis Using Hydro	$0.0486	$0.5983	$0.9805	**$1.5788**	**$1,249**	$1.4468	**9.13%**
	Steam Methane Reformer	$0.0391	$0.4811	$0.9805	**$1.4616**	**$566**	$1.3116	**11.44%**
Decentralized	Electrolysis using Grid	$0.0350	$0.4306	$0.9805	**$1.4111**	**$271**	$1.2571	**12.25%**
	Steam Methane Reformer	$0.0321	$0.3957	$0.9805	**$1.3762**	**$68**	$1.2288	**12.00%**
	Methanol Reforming	$0.0272	$0.3354	$0.9805	**$1.3159**	**-$284**	$1.1675	**12.71%**
	Gasoline Reforming	$0.0483	$0.5947	$0.9805	**$1.5752**	**$1,228**	$1.3990	**12.59%**

The difference in the responsiveness of the heavy-duty and light-duty pathways to these sales and excise tax policy packages could be due, in part, to the large difference in the federal excise tax applied to diesel ($0.04 per litre) versus gasoline ($0.10 per litre).

Increasing the federal excise tax on diesel to $0.10 per litre, with the same sales and excise tax exemptions as above, and the emissions taxes, yields the results in Table 62 below.

Table 62 Results for heavy-duty vehicle (increased diesel excise tax, vehicle PST exempt, hydrogen excise tax exempt, and emissions taxes)

		Tax inclusive price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**Percentage Change**
Centralized	Diesel	$0.0277	$0.5114	$0.8895	**$1.4010**	**$0**	$1.0770	**30.08%**
	Electrolysis Using Nuclear	$0.0486	$0.5985	$0.9805	**$1.5790**	**$1,039**	$1.4468	**9.14%**
	Electrolysis Using Coal	$0.0610	$0.7513	$0.9805	**$1.7318**	**$1,930**	$1.4468	**19.70%**
	Electrolysis Using Wind	$0.0484	$0.5965	$0.9805	**$1.5771**	**$1,027**	$1.4468	**9.01%**
	Electrolysis Using Hydro	$0.0486	$0.5983	$0.9805	**$1.5788**	**$1,037**	$1.4468	**9.13%**
	Steam Methane Reformer	$0.0391	$0.4811	$0.9805	**$1.4616**	**$354**	$1.3116	**11.44%**
Decentralized	Electrolysis using Grid	$0.0350	$0.4306	$0.9805	**$1.4111**	**$59**	$1.2571	**12.25%**
	Steam Methane Reformer	$0.0321	$0.3957	$0.9805	**$1.3762**	**-$144**	$1.2288	**12.00%**
	Methanol Reforming	$0.0272	$0.3354	$0.9805	**$1.3159**	**-$496**	$1.1675	**12.71%**
	Gasoline Reforming	$0.0483	$0.5947	$0.9805	**$1.5752**	**$1,016**	$1.3990	**12.59%**

Increased diesel excise tax has an impact: two hydrogen pathways are lower than diesel (the decentralized steam methane reformer and methanol reformer pathways), and one is within sensitivity range (the decentralized electrolysis pathway).

The centralized hydrogen pathways all remain far more costly, and would probably require either infrastructure assistance, or waiting for a larger fleet size over which to defray the investment costs.

Another possible method to make the hydrogen pathway costs for the heavy-duty vehicles more cost competitive would be to allow a full rebate of the GST costs for the operation and acquisition of hydrogen fuel-cell vehicles, as opposed to the partial rebate allowed in the above scenarios. However, this incentive works here because of the assumption that the heavy-duty vehicles are municipal transit buses. Other heavy-duty vehicles, diesel or hydrogen, might already receive a full input tax credit for their GST outlays, if the expenses are incurred as part of a taxable business, such as a trucking company.

The impacts of such a change are shown in Table 63 below, again incorporating the sales and excise tax exemptions, and emissions taxes, and the diesel excise tax rate of $0.10 per litre.

Table 63 Results for heavy-duty vehicle (full GST rebate, vehicle PST exempt, hydrogen excise tax exempt, and emissions taxes)

		Tax inclusive price of fuel per MJ	Fuel costs per km	Other costs per km	**Total Costs per km**	**$/month difference from diesel**	Base Case Results	**Percentage Change**
Centralized	Diesel	$0.0277	$0.5114	$0.8895	**$1.4010**	**$0**	$1.0770	**30.08%**
	Electrolysis Using Nuclear	$0.0472	$0.5811	$0.9635	**$1.5446**	**$838**	$1.4468	**6.76%**
	Electrolysis Using Coal	$0.0592	$0.7294	$0.9635	**$1.6929**	**$1,703**	$1.4468	**17.02%**
	Electrolysis Using Wind	$0.0470	$0.5792	$0.9635	**$1.5427**	**$827**	$1.4468	**6.63%**
	Electrolysis Using Hydro	$0.0472	$0.5808	$0.9635	**$1.5443**	**$836**	$1.4468	**6.74%**
	Steam Methane Reformer	$0.0379	$0.4671	$0.9635	**$1.4306**	**$173**	$1.3116	**9.07%**
Decentralized	Electrolysis using Grid	$0.0339	$0.4180	$0.9635	**$1.3815**	**-$113**	$1.2571	**9.90%**
	Steam Methane Reformer	$0.0312	$0.3842	$0.9635	**$1.3477**	**-$311**	$1.2288	**9.67%**
	Methanol Reforming	$0.0264	$0.3256	$0.9635	**$1.2891**	**-$653**	$1.1675	**10.41%**
	Gasoline Reforming	$0.0469	$0.5774	$0.9635	**$1.5409**	**$816**	$1.3990	**10.14%**

While this simulation provides some improvement for the hydrogen pathways as compared to Table 62 above, it is still insufficient to bring any of the centralized pathways into a cost competitive range.

Conclusion

This study examined the economics of hydrogen as a transportation fuel. As part of this analysis, hydrogen was compared to gasoline and diesel. The impact of including externalities and various government policy options on the comparison was also reviewed.

Part 1 compared the direct costs associated with the production, distribution, and consumption of the fuel. This analysis indicated that the acquisition costs for the hydrogen fuel-cell vehicle represent one of the most important factors contributing to the costs of hydrogen as a fuel for transportation.

One of the most important factors contributing to the costs of using hydrogen as a fuel for transportation came from the acquisition costs for the hydrogen fuel-cell vehicle. For the base case scenario none of the hydrogen pathways were competitive with gasoline or diesel pathways. However, it was shown that by decreasing the hydrogen pathways' associated vehicle costs, by setting the purchase price of a fuel cell vehicle equal to its internal combustion engine or combustion ignition engine counterpart, or by decreasing the maintenance costs and increasing the life of the vehicle, hydrogen could become a competitive product, for some of the production pathways. This was more effective than a significant reduction in the costs for the production machinery and equipment, or decreased primary energy purchase prices.

Secondly, the distribution infrastructure, in this case a pipeline, was also identified as being a key contributor to the cost difference for the centralized pathways. One of the main reasons why the pipeline costs were so significant in the base case is due to the fleet size being supported by the pipeline being very small. It is unlikely that a pipeline would be built in order to support such a small fleet size; in fact, it is unlikely that auto manufacturers would have a production run of such a small number of vehicles. The impact of the pipeline costs would diminish, however, as the number of vehicles supported by the pipeline infrastructure grows, until such a time as the pipeline has reached its maximum capacity.

It is beyond the scope of this study to determine optimal distribution pathways for various fleet sizes, and further work on this topic is probably warranted. As such, it is difficult to draw conclusions with respect to the competitiveness of the centralized pathways based on this analysis. However, these results can lead to some generalized conclusions regarding the applicability of centralized versus decentralized production. In communities that have small fleet sizes, such as rural areas and communities, decentralized production may prove to be a more economical solution for providing hydrogen fuel. In contrast, as the sensitivity analysis has indicated that centralized production with a pipeline distribution infrastructure can become economical once the fleet size reaches a sufficient size, more densely populated regions of the country may be best served under such a model.

The data available for some of the costs, including the price premium for a hydrogen fuelled fuel-cell vehicle over a gasoline fuelled internal combustion engine vehicle, are based on literature estimates and not actual cost data. Sensitivity analyses were conducted around critical factors, such as the capital costs for the equipment and the vehicle acquisition costs. The model has a reasonable margin of error when comparing the critical value of the total costs per km for any given pathway.

Incorporating the externalities in Part 2 of the study reinforced the degree to which vehicle acquisition and other non-fuel related costs affect the total costs. For example, for the light-duty vehicles, the costs associated with emissions improved the relative costs of some of the hydrogen pathways as compared to the gasoline pathways. However, these improvements were countered when the associated safety costs were included. For the light-duty vehicles, these safety costs directly affected the operating costs for the vehicle, not the price of the fuel.

The situation differs for the heavy-duty vehicles. For some of the hydrogen pathways, the additional cost imposed by incorporating the safety costs countered the relative cost gains that occur, relative to diesel, from including emissions costs. However, there was still an overall improvement. The safety costs primarily affected the price of the fuel, not the operating costs for the vehicle.

In Part 3 of the report, policy options that could make hydrogen more competitive with gasoline and diesel were examined, as well as options that could also encourage emissions reductions.

The results in Part 3 were consistent with those in Parts 1 and 2. In particular, policy options that directly decreased the costs of operating a hydrogen fuel-cell vehicle resulted in hydrogen pathways that are competitive with gasoline and diesel. For example, a provincial sales tax exemption on the purchase price of a hydrogen fuel-cell vehicle, in conjunction with excise tax exemptions for hydrogen, yielded four competitive light-duty vehicle hydrogen pathways, and one competitive heavy-duty vehicle pathway.

The use of sales and excise tax incentives is largely technologically neutral across the various hydrogen production methods. As a result, it does not address the possible policy goal of reducing greenhouse gas and other airborne emissions. To achieve this objective, an emissions tax is the most effective instrument. An emissions tax on the production of fuel yielded results for the light-duty vehicles quite similar to the sales and excise tax exemptions: four pathways become competitive, but not cheaper, than gasoline. Emissions taxes were not quite as effective for the heavy-duty vehicles: none of the modelled pathways become competitive.

Implementing the sales and excise tax exemptions in conjunction with emissions taxes yields more effective results. All of the light-duty vehicle hydrogen pathways are competitive with gasoline. In fact, most of the hydrogen pathways become less expensive than gasoline. For the heavy-duty vehicle pathways, one pathway (the methanol reformer) falls below the costs for diesel, with another pathway (decentralized steam methane reforming) becoming competitive.

One of the advantages of the combination of sales and excise tax incentives for the consumer, and emissions tax incentives for the producers, is that the revenues from the emissions taxes can help to offset the lost revenues from the sales and excise tax exemptions.

One factor in regards to this combination of policy support instruments that needs to be considered is that these instruments are largely focused at supporting adoption of low-associated emission hydrogen in the domestic market, but does not necessarily support the development of a hydrogen export market.

The imposition of the emissions taxes will raise the cost of all fuels being produced, which could make exports of those fuels less competitive, while the sales and excise tax exemptions only benefit the domestic market. When exporting hydrogen, the producer could be granted a credit for their emissions tax, similar to the export of goods under the GST, in order to make domestically produced hydrogen competitive on the international market. However, this could make domestic producers prefer to sell internationally, and lead to supply issues for the domestic market, driving up the price of hydrogen, thereby making hydrogen uncompetitive with gasoline once again.

Another issue associated with the international trade of hydrogen, in the presence of domestic emissions taxes, is how to deal with imports. If hydrogen is imported, an import tariff might need to be imposed to reflect the domestic emissions taxes, but the method of production of the imported hydrogen might not be known. This raises the questions of whether imported hydrogen should have to have its production method identified, or should a general tariff, equivalent to the average emissions rate, be applied?

Further work is obviously needed in a few areas. First of all, the production costs for the pathways in this study need further analysis, probably requiring the advice and support from the industry. Secondly, other pathways need to be considered, such as alternative vehicle types, alternative methods of distributing hydrogen from a centralized production facility, and other methods of production. Finally, an understanding of how the international market for hydrogen might operate, and how that market would interface with domestic policies, needs to be analyzed.

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Appendix A: Adoption of Hydrogen Fuel Cell Vehicles

Size of the Fleet

In this study a fleet size of 5,000 personal light vehicles, and 500 mass transit vehicles has been chosen to determine the quantity of fuel the production equipment will need to produce. These numbers are somewhat arbitrarily chosen and are not meant to serve as a prediction regarding the adoption rate of hydrogen fuel cell vehicles. To put these numbers in context, these numbers correspond to roughly the size of the total taxi fleet in Toronto, and one-third the bus fleet of the TTC.

Charts 1, 2, and 3 of this Appendix to the study show possible adoption scenarios for hydrogen fuel cell vehicles. These adoption scenarios are based on Natural Resources Canada HFC vehicle incremental and accelerated penetration forecasts outlined in the table below.

Light Personal FCV Penetration Forecasts.

	Incremental	Accelerated
2010	9,956 cars	19,912 cars
2020	694,740 cars	1,331,585 cars

The adoption scenarios presented in Appendix A display an s-curve growth in the fleet of fuel cell vehicles. Based in these charts, the scenario of a fleet of 5,000 personal light vehicles would take place sometime between the year 2008 and 2009, in both the rapid and slower adoption scenarios.

However, the actual growth rate is not likely to display the slow incremental ramp up in the number of vehicles in the early years as displayed in Appendix A. It is unlikely manufacturers would be willing to produce vehicles in the small numbers that occur in the initial years of the charts (eg 10 cars in 2004, 30 in 2005, etc.). This is an example of the classic “chicken and egg” dilemma that can face the launch of any new class of product, such as that faced by the introduction of CDs and DVDs, where studios wouldn’t release products in the new medium until consumers owned the hardware, and consumers didn’t want to own the hardware until product in the new medium was available. The solution to the dilemma usually relies on there being a number of “early adopters” who are willing to pay the high initial costs of the new product, in order to reap the benefits the new product might offer.

In this case, the early adopters might well be owners of large fleets of vehicles, such as taxi companies. Such early adopters would be able to purchase vehicles in sufficient numbers so as to be attractive for manufactures to start a new production line. In addition, fleet owners are also more likely to make investments in their own fuelling infrastructure, a significant hurdle faced by any early adopter of these vehicles.

This could also affect the pattern of adoption in rural verses urban areas. As the bulk of large fleet operations are centred in urban areas, this will likely help bring publicly available fuelling infrastructure to urban areas. If there are distribution pipelines, or fuel delivery vehicles, already supporting the area, commercial fuelling stations will be able to draw upon those resources.

In contrast, the infrastructure to support commercial refuelling stations in rural areas would need to be developed in isolation. As discussed in the conclusion of this study, this would likely involve investments in small, decentralized hydrogen production facilities, on-site at those refuelling stations.