Greenhouse Gas and Cost Impacts of Canadian Electric Markets with Regional Hydrogen Production

***

for
Natural Resources Canada

FINAL REPORT

March 2004

***

by
ICF Consulting Inc.

powered by perspective

This Page Intentionally Blank.

EXECUTIVE SUMMARY

Transportation, vehicle-related greenhouse gas (GHG) emissions contribute a significant portion of Canada's national GHG emission totals. Therefore, the national climate change plan has provided support for transportation measures. One measure to reduce transportation GHG emissions being considered is encouraging advancements to achieve a hydrogen production and fuelling infrastructure for fuel cell vehicles.

The analysis presented in this report provides an evaluation of the potential for economic production of hydrogen by electrolysis within Canada in the context of the power generation sector. This assignment is intended to support Natural Resources Canada and the Canadian Transportation Fuel Cell Alliance (CTFCA) in the ongoing work of evaluating the viability of electrolysis as a fuelling pathway to hydrogen by assessing the supply of electricity available within each province and the cost and GHG emissions associated with that supply in the context of added demand due to hydrogen production. In Phase 1, the bulk of the effort was spent in building and running a model of the power generation sector across Canada and carrying out the order-of-magnitude analysis. In Phase 2, efforts were concentrated on refining the assumptions from Phase 1 and running the new scenarios along with several sensitivities. This analysis includes results of Phases 1 and 2 for the key years 2010 and 2020 (providing medium- and long-term outlooks) under several hydrogen demand scenarios.

The method employed to accomplish this task involved the following three steps:

1. Quantify additional electricity demand to meet hydrogen requirements based on forecast penetration of fuel cell vehicles in Canada's transportation fleet (discussed in Sections 2 and **3** with Phase 1 and 2 specific factors);
2. Run the IPM® model utilizing the data from step one to determine the response of provincial electric markets to that increased demand (discussed below); and
3. Quantify the GHG impact through the application of life-cycle emission factors to the modelling outputs of electric generation by capacity type (discussed in Sections 2 and **3** with Phase 1 and 2 specific factors).

In Phase 1 (P1), ICF was instructed to make the simplifying assumption that only light-duty vehicles (cars) would adopt hydrogen technology. The resulting number of vehicles as well as fuel efficiencies and electricity required to produce hydrogen were provided by Natural Resources Canada and the Studies & Assessments Working Group (SAWG) of the CTFCA. Another key assumption was that the hydrogen stations would take advantage of lower, off-peak electricity prices and produce hydrogen in the off-peak hours only. (This assumption was tested in a Phase 2 sensitivity described below.)

In Phase 1, two scenarios were considered to reflect differing rates of adoption of hydrogen-powered fuel cell vehicles. The scenarios were labelled “Incremental” and “Accelerated” based on the degree of vehicle penetration.

- In the **P1 Incremental Scenario**, penetration rates in 2010 and 2020 of 0.5 percent and 6 percent, respectively, were adopted.
- In the **P1 Accelerated Scenario**, 1.8 percent and 11.5 percent penetration rates were adopted in the same years, respectively.

Both scenarios in Phase 1 assumed that the additional energy load required to supply the demand for electrolysis would be spread over the off-peak generation hours (as defined by the load profile of each province) to take advantage of low-cost power.

In Phase 2 (P2), the parameters from Phase 1 were refined to include more “realistic” rates of adoption, as defined by the SAWG, of hydrogen-powered fuel cell vehicles, disaggregation of the vehicles utilizing hydrogen (into cars and light-duty trucks), revised gasoline consumption, hydrogen consumption and electricity required to electrolyse water to produce hydrogen. Similar to Phase 1, “Incremental” and “Accelerated” scenarios were analyzed.

- In the **P2 Incremental Scenario**, penetration rates in 2010 and 2020 of 0.1 percent and 6.0 percent respectively were adopted.
- In the **P2 Accelerated Scenario**, 0.2 percent and 11.5 percent penetration rates were adopted in 2010 and 2020, respectively.

As in Phase 1, both of these scenarios assumed that additional power electric demand would be spread over off-peak hours.

In addition to revising the two core scenarios, the SAWG specified two sensitivities on each of those Phase 2 core scenarios:

- A **High Carbon Price** of $53.33CDN/tonne of CO_2 ($40USD/tonne)
- Additional power demand for electrolysis was distributed throughout the day to include peak power generation hours, rather than loading the additional demand in only off-peak hours (**Time-of-Day**).

The total estimated increase in electricity required (at the regional level) to meet hydrogen demand through electrolysis was determined for 2010 and 2020 under the Incremental and Accelerated penetration scenarios based on the energy equivalency of the fuels, or the amount of fuel (gas or hydrogen) required to drive an LDV the equivalent distance. Therefore, an equivalent amount of hydrogen can be estimated and the required electricity to produce the necessary hydrogen can be calculated. A very important assumption is that all hydrogen will be produced via electrolysis. Analysis in this report does not extend to the concept of competing technologies or sources for hydrogen production. Sensitivity to these factors was outside the scope of this study.

Both the Phase 1 and 2 analyses were performed using ICF Consulting’s proprietary Integrated Planning Model (IPM®). IPM® was used to project regional capacity additions, generation, emissions and electric prices for each of the provinces studied based on the additional demand specified under each of the scenarios. These results were then used to determine the relative economic and environmental impacts, in terms of greenhouse gas (GHG) emissions, of increased electricity demand for hydrogen production across Canada.

Representing the Canadian electric system for an analysis such as this required several assumptions, including an accurate representation of existing generating units in each province, transmission linkages between provinces, and peak and energy demand forecasts by province. Based on these inputs and other assumptions reviewed and approved by Natural Resources Canada, IPM® was used to forecast operation (dispatch) of existing units and the addition and operation of new capacity by province to meet the electric demand for electrolysis. The dispatch of existing and new units in the system was aggregated by capacity type to provide the basis for the quantification of the GHG emissions impact.

Finally, it is important to note that the overall project objective (Phase 1 and Phase 2) was to analyse the potential impacts on national GHG emissions and consumer cost of supplying additional electricity required to supply hydrogen (through the electrolysis of water) to the transportation sector for use in fuel cells. In order to clearly define the project, the scope of the study was limited in the following ways:

- The scope of this analysis focussed only on electrolysis as a fuelling pathway. Other production technologies such as steam methane reforming could also be used to produce hydrogen but these sources of hydrogen were not included in the analysis.
- The electric markets alone were considered in this study. No costs associated with hydrogen production infrastructure were considered, nor was any account made for the cost of water used in electrolysis (9L per kg of H_2).
- Nine of the Canadian provinces were modelled with electricity transmission interconnections specified. Prince Edward Island was excluded because it imports the majority of its power and has limited transmission capability. The Territories were also not included due to their differing power generation structure when compared to the rest of the country.
- Only the years 2010 and 2020 were modelled in order to provide 10- and 20- year outlooks for the power generation sector.
- Emission factors used in step 3 were "life-cycle" based. Therefore, the GHG emissions displaced may not occur in the same region or country as the electricity use. For example, production and refining may not occur in the same region as the electricity use.

Results

The cost and emissions impacts of generating the electricity necessary to supply the demand for hydrogen are driven by the mix of capacity types used to supply the electricity. The system response to the increased power demand was similar in both Phase 1 and Phase 2 Incremental and Accelerated scenarios. The additional electricity required to produce hydrogen is supplied by a combination of existing generation, generation from new, gas-fired combined cycle units and trade. Some provinces are able to meet demand from internal resources. For example, British Columbia is forecast to reduce exports and utilize existing, provincial capacity to meet additional demand. Other provinces, such as Ontario, are likely to require additional imports and new capacity. Because of its competitive cost and environmental performance, all new capacity added to the system in 2010 and 2020 is gas-fired combined cycle.

The provincial dispatch mix was used to determine the GHG impact of the additional power demand for hydrogen production. The net GHG impact was calculated as the sum of the emissions increase from power production less the avoided emissions from replacing gasoline. All emissions were estimated using life-cycle emission factors to capture a more complete footprint of the fuel use. Therefore, even though results are presented on a provincial or federal level, the emissions incurred or avoided may be representative of larger boundaries (Canadian vs. provincial and international vs. national). For example, emission factors for coal include upstream activities plus combustion; however, the coal combusted in Ontario may have been produced and refined in the Western provinces or the U.S.

As expected, provinces dependent on fossil fuels fare worse than those provinces that utilize hydroelectric, nuclear or a broader mix of capacity types with regard to the impact of producing hydrogen via electrolysis. In the lower-emitting provinces, fewer incremental emissions are produced per unit of hydrogen. However, regardless of the provincial capacity mix, the same amount of emissions from gasoline-powered LDVs is displaced per unit of hydrogen. Therefore, from an environmental standpoint, the lower-emitting provinces reflect the best opportunity for realizing emissions reductions by switching to hydrogen-based transportation. Since, a hydrogen fuelling infrastructure would have to be implemented country-wide, however, federal net change must be considered.

Figure E- 1 shows the change in GHG emissions by province in 2020 under the P1 Accelerated Scenario. These results are representative of all Phase 1 scenario runs. Taking into account the displaced emissions from gasoline use and assuming all provinces implement hydrogen production, Canada would see a net GHG reduction between 1.1 and 2.2 million tonnes in 2020 from the P1 Incremental and P2 Accelerated scenarios, respectively. In other words, the GHG emissions associated with the gasoline displaced by hydrogen exceeded, on a national basis, the emissions associated with the electricity required to generate the hydrogen.

When interpreting the GHG emissions results for both Phases 1 and 2, the reader should note that these emissions forecasts are based on life-cycle emissions factors applied to the generation mix supplying the electricity for electrolysis in the hours examined (i.e., off-peak and peak). While the displaced emissions from gasoline may offset those calculated emissions, total GHG emissions from the electric sector may increase relative to the Base Case in response to supplying the additional demand required for electrolysis. The overall impact on Canada-wide emissions based on additional generation alone was not the focus of this study and has not been calculated for this analysis.

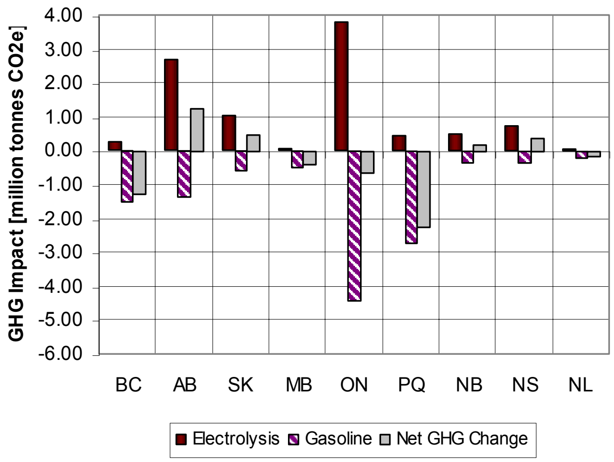


Figure E- 1 GHG Impact in P1 2020 Accelerated Scenario

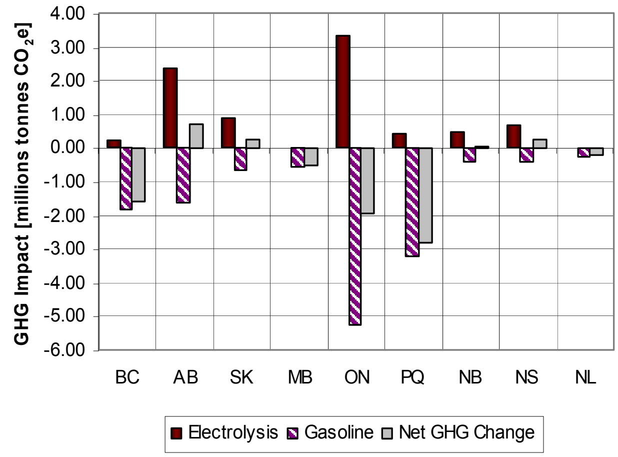


Figure E- 2 GHG Impact in P2 2020 Accelerated Scenario

Figure E- 2 presents net GHG emissions impact in 2020 under the P2 Accelerated Scenario. Under the Phase 2 scenarios, Canada would see a net GHG reduction between 2.9 and 5.6 million tonnes of CO_2 in 2020 from the P2 Incremental and P2 Accelerated scenarios, respectively.

Given the assumptions used in Phase 1 of the analysis, the power-generation emissions-intensity threshold for beneficial GHG impacts was 0.44 tonnes of CO_2e/MWh in 2010 and 0.42 tonnes of CO_2e/MWh in 2020. This threshold represents the electricity equivalent emissions from combustion of gasoline. Provincial systems comprised mainly of natural gas turbines do not achieve these rates. At least some share of hydroelectric, nuclear or other non-emitting sources of electricity is therefore required to make hydrogen production via electrolysis viable. However, in Phase 2, the threshold increased to 0.53 tonnes of CO2e/MWh due to the inclusion of light-duty trucks among other assumptions. Figure E- 3and Figure E- 4 show the GHG intensities of the nine provinces studied relative to the 2020 target intensity of 0.42 tonnes CO_2e per MWh for Phase 1 and 0.53 tonnes CO2e per MWh in Phase 2.

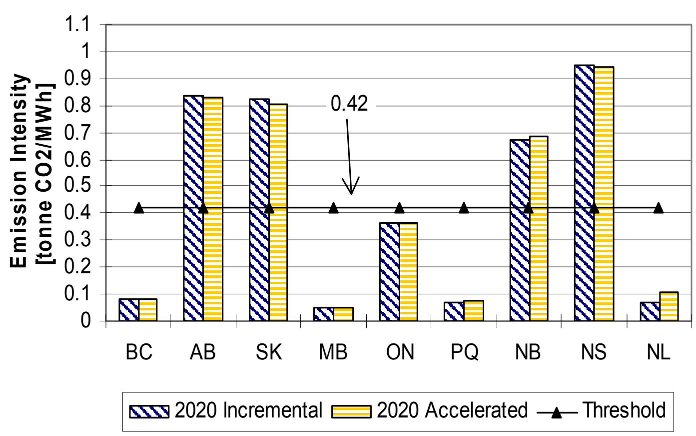


Figure E- 3 Phase 1 Power Generation Emission Intensity

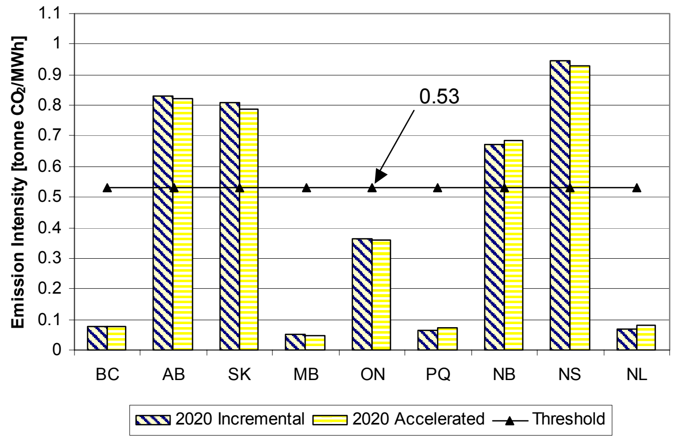


Figure E- 4 Phase 2 Power Generation Emission Intensity

In Phase 1, wholesale electricity prices increased by up to 15 percent in 2020 in the P1 Incremental Scenario and by over 20 percent in 2020 in the P1 Accelerated Scenario. The magnitude of the impact in each province depended on the manner in which it chose to meet the additional demand requirements. In many regions, the additional generation was supplied by existing or new gas-fired capacity. The time of the day during which the additional power was generated impacted the average price of the day. In the Phase 1 analysis, it was assumed that the additional generation would be supplied in the off-peak hours only. When this extra load resulted in a new type of marginal generation, such as gas-fired capacity, coming on-line when previously no capacity of that type had been used in that time period, the marginal cost of production increased in that hour. Additionally, regions relying heavily on imports faced the higher prices realized in the supplying regions under the Hydrogen Scenarios and, therefore, realized higher average annual prices themselves.

In Phase 2, wholesale prices increased in all provinces, by slightly above 10% in 2020 in the P2 Incremental Scenario and by almost 15% in 2020 in the P2 Accelerated Scenario. Similar to Phase 1, additional generation was supplied by existing or new gas-fired capacity, which determined the impact on price.

Since the successful adoption of hydrogen will depend on its comparative cost relative to gasoline, the electricity costs were normalized to equivalent gasoline units for both Phases 1 and 2. The price of electricity to produce the hydrogen required to displace one litre of gasoline was found to range from $0.33 per kg of hydrogen (Ontario) to $0.24 per kg of hydrogen (Manitoba) in Phase 1. Figure E- 5 shows results for both the Incremental and Accelerated Scenarios. Compared to the average national market price of gasoline at the time of this analysis (January, 2004), $0.46/L (pre-tax) and $0.77/L (post-tax), hydrogen appears to be an economically-viable alternative. Similarly, Phase 2 normalized prices range from $0.19 per kilogram of hydrogen in Newfoundland and Manitoba to $0.25 in Ontario in the 2020 P2 Accelerated Scenario with regional results shown in Figure E- 6.

It is important to note that the prices presented above do not include costs associated with storing and distributing hydrogen at the retail level. These costs may prove to be significant but were not included in the scope of this study.

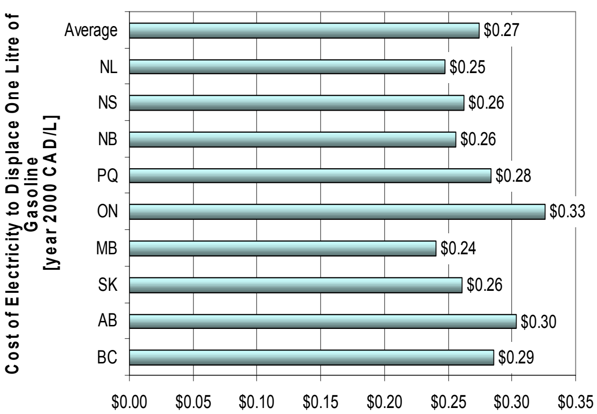


Figure E- 5 Cost of Electricity Required to Displace One Litre of Gasoline in Phase 1 (P1 2020 Accelerated Scenario)

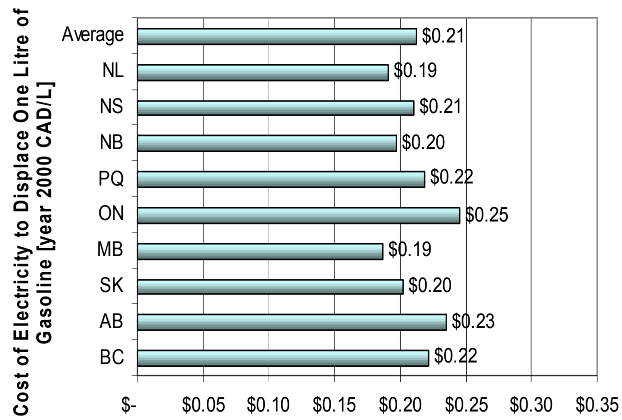


Figure E- 6 Cost of Electricity Required to Displace One Litre of Gasoline in Phase 2 (P2 2020 Accelerated Scenario)

For Phase 2, two sensitivity cases were run off of each Scenario, adding four runs to the already discussed Incremental and Accelerated Scenarios. The High Carbon Price sensitivity case showed that a $53.33CDN/tonne CO_2 ($40 USD/tonne) price was sufficiently high to move the fossil-dependent provinces away from coal toward greater dependence on gas or hydro capacity or imports from low-emitting provinces. This shift resulted in a large increase in country-wide net GHG reductions over the base scenario of 9.0 million tonnes of CO_2e in the 2020 Accelerated High Carbon Case versus 5.6 in the P2 2020 Accelerated Off-Peak Scenario. The new capacity built combined with the dependence on a higher cost fuel increased the average annual electricity prices over 80% in some provinces versus the P2 Accelerated Off-Peak scenario. As shown in Figure E-7, the normalized cost of electricity ranged from $0.23 per kilogram of hydrogen in British Columbia to $0.37 in Saskatchewan, which are still below the January 2004 market price of gasoline.

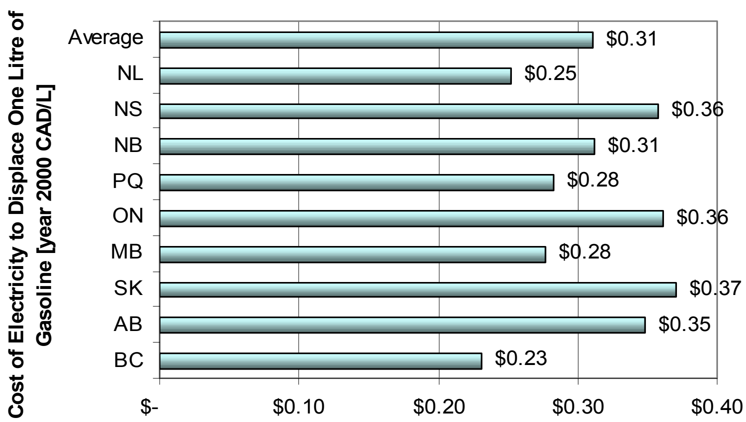


Figure E- 7 Cost of Electricity Required to Displace One Litre of Gasoline in Phase 2 High Carbon Sensitivity (2020 Accelerated)

The other sensitivity, the Time-of-Day sensitivity case, captured the impacts of raising not only the electricity demand, but the peak demand as well. In these cases, the additional demand for electricity for use in electrolysis was spread over all hours of the day rather than just the off-peak hours. The intent of the case was to reflect the necessity to produce and supply hydrogen for transportation needs throughout the day rather than just at night. The generation mix under these cases was very similar to the corresponding base scenario. However, there was a slight improvement in the net GHG impact with a total national reduction of 6.1 million tonnes CO_2 versus 5.6 million in P2 2020 Accelerated Scenario. The larger reduction in the Time-of-Day sensitivity was due to the more diverse, and less fossil-intensive, generation mix used to generate the additional electricity. Electricity prices also were higher under this sensitivity with an average provincial increase of 3.5%, numbers shown in Figure E- 8.

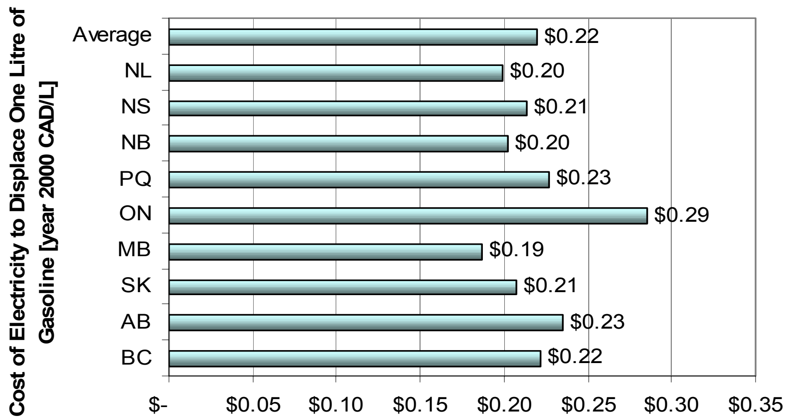


Figure E- 8 Cost of Electricity Required to Displace One Litre of Gasoline in Phase 2 Time-of-Day Sensitivity (2020 Accelerated)

TABLE OF CONTENTS

INDEX OF FIGURES

INDEX OF TABLES

ABBREVIATIONS

AEO - Annual Energy Outlook (U.S Department of Energy/Energy Information Administration)
AFBC - Atmospheric Fluidized Bed Combustion
AMG - Analysis and Modelling Group
Btu - British Thermal Units
CAD - Canadian
CC - Combined Cycle
CCR - Capital Charge Rate
CDN - Canadian
CERI - Canadian Energy Research Institute
CFS - Canadian Forest Service
CHP - Combined Heat and Power
CNA - Canadian Nuclear Association
CO_2 - Carbon Dioxide
CO_2e - Carbon Dioxide equivalent
CT - Combustion Turbine
CTFCA – Canadian Transportation Fuel Cell Alliance
ECAR - East Central Area Reliability Coordination Agreement
EIA - Energy Information Administration (U.S.)
EPA - Environmental Protection Agency
FERC - Federal Energy Regulatory Commission
FGD - Flue Gas Desulphurization
FOM - Fixed Operating and Maintenance Costs
GJ - GigaJoules
GW - Gigawatt
GWh - Gigawatt hour
HDV - Heavy-Duty Vehicles
Hg - Mercury
HHV - Higher Heating Value
ICE – Internal Combustion Engine
IDC - Interest During Construction
IGCC - Integrated Gasification Gas Combined Cycle
IPM® - Integrated Planning Model
IPP - Independent Power Producer
kg - kilogram
kW - kilowatt
kWh - kilowatt hour
LDGV - Light-Duty Gasoline Vehicles
LDT – Light-Duty Trucks
LDV - Light-Duty Vehicles
LFG - Landfill Gas
LSFO - Limestone Forced Oxidation
MAPP - Mid-continent Area Power Pool
MEL - Magnesium Enhanced Lime
MERS - Multi-pollutant Emission Reduction Strategy
mills - thousandth of dollars ($0.00#)
MJ - MegaJoules
MMBtu - Million British Thermal Units
MW - Megawatt
MWh - Megawatt Hour
NANGAS® - North American Natural Gas Analysis System
NCCP - National Climate Change Process
NEB - National Energy Board (Canada)
NEEDS - National (U.S.) Electric Energy System
NERC - North American Electric Reliability Council
NO_X - Nitrous Oxides
NPCC - Northeast Power Coordinating Council
NRCan - Natural Resources Canada
O&M - Operating and Maintenance
PM - Particulate Matter
RPS - Renewable Portfolio Standards
SAWG – Studies & Assessments Working Group
SCR - Selective Catalytic Reduction
SNCR - Selective Non-Catalytic Reduction
SMR – Steam methane Reforming
SO_2 - Sulphur Dioxide
t - metric tonne
VOM - Variable Operating and Maintenance Costs
WPPI - Wind Power Production Incentive
WSCC - Western Systems Coordinating Council

1 INTRODUCTION

1.1 BACKGROUND

Canada's 2001 Greenhouse Gas (GHG) Inventory[1] reported that transportation vehicle-related emissions have grown to 187,000 kt of CO_2 equivalent, or approximately 25 percent of the national total. Therefore, any national plan to reduce Canada's total annual GHG emissions must address the transportation sector's dependence on fossil fuels. To this end, the Government of Canada's Action Plan 2000 on Climate Change established several programs aimed at reducing GHG emissions and decreasing fossil fuel consumption in the transportation sector through increasing vehicle fuel efficiencies and investing in the development of new fuels and technologies.

One of these programs established the five-year, $23-million Canadian Transportation Fuel Cell Alliance (CTFCA). Its principal objective is to encourage advancements in hydrogen and fuel cell technologies and to achieve GHG reductions by developing a fuelling infrastructure for fuel cell-powered vehicles.

Hydrogen is an energy carrier, or medium for energy storage. Today, 95 percent of hydrogen gas is consumed at the production site as a processing gas with 60 percent of global hydrogen used in ammonia production, 23 percent in petrochemical refining and 9 percent in methanol production[2]. Unlike coal or natural gas, hydrogen cannot be drilled or extracted directly from the ground. Hydrogen must be produced through a variety of available methods, all requiring an input of energy. Hydrogen production methods include but are not limited to: steam methane reforming, coal gasification, partial oxidation of hydrocarbons, biomass gasification, biomass pyrolysis, electrolysis, and photoelectrolysis.

The two best understood and most commercially-used hydrogen production technologies are steam methane reforming (SMR) and electrolysis. SMR is a well-developed (80 percent of current global hydrogen production), fully commercialized process by which high temperature steam (+700^{o}C) in the presence of a catalyst is used to crack methane. However, due to SMR's use of hydrocarbon-based fuels, this technology will continue to face issues related to depleting resources and greenhouse gas emissions.

Electrolysis is a process in which hydrogen is produced by an electrochemical reaction between electricity and water. By passing an electric current between two metal electrodes in water, a very pure hydrogen gas is formed at the negative electrode and oxygen at the positive electrode. The large advantage of electrolysis lies in its stability in providing distributed, small-scale hydrogen production on-site and by eliminating the need for an extensive hydrogen infrastructure, storage or transportation. It therefore opens the door for hydrogen production at fuelling stations, residences and commercial buildings. Additionally, coupled with renewable energy, hydrogen may be produced via electrolysis in a zero emissions manner.

This environmental advantage, however, will be realized only if the consumer accepts the cost of hydrogen produced via electrolysis as reasonable. Additionally, environmental impacts must be considered; that is, the net carbon impact from substituting gasoline with hydrogen as a transportation fuel source and from emissions related to the generation of electricity to produce the hydrogen. The cost of hydrogen production will depend largely on the cost of the electricity inputs into the process and is, therefore, dependent on the characteristics of provincial energy production systems. The generation mix within a province, or the combination of fuel sources used to generate electricity, will be a key determinant of the production cost and of the net environmental impact. To

[1] Environment Canada, 2003
[2] Reed, 2002.

determine the economic viability of hydrogen production on a regional basis, therefore, a projection of the response of each province's electricity generation mix to the increased demand for electrolysis and the change in provincial power prices must be undertaken. Because of the nature of the transportation sector, however, the outcome must be considered on a Canada-wide basis.

The analysis presented in this report provides an evaluation of the potential for economic production of hydrogen by electrolysis within Canada in the context of the power generation sector. This assignment is intended to support Natural Resources Canada and the CTFCA in the ongoing work of evaluating the viability of electrolysis as a fuelling pathway to hydrogen by assessing the supply of electricity available within each province and the cost and GHG emissions associated with that supply. In Phase 1, the bulk of the effort was spent in building and running a model of the power generation sector across Canada and carrying out the order-of-magnitude analysis. In Phase 2, efforts were concentrated on refining the assumptions from Phase 1 and running the new scenarios along with several sensitivities. This analysis includes results of Phases 1 and 2 for the key years 2010 and 2020 (providing 10- and 20-year outlooks) under several hydrogen demand scenarios.

In Phase 1, two scenarios were considered that reflected differing rates of adoption of hydrogen-powered fuel cell vehicles. The scenarios were labelled "Incremental" and "Accelerated" based on the degree of vehicle penetration.

- In the Incremental Scenario, penetration rates in 2010 and 2020 of 0.5 percent and 6 percent, respectively, were adopted.
- In the Accelerated Scenario, 1.8 percent and 11.5 percent penetration rates were adopted in the same years, respectively.

In Phase 2, the parameters from Phase 1 were refined to include more "realistic" rates of adoption, as defined by the Studies & Assessments Working Group (SAWG) of the CTFCA, of hydrogen-powered fuel cell vehicles, disaggregation of the vehicles utilizing hydrogen (into cars and light-duty trucks), gasoline consumption, hydrogen consumption and electricity required to electrolyse water to produce hydrogen.

- In the Incremental Scenario, penetration rates in 2010 and 2020 of 0.1 percent and 6.0 percent, respectively were adopted.
- In the Accelerated Scenario, 0.2 percent and 11.5 percent penetration rates were adopted in 2010 and 2020, respectively.

In addition to revising the two core scenarios, the SAWG specified two sensitivities to each of those Phase 2 core scenarios:

- A high carbon price of $53.33CDN/tonne of CO_2 ($40USD/tonne)
- Additional power demand for electrolysis was distributed throughout the day to include peak power generation hours, rather than loading the additional demand in only off-peak hours, as was done for the core scenarios

The analysis in both phases was performed using ICF Consulting's proprietary Integrated Planning Model (IPM®). IPM® was used to project regional capacity additions, generation, emissions and electricity prices for each of the provinces studied based on the additional demand specified under each of the scenarios and sensitivities.

The IPM® outputs from Phases 1 and 2 were used to determine the relative economics and environmental impacts of increased electricity demand for hydrogen production, thereby identifying provincial-level cost and GHG impacts associated with hydrogen production.

These analyses serve as a foundation upon which to base further analysis of hydrogen adoption rates, provincial energy systems and the use of hydrogen in offsetting Canadian carbon emissions.

1.2 METHODOLOGY

The analyses in Phases 1 and 2 provided an assessment of the electric power generation sector in Canada and attempted to represent the diverse and unique structure of the power generation industry at the regional level under several scenarios associated with hydrogen production. Evaluation of the potential for and potential cost of a hydrogen production infrastructure was outside the scope of this project and was not addressed in either Phase 1 or 2. This section describes the analytic framework used in developing an assessment of Canada's generation system and the regional intricacies in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia and Newfoundland and Labrador.

1.2.1 Objective & Scope

The overall project objective (Phase 1 and Phase 2) was to analyse the potential impacts on national GHG emissions and consumer cost of supplying additional electricity (by electrolysis of water) required to supply hydrogen to the transportation sector for use in fuel cells. The method employed to accomplish this involved the following three steps:

1. Quantify additional electricity demand to meet hydrogen requirements based on forecast penetration of fuel cell vehicles in Canada's transportation fleet (discussed in Sections 2 and 3 with Phase 1 and 2 specific factors);
2. Run IPM® model utilizing the data from step one to determine the response of provincial electric markets to that increased demand (discussed below); and
3. Quantify the GHG impact through the application of life-cycle emission factors to the modelling outputs of electric generation by capacity type (discussed in Sections 2 and 3 with Phase 1 and 2 specific factors).

In order to clearly define the project, the scope of the study was limited in the following ways:

- The electric markets alone were considered in this study. No costs associated with hydrogen production infrastructure were considered, nor was any account made for the cost of water used in electrolysis (9L per kg of H_2).
- Nine of the Canadian provinces were modelled with electricity transmission interconnections specified. Prince Edward Island was excluded because it imports the majority of its power and has limited transmission capability. The Territories were also not included due to their differing power generation structure when compared to the rest of the country.
- The years 2010 and 2020 were modelled in order to provide 10- and 20- year outlooks for the power generation sector.
- Emission factors used in step 3 were "life-cycle" based. Therefore, the GHG emissions displaced may not occur in the same region or country as the electricity use. For example, production and refining may not occur in the same region as the electricity use.

1.2.2 Approach

To analyze the impacts of increasing demand for electricity on provincial energy markets and CO_2 emissions, a number of basic assumptions common to both phases of work had to be made.

- The fuelling regime across the study period was assumed to remain constant. Information on forecasts of 2010 and 2020 fuel usage were provided by Natural Resources Canada.
- The penetration rates (applied to total vehicle fleet) were assumed to capture other vehicle types.
- Only light-duty vehicles (LDVs[3]) were considered and all vehicles were assumed to rely on gasoline.
- The IPM®'s Base Case was built in January 2003 on the most current information publicly available at the time and represents a business-as-usual (BAU) scenario. It assumes continuation of the current electricity demand based on third-party sources that do not include expanding electricity demand to produce hydrogen.

Given the diverse nature of the power sector across the Canadian landscape and the sophisticated tools and level of analyses available to this sector, the modelling for this project must be based on a detailed sector representation accounting for transactions between sources and across provincial borders. The analytic framework was required to capture the regional opportunities for growth in the power sector while taking into account constraints, regulations and guidelines. In addition, the framework should capture the response of the power sector to expected changes in the electric market over time, including changes in capacity and other factors that may affect the sector's operations. Furthermore, the analysis should capture detailed dispatch changes and investment decisions (including renewables and repowering) as well as emission control options and new technologies.

To satisfy these analytical needs, ICF employed IPM® to forecast electricity prices and power capacity dispatch choices by province. The goal was not to generate specific GHG emission values or predict exact costs of electricity per unit of hydrogen produced. Rather, it was to create a tool to be used to provide insight into the possible impacts from different policy perspectives and also assess the impacts of changes in policy, technology, and commodity fuel prices over time.

To perform the analysis, ICF began with a 'control' or 'Base' Case (often called "Business as Usual") against which alternate scenarios would be compared. These alternate cases can be thought of as experiments to determine the impact of changing the electric demand assumptions in response to the need for electrolysis. Key assumptions for the Base Case are addressed later in this section and in Appendix A. When the Base Case assumptions and the formulation of the scenarios are internally consistent, the difference between a scenario and the Base Case will reflect the impact of the difference in the key variable. In the core scenarios modeled, this key variable was the increased demand for electricity required to produce hydrogen to fuel LDVs via electrolysis.

Analysis Methodology and The Integrated Planning Model (IPM®)

IPM® is a detailed engineering-economic capacity expansion and production costing model of the power sector that simultaneously accounts for conditions in the wholesale electric, fuel and environmental markets. IPM® determines the least-cost way to meet a system's electricity demand, provided by the user, while meeting a number of constraints over the time frame under study. Figure

[3] Defined as 10,000 lbs or less. Phase 1 represented the fleet as cars. Phase 2 represented the fleet as cars and light-duty trucks.

1-1 diagrams the key inputs and outputs of IPM®. The boxes on the top and sides of the diagram reflect the inputs and constraints to the model, including transmission capacity among regions, the cost and performance of new capacity options and components of environmental regulations.

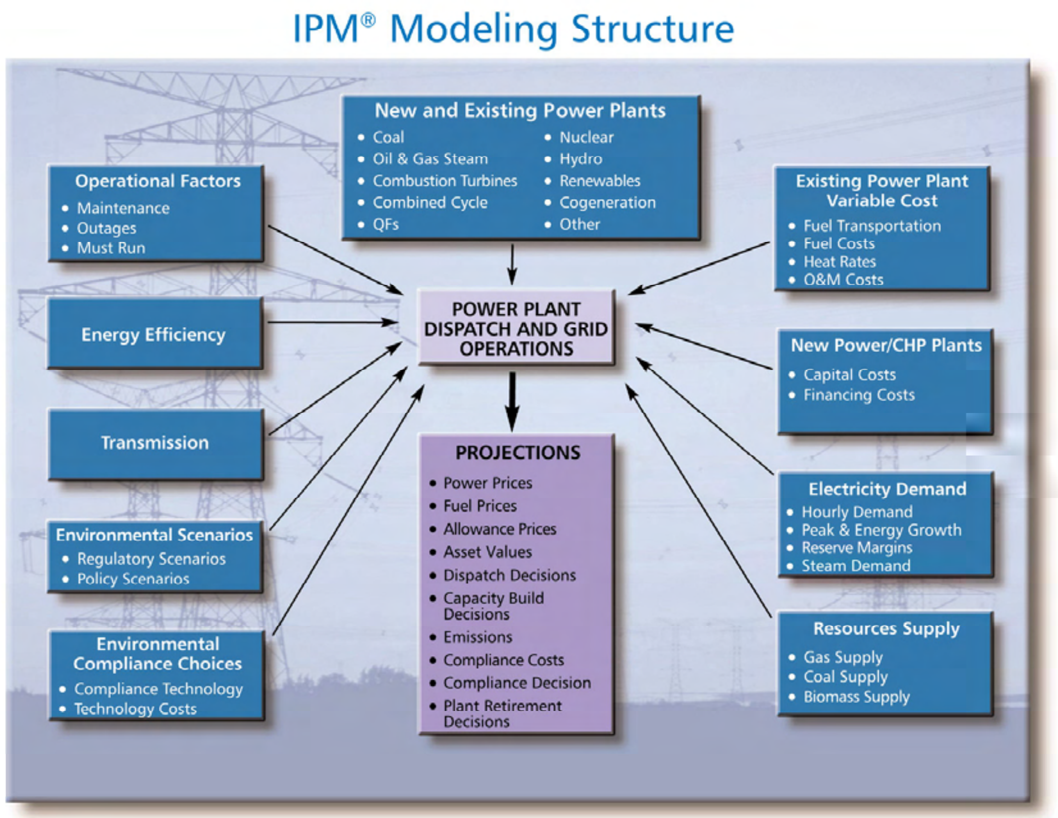


Figure 1-1 The Integrated Planning Model®

The model is based on a detailed database containing cost and performance information for all grid-connected boilers and generators in Canada. A portion of this database was developed as part of Phase 1 of this study. This unit population served as the starting point for this analysis upon which to examine the potential for the market to meet additional demand created by the need for electrolysis to produce hydrogen.

For each modelled year in IPM®, demand is defined by the total level of electricity required to be generated and the peak demand level. Because IPM® dispatches the system on the basis of seasonal load duration curves, an hourly load curve is also required. The hourly load curve reflects the relative demand in each of 8760 hours in the year. IPM® converts this load curve into “load segments” for a typical year based on the seasonal definition used in the modelling – in this case, four seasons, each with 10 segments (from peak to base). The load curve for a typical, or weather-normal year, is scaled to match the energy and peak forecasts for each model run year.

For the purpose of this project, hourly load curves for each region were obtained directly from the utilities in each region, where available. These curves were used to represent the hourly profile of future electric demand. In Alberta, the load curve was obtained from the Alberta Power Pool.

Manitoba and New Brunswick were the only regions for which we were not able to obtain actual data. For those provinces, load curves from neighbouring, similar regions were used.[4]

For this analysis, the additional demand was exogenously calculated and entered into IPM® as a revised input to the Base Case. To determine the least cost method of meeting this higher demand, IPM® compares the relative economics of constructing a new generating unit with the cost of alternative sources of electric power, including increasing dispatch at existing units, if possible, and/or adjusting net exports. A wide variety of new capacity options, both fossil and renewable, are defined for IPM® to select from, all characterized in terms of their capital costs, operating and maintenance costs, fuel costs, fuel quality, heat rates, reliability, environmental performance and construction lead times. In evaluating the potential for import/export, IPM® considers transmission capability among regions, as defined by the user, and the cost of transmitting power. The regions modelled for this analysis are shown in Figure 1-2[5].

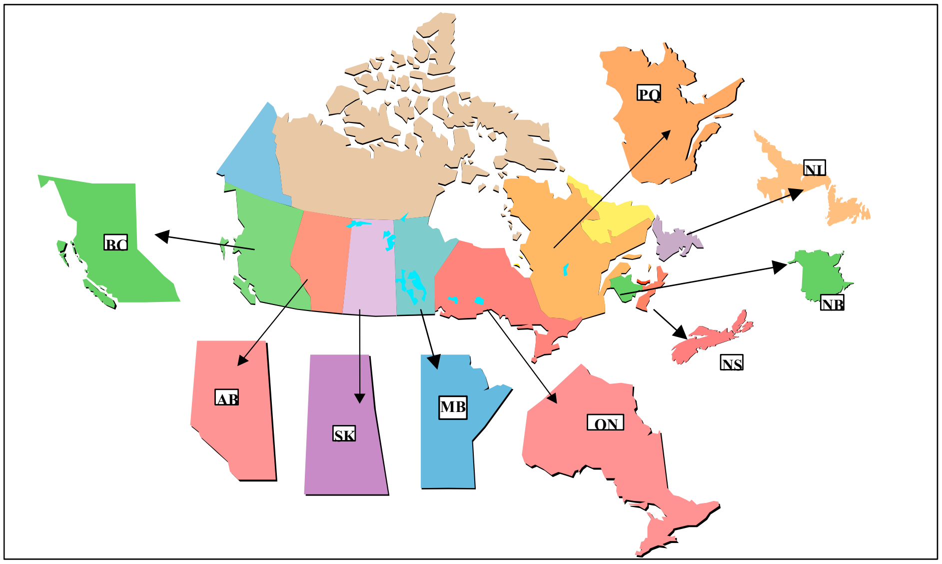


Figure 1-2 Geographic Structure – Modelled Provinces

For the purposes of this analysis, no explicit constrains were placed on the types of capacity development needed to supply the additional electric demand. All capacity addition decisions were made endogenously within IPM® on the basis of the relative economics of the options provided. Non-economic interests in provinces that may influence the choice of a particular type of new capacity over another, therefore, were not addressed. As discussed below, however, firmly planned capacity additions available at the beginning of the study were included.

IPM® dispatches, or operates in a given time period, new and existing units based on their marginal cost of generation, including fuel costs, operations and maintenance costs, and any environmental charges that are incurred as a result of operating the unit. Generation from units is "stacked" from the low-cost provider to the highest cost provider, accounting for any operating constraints on the units, until the electric demand in a particular load segment is met. IPM® simulates a competitive wholesale electric market, so the electric price in any year, season and load segment modeled within IPM® is set by the marginal cost of generation in that segment.

[4] The British Columbia load shape was used to approximate Manitoba's load shape since it was also a heavily hydro-dependant province. The load shape from the utility Maine Central Power was used to approximate New Brunswick's load shape due to geographical proximity.
[5] Prince Edward Island was not modelled due to its relatively small generation capacity and limited transmission capability. Territories were also not modelled due to their power generation structure.

Key outputs resulting from the least cost solution arrived at by IPM®, therefore, include dispatch at each unit by segment, season and year, capacity additions in each province, transmission among provinces, and provincial electric prices. As described above, all price results from IPM® are marginal price results, even though those marginal prices may be averaged over the course of a year to generate a yearly marginal price. Because IPM® is a bottom-up model, all operating data, including generation, fuel input, cost and emissions, are available at the unit level, as well as aggregated into provincial results.

In arriving at its solution, IPM®, like any model, takes into account only the data provided to it. To this end, ICF attempts to maintain up-to-date information on likely capacity additions and pollution control installations by tracking public announcements. New capacity that is considered "firm", meaning at or very near construction, is entered into IPM® and considered in the solution. Similarly, operational requirements, such as must-run constraints, are also implemented as information permits. Recent announcements regarding planned capacity additions that were not incorporated into this analysis because of the timing of the information, may change the model results.

Base Case

The Base Case represented a business-as-usual scenario as it assumed continuation of current requirements and demand, and was the starting point of comparison for the demand scenarios. For both phases, a common Base Case, created under the Phase 1 effort in January 2003 was used in order to ensure consistency and comparability of the results. Inputs were based on best available data at that time. For purposes in this report, the Base Case was assumed to include existing environmental regulations in Ontario and a CO_2 policy representative of what may occur with Canada's implementation of a Canadian Climate Change Policy. To carry out this analysis of the provincial-level electrical power sector in Canada, IPM® was populated with all relevant (and agreed to) information required to run the Base Case. Key assumptions for the Base Case are addressed later in this section. Other assumptions are included in Appendix A. It assumed that power generators in the nine provinces would meet future demand as forecasted from current BAU assumptions for electricity in a least-cost way, but face no additional energy requirements. For the Base Case, ICF worked with Natural Resources Canada to develop assumptions on key drivers including future base case electricity demand, cost and performance of generation technologies, and fuel prices.

Modelling Inputs

Building on IPM®'s database of existing generating units throughout Canada, the key data inputs were (1) transmission and (2) electricity demand.

Transmission Interconnections

Transmission links in IPM® connect the regions and allow for consideration of inter-regional trade. IPM® models power markets on a regional basis, explicitly modelling transmission linkages between regions. Nine provinces within Canada were modelled in this study: British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador. In the modelling, interregional transmission capabilities between contiguous (bordering) provinces are explicitly modelled. These transfer capabilities are represented as two-way capacity constraints.[6] Power can flow between the two regions, if economic to do so, up to the limit of the transmission capacity, taking into account losses and wheeling charges for use of the transmission system. Losses reflect a standard assumption of 3 percent per kWh transmitted, while the wheeling charge[7] is $3.88CDN/MWh.[8]

[6] NERC 2001a. and NERC 2001b.
[7] A "wheeling charge", which is also known in some markets as the "through" service, is the cost (imposed by a regional market operator and incurred by the transmission customer) for power transfers across a regional market with an approved open access transmission tariff.
[8] ICF standard assumption. Note that all dollar values are in year 2000 Canadian dollars.

Transactions with the U.S. were also modelled as the potential to purchase power at some average price up to the limits of the transmission tie between the two regions. This price was based on analyses by ICF.[9] These types of potential interactions were modelled for British Columbia, Saskatchewan, Manitoba, Ontario, Quebec and New Brunswick. Figure 1-3 and Figure 1-4 show the transmission capacities for each direction of power transfers. Note that while trade of electricity between Canada and the U.S. would likely shift in response to a carbon policy in Canada, the U.S. may be limited by capacity constraints and/or regulatory constraints, such as the Kyoto Protocol, from shipping additional, potentially fossil-fuelled power to Canada.

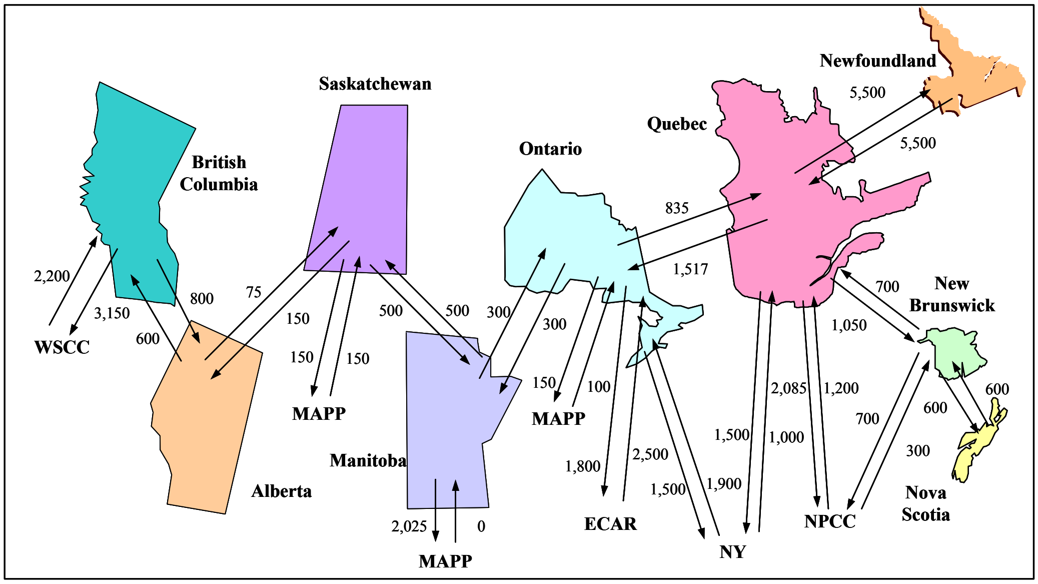


Figure 1-3 Summer Transmission Interconnect Capacities (MW)

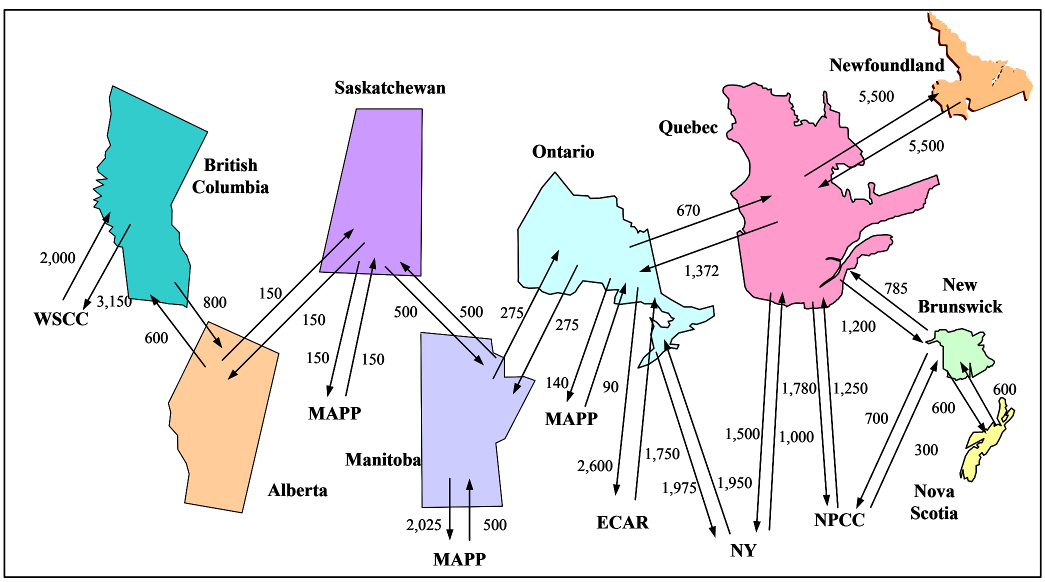


Figure 1-4 Winter Transmission Interconnect Capacities (MW)

[9] Price of potential transaction between the U.S. and Canada were based on ICFs' Bulk Power Service, an annual subscriber service of regional power market energy and capacity price forecasts, 2000.

Electricity Demand

The electricity demand was the basis for the scenario work as explained below. Forecasts of peak and energy demand were taken from the National Energy Board (NEB).[10] For the Base Case, the NEB higher demand case (Case 1) was used. Table 1-1 and Table 1-2 show growth rates over five year intervals for peak and energy demand by province.

Table 1-1 Provincial Peak Demand Annual Average Growth Rates

Province/ Time Interval	BC	AB	SK	MB	ON	PQ	NB	NS	NL
2000-2005	1.98%	1.61%	1.61%	1.60%	2.12%	1.32%	0.08%	0.64%	1.09%
2005-2010	1.20%	0.84%	1.35%	1.00%	1.89%	0.76%	0.46%	0.71%	1.11%
2010-2015	1.04%	1.84%	1.25%	0.91%	2.34%	1.11%	0.99%	0.77%	0.96%

Table 1-2 Provincial Energy Demand Annual Average Growth Rates

Province/ Time Interval	BC	AB	SK	MB	ON	PQ	NB	NS	NL
2000-2005	2.22%	1.71%	1.80%	1.91%	2.34%	1.67%	0.50%	0.90%	1.39%
2005-2010	1.43%	0.94%	1.55%	1.31%	2.10%	1.10%	0.87%	0.97%	1.40%
2010-2015	1.28%	1.93%	1.44%	1.20%	2.55%	1.44%	1.40%	1.04%	1.25%

Electric demand in Canada was assumed in this analysis to grow at roughly 1.7% per year from 2005 to 2020. By 2020, Canada will demand nearly 700,000 billion kWh of electricity and two-thirds of that demand will come from the provinces of Ontario and Quebec. Figure 1-5 below shows Base Case provincial demand in 2020.

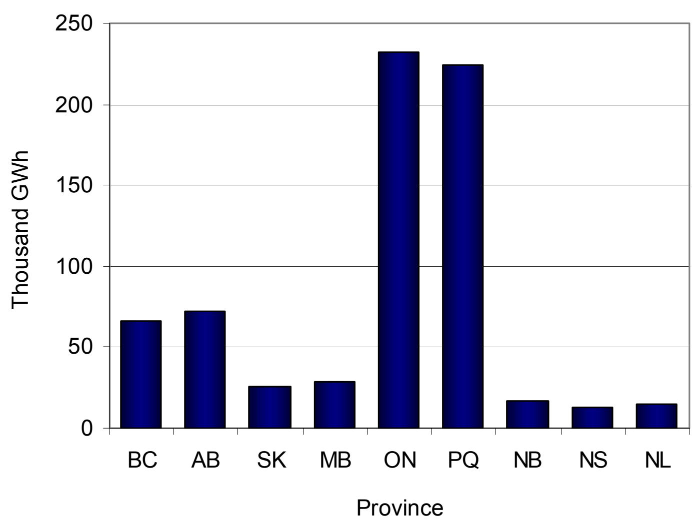


Figure 1-5 Base Case Provincial Demand in 2020

The source of generation required to supply provincial demand tends to be one-sided, favouring either hydro-electric or fossil-fired generation. Nearly 50 percent of total system-wide demand is met with hydroelectric power, with the generation mix in 4 provinces – Manitoba, Quebec, British Columbia and Newfoundland – relying on a 90 percent or greater share for their generation

[10] NEB, 1999

requirements. Coal- and gas-fired capacity contribute 15 percent and 18 percent, respectively, to the system generation requirements, but dominate the mix in some provinces. In Alberta, Saskatchewan and Nova Scotia, over 85 percent of generation is met with fossil-fired capacity. A broader mix of capacity types supplies generation in Ontario and New Brunswick. Figure 1-6 shows the generation mix in the Base Case in 2020 by province.

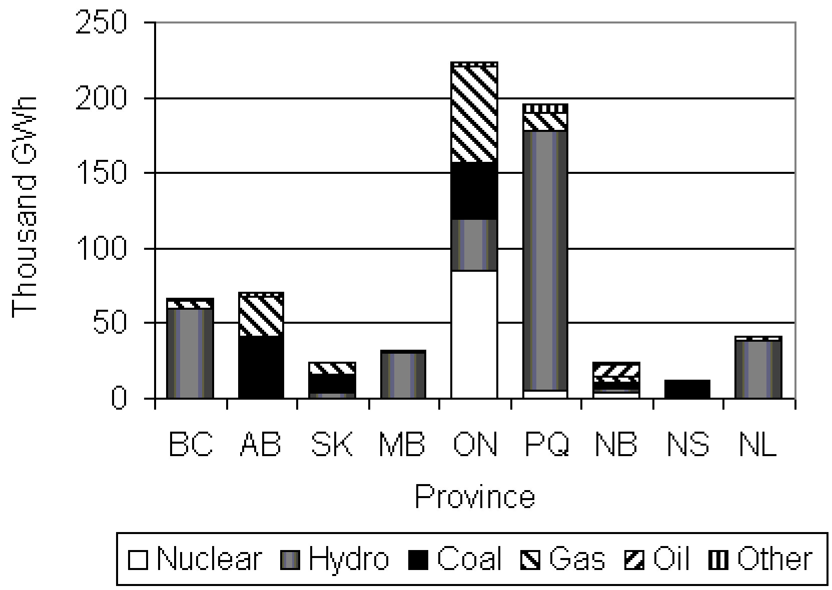


Figure 1-6 Base Case Provincial Generation Mix in 2020[11]

The approach described above was the common foundation for all phases of this project. This ensured consistency through the project and gave confidence that impacts seen in the analysis are a result of the different assumptions and not an artifice of the approach. The following sections of this report detail the analysis components and results specific to each phase.

[11] "Oil" in this analysis refers to liquid fuels, including orimulsion (derived from coal) used in New Brunswick.

2 PHASE 1

2.1 PHASE 1 SCENARIO DEVELOPMENT

To analyze the impacts of increasing demand for electricity on provincial energy markets and CO_2 emissions due to hydrogen production by electrolysis, ICF developed, with guidance from Natural Resources Canada, a Base Case and two demand scenarios for Phase 1 (P1). The Base Case established a set of results against which to compare the relative impacts of the two demand scenarios (see Section 1.2.2 for a more detailed description of the Base Case). This comparison determined the response of the electricity market to meet the needs of production of hydrogen via electrolysis in specific geographic regions.

Two scenarios were analyzed; one in which hydrogen technology was assumed to be adopted at a conservative rate through 2010 and increasing in availability by 2020 (an Incremental scenario); the second in which the adoption of hydrogen technology was assumed to occur in an Accelerated manner.

Note that the premise of the introduction of a hydrogen economy relied on a carbon-constrained market. That is, that the presence of a monetary value on carbon emissions would cause a shift from the GHG-emitting vehicle fuels, especially gasoline, to cleaner, hydrogen-fuelled vehicles. For the purposes of this analysis, a carbon cost of $10 CDN/tonne[12] of CO_2 was included in the Base Case and the demand scenarios.[13]

The scenarios analyzed the potential impacts of an increase in the energy demand on the power sector. The basis of the scenarios was an estimate of the increased electricity production required due to the adoption of hydrogen under two scenarios (P1 Incremental and P1 Accelerated) in 2010 and 2020. IPM® then quantified the sector dispatch impact and cost of the increased electricity required under the 2 scenarios in 2010 and 2020. Relying on the numerous IPM® outputs (electricity price, generation by capacity type, etc.), an analysis was performed in order to determine net the GHG benefit of the adoption of fuel cell technology and hydrogen fuelling via electrolysis under each scenario.

2.1.1 Hydrogen Economy Scenarios

The analysis was based on the quantification of the amount of electricity required to supply hydrogen via electrolysis under two different hydrogen demand scenarios (P1 Incremental and P1 Accelerated). Each scenario assumed a different penetration rate of hydrogen use. Note that the penetration rates as defined below were percentages of total fleet, not only new sales, and should be regarded as initial scenarios. At the end of Phase 1, these initial rates were deemed too optimistic by the Working Group and were refined for Phase 2.

- **P1 Incremental Scenario.** Under the incremental scenario, 0.5 percent of the total LDVs in each region were assumed to operate solely on hydrogen by 2010 and 6 percent by 2020. That is, by 2010, 0.5 percent of the LDV kilometres travelled estimated in the base "no-hydrogen" case (see Section 1.2.2), are displaced and the need met by hydrogen-powered LDVs.

[12] The Government of Canada has indicated that it will provide Large Final Emitters such as power generating stations access to carbon credits at $15/tonne of CO_2 should no credits remain available at less than $15/tonne.
[13] Other existing, relevant emission regulations were included. This refers to the Ontario Regulation 397 governing emissions of NO_X and SO_2 from power generation facilities.

- **P1 Accelerated Scenario.** Under the accelerated scenario, we assumed that 1.8 percent of the total LDVs operated on hydrogen by 2010 and 11.5 percent by 2020. Therefore, 1.8 percent of LDV kilometres travelled estimated in the base case are displaced with the need being met by hydrogen-powered LDVs by 2010 and 11.5 percent displaced by 2020.

The scenarios aimed to support Natural Resources Canada in evaluating the viability and best strategy for integrating hydrogen fuelling in future years based on projected capacity needs, associated GHG emissions and cost.

IPM® projected the source of the increased electrical power generation by fuel type and province due to hydrogen production via electrolysis, as well as the resulting electricity price. Based on this mix of generation sources, the GHG impact was quantified using an emission factor based on the total life-cycle emissions (production, processing, transportation, storage) associated with the fuel combusted at the generating station. These emissions factors were provided by Natural Resources Canada's GHGenius model.

2.2 PHASE 1 ASSUMPTIONS – KEY MODELLING INPUTS

The total estimated increase in electricity required (at the regional level) to meet hydrogen demand through electrolysis was determined for 2010 and 2020 under the P1 Incremental and P1 Accelerated penetration scenarios based on the following methodology. The basis of this methodology was the energy equivalency of the fuels, that is, the comparison of amount of fuel (gas or hydrogen) to drive an LDV an equivalent distance. Therefore, given the total amount of gasoline used and the fuel efficiency, the vehicle kilometres travelled could be calculated and from that derived the equivalent amount of hydrogen needed to go the same distance. The required electricity to produce this hydrogen was estimated and then input into IPM®..

Two simplifying assumptions made for the analysis were that 1) only LDVs[14] would be considered and 2) all vehicles currently use gasoline. Incorporating a more accurate fleet mix, assuming for example, a portion of buses and other heavy-duty vehicle (HDV) fleets will also adopt hydrogen, or that the fleet uses other, less-GHG intensive fuels than gasoline, would impact the amount of hydrogen needed and, therefore, the additional electricity required. Sensitivity to these factors was outside the scope of this initial Phase 1 study, but a comparison of the scenarios will give a feeling of sensitivity to demand.

2.2.1 Determining Gasoline Usage

The total volume of fuel (gasoline) demanded by LDVs in a base case for both 2010 and 2020 was provided by Natural Resources Canada and assumed no introduction of hydrogen fuel cell vehicles, but did account for fuel efficiency improvements. These volumes were taken from the Natural Resources Canada scenario "Greening the Pump"[15]. These national numbers were converted to regional estimates based on the relative number of LDVs per region (as a percentage of the over 17 million LDVs nationally, see Figure 2-1). These percentages were assumed to remain constant throughout the study.

[14] Defined as 10,000 lbs or less and represented by a single set of fuel and emission characteristics.
[15] Energy Technology Futures. 2002b.

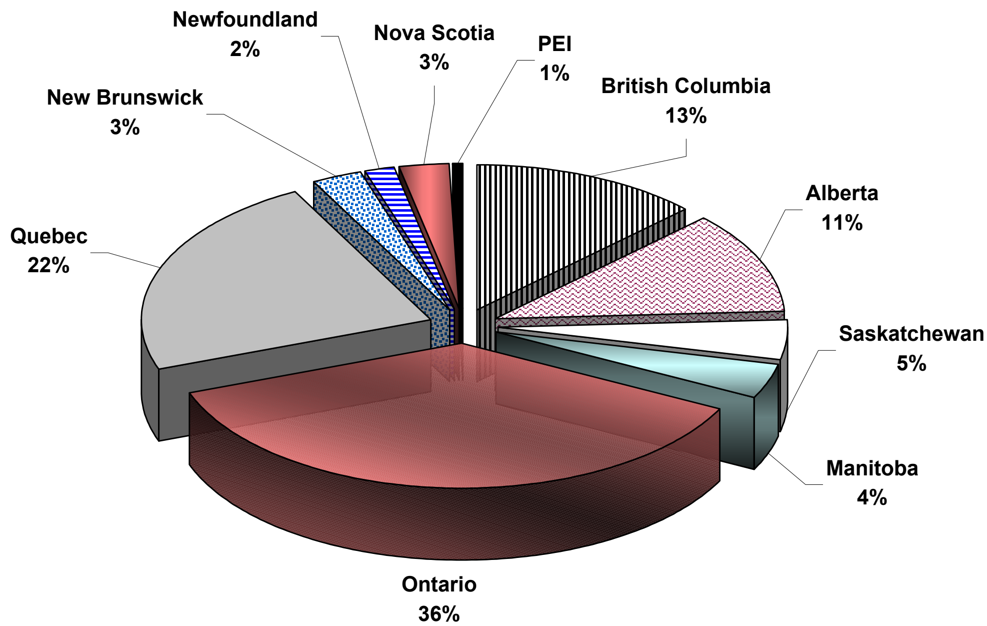


Figure 2-1 Regional Percentages of LDVs[16]

The scenario penetration rates were applied to the LDV fleet numbers to then estimate the **amount of gasoline replaced** by hydrogen as shown in Table 2-1. As mentioned in section 2.1, these penetration rates should be viewed as the starting point for the analysis with refinement of the rates in subsequent work in Phase 2 and possibly Phase 3.

Table 2-1 Phase 1 Scenario Penetration Rates of Total LDV Fleet

Scenario	Year	Penetration Rate [%]	Hydrogen Fleet [million LDV]
Phase 1 Incremental	2010	0.5	0.1
	2020	6.0	1.2
Phase 1 Accelerated	2010	1.8	0.4
	2020	11.5	2.4

[16] Talbot, R. 2003. Based on information provided by Desrosiers Automotive Consultants

2.2.2 Gasoline to Equivalent Hydrogen

Based on forecast fuel efficiencies shown in Table 2-2[17], the gasoline usage was converted to hydrogen through equivalent vehicle kilometres travelled (VKT).

Table 2-2 Phase 1 Canadian Passenger Fleet Fuel Efficiencies

Year	Gasoline Efficiency [L/100 km]	Percent Improvement	Hydrogen Efficiency [kg/100 km]	Based on
2000	8.18			
2010	8.10	1% from 2000	1.2	lower efficiency
2020	6.50	21% from 2000	1.0	middle efficiency

Therefore,

Hydrogen [kg] = Gasoline [L] / Gasoline Efficiency [L/km] * Hydrogen Efficiency [kg/km]

2.2.3 Hydrogen to Electricity Demand

Finally, the hydrogen was converted to electricity demand using assumptions around the amount of electricity required to electrolyse hydrogen. This analysis assumed 47 kWh of electricity were required to produce one kilogram of hydrogen by electrolysis.[18] This value included electricity to produce the hydrogen but did not account for power required to compress or dispense the hydrogen. It is acknowledged that this estimate is conservative and the actual value may be closer to 55 kWh/kg of hydrogen. Table 2-3 shows a summary of the additional electricity required under each scenario in 2010 and 2020. Figure 2-2 and Figure 2-3 show the percentage increases in demand analyzed under each of the scenarios.

Table 2-3 Additional Electricity Required to Produce Hydrogen by Region [GWh]

Scenario	Year	BC	AB	SK	MB	ON	PQ	NB	NS	NL
Phase 1 Incremental	2010	182	164	65	54	531	325	39	41	22
	2020	1,859	1,681	667	550	5,437	3,328	404	422	232
Phase 1 Accelerated	2010	654	591	234	193	1,912	1,170	141	148	82
	2020	3,564	3,222	1,278	1,054	10,421	6,379	773	809	444

[17] Ibid.

[18] U.S. Department of Energy H2 Information Network (http://www.eere.energy.gov/hydrogenandfuelcells/hydrogen/faqs.html)

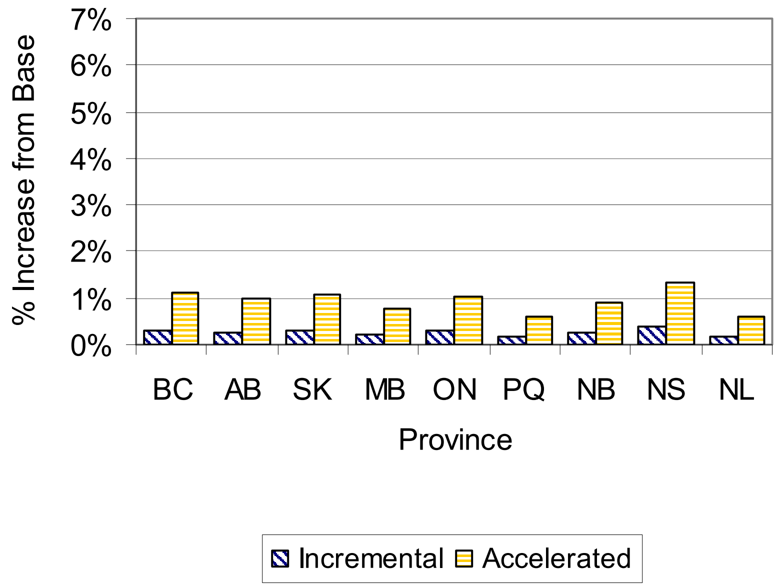


Figure 2-2 Percent Increase in P2 Electricity Demand from Base Case by 2010

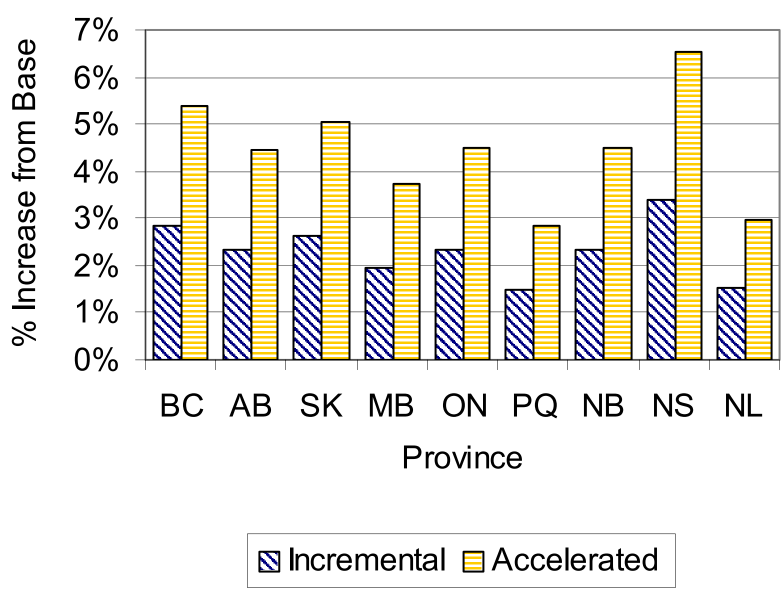


Figure 2-3 Percent Increase in P1 Electricity Demand from Base Case by 2020

The P1 Incremental Demand Scenario drove up electricity demand relative to the Base Case by 1.5 to 3.5 percent of total provincial demand by 2020, depending on the province. The P1 Accelerated Demand Scenario nearly doubled the requirement of the P1 Incremental Demand Scenario.

For the purpose of this analysis, this additional demand requirement was assumed to be distributed over those hours when provincial demand would typically be at its lowest. This generation profile would ensure that the electric power necessary to serve this new demand would be provided at the lowest cost with minimal peak capacity requirements on the province. Figure 2-4 illustrates how the additional generation requirement was implemented in the load profile of the provinces. This figure shows total generation in British Columbia over the course of the year 2020 in each hour of the day (hour “1” is equivalent to the time between midnight and 1 A.M., hour “2” to between 1 A.M. and 2 A.M., etc.) for the Base Case and the increments necessary under the P1 Incremental and P1 Accelerated Scenarios. The addition of electricity demand for hydrogen production flattened the load profile over the course of the day without adding to load in the peak hours.

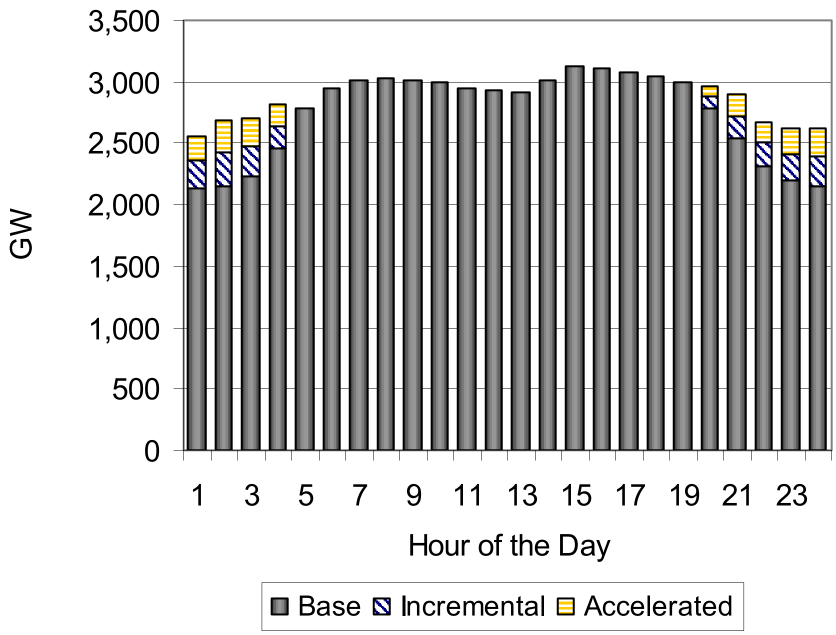


Figure 2-4 Adjusted Hourly P1 Demand in British Columbia in 2020

A heavier reliance by hydrogen producers on electricity generated during peak hours, such as hours 15 though 17 in Figure 2-4, was analysed in Phase 2.

2.3 PHASE 1 RESULTS

This section presents the results from the Phase 1 IPM® analysis of the electric sector and compares the GHG emissions calculated based on those results to emissions associated with the displacement of gasoline. The IPM® analysis provided the dispatch decisions, reported as generation by capacity type, and the provincial electric prices arising from the added electricity demand required to produce hydrogen via the electrolysis of water. These results fed into the post-modelling component of the analysis aimed at comparing the emissions associated with hydrogen production to the displaced or avoided emissions from gasoline on a life-cycle basis. All energy prices are presented on a normalized basis for context.

IPM® Results

The relative economics of hydrogen for use in the transportation sector will depend on numerous factors, including, among other things, the cost of infrastructure necessary to produce and store the hydrogen and the cost of electricity used in the production process. The effectiveness of hydrogen as a means to reduce Canadian carbon emissions will be determined by the demand for hydrogen in place of gasoline and the environmental profile of the electricity used to produce that hydrogen. Based on the Phase 1 hydrogen demand scenarios described above, this analysis addresses two of these determining factors: the cost of the electricity input to the hydrogen production process and the GHG emissions associated with that additional electricity generation. This section presents the results of the IPM® analysis at a provincial level aimed at evaluating and quantifying regional siting-related impacts of electrolysis based on emissions and pricing indicators.

2.3.1 Results: Phase 1 Incremental and Accelerated Off-Peak Scenarios

2.3.1.1 Electric Market Response to Demand Scenarios

The response of the provincial electric systems to the increase in required load described above (under P1 Incremental and P1 Accelerated scenarios) will determine the impact of the demand scenarios on electric prices and emissions profiles. The following sections discuss the environmental and cost components necessary to determine the viability of hydrogen production.

Impacts on Generation Mix

The cost and emissions impacts of generating the electricity necessary to supply the demand for hydrogen was driven by the mix of capacity types used to supply the electricity. The additional electricity required to produce hydrogen was supplied by a combination of existing generation, generation from new gas-fired combined cycle units and trade. Table 2-4 below summarizes the measures taken by each province.

Table 2-4 Provincial Measures to Meet Additional Demand Requirements

Province	Actions Taken to Supply Additional Demand
British Columbia	British Columbia met the demand by increasing utilization of its existing gas-fired assets and reducing exports to Alberta relative to the Base Case.
Alberta	Alberta offset lower imports from British Columbia by increasing imports from neighbouring Saskatchewan. It also increased utilization of its gas-fired capacity and added 200 MW of additional combined cycle capacity to its system by 2020 to meet the demand requirements.
Saskatchewan	Higher exports to Alberta and higher demand to meet hydrogen production needs drove Saskatchewan to add 220 MW of new combined cycle capacity relative to the Base Case by 2020. It relied on this new capacity and increased utilization at its existing gas-fired assets to meet the new demand and replace 0.6 billion kWh previously supplied by Manitoba.
Manitoba	The additional demand in Manitoba was met by reducing exports and with a small increase in the utilization of its coal assets. The reduction in power shipped to Saskatchewan also allowed it to supply additional power to the higher-priced Ontario market.
Ontario	Ontario relied on new, gas-fired generation to meet the additional demand needs in 2010. By 2020, the additional demand was met by a combination of trade and higher utilization of fossil-fired capacity. Imports increased by 3.5 billion kWh, half from Manitoba and half from Newfoundland by way of Quebec, and Ontario reduced exports to the U.S. Also, 5 billion kWh of additional generation was supplied by existing coal and new and existing gas-fired capacity.
Quebec	In 2010, Quebec relied on decreased net exports to the U.S. to meet its additional demand needs. In 2020, Quebec added new combined cycle capacity to supply, in the Accelerated Scenario, one-half of the additional demand. This new capacity would have been added in later years to meet growing demand, but was installed earlier as a result of the hydrogen production demand. The remaining half of the new demand was met with imports from Newfoundland.
New Brunswick	New Brunswick relied on a combination of higher utilization at its fossil-fired units and reduced exports to Quebec to meet the new demand requirements.
Nova Scotia	The hydrogen production demand in Nova Scotia was met primarily with 55 MW of combined cycle additions incremental to the Base Case by 2020. Utilization of coal-fired assets also increased slightly.
Newfoundland	In 2010, Newfoundland backed off exports to Quebec to meet its new demand requirements. In 2020, demand in Newfoundland was 0.4 billion kWh higher in the Accelerated Demand Scenario than in the Base Case. Generation in 2020, however, increased by ten times that amount to also cover 3 billion kWh of increased exports to Quebec. All of this additional power was supplied by nearly 800 MW of new combined cycle capacity, double that installed in the Base Case.

Table 2-5 and Table 2-6 show in more detail the generation mix in each province resulting from the additional demand. The tables show, for each province (row), the percentage of total generation supplied by each type of capacity (columns) in the focus hours. The sum of the percentages across any province add to 100%. The shares shown here reflect the generation mix in the hours in which the additional load was assigned (Section 1.2.2). Table 2-5 and Table 2-6 show 2020 numbers only; see 0 for a full listing.

Table 2-5 Percent of Dispatch Supplied by Fuel Type and Region in Hydrogen Production Segments (2020 Phase 1 Incremental Scenario)

	Coal	Gas	Oil	Hydro	Nuclear	Non-Carbon Other
BC	0%	12%	0%	86%	0%	2%
AB	57%	40%	0%	0%	0%	3%
SK	57%	37%	0%	5%	0%	1%
MB	2%	0%	0%	98%	0%	0%
ON	18%	32%	0%	6%	43%	1%
PQ	0%	9%	0%	85%	3%	3%
NB	16%	20%	38%	2%	22%	2%
NS	77%	19%	0%	1%	0%	3%
NL	0%	9%	0%	91%	0%	0%

Table 2-6 Percent of Dispatch Supplied by Fuel Type and Region in Hydrogen Production Segments (2020 Phase 1 Accelerated Scenario)

	Coal	Gas	Oil	Hydro	Nuclear	Non-Carbon Other
BC	0%	11%	0%	87%	0%	2%
AB	56%	41%	0%	0%	0%	3%
SK	54%	40%	0%	5%	0%	1%
MB	2%	0%	0%	98%	0%	0%
ON	18%	32%	0%	8%	41%	1%
PQ	0%	10%	0%	84%	3%	3%
NB	16%	20%	40%	0%	22%	2%
NS	75%	21%	0%	1%	0%	3%
NL	0%	17%	0%	83%	0%	0%

The use of existing and new gas-fired capacity increased generation from gas at the national level by 16TWh, or 13 percent, by 2020 in the P1 Accelerated Scenario relative to the Base Case. The remaining new demand requirements were met with imports from the U.S. and small increases in coal- and oil-fired generation.

2.3.1.2 GHG Emissions Impacts of Generation for Hydrogen Production

The change in dispatch in each province outlined in Table 2-5 and Table 2-6 above was used to determine the GHG impact of supplying power to the hydrogen production process. While gas-fired capacity, existing and new, supplies the majority of additional generation and drives the marginal cost of generation, as described in Table 2-4, the hydrogen producer will not necessarily receive electricity directly from those sources. Instead, the producer will use electricity from the same mix of sources available to other consumers and must have its emissions impact determined consistent with that mix. Therefore, the dispatch percentages for the entire capacity fuel mix during the focus hours were used to estimate GHG emissions from power generation.

Net GHG Impact from Avoided Gasoline and Increased Electricity Usage

The GHG impact represents the net impact of two related activities; producing additional electricity to electrolyse water to manufacture hydrogen, which tends to increase emissions, and using that hydrogen in place of gasoline for the specified percentage of LDVs, which reduces transportation sector emissions.

The net GHG impact was determined by:

Net GHG Impact (avoided gasoline and increased electricity usage) =
GHG emissions associated with electricity generation –
GHG emissions avoided due to displaced gasoline usage

A negative GHG impact, as calculated here, signifies a net reduction in the emissions generated by supplying a level of transportation service. The calculation of these two components is discussed in greater detail below.

GHG Emissions Avoided from Hydrogen Use

GHG emissions avoided due to displaced gasoline were estimated based on:

- The estimated gasoline displaced under each P1 scenario for 2010 and 2020 (refer to section 2.2.1 for discussion of methodology and Table 2-2 for fuel efficiencies), and
- Full, life-cycle emission factors provided by Natural Resources Canada[19].

The estimate of gasoline (million litres) displaced under each P1 scenario for 2010 and 2020 was determined in the process of estimating the additional electricity demand under each scenario. This data was employed along with a full, life-cycle emission factor to quantify the GHG emissions avoided due to the displacement of gasoline. The emission factor included CO_2, N_2O and CH_4 emissions from vehicle operation (combustion), fuel dispensing, production, and transport (see Table 2-7). Emission factors were based on assumed fuel efficiencies in Table 2-2.

Table 2-7 Phase 1 GHG Emission Factors Associated with Gasoline – LDV Usage (Life-Cycle)

		2010			
Gas 30ppm S (fuel cycle)	402.9	Grams of CO2eq	per	1	Mile
	250.40	Grams	per	1	km
	250.40	Tonnes	per	1,000,000	km
		2020			
Gas 30ppm S (fuel cycle)	318.6	Grams	per	1	Mile
	198.01	Grams	per	1	km
	198.01	Tonnes	per	1,000,000	km

Ref. Talbot, R. 2003.
Note that GHG emission factors exclude vehicle assembly and transport and materials in vehicles (including storage) and lube oil production/use. These actions are presumed to be approximately the same for hydrogen vehicles.

[19] Talbot, R. 2003.

Figure 2-5 provides the emissions avoided by province due to the displacement of gasoline-powered LDVs with hydrogen-powered vehicles under the P1 Incremental and P1 Accelerated scenarios for 2010 and 2020. In all figures, a negative value indicates a reduction in emissions.

Figure 2-5 P1 Emissions Avoided Due to Displacement of Gasoline (by Province)

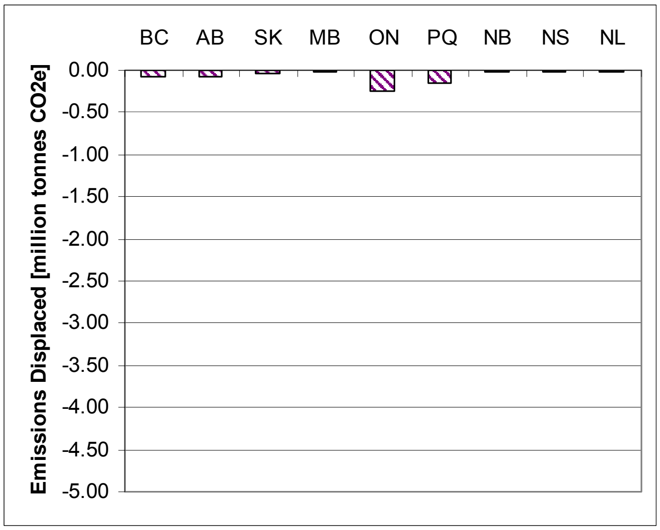


Figure 2-5a Emissions from Gasoline Usage by Province (2010 P1 Incremental)

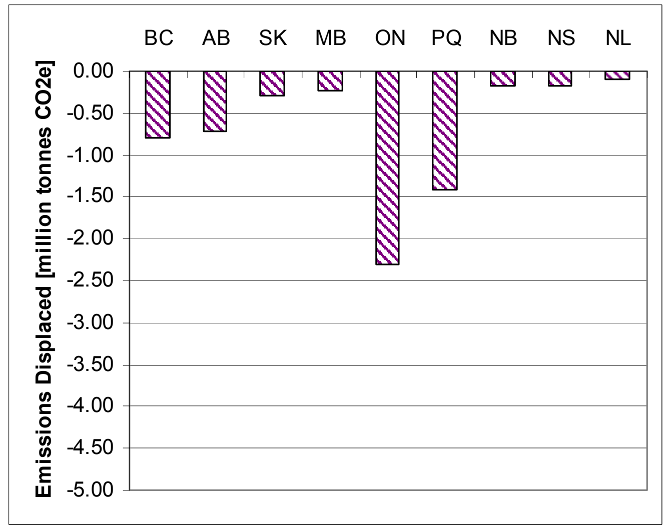


Figure 2-5b Emissions from Gasoline Usage by Province (2020 P1 Incremental)

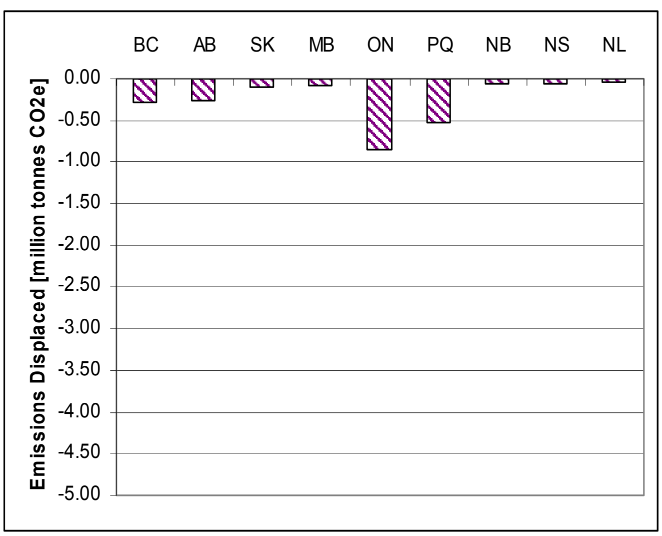


Figure 2-5c Emissions from Gasoline Usage by Province (2010 P1 Accelerated)

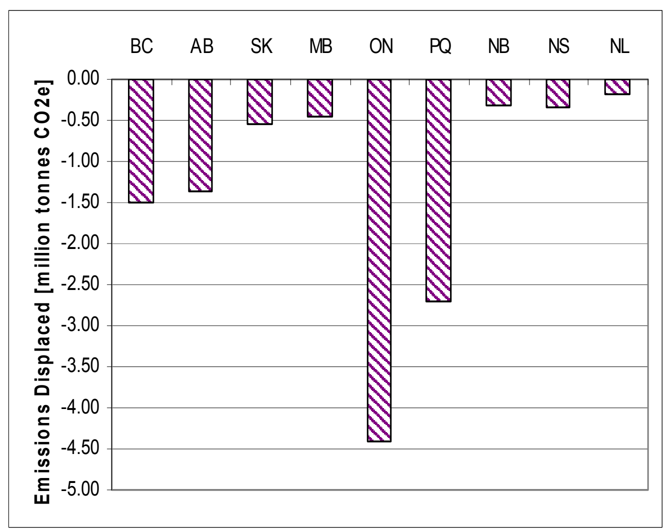


Figure 2-5d Emissions from Gasoline Usage by Province (2020 P1 Accelerated)

Because a single conversion factor was used to represent the production and consumption of gasoline, the GHG emissions avoided were directly proportional to the number of vehicles that were assumed to enter into the market by 2010 and 2020 under differing penetration rates (P1 Incremental and P1 Accelerated). That is, the more vehicles that adopt hydrogen at the provincial level, the greater the GHG emissions avoided. The provinces with the largest fleets therefore displaced the greatest amount of GHGs as a result of making the transition to hydrogen-based transportation.

GHG Emissions from Additional Electricity Generation

Differing modes of producing electricity have very different GHG intensities. The GHG emissions associated with the production of a set amount of electricity, therefore, depended on the source of the power (that is, coal, gas, oil, hydro or nuclear). The calculation of GHG emissions associated with electricity generation was estimated based on:

- The source (by fuel-type) of the electricity required to meet the increased demand under each P1 scenario for 2010 and 2020 (IPM® output – see example Table 2-5 and Table 2-6),
- The estimated electricity demand under each P1 scenario for 2010 and 2020 (refer to section 2.2.3 for discussion of methodology), and
- The source-specific full life-cycle emission factors modified to account for fuelling-related emissions provided by Natural Resources Canada.

The source-specific emission factors included full life-cycle quantification of the GHG emissions (CO_2, N_2O and CH_4) upstream (exploration, production, transport) and from combustion. These coefficients were provided by Natural Resources Canada from the GHGenius model. For the purpose of this analysis, each of the emission factors was increased by 5 percent to account for the emissions associated with hydrogen fuel dispensing. The 5 percent was based on information provided by Natural Resources Canada from its GHGenius model which assesses the full life-cycle emissions associated with hydrogen. The resulting factors are shown in Table 2-8.

Table 2-8 Phase 1 GHG Emission Factors Associated with Stationary Combustion

2010					
Coal	1.134	tonnes of CO2eq	per	1	MWh
NG-turbine	0.4956	tonnes of CO2eq	per	1	MWh
NG-boiler	0.6531	tonnes of CO2eq	per	1	MWh
Oil	1.03845	tonnes of CO2eq	per	1	MWh
Hydro	0.02835	tonnes of CO2eq	per	1	MWh
Nuclear	0.0147	tonnes of CO2eq	per	1	MWh
Other	0	tonnes of CO2eq	per	1	MWh
2020					
Coal	1.1172	tonnes of CO2eq	per	1	MWh
NG-turbine	0.49455	tonnes of CO2eq	per	1	MWh
NG-boiler	0.6195	tonnes of CO2eq	per	1	MWh
Oil	1.0185	tonnes of CO2eq	per	1	MWh
Hydro	0.02835	tonnes of CO2eq	per	1	MWh
Nuclear	0.01365	tonnes of CO2eq	per	1	MWh
Other	0	tonnes of CO2eq	per	1	MWh

Note: Emission Factors from Natural Resources Canada's GHGenius program.[20]

[20] Talbot, R. 2003.

The GHG emissions associated with the electricity generated to meet the increased demand due to hydrogen production via electrolysis under the two P1 scenarios for 2010 and 2020 are provided below (see Figure 2-6).

Figure 2-6 P1 GHG Emissions Associated with Increased Electricity Demand

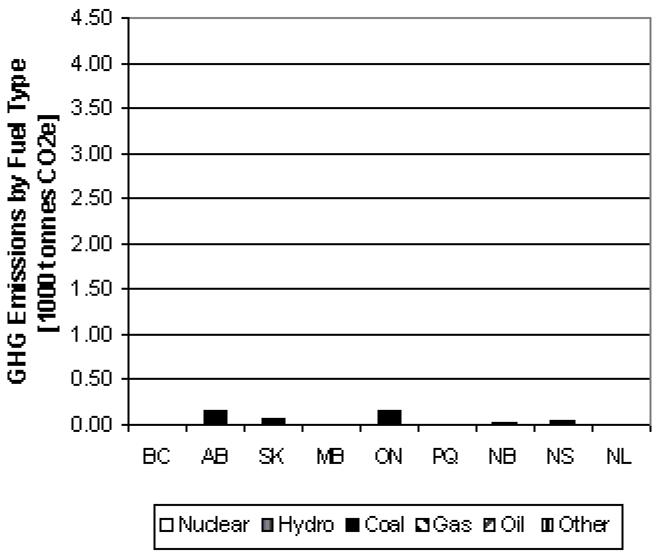


Figure 2-6a Emissions by Fuel Type for 2010 P1 Incremental Scenario

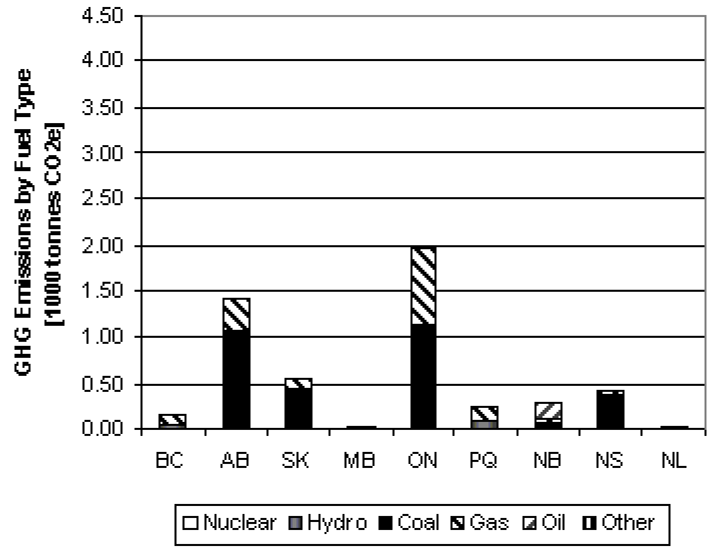


Figure 2-6b Emissions by Fuel Type for 2020 P1 Incremental Scenario

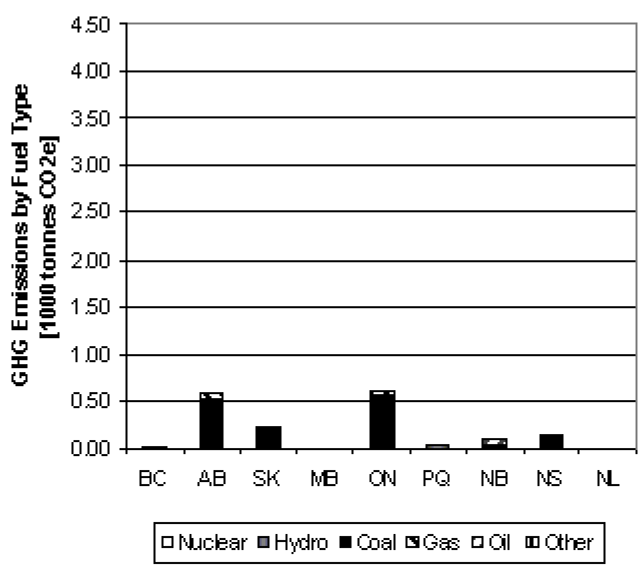


Figure 2-6c Emissions by Fuel Type for 2010 P1 Accelerated Scenario

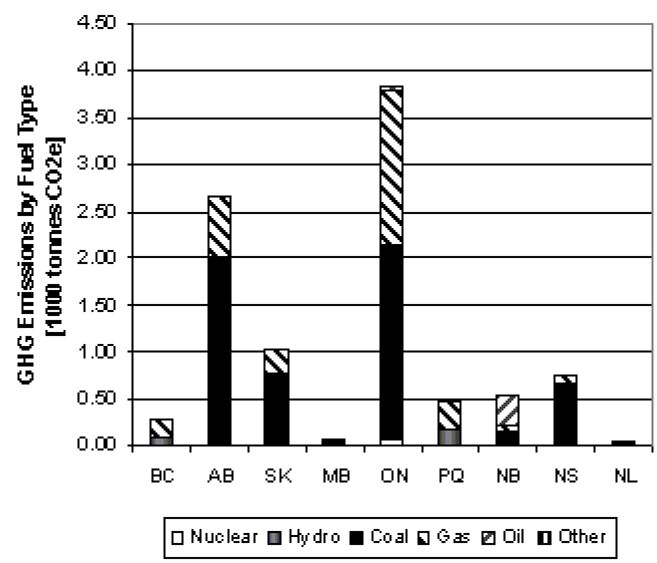


Figure 2-6d Emissions by Fuel Type for 2020 P1 Accelerated Scenario

At the provincial level, the results showed that the emissions associated with the production of electricity are dependent primarily on the source of the electricity. That is, provincial emissions were highest in those provinces that were dependent on fossil-fired generation and lowest in those provinces dependent on hydroelectric and nuclear to meet the electricity demand.

Net GHG Impact from Avoided Gasoline and Increased Electricity Usage on GHG Emissions

The net GHG impacts of partially substituting hydrogen for gasoline in the transportation sector are shown in the following figures. Recall that a negative value reflects a net reduction in emissions, or that the emissions offset by moving from gasoline to hydrogen are greater than the emissions generated for the production of the hydrogen through electrolysis. Provinces dependent on fossil fuels fared worse than those provinces that utilized hydroelectric, nuclear or a broader mix of capacity types. In the lower-emitting provinces, fewer incremental emissions were produced per unit of hydrogen. However, regardless of the province, the same amount of emissions from gasoline-powered LDVs were displaced per unit of hydrogen. Therefore, from an environmental standpoint, the lower-emitting provinces reflected the best opportunity for realizing emissions reductions by switching to hydrogen-based transportation. Table 2-9, Table 2-10 and Figure 2-7 show the net GHG impacts.

Figure 2-7 P1 Net GHG Impact (Avoided Gasoline and Increased Electricity Usage) of Hydrogen Substitution

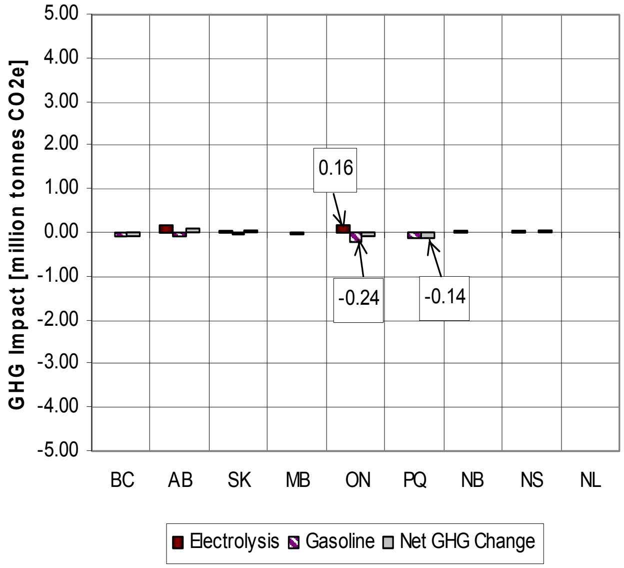


Figure 2-7a GHG Impact in 2010 – P1 Incremental Scenario

Figure 2-7b GHG Impact in 2020 – P1 Incremental Scenario

Figure 2-7c GHG Impact in 2010 – P1 Accelerated Scenario

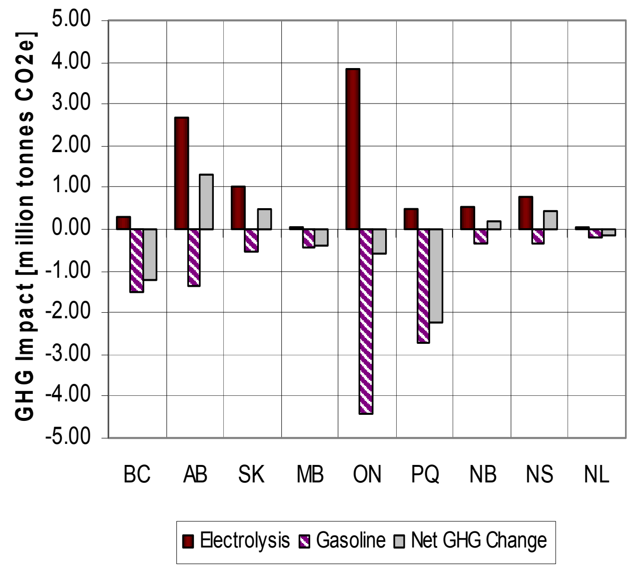


Figure 2-7d GHG Impact in 2020 – P1 Accelerated Scenario

Table 2-9 Impact of Hydrogen Substitution Phase 1 Incremental Scenario (CO_2)

	by 2010 (million tonnes CO_2)			by 2020(million tonnes CO_2)		
Province	**Electrolysis**	**Gasoline**	**Net GHG Change**	**Electrolysis**	**Gasoline**	**Net GHG Change**
BC	0.007	-0.081	-0.074	0.154	-0.787	-0.633
AB	0.161	-0.073	0.088	1.407	-0.711	0.696
SK	0.062	-0.029	0.033	0.549	-0.282	0.267
MB	0.003	-0.024	-0.021	0.029	-0.233	-0.204
ON	0.164	-0.237	-0.073	1.998	-2.301	-0.302
PQ	0.009	-0.145	-0.136	0.227	-1.408	-1.181
NB	0.027	-0.018	0.010	0.271	-0.171	0.100
NS	0.042	-0.018	0.024	0.402	-0.179	0.223
NL	0.001	-0.010	-0.009	0.016	-0.098	-0.082
Total	**0.475**	**-0.635**	**-0.159**	**5.053**	**-6.169**	**-1.116**

Table 2-10 Impact of Hydrogen Substitution Phase 1 Accelerated Scenario (CO_2)

	by 2010 (million tonnes CO_2)			by 2020 (million tonnes CO_2)		
Province	**Electrolysis**	**Gasoline**	**Net GHG Change**	**Electrolysis**	**Gasoline**	**Net GHG Change**
BC	0.024	-0.291	-0.268	0.283	-1.508	-1.225
AB	0.575	-0.264	0.312	2.668	-1.363	1.305
SK	0.222	-0.104	0.117	1.027	-0.541	0.487
MB	0.010	-0.086	-0.076	0.056	-0.446	-0.390
ON	0.598	-0.852	-0.254	3.816	-4.409	-0.594
PQ	0.031	-0.522	-0.490	0.462	-2.699	-2.237
NB	0.099	-0.063	0.036	0.529	-0.327	0.201
NS	0.151	-0.066	0.085	0.761	-0.342	0.419
NL	0.002	-0.036	-0.034	0.048	-0.188	-0.140
Total	**1.714**	**-2.286**	**-0.572**	**9.649**	**-11.824**	**-2.175**

Figure 2-8 details the GHG impact in those provinces where, under this analysis, it would be beneficial in GHG terms to produce hydrogen via electrolysis.

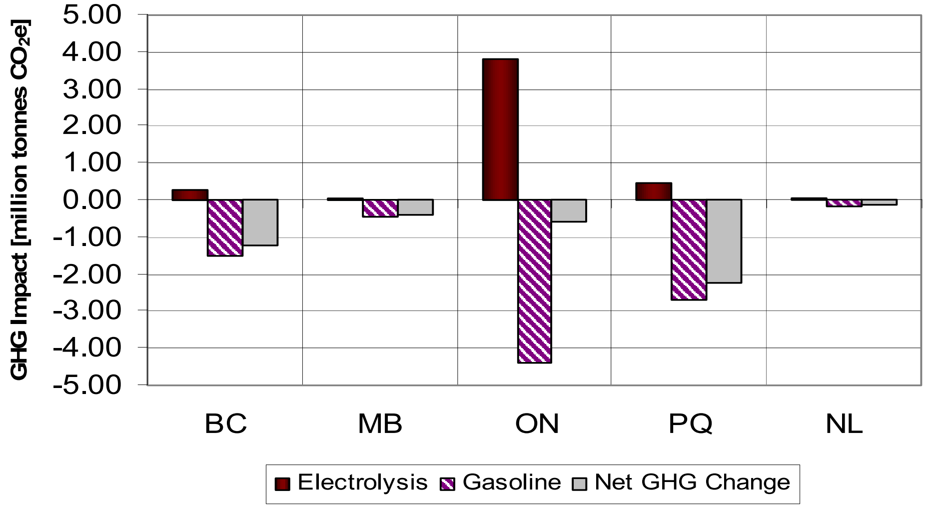


Figure 2-8 GHG Impact in 2020 – P1 Accelerated Scenario

Those provinces where the GHG emissions intensity associated with the power generated was less than 0.44 tonnes of CO_2e/MWh in 2010 and 0.42 tonnes of CO_2e/MWh in 2020 result in a beneficial GHG impact (that is, a net reduction in GHG emissions). That threshold value represents the electricity emissions equivalent to emissions from mobile combustion of gasoline. This value was calculated by converting the GHG emission factor for mobile combustion of gas (tonnes GHG/km) to equivalent emissions per kg of hydrogen using the fuel efficiency of hydrogen (tonnes hydrogen/km). With the amount of electricity required to electrolyze a kilogram of hydrogen, it was then possible to calculate an equivalent emissions per electricity generation. As shown in Table 2-8, a provincial electric system made up entirely of natural gas turbines would not achieve these rates. At least some share of hydroelectric, nuclear or other non-emitting sources of electricity would be required to make hydrogen production and use viable. Figure 2-9 shows the GHG intensities of the nine provinces studied in Phase 1 relative to the 2020 target intensity of 0.42 tonnes CO_2e per MWh.

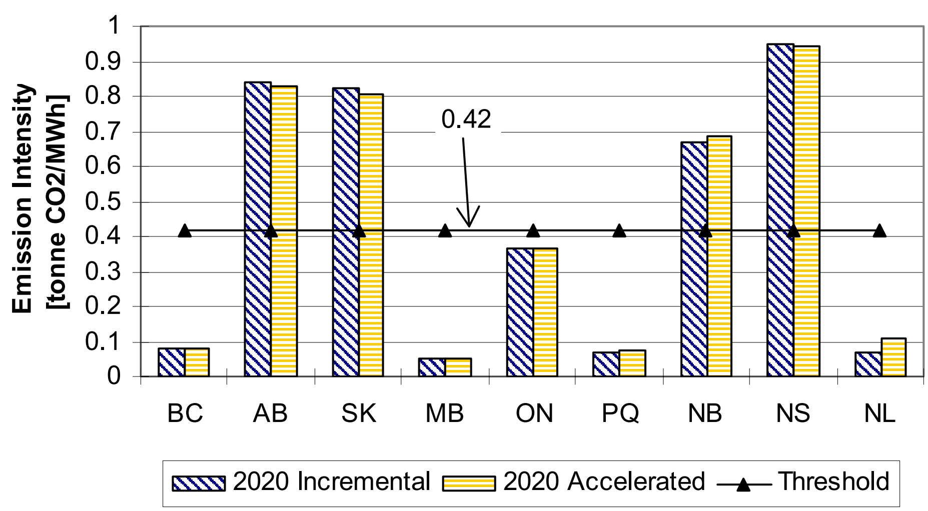


Figure 2-9 P1 Emission Intensity by Region

2.3.1.3 Impacts on Electricity Prices

The cost effectiveness of hydrogen as a fuel source for transportation will depend on the cost of generating the hydrogen, composed primarily of the cost of the electricity input into that process, and the relative cost of the gasoline alternative. This section focuses on the first component of that total cost -- the cost of the electricity input into the production of hydrogen.

In IPM®, electricity prices reflect the cost of generation at the marginal unit, or the unit setting the price in each season and load segment. That cost is the sum of variable operating and maintenance (O&M) costs, fuel costs, and environmental charges paid to comply, in this case, with the national climate change regulation and, in Ontario, with the provincial NO_X and SO_2 policies. The absolute impacts of the P1 Incremental and P1 Accelerated Demand Scenarios on provincial annual average electricity prices are shown in Figure 2-10. Note that all dollar values are in year 2000 Canadian dollars.

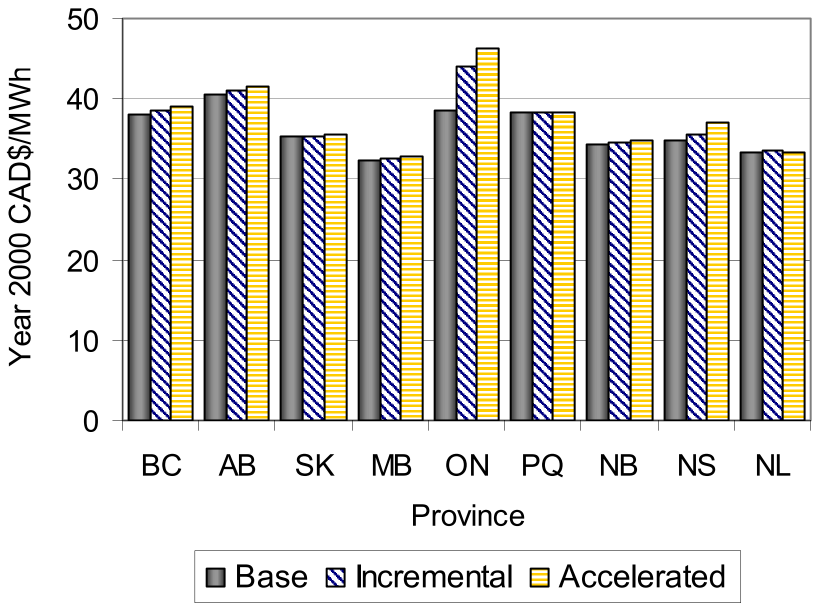


Figure 2-10 P1 Provincial Energy Prices in 2020

Prices increased in all provinces, by up to 15 percent in 2020 in the P1 Incremental Scenario and by over 20 percent in 2020 in the P1 Accelerated Scenario as shown in Figure 2-11. The magnitude of the impact in each province depended on the manner in which it chose to meet the additional demand requirements. In many regions, as discussed above, the additional generation was supplied by existing or new gas-fired capacity. If this capacity was utilized in the P1 Hydrogen Scenarios at times of the day during which it was **not** used in the Base Case, the marginal cost of generation in those times would increase, thereby increasing the average cost of production for the entire day. Regions relying heavily on imports will face the higher prices realized in the supplying regions under the P1 Hydrogen Scenarios and, therefore, realize higher average annual prices themselves.

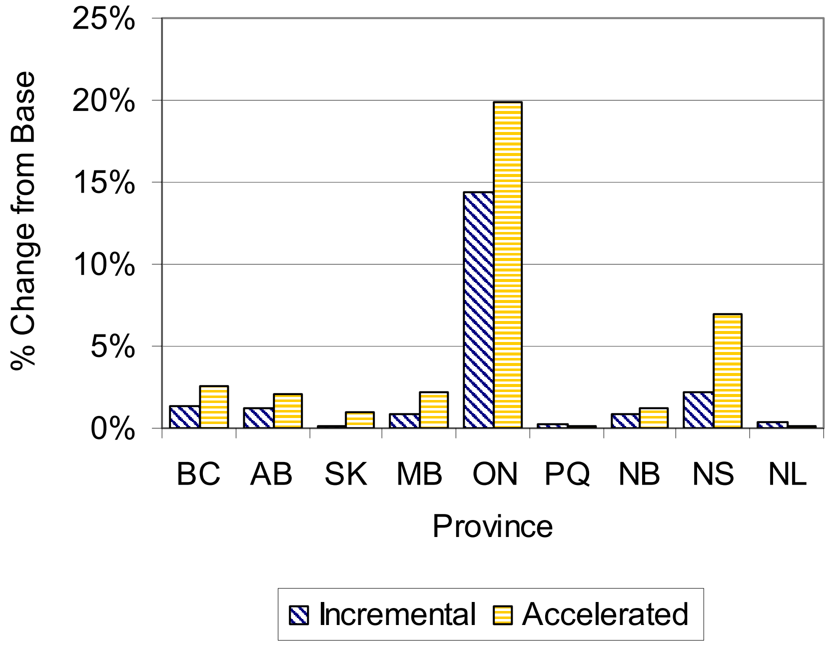


Figure 2-11 Percent Change in 2020 P1 Average Annual Energy Price from Base Case

Analysis of Cost of Hydrogen Production

As discussed above, the successful adoption of hydrogen will depend on the cost of its production and the competitiveness of the resulting cost as compared to gasoline. This section uses the IPM® energy price results discussed above to calculate the cost to the consumer of hydrogen for transportation. The costs detailed in this analysis were based on the assumption that 47 kWh of electricity are required to produce one kilogram of hydrogen. Assumptions related to the fuel efficiency forecast assumptions for hydrogen and gasoline for 2010 and 2020 were discussed in Section 2.2.

Figure 2-12 and Figure 2-13 translate the energy prices shown in Figure 2-10 into costs required per unit of hydrogen produced.

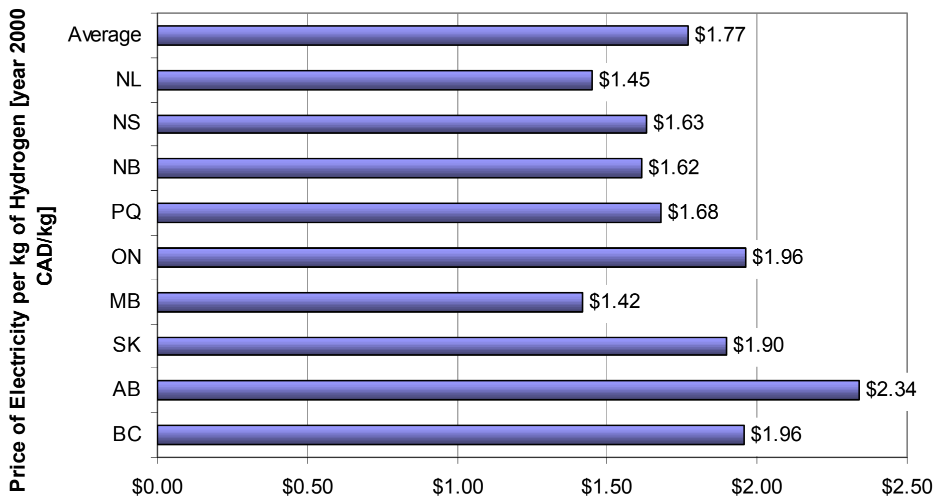


Figure 2-12 Electricity Costs in 2020 P1 Incremental Scenario

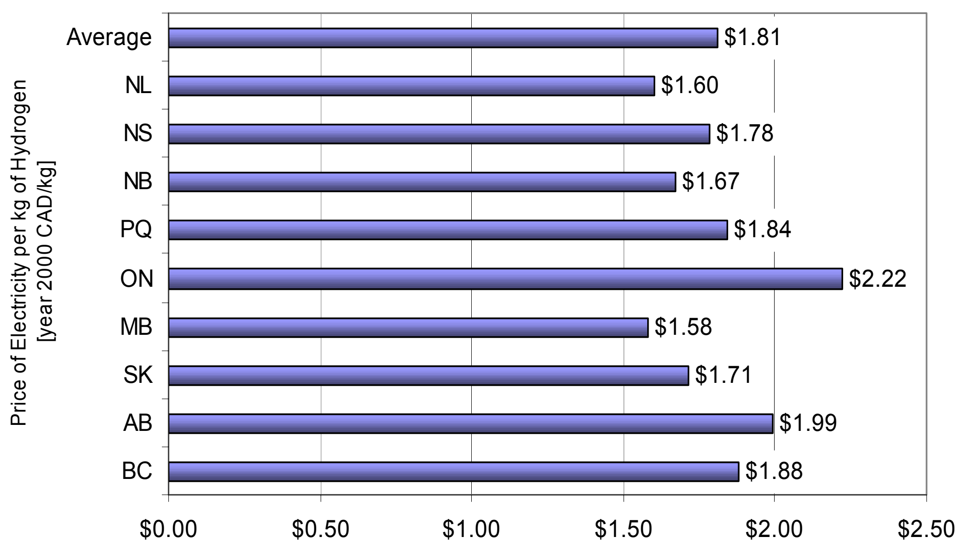


Figure 2-13 Electricity Costs in 2020 P1 Accelerated Scenario

Figure 2-14 and Figure 2-15 detail the price of electricity to produce hydrogen required to displace one litre of gasoline (based on forecast fuel efficiencies). Therefore, the prices shown are intended to be comparable to the market price for a litre of gasoline in each of the provinces. In 2020 in the Accelerated Scenario, the price of electricity varies from $0.34 per kilogram of hydrogen in Ontario to $0.24 in Manitoba. These values compare to a current average national market price for gasoline of $0.46/L (pre-tax) and a post-tax price of $0.77 per litre[21]. Note that the regional pre-tax prices varies significantly (from $0.44/L in Toronto to $0.66/L in Vancouver), albeit all higher than the price for hydrogen. Based on this analysis it appears that hydrogen would be an economically viable replacement for gasoline.

However, it is important to note that while the price of gasoline compares higher than the price of hydrogen, these gasoline prices include the cost of crude, refining and marketing. Regional prices also may reflect the economies of scale for large cities and other regional differences. The prices of hydrogen provided here do not include those costs, which are expected to be material, associated with supply of water for electrolysis and storing and distributing hydrogen at the retail level.

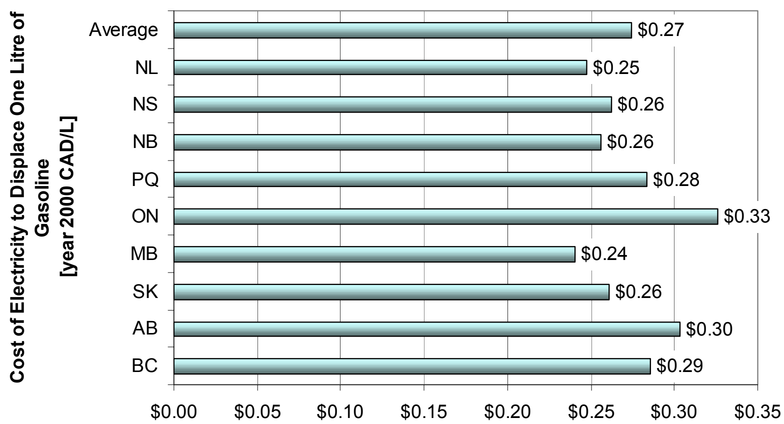


Figure 2-14 Cost of Electricity Required to Displace One Litre of Gasoline (2020 P1 Incremental)

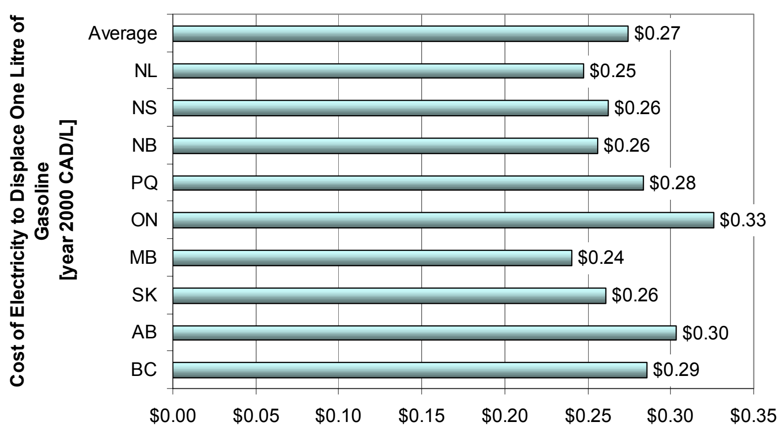


Figure 2-15 Cost of Electricity Required to Displace One Litre of Gasoline (2020 P1 Accelerated)

[21] www.petro-canada.ca Spring, 2003.

2.4 PHASE 1 CONCLUSIONS

Regional hydrogen production to serve Canada's transportation needs is one avenue to reduce greenhouse gas emissions under the pending carbon constraints. However, in order to produce the hydrogen fuel, electricity requirements will rise above the business as usual demand. Therefore, the *net* GHG emission impact must be considered as well as the electricity price impact.

This analysis provided an initial estimation of these two key impacts. Those two impacts will have to be considered by government and consumers alike in determining the value of establishing a hydrogen infrastructure for electrolysis as a fuelling pathway for hydrogen. Assumptions were based on previous Natural Resources Canada scenario work and communication with the Canadian Transportation Fuel Cell Alliance's Studies and Assessments Working Group on details such as forecast fuel efficiency and life-cycle GHG emission coefficients. Two scenarios were developed consisting of different hydrogen penetration rates: Incremental and Accelerated.

The two scenarios provided starting points for quantifying the **GHG emissions impact** of the increased electricity demand due to electrolysis. The analysis showed that, in 2020 under the Incremental scenario, every kilogram of hydrogen replaced 6.75 L of gasoline in light-duty vehicles and 20.9 kg of CO_2 equivalent emissions. Under the Accelerated scenario, in 2020, every kilogram of hydrogen replaced 6.5 L of gasoline and 19.8 kg of CO_2 equivalent emissions. The difference was due to forecast relative fuel efficiency improvements in the future.

The modelling efforts provided a breakdown of the fuel mix behind the generation of additional electricity for hydrogen production. This breakdown was used to quantify the GHG impact. A desired GHG impact, that is, a reduction in overall emissions, is achieved in those provinces where electricity emission intensities were 0.42 tonnes CO_2e/MWh or lower in 2020 and 0.44 tonnes CO2e/MWh or lower in 2010. In other words, where power generation produces 0.42 tonnes of CO2e or lower in 2020, the increased emissions from producing electricity to manufacture hydrogen *is lower than* the emissions displaced from avoiding gasoline combustion, thereby creating a net benefit. Therefore, provinces powered primarily by hydroelectric sources find a net GHG benefit from the implementation of regional hydrogen production via electrolysis. These were British Columbia, Manitoba, Quebec and Newfoundland and Labrador. Conversely, provinces that are reliant on fossil fuel-fired electricity see a net increase in GHG emissions associated with hydrogen production, despite displaced emissions associated with LDV fuel use. These provinces were Alberta, Saskatchewan, New Brunswick and Nova Scotia. Ontario's electricity fuel mix brings this province in at just under the 0.42 tonne/MWh target.

It is important to note that due to inter-provincial travel, it would not be practical to solely implement electrolysis in the hydro-rich provinces. Therefore, the emissions impacts in all provinces must be considered when developing a hydrogen fuelling infrastructure. The total GHG impact across the country still showed a net reduction when all provincial impacts, positive and negative, are totalled. The reduction ranged from 2.2 to 4.4 million tonnes of CO_2e. It should also be noted that other provinces might choose to produce hydrogen using different production technologies such as steam methane reforming or a host of other hydrogen fuelling pathways. These other hydrogen production pathways were outside of the scope of work being considered for this report.

Impacts on electricity prices vary by province based on the generation mix used to meet the additional demand from hydrogen producers for electricity. Provinces with spare capacity to meet the higher demand faced lower price increases than the provinces that require significant capacity investments or increased exports to satisfy the requirements. Ontario saw the largest percent increase (approximately 20 percent relative to the Base Case) in the Accelerated Scenario in 2020. Transmission capacity constraints from the U.S. and overburdened transmission lines from

Newfoundland via Quebec leave Ontario with no option but to increase its fossil-fired generation under SO_2, NO_X regulation and the national carbon constraint. However, most other provinces saw price increases of less than 5 percent in 2020. These electric price impacts are one determinant of the cost of producing hydrogen.

To provide context to the electricity prices, it was useful to make a comparison to the gasoline prices. Across all provinces, the cost of electricity for hydrogen production to displace a litre of gasoline averages $0.28/L in the Accelerated Scenario in 2020. This price was lower than the average cost of gasoline, but did not include operational and other costs associated with hydrogen production and distribution. In comparison, the pre-tax price of gasoline was approximately $0.47/L currently and includes cost of crude, refining and marketing.

The decision to move forward on the development of a hydrogen infrastructure in Canada will need to weigh both the environmental and cost impacts discussed above. A higher confidence will be required on the GHG offsets produced and a resolution on the ownership of those offsets under a Canadian Climate Change policy. Additional cost components, including the operating cost of a retail hydrogen station, will also have to be considered. The results of this analysis, however, show that there are net environmental benefits to be gained at costs comparable to fuel prices today.

Due to the preliminary nature of this assignment, assumptions were based on readily available reviews, historic trends and forecasts and only two scenarios were run. They were intended as a starting point for future analysis as it was outside the scope of this assignment to test the sensitivities around each of the assumptions. A more detailed analysis based on alternate scenarios would increase the confidence in the results. Additionally, several other factors were not included in this analysis, including costs associated with water use for electrolysis and costs associated with the hydrogen production infrastructure and distribution at the retail level. As such, these results should be taken as a "first cut", aimed at establishing a starting point and identifying avenues of further investigation. It is worth noting that this analysis has provided a populated model of the provinces from which further sensitivities and scenarios can easily be explored.

3 PHASE 2

3.1 PHASE 2 SCENARIO DEVELOPMENT

Phase 1 presented an order-of-magnitude analysis of the provincial energy market and GHG emission impacts associated with increased power demand for hydrogen production. To build on Phase 1, ICF developed, with guidance from the Studies & Assessments Working Group (SAWG) of the CTFCA, two refined demand scenarios for Phase 2 (P2) as well as two sensitivities each. The Base Case created for Phase 1 (see Section 1.2.2 for a more detailed description of the Base Case) established a set of results against which to compare the relative impacts of the two Phase 2 demand scenarios and four sensitivities.

Similar to Phase 1, these Phase 2 comparisons evaluated the viability of electrolysis as a fuelling pathway to hydrogen considering the cost of the electricity supply and the GHG impacts with more detailed input from the SAWG on key hydrogen-related assumptions.

The two scenarios analyzed were very similar to those in Phase 1; one in which hydrogen technology was assumed to be adopted at a conservative rate through 2010 and increasing in availability by 2020 (an Incremental scenario); the second, a more intensive scenario in which the adoption of hydrogen technology was assumed to occur in an Accelerated manner. Two sensitivities, one based on the time of day in which the additional power would be required and one including a higher carbon price, were then applied to each of the core 'Incremental' and 'Accelerated' scenarios, in effect, creating six different model runs to be analyzed in Phase 2 (see Table 3-1).

Table 3-1 Model Runs for Phase 2

	Core Scenario Assumption	Sensitivity (All scenario assumptions plus change to specific variable)	
		High Carbon Price	**Time-of-Day**
Phase 2 Incremental Off-Peak	Refined numbers for basic assumptions; extra power demand in off-peak hours only; Carbon price $10CAD/tonne CO_2	Carbon price of $53.33CDN/tonne CO_2 ($40 USD/tonne CO_2)	Extra power demand over all hours of the day
Phase 2 Accelerated Off-Peak	Refined numbers for basic assumptions; extra power demand in off-peak hours only; Carbon price $10CAD/tonne CO_2	Carbon price of $53.33CDN/tonne CO_2 ($40 USD/tonne CO_2)	Extra power demand over all hours of the day
Total Model Runs	2	2	2

Recall that the premise of the introduction of a hydrogen economy relied on a carbon-constrained market. Therefore, for the purposes of this analysis, a carbon cost of $10 CDN/tonne[22] of CO_2 was included in the Base Case and demand scenarios.[23]

The scenario analysis showed the potential impacts of an increase in the energy demand on the power sector. The basis of the analysis was an estimate of the increased electricity production

[22] The Government of Canada has indicated that it will provide Large Final Emitters such as power generating stations access to carbon credits at $15/tonne of CO_2 should no credits remain available at less than $15/tonne. For the purposes of this exercise a price of $1o/tonne of CO_2 was applied.
[23] Other existing, relevant emission regulations were included. This refers to the Ontario Regulation 397 governing emissions of NO_X and SO_2 from power generation facilities.

required due to the adoption of hydrogen under the two refined scenarios (P2 Incremental Off-Peak and P2 Accelerated Off-Peak)[24] in 2010 and 2020 as well as two sensitivities (time of day that power is generated and high cost of carbon). IPM® quantified the electric sector dispatch impact and resulting electricity price under each of the resulting six model runs in 2010 and 2020. Relying on the numerous IPM® outputs (price, generation by capacity type, etc.), as was done in Phase 1, an analysis was performed to determine net GHG benefit of the adoption of fuel-cell technology and hydrogen fuelling via electrolysis under each scenario and sensitivity.

3.1.1 Hydrogen Economy Scenarios

The analysis was based on the amount of electricity required to supply hydrogen via electrolysis under two different hydrogen demand scenarios (P2 Incremental and P2 Accelerated). Each scenario assumed a different penetration rate of hydrogen use. These rates have been refined for Phase 2 from the values used in Phase 1..

- **P2 Incremental Off-Peak Scenario.** Under the incremental scenario, 0.1 percent of the total vehicle fleet in each region was assumed to operate solely on hydrogen by 2010 and 6 percent by 2020. That is, by 2010, 0.1 percent of the fleet kilometres travelled estimated in the base "no-hydrogen" case, was assumed to be met by hydrogen-powered vehicles.

- **P2 Accelerated Off-Peak Scenario.** Under the accelerated scenario, the Working Group assumed that 0.2 percent of the total vehicle fleet would operate on hydrogen by 2010 and 11.5 percent by 2020. Therefore, 0.2 percent of fleet kilometres travelled estimated in the base case would be replaced by travel in hydrogen-powered LDVs by 2010 rising to 11.5 percent by 2020.

As in Phase 1, IPM® was used to produce a forecast of generation by fuel type and province used to supply the additional demand required for electrolysis. Based on this mix of generation sources, the GHG impact was quantified using a total life-cycle emission factor (that includes production, processing, transportation, and storage) associated with the fuel combusted at the generating station. These emissions factors were provided by Natural Resources Canada's GHGenius model.

3.2 PHASE 2 ASSUMPTIONS – KEY MODELLING INPUTS

The vehicle fleet characteristics were refined in Phase 2. The group of vehicles that fell under the light-duty vehicle (LDV) label in Phase 1 were defined to be only cars (vehicles less than 10,000 lbs represented by one set of fuel and emission characteristics). In Phase 2, the LDV fleet was defined as cars and light-duty trucks and was represented by two sets of fuel and emission characteristics, including fuel efficiency.

The total estimated increase in electricity required (at the regional level) to meet hydrogen demand through electrolysis was determined for 2010 and 2020 under the P2 Incremental Off-Peak and P2 Accelerated Off-Peak penetration scenarios based on information supplied by Natural Resources Canada. Projections of vehicle kilometres travelled (VKT) and fuel efficiencies were used to derive estimates of gasoline consumption. From those values, and using the energy equivalency of gasoline and hydrogen, the equivalent amount of hydrogen needed to travel the same distance could be derived. From this result, the electricity required to supply this quantity of hydrogen could be estimated for entry into IPM®.

[24] Recall that it was assumed that the additional demand would be required in off-peak hours when power prices were lower. This is to distinguish the scenario from the later sensitivity where power is required in all hours of the day. (see Section 3.2 and Figure 3-3)

One simplifying assumption for both Phase 1 and Phase 2 was that all vehicles are presently using gasoline. However, the distinct use of truck characteristics as a refinement of the Phase 1 fleet information will impact the amount of gasoline required, the equivalent amount of hydrogen necessary and, therefore, additional electricity required in Phase 2.

3.2.1 Determining Equivalent Gasoline Usage

The total volume of fuel (gasoline) demanded by cars and light-duty trucks for both 2010 and 2020 was calculated using the number of each type of vehicle, the VKT per vehicle per year, and the fuel efficiency for each vehicle type (Table 3-3), all of which were provided by Natural Resources Canada (see below for sample equation).

Total Gasoline Fuel Consumption (L) =

[Number of Cars * VKT per Car per year *Gasoline Fuel Efficiency (L/100 km)] +
[Number of Light-Duty Trucks (LDT) * VKT per LDT per year * Gasoline Fuel Consumption (L/100 km)]

The national consumption results were converted to regional estimates based on the relative number of LDVs per region (as a percentage of the over 17 million LDVs nationally, see Figure 2-1 in Section 2.2). The scenario penetration rates were applied to the LDV fleet numbers to then estimate the **amount of gasoline replaced** by hydrogen as shown in Table 3-2.

Table 3-2 Phase 2 Scenario Penetration Rates of Total LDV Fleet

Scenario	Year	Penetration Rate [%]	Hydrogen Fleet [million LDV]	
			Cars	Light-Duty Trucks
Phase 2 Incremental	2010	0.1	0.010	0.008
	2020	6.0	0.695	0.536
Phase 2 Accelerated	2010	0.2	0.020	0.016
	2020	11.5	1.332	1.026

Note: Updated from Phase 1 numbers on page 2-3.

3.2.2 Determining Equivalent Hydrogen Usage

Based on forecast fuel efficiencies shown in Table 3-3, the amount of hydrogen required to travel the same forecasted distance as used in the gasoline computations was calculated. Therefore, the hydrogen and gasoline requirements are equivalent based on work output. A sample equation for a given year is shown below.

Total Hydrogen Fuel Consumption (kg) =

[Number of Cars * VKT per Car per year * Hydrogen Fuel Consumption (kg/km) * Penetration Rate] +
[Number of LDT * VKT per LDT per year * Hydrogen Fuel Consumption (kg/km) * Penetration Rate]

Table 3-3 Phase 2 Fuel Efficiencies

Light-duty Vehicle	Year	Gasoline Efficiency [L/100 km]	Percent Improvement	Hydrogen Efficiency [kg/100 km]	Based on
Cars	2000	9.7			
	2010	9.3	4% from 2000	1.4	lower efficiency
	2020	8.7	10% from 2000	1.0	middle efficiency
Light-duty Trucks	2000	13.7			
	2010	13.3	3% from 2000	1.86	using CAFC ratios
	2020	12.5	9% from 2000	1.33	using CAFC ratios

Ref: Talbot, R. 2003. (Working Group update from Phase 1 numbers on page 2-4).

3.2.3 Converting Hydrogen Demand to Electricity Demand

Finally, the hydrogen was converted to electricity demand using assumptions of the electricity required to electrolyse hydrogen. This analysis assumed 55 kWh and 50 kWh of electricity are required to produce one kilogram of hydrogen by electrolysis[25] in 2010 and 2020 respectively. These are higher requirements than were assumed in Phase 1. Note that these conversion values included the electricity to produce the hydrogen and to support compression to 350 bar, but they did not account for the electricity needed to refuel vehicles (powering dispensers, detectors, billing machines or energy to power the balance of the station). Table 3-4 shows a summary of the additional electricity required under each scenario in 2010 and 2020. Figure 3-1 and Figure 3-2 show the percentage increases in demand analyzed by province under each of the core scenarios.

Table 3-4 Additional Electricity Required to Produce Hydrogen by Region [MWh]

Scenario	Year	BC	AB	SK	MB	ON	PQ	NB	NS	NL
Phase 2 Incremental Off-Peak	**2010**	36,212	32,738	12,981	10,712	105,893	64,815	7,858	8,225	4,516
	2020	1,665,047	1,496,259	593,280	489,590	4,839,704	2,962,299	359,160	375,899	206,409
Phase 2 Accelerated Off-Peak	**2010**	72,425	65,467	25,962	21,424	211,785	129,630	15,717	16,449	9,032
	2020	3,172,172	2,867,830	1,137,120	938,380	9,276,100	5,677,741	688,391	720,472	395,617

[25] U.S. Department of Energy H2 Information Network (http://www.eere.energy.gov/hydrogenandfuelcells/hydrogen/faqs.html) provided by the working group.

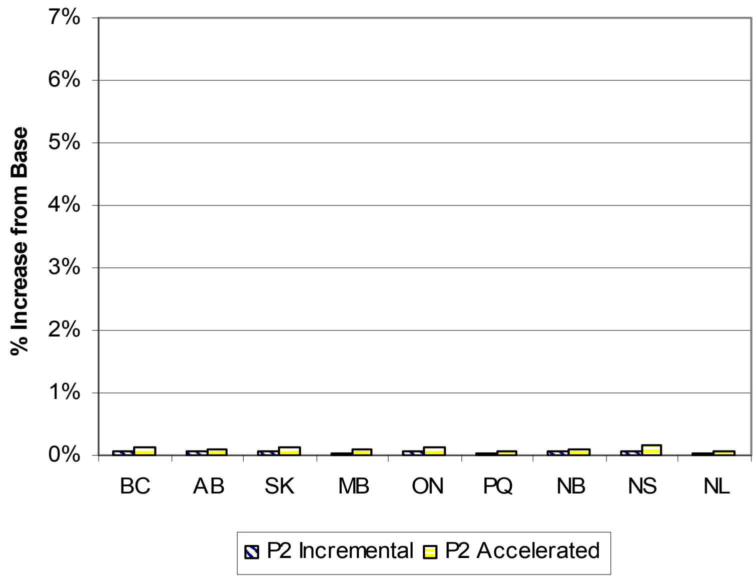


Figure 3-1 Percent Increase in Demand from Base Case by 2010 – P2 Off-Peak

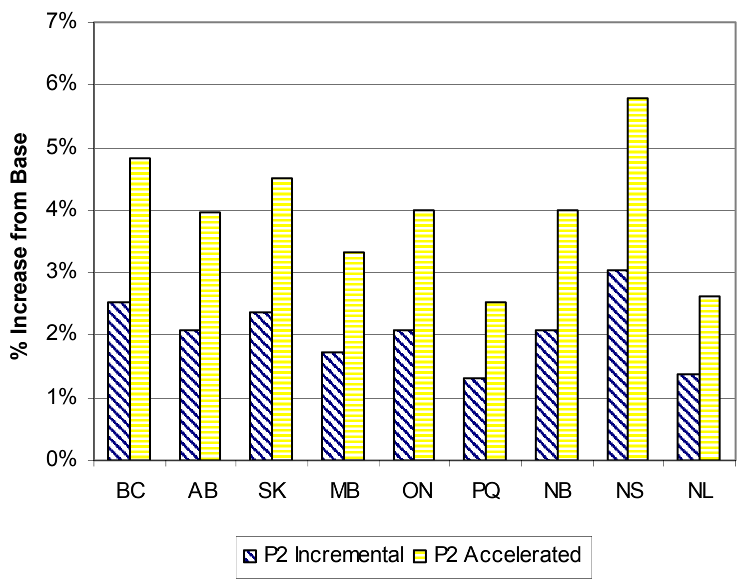


Figure 3-2 Percent Increase in Demand from Base Case by 2020 – P2 Off-Peak

The P2 Incremental Off-Peak scenario drove up electricity demand relative to the Base Case by 1.3 to 3.0 percent of total provincial demand by 2020, depending on the province. The P2 Accelerated Off-Peak scenario nearly doubled the requirement of the P2 Incremental Off-Peak scenario.

The several changes to the assumptions from Phase 1 to Phase 2 combine to lower the final demand numbers. See Appendix F for a detailed comparison of the calculations.

For the purpose of this analysis, the additional electricity demand requirement was assumed to be distributed over those hours when provincial demand would typically be at its lowest, as was done for the Phase 1 analysis. This generation profile would ensure that the electric power necessary to serve this new demand would be provided at the lowest cost and avoid adjustments to peak capacity requirements on the province. Figure 3-3 illustrates how the additional generation requirement was implemented in the load profile of the provinces. This figure shows total generation in British Columbia over the course of the year 2020 in each hour of the day (hour “1” is equivalent to the time between midnight and 1 A.M., hour “2” to between 1 A.M. and 2 A.M., etc.) for the Base Case and the increments necessary under the P2 Incremental and P2 Accelerated Scenarios. The addition of electricity demand for hydrogen production flattens the load profile over the course of the day without adding to load in the peak hours.

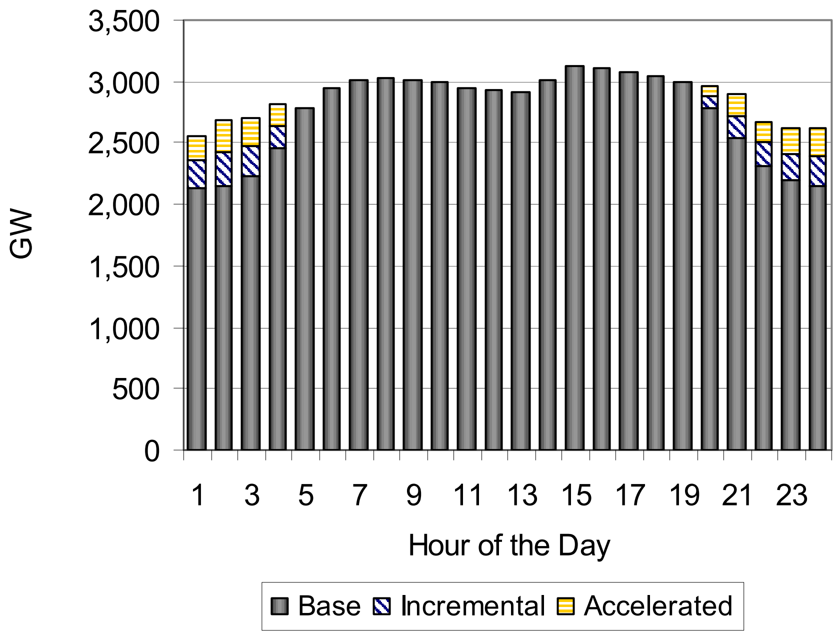


Figure 3-3 Adjusted Hourly P1 Demand in British Columbia in 2020

A heavier reliance by hydrogen producers on electricity generated during peak hours, such as hours 15 though 17 in Figure 3-3, is examined in the Phase 2 Time-of-Day sensitivity analysis in Section 3.3.2.

3.3 PHASE 2 RESULTS

This section presents the electric market results from the Phase 2 IPM® analysis and the resulting net GHG emissions associated with the displacement of gasoline. The IPM® analysis provided the dispatch decisions and energy prices arising from the added electricity demand required to produce hydrogen by region. These results fed into the post-modelling component of the analysis aimed at comparing the emissions associated with hydrogen production to the displaced or avoided emissions from gasoline on a life-cycle basis.

This section presents the results of the scenarios analyzed in Phase 2. The core Incremental and Accelerated Off-Peak Scenarios are discussed first, followed by the High Carbon Price and Time-of-Day sensitivities. Both sets of sensitivities are compared back to the core scenarios so that the impacts of the variable being tested – CO_2 price or the hourly timing of hydrogen production – are isolated from the impacts of the core scenarios themselves.

IPM® Results

The relative economics of hydrogen for use in the transportation sector will depend on numerous factors, including, among other things, the cost of infrastructure necessary to produce and store the hydrogen and the cost of electricity used in the production process. The effectiveness of hydrogen as a means to reduce Canadian carbon emissions will be determined by the demand for hydrogen in place of gasoline and the environmental profile of the electricity used to produce that hydrogen. Based on the Phase 2 hydrogen demand scenarios described above, this analysis addresses two of these determining factors: the cost of the electricity input to the hydrogen production process and the GHG emissions associated with that additional electricity generation. This section presents the results of the IPM® analysis at a provincial level aimed at evaluating and quantifying regional siting-related impacts of electrolysis based on emissions and pricing indicators.

3.3.1 Results: Phase 2 Incremental and Accelerated Off-Peak Scenarios

3.3.1.1 Electric Market Response to Demand Scenarios

The response of the provincial electric systems to the increase in required load, under P2 Incremental and P2 Accelerated off-peak scenarios, determined the impact of the demand scenarios on electric prices and emissions profiles. The following sections discuss the environmental and cost components necessary to determine the viability of hydrogen production.

Impacts on Generation Mix

The cost and emissions impacts of generating the electricity necessary to supply the demand for hydrogen in Phase 2 were driven by a very similar mix of dispatch and new capacity build decisions used to supply the electricity in the Phase 1 scenarios. Refer to Table 2-4, page 2-8 in Phase 1 section of this report for a full description. In general, the additional electricity required to produce hydrogen would be supplied by a combination of, in hydro-rich provinces, slight increases of fossil-fired generation and reduced exports to neighbouring regions. In other provinces, new gas-fired capacity was brought online to satisfy increased demand in addition to a mix of increased fossil-fired generation (including existing gas capacity) and shifts in net exports relative to the Base Case.

Table 3-5 and Table 3-6 show the generation mix in each province, or the share of electricity generated in the off-peak hours by each fuel source, resulting from the additional demand placed on them. The shares shown here reflect the mix in the hours in which the additional load was assigned. Table 3-5 and Table 3-6 show 2020 numbers only -- see Appendix D for a full listing.

Table 3-5 Percentage Dispatch by Fuel Type and Region in Hydrogen Production Segments (2020 Phase 2 Incremental Off-Peak Scenario)

	Coal	Gas	Oil	Hydro	Nuclear	Non-Carbon Other
BC	0%	12%	0%	86%	0%	2%
AB	57%	40%	0%	0%	0%	3%
SK	56%	38%	0%	5%	0%	1%
MB	2%	0%	0%	98%	0%	0%
ON	18%	32%	0%	6%	43%	1%
PQ	0%	9%	0%	85%	3%	3%
NB	16%	20%	39%	1%	23%	2%
NS	77%	19%	0%	0%	0%	3%
NL	0%	9%	0%	91%	0%	0%

Table 3-6 Percentage Dispatch by Fuel Type and Region in Hydrogen Production Segments (2020 Phase 2 Accelerated Off-Peak Scenario)

	Coal	Gas	Oil	Hydro	Nuclear	Non-Carbon Other
BC	0%	11%	0%	87%	0%	2%
AB	56%	41%	0%	0%	0%	3%
SK	53%	40%	0%	6%	0%	1%
MB	2%	0%	0%	98%	0%	0%
ON	17%	32%	0%	8%	42%	1%
PQ	0%	10%	0%	84%	3%	3%
NB	16%	19%	41%	1%	22%	2%
NS	75%	21%	0%	1%	0%	3%
NL	0%	12%	0%	88%	0%	0%

The use of existing and new gas-fired capacity to supply the new demand increases generation from gas at the national level by over 17 TWh, or 14 percent, by 2020 in the P2 Accelerated Scenario relative to the Base Case. The remaining new demand requirements were met with imports from the U.S. and small increases in coal- and oil-fired generation.

3.3.1.2 GHG Emissions Impacts of Generation for Hydrogen Production

The change in dispatch in each province outlined in Table 3-5 and Table 3-6 above was used to determine the GHG impact of supplying power to the hydrogen production process. While gas-fired capacity, existing and new, supplies the majority of additional generation and drives the marginal cost of generation, as described in Table 2-4, the hydrogen producer will not necessarily receive electricity directly from those sources. Instead, the producer will use electricity from the same mix of sources available to other consumers and must have its emissions impact determined consistent with that mix. Therefore, the dispatch percentages for the entire capacity fuel mix were used to estimate GHG emissions from power generation.

Net GHG Impact from Avoided Gasoline and Increase Electricity Usage

The GHG impact represented the net impact of two related activities -- producing additional electricity to electrolyse water to produce hydrogen, which tends to increase electric sector emissions, and using that hydrogen in place of gasoline for the specified percentage of cars and light-duty trucks, which lowers transportation sector emissions. The net GHG impact was determined by:

Net GHG Impact (avoided gasoline and increased electricity usage) = GHG emissions associated with electricity generation –
GHG emissions avoided due to displaced gasoline usage

A negative GHG impact resulting from this calculation signifies a net reduction in the emissions generated by supplying a level of transportation service. The calculation of these two components is discussed in greater detail below.

GHG Emissions Avoided from Hydrogen Use

GHG emissions avoided due to displaced gasoline were estimated based on:

- The estimated gasoline displaced under each P2 scenario for 2010 and 2020 (refer to Section 3.2 for discussion of methodology and Table 3-3 for fuel efficiencies), and
- Full, life-cycle emission factors provided by Natural Resources Canada (see Table 3-9).

The estimate of gasoline (million litres) displaced under each P2 scenario for 2010 and 2020 determined in Section 3.2 was employed along with a full, life-cycle emission factor to quantify the GHG emissions avoided due to the displacement of the gasoline. The emission factor included CO_2, N_2O and CH_4 emissions from vehicle operation (combustion), fuel dispensing, production, and transport (see Table 3-7 and Table 3-8).

Table 3-7 Phase 2 GHG Emission Factors Associated with Gasoline for Car Usage (Life-Cycle)

2010					
Gas 30ppm S (fuel cycle)	466.2	Grams of CO2eq	per	1	Mile
	289.75	Grams	per	1	km
	289.75	Tonnes	per	1,000,000	km
2020					
Gas 30ppm S (fuel cycle)	433.3	Grams	per	1	Mile
	269.30	Grams	per	1	km
	269.30	Tonnes	per	1,000,000	km

Ref. Talbot, R. 2003. Updated from Phase 1 numbers on page 2-10.
Note that GHG emission factors exclude vehicle assembly and transport and materials in vehicles (including storage) and lube oil production/use. These actions are presumed to be approximately the same for hydrogen vehicles.

Table 3-8 Phase 2 GHG Emission Factors Associated with Gasoline for Light-Duty Truck Usage (Life-Cycle)

2010					
Gas 30ppm S (fuel cycle)	675.3	Grams of CO2eq	per	1	Mile
	419.70	Grams	per	1	km
	419.70	Tonnes	per	1,000,000	km
2020					
Gas 30ppm S (fuel cycle)	632.3	Grams	per	1	Mile
	392.98	Grams	per	1	km
	392.98	Tonnes	per	1,000,000	km

Ref. Talbot, R. 2003.
Note that GHG emission factors exclude vehicle assembly and transport and materials in vehicles (including storage) and lube oil production/use. These actions are presumed to be approximately the same for hydrogen vehicles.

Figure 3-4 provides the emissions avoided by province due to the displacement of gasoline-powered cars and light-duty trucks with hydrogen-powered vehicles under the P2 Incremental and P2 Accelerated scenarios for 2010 and 2020. In all figures, a negative value indicates a reduction in emissions. Note that the scale of the figures is different from those in Phase 1 to accommodate the larger emissions reductions.

The trucks in the vehicle fleet had higher emission factors and poorer fuel efficiencies than the other vehicles. Both factors contributed to a higher amount of avoided emissions in Phase 2 versus Phase 1. This was best seen in the 2020 Accelerated case. The provinces with larger vehicle fleets, such as Ontario and Quebec, had the largest amount of avoided GHG emissions when transitioning from gasoline to hydrogen since the emission factors are directly related to fleet VKT and, therefore, fleet size.

Since the provincial share of vehicles, cars and light-duty trucks, was based on the regional percentage of all light-duty vehicles (Figure 2-1), the GHG emissions avoided were directly proportional to the number of vehicles that were assumed to enter into the market by 2010 and 2020 under the differing penetration rates (P2 Incremental and P2 Accelerated). That is, the more vehicles that adopt hydrogen at the provincial level, the greater the GHG emissions avoided. The provinces with the largest fleets therefore displaced the greatest amount of GHGs as a result of making the transition to hydrogen-based transportation.

Figure 3-4 P2 Emissions Avoided Due to Displacement of Gasoline (by Province)

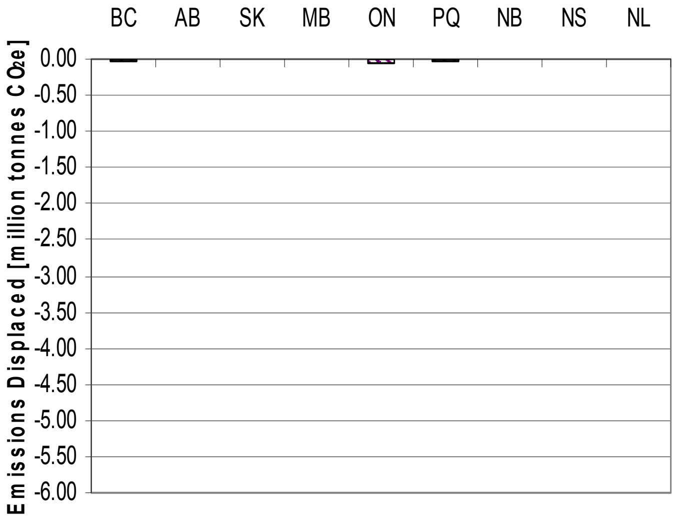


Figure 3-4a Emissions from Gasoline Usage by Province (2010 P2 Incremental Off-Peak)

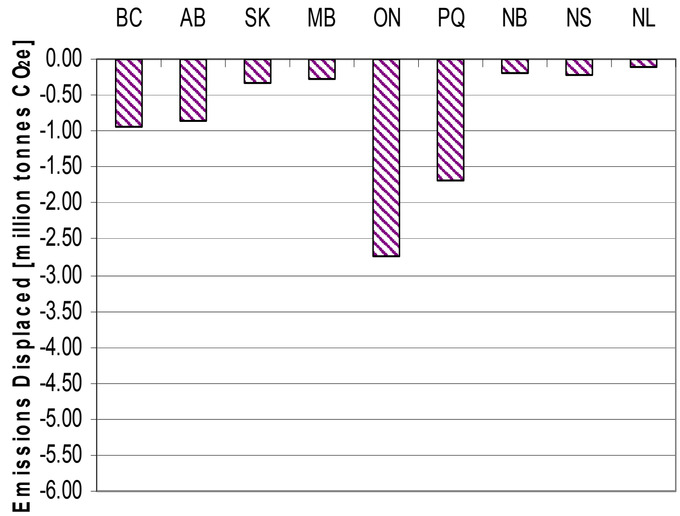


Figure 3-4b Emissions from Gasoline Usage by Province (2020 P2 Incremental Off-Peak)

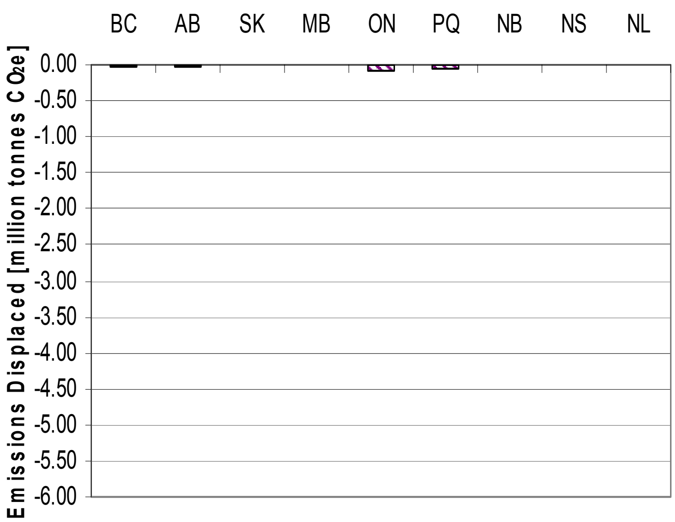


Figure 3-4c Emissions from Gasoline Usage by Province (2010 P2 Accelerated Off-Peak)

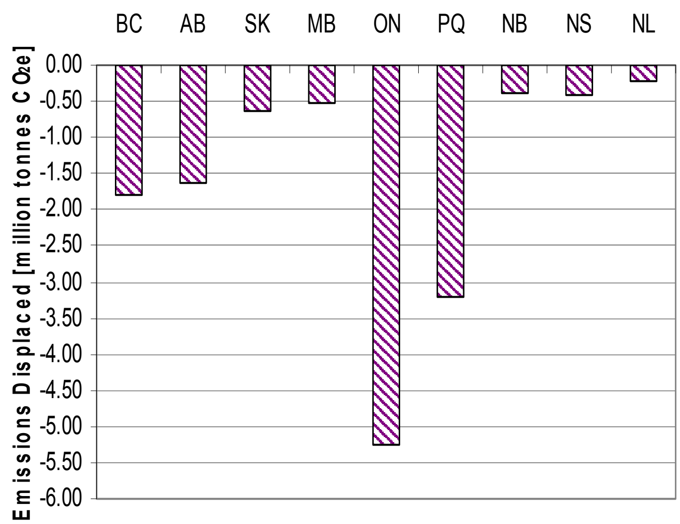


Figure 3-4d Emissions from Gasoline Usage by Province (2020 P2 Accelerated Off-Peak)

GHG Emissions from Additional Electricity Generation

Differing modes of producing electricity had very different GHG intensities. The GHG emissions associated with the production of a set amount of electricity, therefore, depended on the source of the power (that is, coal, gas, oil, hydro or nuclear). The calculation of GHG emissions associated with electricity generation was estimated based on:

- The source (by fuel-type) of the electricity required to meet the increased demand under each P2 scenario for 2010 and 2020 (IPM® output – see Table 3-5 and Table 3-6),
- The estimated electricity demand under each P2 scenario for 2010 and 2020 (refer to section 3.2 for discussion of methodology), and
- The source-specific full, life-cycle emission factors modified to account for fuelling-related emissions (tonnes of CO_2 equivalent per MWh) provided by Natural Resources Canada.

The source-specific emission factors included full life-cycle quantification of the GHG emissions (CO_2, N_2O and CH_4) upstream (exploration, production, transport) and from combustion. These coefficients were provided by Natural Resources Canada from the GHGenius model. Phase 2 emission factors were updated from Phase 1 by Natural Resources Canada. In the same way as was done in Phase 1, each of the emission factors was increased by 5 percent to account for the emissions associated with hydrogen fuel dispensing. The 5 percent was based on information provided by Natural Resources Canada from its assessment of the full life-cycle emissions associated with hydrogen. The resulting emission factors are shown in Table 3-9.

Table 3-9 Phase 2 GHG Emission Factors Associated with Stationary Combustion

2010					
Coal	1.1214	tonnes of CO_2eq	per	1	MWh
NG-turbine	0.4956	tonnes of CO_2eq	per	1	MWh
NG-boiler	0.6531	tonnes of CO_2eq	per	1	MWh
Oil	1.0374	tonnes of CO_2eq	per	1	MWh
Hydro	0.0252	tonnes of CO_2eq	per	1	MWh
Nuclear	0.01365	tonnes of CO_2eq	per	1	MWh
Other	0	tonnes of CO_2eq	per	1	MWh
2020					
Coal	1.10355	tonnes of CO_2eq	per	1	MWh
NG-turbine	0.49455	tonnes of CO_2eq	per	1	MWh
NG-boiler	0.6195	tonnes of CO_2eq	per	1	MWh
Oil	1.0164	tonnes of CO_2eq	per	1	MWh
Hydro	0.0252	tonnes of CO_2eq	per	1	MWh
Nuclear	0.0126	tonnes of CO_2eq	per	1	MWh
Other	0	tonnes of CO_2eq	per	1	MWh

Emission Factors from Natural Resources Canada's GHGenius program.[26]

Figure 3-5 shows the GHG emissions associated with the electricity generated to meet the increased demand under the two Phase 2 off-peak scenarios for 2010 and 2020. Note that the scale has been kept the same as in Phase 1 for straightforward comparison.

As was observed in Phase 1, the results at the provincial level show that the emissions associated with the production of electricity are dependent primarily on the source of the electricity. That is, provincial emissions were highest in those provinces that are dependent on fossil-fired generation

[26] Talbot, R. 2003. Updated from Phase 1 numbers on page 2-12.

and lowest in those provinces dependent on hydroelectric and nuclear to meet the electricity demand due to hydrogen production. Due to the decreased amount of additional demand in Phase 2 compared to Phase 1, emissions from the resulting electricity mix were also lower.

Figure 3-5 P2 GHG Emissions Associated with Increased Electricity Demand

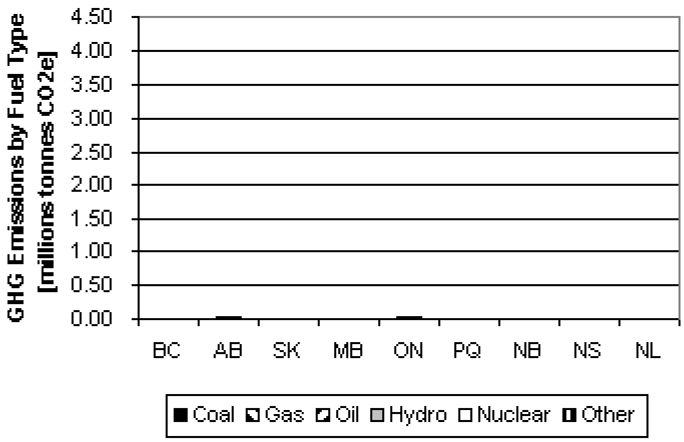


Figure 3-5a Emissions by Fuel Type for 2010 P2 Incremental Off-Peak Scenario

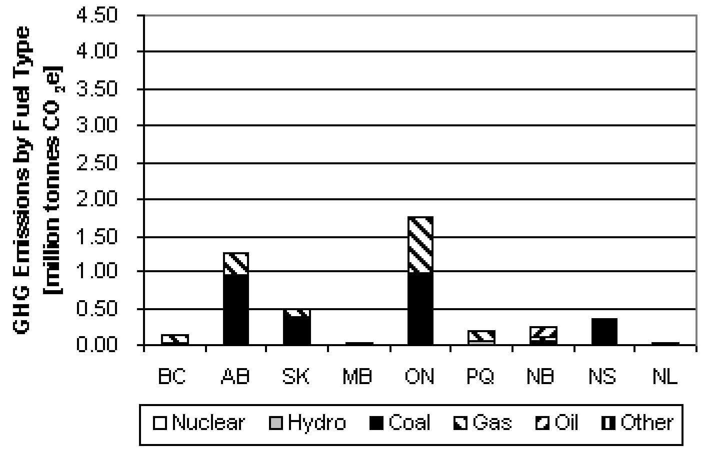


Figure 3-5b Emissions by Fuel Type for 2020 P2 Incremental Off-Peak Scenario

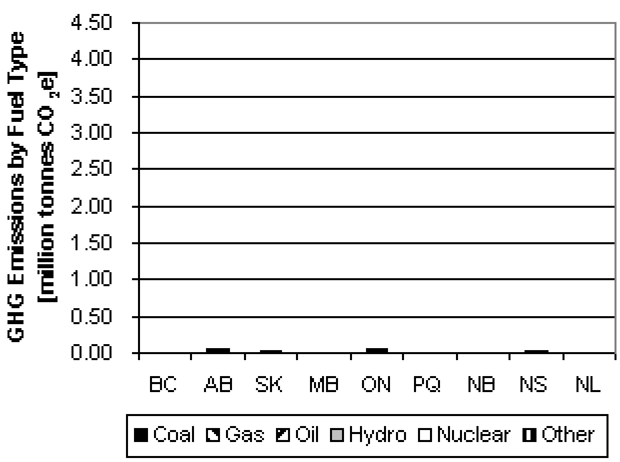


Figure 3-5c Emissions by Fuel Type for 2010 P2 Accelerated Off-Peak Scenario

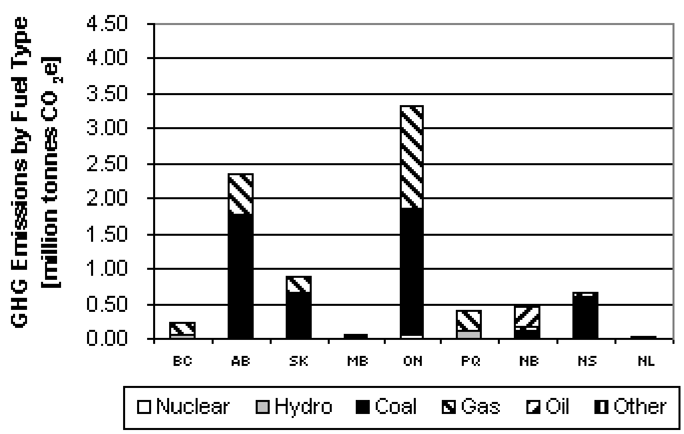


Figure 3-5d Emissions by Fuel Type for 2020 P2 Accelerated Off-Peak Scenario

Net GHG Impact from Avoided Gasoline and Increased Electricity Usage on GHG Emissions

The net GHG impacts of partially substituting hydrogen for gasoline in the transportation sector are shown in the following figures. Recall that a negative value reflects a net reduction in emissions, or that the emissions offset by moving from gasoline to hydrogen are greater than the emissions generated for the production of the hydrogen. Provinces dependent on fossil fuels fared worse than those provinces that utilize hydroelectric, nuclear or a broader mix of capacity types. In the lower-emitting provinces, fewer incremental emissions were produced per unit of hydrogen. However, regardless of the province, the same amount of emissions from gasoline-powered cars and light-duty trucks were displaced per unit of hydrogen. Therefore, from an environmental standpoint, the lower-emitting provinces offered the best opportunity for realizing emissions reductions by switching to hydrogen-based transportation. Table 3-10, Table 3-11 and Figure 3-6 show the net GHG impacts.

Table 3-10 Emissions Impact of Hydrogen Substitution Phase 2 Incremental Off-Peak Scenario (CO_2)

	by 2010 (million tonnes CO_2)			by 2020(million tonnes CO_2)		
Province	**Electrolysis**	**Gasoline**	**Net GHG Change**	**Electrolysis**	**Gasoline**	**Net GHG Change**
BC	0.001	-0.014	-0.013	0.131	-0.935	-0.804
AB	0.032	-0.013	0.019	1.241	-0.845	0.396
SK	0.012	-0.005	0.007	0.480	-0.335	0.145
MB	0.001	-0.004	-0.004	0.024	-0.277	-0.253
ON	0.033	-0.042	-0.008	1.754	-2.735	-0.981
PQ	0.002	-0.026	-0.024	0.194	-1.674	-1.480
NB	0.005	-0.003	0.002	0.242	-0.203	0.039
NS	0.008	-0.003	0.005	0.356	-0.212	0.146
NL	0.000	-0.002	-0.002	0.014	-0.117	-0.103
Total	**0.094**	**-0.112**	**-0.017**	**4.436**	**-7.333**	**-2.897**

Table 3-11 Emissions Impact of Hydrogen Substitution Phase 2 Accelerated Off-Peak Scenario (CO_2)

	by 2010 (million tonnes CO_2)			by 2020 (million tonnes CO_2)		
Province	**Electrolysis**	**Gasoline**	**Net GHG Change**	**Electrolysis**	**Gasoline**	**Net GHG Change**
BC	0.002	-0.029	-0.026	0.238	-1.792	-1.554
AB	0.064	-0.026	0.038	2.357	-1.621	0.737
SK	0.024	-0.010	0.014	0.894	-0.643	0.252
MB	0.001	-0.008	-0.007	0.045	-0.530	-0.485
ON	0.066	-0.083	-0.018	3.321	-5.242	-1.921
PQ	0.003	-0.051	-0.048	0.406	-3.208	-2.803
NB	0.011	-0.006	0.005	0.470	-0.389	0.081
NS	0.017	-0.006	0.010	0.669	-0.407	0.262
NL	0.000	-0.004	-0.003	0.033	-0.224	-0.191
Total	**0.187**	**-0.224**	**-0.036**	**8.434**	**-14.055**	**-5.622**

Figure 3-6 P2 Net GHG Impact (Avoided Gasoline and Increased Electricity Usage) of Hydrogen Substitution

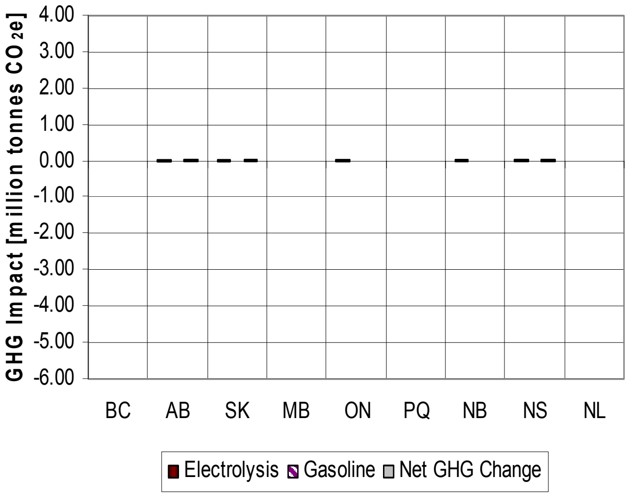


Figure 3-6a GHG Impact in 2010 – P2 Incremental Off-Peak Scenario

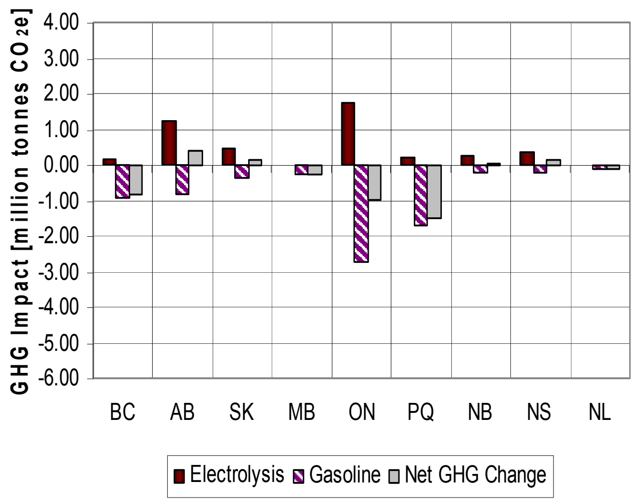


Figure 3-6b GHG Impact in 2020 – P2 Incremental Off-Peak Scenario

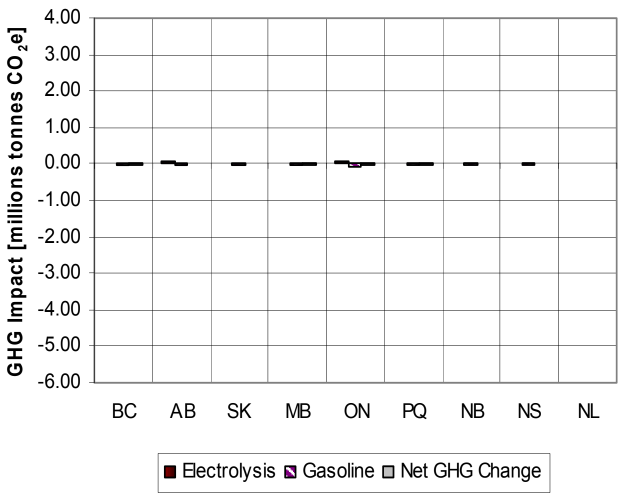


Figure 3-6c GHG Impact in 2010 – P2 Accelerated Off-Peak Scenario

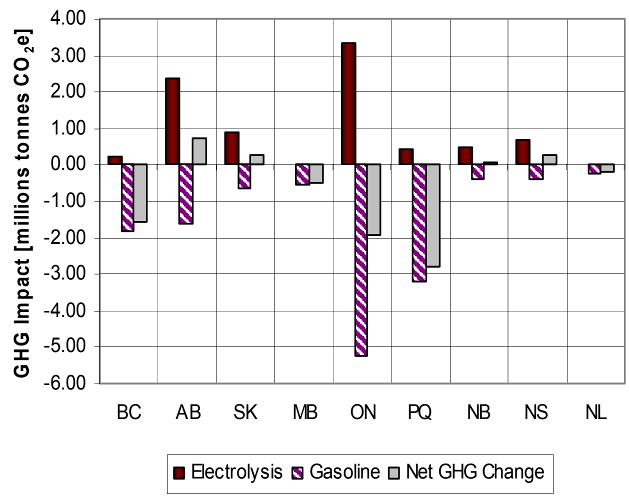


Figure 3-6d GHG Impact in 2020 – P2 Accelerated Off-Peak Scenario

Those provinces where the GHG emissions intensity associated with the power generated was less than 0.39 tonnes of CO_2e/MWh in 2010 and 0.53 tonnes of CO_2e/MWh in 2020 result in a beneficial GHG impact (that is, a net reduction in GHG emissions). The threshold value represents the electricity emissions equivalent to emissions from the combustion of gasoline. This value was calculated by converting the GHG emission factor for mobile combustion of gas (tonnes GHG/km) to equivalent emissions per kg of hydrogen using the fuel efficiency of hydrogen (tonnes hydrogen/km). With the amount of electricity required to electrolyze a kilogram of hydrogen, it was then possible to calculate an equivalent emissions per electricity generation. Figure 3-7 shows the GHG intensities of the nine provinces studied in Phase 2 relative to the 2020 target intensity of 0.53 tonnes CO_2e per MWh.

Although the inclusion of trucks in the vehicle fleet raised the threshold value from what resulted in Phase 1, the provinces that tended to show a net GHG reduction are the same as in Phase 1.

Since a hydrogen infrastructure cannot be separated over provinces (that is, to drive across provinces, fuelling stations would be required in all intermediate provinces) it was useful to consider total net GHG change over the country as shown in Table 3-10 and Table 3-11. There were 2.9 and 5.6 million tonne CO_2 reductions in the Phase 2 Incremental Off-Peak and Phase 2 Accelerated Off-Peak scenarios, respectively. The reduction in the Accelerated scenario was 1.5 times greater than that realized in the Accelerated scenario in Phase 1 and 2.6 times greater than the corresponding result in the Phase 1 Incremental scenario. These more sizable reductions were driven by the increased avoided emissions resulting from the inclusion of trucks in the Phase 2 analysis and the decreased additional electricity demand resulting from the modified conversion assumptions.

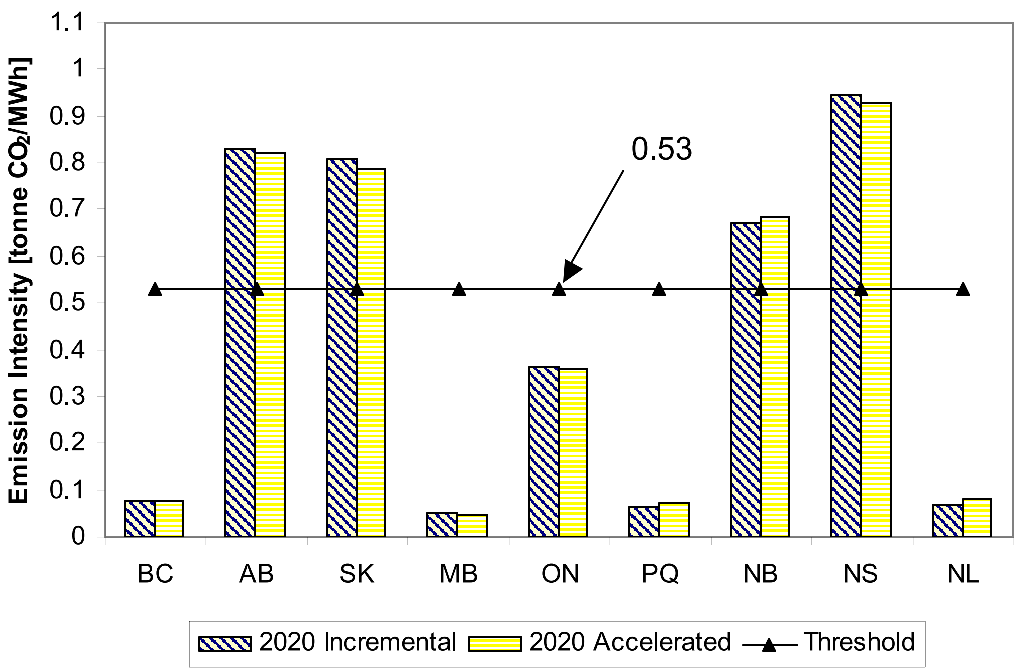


Figure 3-7 P2 Emission Intensity by Region for Off-Peak Scenarios

3.3.1.3 Impacts on Electricity Prices

The cost effectiveness of hydrogen as a fuel source for transportation will depend on the cost of generating the hydrogen, composed primarily of the cost of the electricity input into that process, and the relative cost of the gasoline alternative. This section focuses on the first component of that total cost -- the cost of the electricity input into the production of hydrogen.

In IPM®, electricity prices reflect the cost of generation at the marginal unit, or the unit setting the price in each season and load segment. That cost is the sum of variable operating and maintenance (O&M) costs, fuel costs, and environmental charges paid to comply, in this case, with the national climate change regulation and, in Ontario, with the provincial NO_X and SO_2 policies. The absolute impacts of the P2 Incremental and P2 Accelerated Demand Scenarios on provincial annual average electricity prices are shown in Figure 3-8. Note that all dollar values are in year 2000 Canadian dollars.

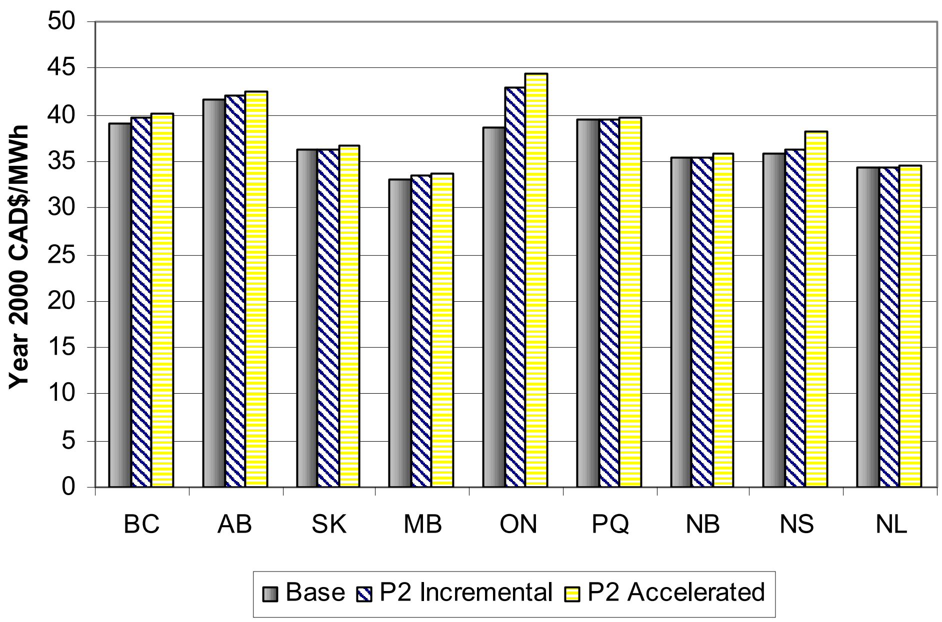


Figure 3-8 P2 Provincial Energy Prices in 2020

Prices increased in all provinces, rising by slightly more than 10% in 2020 in the P2 Incremental Scenario and by almost 15% in 2020 in the P2 Accelerated Scenario (Figure 3-9). The magnitude of the impact in each province depended on the manner in which it chose to meet the additional demand requirements. In many regions, as discussed above, the additional generation was supplied by existing or new gas-fired capacity. If this capacity was utilized in the scenarios at times of the day during which it was **not** used in the Base Case, the marginal cost of generation in those times increased, thereby increasing the average cost of production for the entire day. Regions relying heavily on imports faced the higher prices realized in the supplying regions and, therefore, realized higher average annual prices themselves.

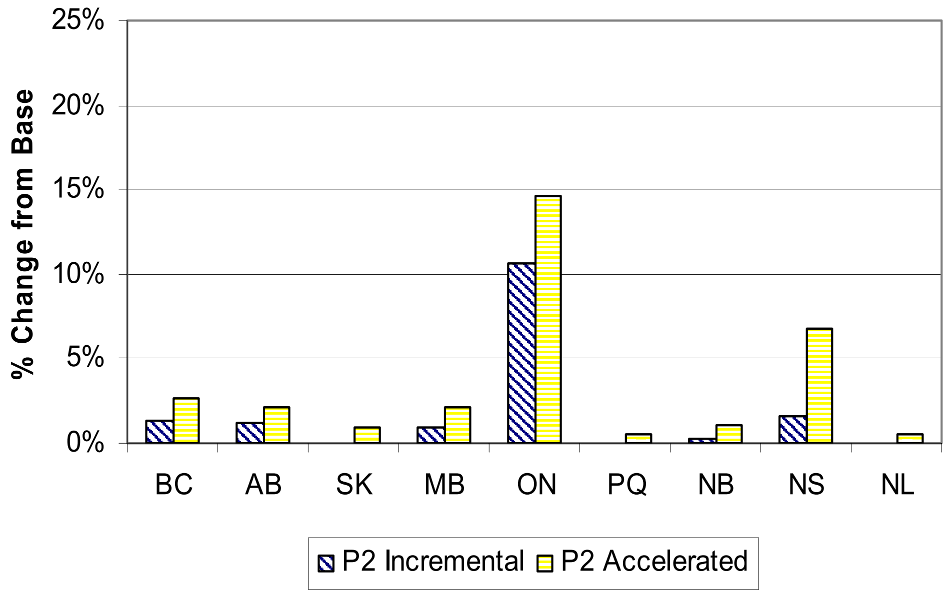


Figure 3-9 Percent Change in 2020 P2 Average Annual Energy Price from Base Case

Analysis of Cost of Hydrogen Production

As discussed above, the successful adoption of hydrogen will depend on the cost of its production and the competitiveness of the resulting cost as compared to gasoline. This section uses the IPM® energy price results discussed above to calculate the cost to the consumer of hydrogen for transportation. The costs detailed in this analysis are based on the assumption that 55 kWh and 50 kWh of electricity are required to produce one kilogram of hydrogen in 2010 and 2020, respectively. Note that the costs shown below are wholesale market costs which do not reflect the transmission and distribution costs that will be incurred by the eventual electrolysis generator.

Figure 3-10 and Figure 3-11 translate the energy prices shown in Figure 3-8 into costs required per unit of hydrogen produced.

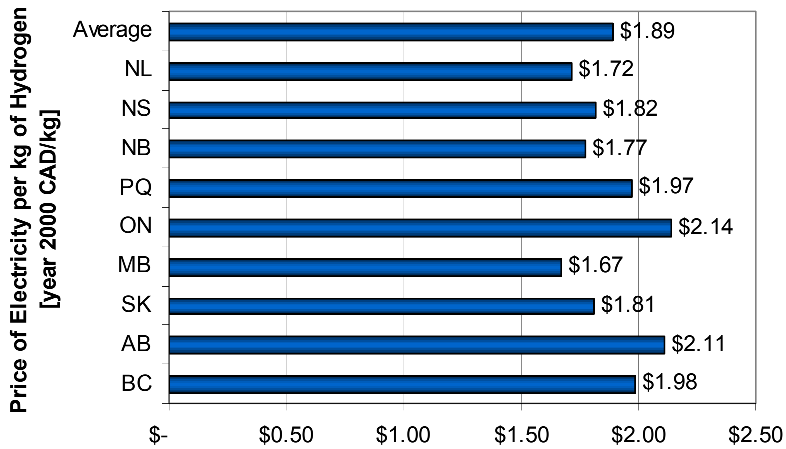


Figure 3-10 Electricity Costs in 2020 P2 Incremental Off-Peak Scenario

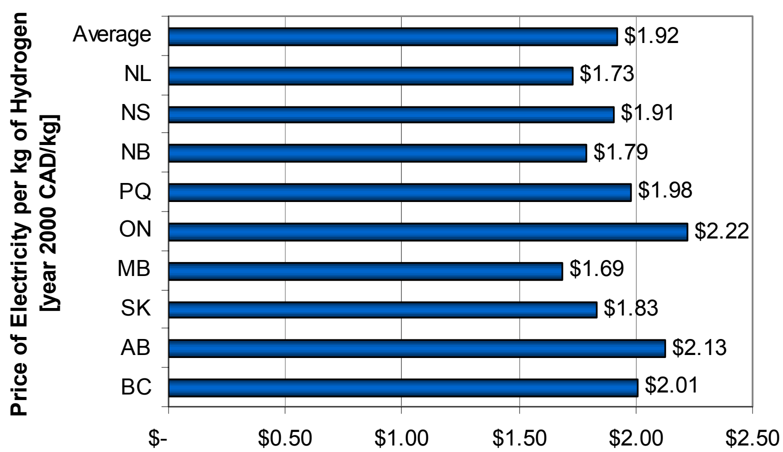


Figure 3-11 Electricity Costs in 2020 P2 Accelerated Off-Peak Scenario

Figure 3-12 and Figure 3-13 convert the values presented above into an equivalent price of electricity required to displace one litre of gasoline (based on forecast fuel efficiencies). The prices shown can be compared to the market price for a litre of gasoline in each of the provinces. In 2020 in the Accelerated Scenario, the equivalent price of electricity varies from $0.19 per kilogram of hydrogen in Newfoundland and Manitoba to $0.25 in Ontario. These values compare to a current average national market price for gasoline of $0.46/L (pre-tax) and a post-tax price of $0.77 per litre[27]. Note that the regional pre-tax prices vary significantly (from $0.47/L in Toronto to $0.40/L in Charlottetown), albeit all are higher than the prices presented for hydrogen. Based on the

[27] www.petro-canada.ca. January 2004.

examination of this component of the cost of hydrogen, it would appear that hydrogen would be an economically viable replacement for gasoline.

It is important to note that while the price of gasoline includes the cost of crude oil input, refining and marketing. Regional prices also may reflect the economies of scale for large cities and other regional differences. The prices of hydrogen provided here do not include related costs, which are expected to be material, associated with supply of water for electrolysis and the storage and distribution of hydrogen at the retail level.

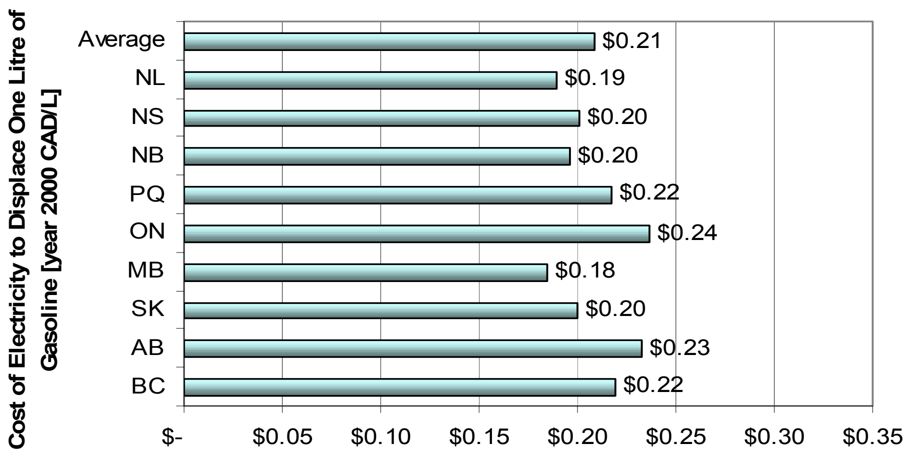


Figure 3-12 Cost of Electricity Required to Displace One Litre of Gasoline (2020 P2 Incremental Off-Peak)

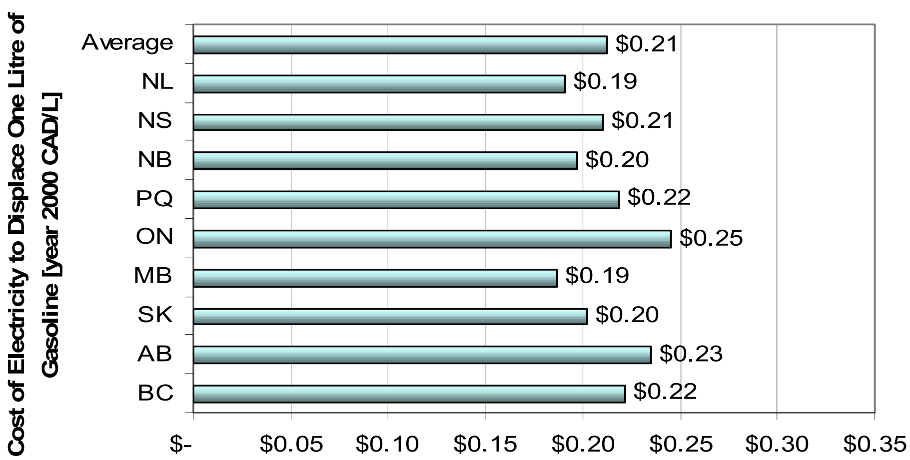


Figure 3-13 Cost of Electricity Required to Displace One Litre of Gasoline (2020 P2 Accelerated Off-Peak)

3.3.2 Sensitivity Cases

As discussed earlier, two sensitivity cases were run for each scenario in Phase 2 to examine the impacts of potential key drivers on the analysis. The sensitivity cases included only changes to the following variables:

- Carbon price; \$53.33CDN/tonne CO_2 (\$40 USD/tonne CO_2) (High Carbon case); and
- Timing of additional electricity demand; spread over the peak and off-peak hours of the day (Time-of-Day).

These sensitivity cases had to be considered in context. For this reason, the High Carbon case sensitivities were compared to the respective P2 Incremental Off-Peak and P2 Accelerated Off-Peak scenarios so that the effect of carbon price as a single variable could be fully understood. The Time-of-Day sensitivities were also compared directly to the P2 Incremental Off-Peak and P2 Accelerated Off-Peak scenarios to capture the impact of the timing of demand on the results.

3.3.2.1 Carbon Price Sensitivity

Electric Market Response to Carbon Price Sensitivities – Impacts on Generation Mix

Table 3-12 and Table 3-13 show in the percentage of generation in the off-peak hours attributable to each fuel type by province for the High Carbon case. The percentages shown here reflect the mix in the hours in which the additional load was assigned (Section 2.2). Table 3-12 and Table 3-13 show 2020 numbers only -- see Appendix E for a full listing.

The higher CO_2 price of \$40CDN/tonne CO_2 (\$40USD/tonne CO_2) shifted dispatch away from coal-fired generation and toward lower emitting gas-fired generation in the provinces that are heavily dependent on fossil-fired generation. Hydro-rich provinces relied on hydro generation and reduced gas generation versus the corresponding P2 scenario. Higher penetration of non-emitting “Non-Carbon Other” technologies, including wind, new small hydro, landfill gas and biomass options, was also seen in many provinces.

Table 3-12 Dispatch by Fuel Type and Region in Hydrogen Production Segments (2020 Phase 2 Incremental High Carbon Case)

	Coal	Gas	Oil	Hydro	Nuclear	Non-Carbon Other
BC	0%	0%	0%	97%	0%	3%
AB	2%	93%	0%	0%	0%	6%
SK	0%	90%	0%	9%	0%	1%
MB	0%	5%	0%	95%	0%	1%
ON	6%	35%	0%	8%	45%	5%
PQ	0%	2%	0%	87%	3%	9%
NB	0%	55%	2%	6%	33%	4%
NS	7%	82%	0%	2%	0%	10%
NL	0%	0%	0%	100%	0%	0%

Table 3-13 Dispatch by Fuel Type and Region in Hydrogen Production Segments (2020 Phase 2 Accelerated High Carbon Case)

	Coal	Gas	Oil	Hydro	Nuclear	Non-Carbon Other
BC	0%	0%	0%	98%	0%	2%
AB	4%	91%	0%	0%	0%	6%
SK	0%	89%	0%	10%	0%	1%
MB	0%	5%	0%	94%	0%	1%
ON	6%	35%	0%	9%	43%	7%
PQ	0%	2%	0%	86%	3%	10%
NB	0%	57%	1%	5%	33%	4%
NS	6%	81%	0%	3%	0%	9%
NL	0%	0%	0%	100%	0%	0%

Net GHG Emissions Impacts of Generation for Hydrogen Production

GHG Emissions Avoided from Hydrogen Use

The GHG emissions avoided from displacement of gasoline with hydrogen were the same in the sensitivity case as in the corresponding scenario. That is, the GHG emission reductions shown in Figure 3-5 for 2010 P2 Incremental Off-Peak scenario were the same for 2010 Incremental High Carbon Price sensitivity. These emission impacts were based on total amount of gasoline displaced and this calculation was not affected by the higher carbon price.

GHG Emissions from Additional Electricity Generation

Figure 3-14 shows the GHG emissions associated with the electricity generated to meet the increased demand due to hydrogen production under the two P2 High Carbon Price sensitivities for 2020. GHG emissions were lower than in the core scenarios, with gas playing a more prominent role. Similar trends were seen in 2010.

Figure 3-14 P2 GHG Emissions Associated with Increased Electricity Demand with High Price of Carbon Sensitivity

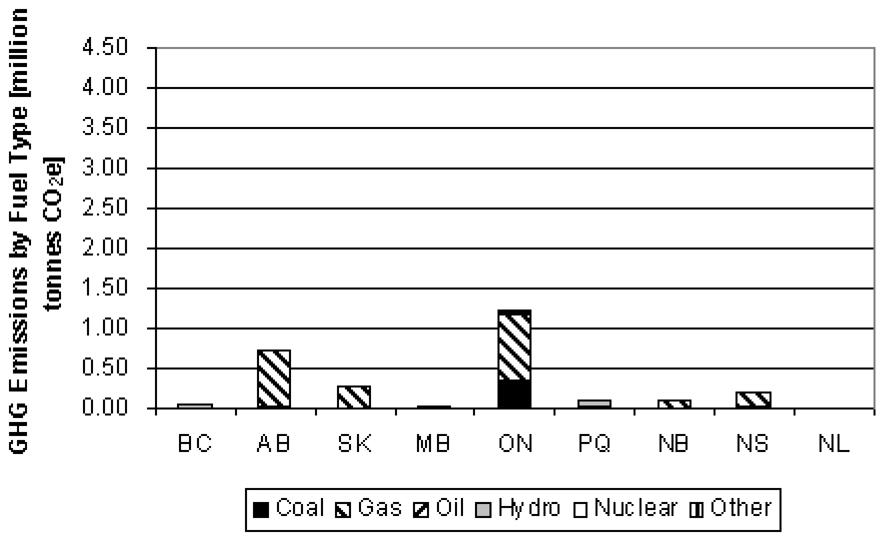


Figure 3-14a Emissions by Fuel Type for 2020 P2 Incremental High Carbon Case

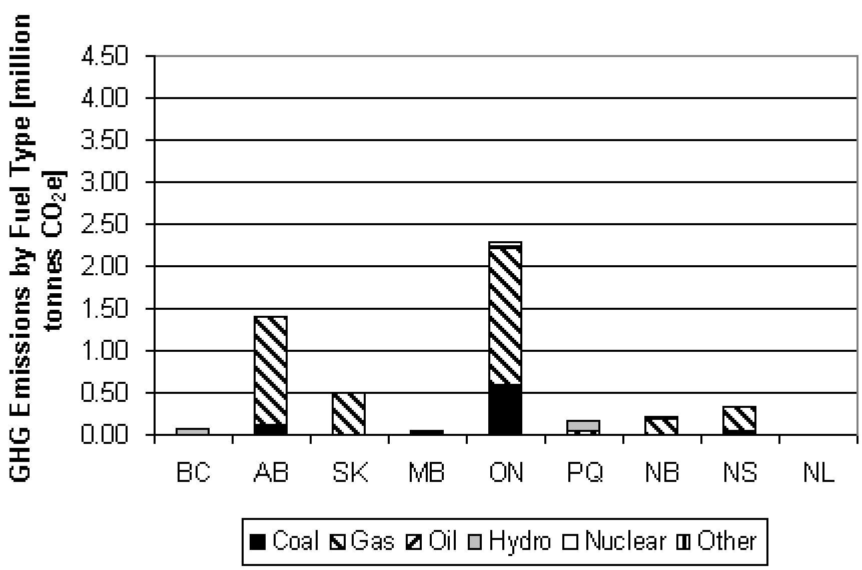


Figure 3-14b Emissions by Fuel Type for 2020 P2 Accelerated High Carbon Case

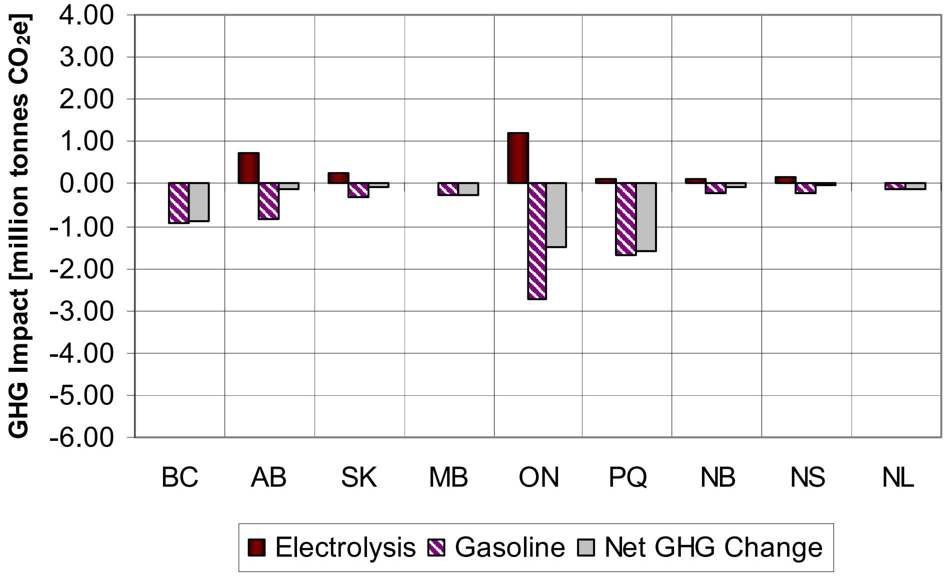
Net GHG Impact from Avoided Gasoline and Increased Electricity Usage on GHG Emissions

The net GHG impacts of partially substituting hydrogen for gasoline in the transportation sector when the price of carbon is high are shown in the following figures. Recall that a negative value reflects a net reduction in emissions, or that the emissions offset by moving from gasoline to hydrogen are greater than the emissions generated for the production of the hydrogen.

The move in power generation away from fossil-fuels meant a greater net GHG reduction in all provinces. The generation mix trends showed less coal being dispatched in 2010 and 2020 when the price of carbon was high, so the GHG emissions reductions were much greater than in the related scenarios. In fact, even the provinces that had shown net GHG increases in the scenarios, showed net reductions under this sensitivity case (see Figure 3-15 and Table 3-14, Table 3-15). For example, New Brunswick and Saskatchewan saw net GHG reductions in the High Carbon price sensitivity, but experienced small increases in the core scenarios. The greater use of gas-fired generation when the price of carbon was high also raised the price of power.

At the provincial level, the results showed that the emissions associated with the production of electricity are dependent primarily on the source of the electricity. For this reason, the High Carbon case affected the provinces differently. Coal-dependent provinces experienced the greatest changes in generation mix while provinces dependent on hydroelectric and nuclear were less affected. Full dispatch results for 2020 are shown in Appendix E.

Figure 3-15 P2 Net GHG Impact (Avoided Gasoline and Increased Electricity Usage) of Hydrogen



Substitution in High Carbon Sensitivity

Figure 3-15a GHG Impact in 2020 – P2 Incremental High Carbon Case

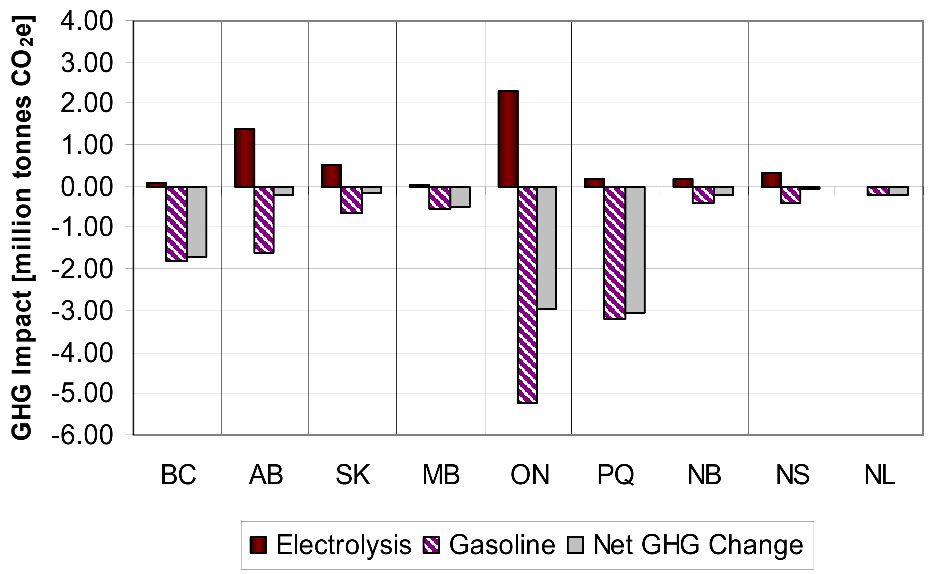


Figure 3-15b GHG Impact in 2020 – P2 Accelerated High Carbon Case

Table 3-14 Impact of Hydrogen Substitution Phase 2 Incremental High Carbon Price Sensitivity (CO_2)

	by 2010 (million tonnes CO_2)			by 2020(million tonnes CO_2)		
Province	**Electrolysis**	**Gasoline**	**Net GHG Change**	**Electrolysis**	**Gasoline**	**Net GHG Change**
BC	0.001	-0.014	-0.013	0.041	-0.935	-0.895
AB	0.017	-0.013	0.004	0.712	-0.845	-0.133
SK	0.006	-0.005	0.001	0.299	-0.335	-0.069
MB	0.000	-0.004	-0.004	0.023	-0.277	-0.253
ON	0.012	-0.042	-0.030	1.217	-2.735	-1.518
PQ	0.002	-0.026	-0.024	0.091	-1.674	-1.582
NB	0.002	-0.003	-0.001	0.105	-0.203	-0.098
NS	0.004	-0.003	0.000	0.180	-0.212	-0.032
NL	0.000	-0.002	-0.002	0.005	-0.117	-0.111
Total	**0.042**	**-0.112**	**-0.069**	**2.642**	**-7.333**	**-4.691**

Table 3-15 Impact of Hydrogen Substitution Phase 2 Accelerated High Carbon Price Sensitivity (CO_2)

	by 2010 (million tonnes CO_2)			by 2020 (million tonnes CO_2)		
Province	**Electrolysis**	**Gasoline**	**Net GHG Change**	**Electrolysis**	**Gasoline**	**Net GHG Change**
BC	0.002	-0.029	-0.027	0.078	-1.792	-1.715
AB	0.034	-0.026	0.008	1.402	-1.621	-0.219
SK	0.011	-0.010	0.001	0.503	-0.643	-0.140
MB	0.001	-0.008	-0.008	0.047	-0.530	-0.483
ON	0.023	-0.083	-0.061	2.293	-5.242	-2.949
PQ	0.003	-0.051	-0.048	0.171	-3.208	-3.037
NB	0.003	-0.006	-0.003	0.205	-0.389	-0.184
NS	0.007	-0.006	0.001	0.341	-0.407	-0.066
NL	0.000	-0.004	-0.003	0.010	-0.224	-0.214
Total	**0.084**	**-0.224**	**-0.139**	**5.049**	**-14.055**	**-9.006**

All nine provinces saw net GHG reductions when the price of carbon was high. The total GHG net impact for Canada was approximately –9.0 million tonnes CO_2e, compared to the P2 Accelerated Off-Peak scenario result of –5.6 million tonnes CO_2e.

Impacts on Electricity Prices

The average annual electricity prices resulting from the High Carbon Price sensitivities are shown versus their corresponding scenarios in Figure 3-16 and Figure 3-17 below. Note that all dollar values are in year 2000 Canadian dollars. Because no cost-effective carbon removal technologies are available to units to reduce CO_2 emissions, the entire cost of shifting from more- to less-carbon intensive fuels is added to the marginal cost of generation for the system. Therefore, almost all provinces showed a marked increase in wholesale electric prices as a result of the high carbon price. BC did not see the large price increase since its generation demand is met by existing capacity and imports and does not require new capacity additions until after 2020. All other provinces added capacity prior to 2020. Figure 3-18 presents the High Carbon case prices as a percentage increase from the corresponding scenario.

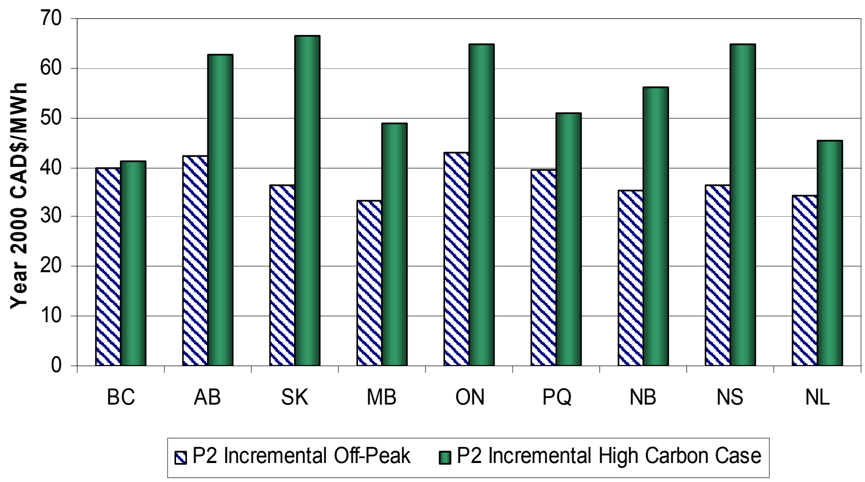


Figure 3-16 Provincial Energy Prices in 2020 – P2 Incremental vs. P2 Incremental High Carbon Case

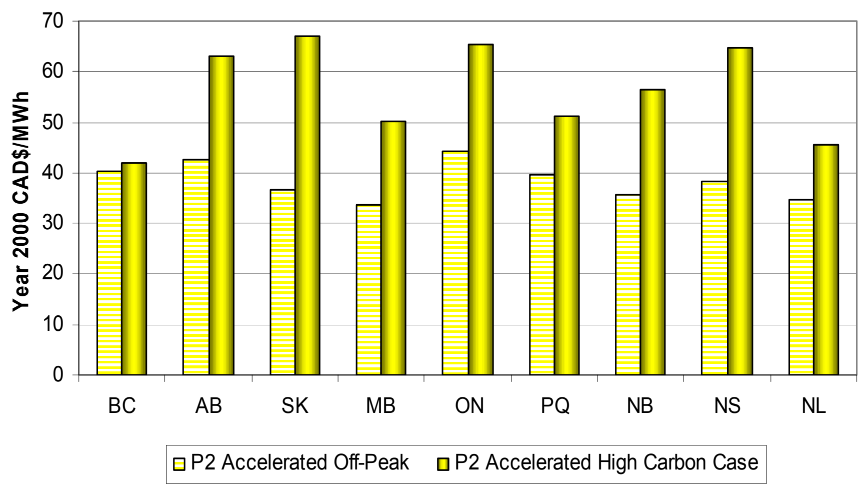


Figure 3-17 Provincial Energy Prices in 2020 – P2 Accelerated vs. P2 Accelerated High Carbon Case

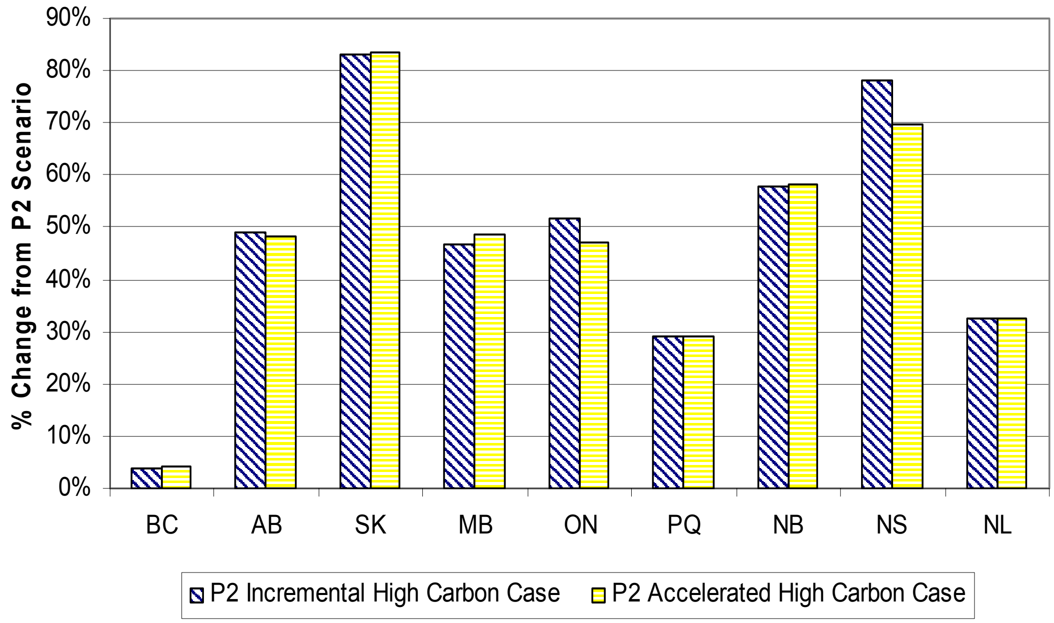


Figure 3-18 Percent Change in 2020 P2 Average Annual Energy Price from P2 Scenario

Analysis of Cost of Hydrogen Production

Figure 3-19 and Figure 3-20 present the energy prices from Figure 3-16 and Figure 3-17 translated into costs required per unit of hydrogen produced for the High Carbon price sensitivity.

As mentioned earlier, the high carbon prices affected the provinces with high fossil dependence more significantly than it did predominately hydro- or nuclear-fuelled provinces. For instance, while Ontario continued to show high prices (compared to the P2 scenarios in Figure 3-10 and Figure 3-11), Saskatchewan moved into the highest rank, where previously it had held the fourth lowest price of the nine provinces.

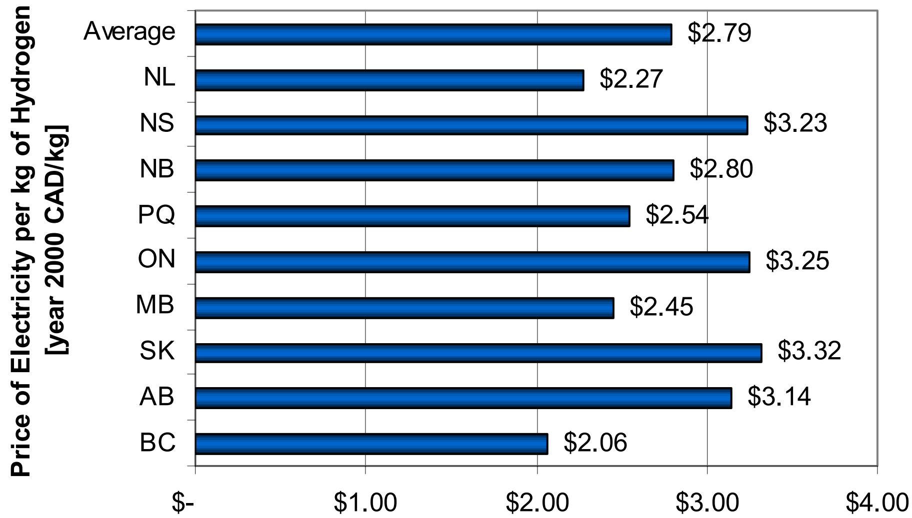


Figure 3-19 Electricity Costs in 2020 P2 Incremental High Carbon Case

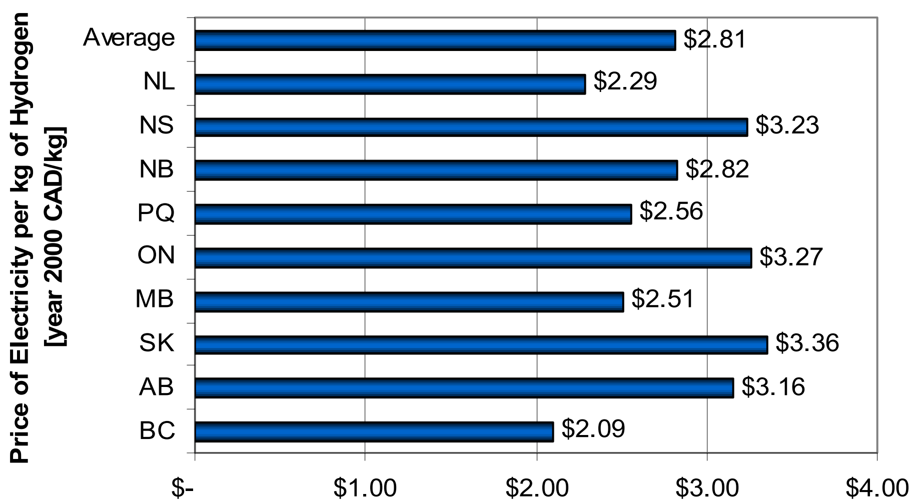


Figure 3-20 Electricity Costs in 2020 P2 Accelerated High Carbon Case

Figure 3-21 and Figure 3-22 show the price of electricity in terms of the hydrogen required to displace one litre of gasoline when the price of carbon is $53.33CDN/tonne CO_2 ($40 USD/tonne CO_2) (based on forecast fuel efficiencies). In 2020 in the Accelerated Scenario, the price of electricity varies from $0.23 per kilogram of hydrogen in British Columbia to $0.37 in Saskatchewan. These values compare to a current average national market price for gasoline of $0.46/L (pre-tax) and a post-tax price of $0.77 per litre.[28]

[28] www.petro-canada.ca

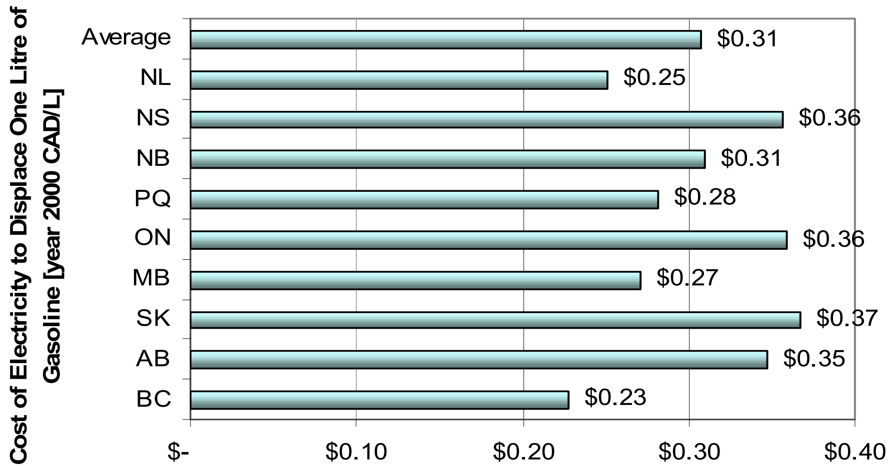


Figure 3-21 Cost of Electricity Required to Displace One Litre of Gasoline (2020 P2 Incremental High Carbon Case)

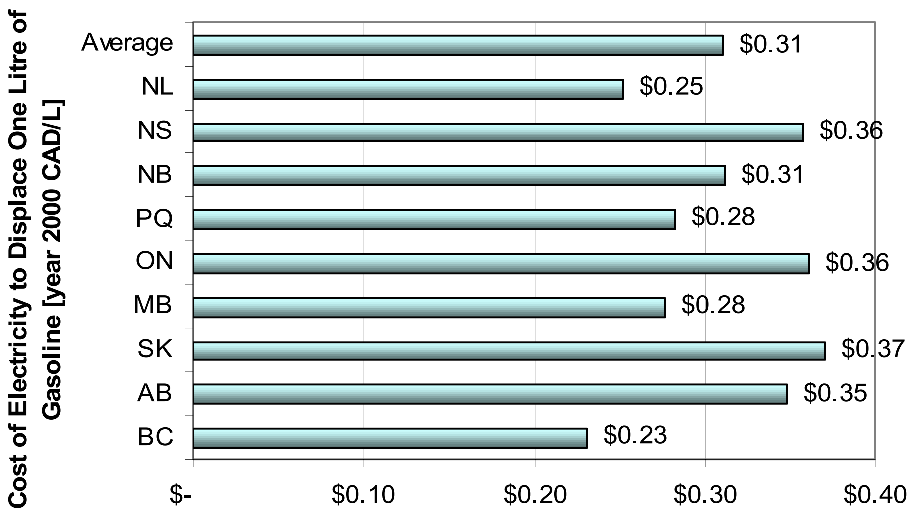


Figure 3-22 Cost of Electricity Required to Displace One Litre of Gasoline (2020 P2 Accelerated High Carbon Case)

3.3.2.2 Time-of-Day Sensitivity

Electric Market Response to Time-of-Day Sensitivities – Impacts on Generation Mix

The Time-Of-Day sensitivity was chosen to gauge the effect of loading the additional demand for electrolysis into peak and off-peak versus just off-peak hours. This demand pattern would be more characteristic of a system that could not easily store large quantities of hydrogen over the course of the day and would therefore require more real-time production. The sensitivity produced subtle effects when compared to the P2 Incremental Off-Peak and Accelerated Off-Peak scenarios. Contrary to the Off-Peak scenarios, in the Time-of-Day sensitivity, the loading increased the peak hour capacity requirements.

Table 3-16 and Table 3-17 show the percentage of provincial generation supplied by fuel type under the Time-of-Day sensitivity. The percentages shown here reflect the mix across all hours of the day. Table 3-16 and Table 3-17 hold 2020 numbers only -- see Appendix E for a full listing.

Table 3-16 Percentage Dispatch by Fuel Type and Region in Hydrogen Production Segments (2020 Phase 2 Incremental Time-of-Day Sensitivity)

	Coal	Gas	Oil	Hydro	Nuclear	Non-Carbon Other
BC	0%	8%	0%	90%	0%	2%
AB	55%	40%	0%	2%	0%	3%
SK	52%	34%	0%	13%	0%	1%
MB	2%	0%	0%	98%	0%	0%
ON	16%	29%	0%	15%	38%	1%
PQ	0%	8%	0%	87%	2%	3%
NB	14%	18%	35%	11%	20%	1%
NS	72%	18%	0%	7%	0%	3%
NL	0%	11%	0%	89%	0%	0%

Table 3-17 Percentage Dispatch by Fuel Type and Region in Hydrogen Production Segments (2020 Phase 2 Accelerated Time-of-Day Sensitivity)

	Coal	Gas	Oil	Hydro	Nuclear	Non-Carbon Other
BC	0%	8%	0%	90%	0%	2%
AB	54%	41%	0%	2%	0%	3%
SK	51%	35%	0%	13%	0%	1%
MB	2%	0%	0%	98%	0%	0%
ON	16%	30%	0%	15%	37%	1%
PQ	0%	7%	0%	88%	2%	3%
NB	13%	21%	35%	11%	19%	1%
NS	75%	15%	0%	7%	0%	3%
NL	0%	16%	0%	84%	0%	0%

Net GHG Emissions Impacts of Generation for Hydrogen Production

GHG Emissions Avoided from Hydrogen Use
The GHG emissions avoided from displacement of gasoline with hydrogen are the same in the sensitivity case as in the corresponding scenario. That is, the same amount of gasoline was displaced and therefore the GHG emission reductions shown in Figure 3-4 for 2010 P2 Incremental Off-Peak scenario were the same in 2010 under the Incremental Time-of-Day sensitivity.

GHG Emissions from Additional Electricity Generation
The GHG emissions associated with the electricity generated to meet the increased demand due to hydrogen production under the Time-of-Day sensitivities for 2010 and 2020 are provided below (Figure 3-23). Results are similar to the corresponding scenarios (Figure 3-5).

Figure 3-23 GHG Emissions Associated with Increased Electricity Demand

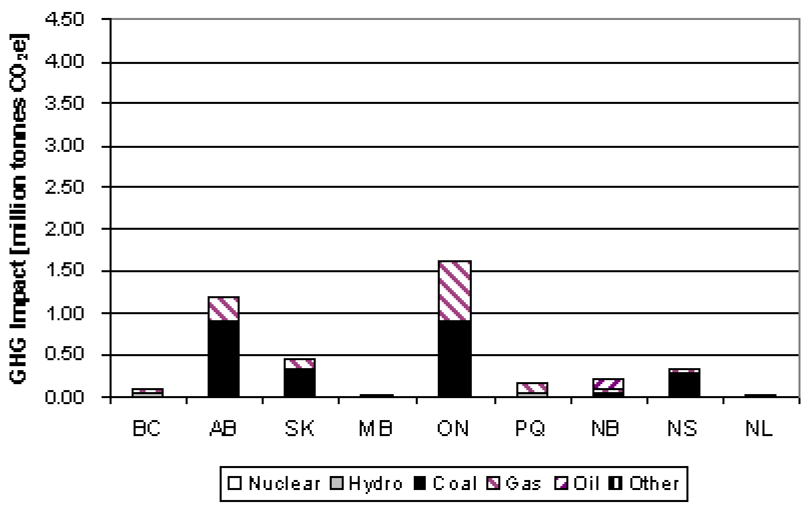


Figure 3-23a Emissions by Fuel Type for 2020 Incremental Time-of-Day Scenario

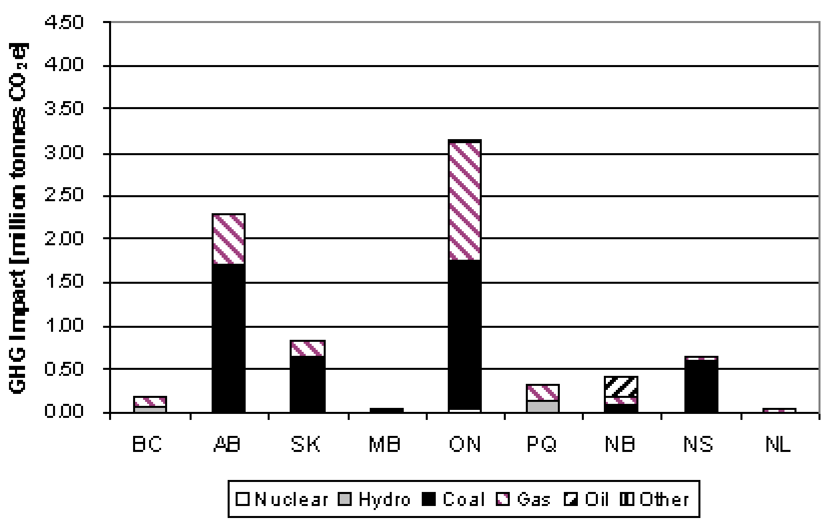


Figure 3-23b Emissions by Fuel Type for 2020 Accelerated Time-of-Day Scenario

As was observed in Phase 1 and Phase 2, the provincial-level results showed that the emissions associated with the production of electricity are dependent primarily on the source of the electricity. That is, provincial emissions were highest in provinces that were dependent on fossil-fired generation and lowest in provinces dependent on hydroelectric and nuclear to meet the electricity demand due to hydrogen production. In the Time-of-Day sensitivity, the additional demand required existing generation to increase operation (similar to the Scenario) and some new generation to be built.

Net GHG Impact from Avoided Gasoline and Increased Electricity Usage on GHG Emissions

The net GHG impacts of partially substituting hydrogen for gasoline in the transportation sector when the electricity generation was distributed throughout the day are shown in the following figures. Recall that a negative value reflects a net reduction in emissions, or that the emissions offset by moving from gasoline to hydrogen are greater than the emissions generated for the production of the hydrogen. Table 3-18 and Table 3-19 and Figure 3-24 shows the net GHG Impact.

Figure 3-24 P2 Net GHG Impact (Avoided Gasoline and Increased Electricity Usage) of Hydrogen Substitution in Time-of-Day Sensitivity

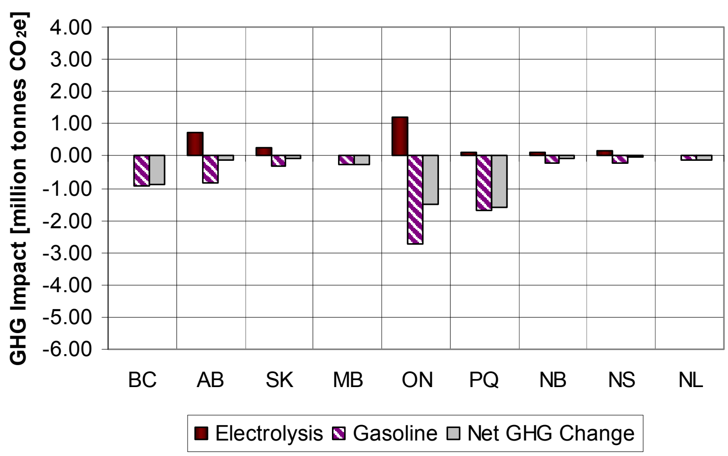


Figure 3-24a GHG Impact in 2020 – P2 Incremental Time-of-Day Case

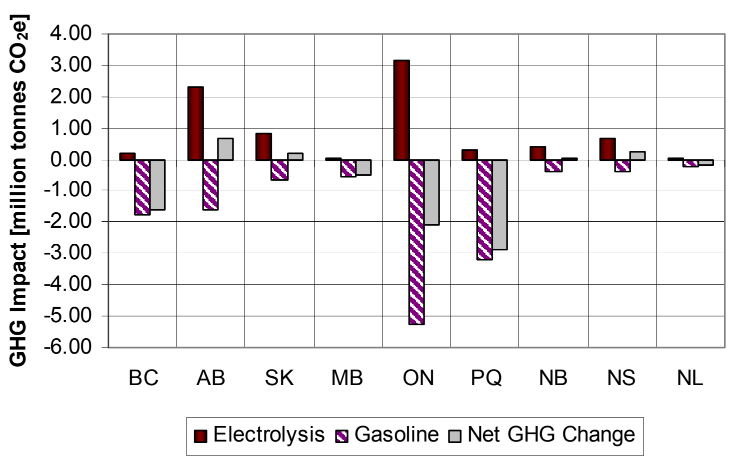


Figure 3-24b GHG Impact in 2020 – P2 Accelerated Time-of-Day Case

Table 3-18 Impact of Hydrogen Substitution Phase 2 Incremental Time-of-Day Sensitivity (CO_2)

	by 2010 (million tonnes CO_2)			by 2020(million tonnes CO_2)		
Province	**Electrolysis**	**Gasoline**	**Net GHG Change**	**Electrolysis**	**Gasoline**	**Net GHG Change**
BC	0.001	-0.014	-0.013	0.105	-0.935	-0.830
AB	0.030	-0.013	0.017	1.203	-0.845	0.357
SK	0.011	-0.005	0.006	0.440	-0.335	0.105
MB	0.001	-0.004	-0.004	0.023	-0.277	-0.254
ON	0.031	-0.042	-0.011	1.632	-2.735	-1.102
PQ	0.002	-0.026	-0.024	0.179	-1.674	-1.495
NB	0.005	-0.003	0.002	0.219	-0.203	0.016
NS	0.008	-0.003	0.004	0.334	-0.212	0.121
NL	0.000	-0.002	-0.002	0.016	-0.117	-0.101
Total	**0.088**	**-0.112**	**-0.024**	**4.151**	**-7.333**	**-3.183**

Table 3-19 Impact of Hydrogen Substitution Phase 2 Accelerated Time-of-Day Sensitivity (CO_2)

	by 2010 (million tonnes CO_2)			by 2020 (million tonnes CO_2)		
Province	**Electrolysis**	**Gasoline**	**Net GHG Change**	**Electrolysis**	**Gasoline**	**Net GHG Change**
BC	0.002	-0.029	-0.026	0.198	-1.792	-1.595
AB	0.060	-0.026	0.035	2.290	-1.621	0.670
SK	0.022	-0.010	0.012	0.844	-0.643	0.202
MB	0.001	-0.008	-0.007	0.047	-0.530	-0.483
ON	0.061	-0.083	-0.022	3.143	-5.242	-2.099
PQ	0.003	-0.051	-0.048	0.321	-3.208	-2.887
NB	0.010	-0.006	0.004	0.420	-0.389	0.031
NS	0.015	-0.006	0.009	0.650	-0.407	0.243
NL	0.000	-0.004	-0.003	0.040	-0.224	-0.184
Total	**0.176**	**-0.224**	**-0.048**	**7.953**	**-14.055**	**-6.102**

Only British Columbia, Manitoba, Ontario, Quebec and Newfoundland saw net GHG reductions when the electricity demand was spread throughout the day. The total GHG net impact for Canada was approximately –6.1 million tonnes CO_2e compared to the P2 Accelerated Off-Peak Scenario, where the net impact was only –5.6 million tonnes CO_2e.

Recall that emissions impacts were estimated based on the generation mix likely to be supplying the electrolyzers at the time the electrolysis is undertaken. In the Off-Peak scenarios, the emissions were calculated based on the mix in the off-peak hours of the day in each province. The Time-of-Day sensitivity reductions, however, were based on dispatch decisions throughout the day. Because a wider variety of capacity types dispatch over the course of the entire day, including gas-fired units and others, to meet peak-hour demand, the generation "dedicated" to electrolysis in the sensitivity case is less concentrated in high-emitting baseloaded coal units. Therefore, the average emission rate associated with that generation is lower than in the Off-Peak scenarios.

Impacts on Electricity Prices

The absolute impacts of the P2 Incremental and P2 Accelerated Time-of-Day Sensitivities on provincial annual average electricity prices are shown in Figure 3-25 and Figure 3-26. Note that all dollar values are in year 2000 Canadian dollars. The percent change of the prices compared to the respective scenarios are shown in Figure 3-27. The price differentials between the Off-Peak and Time-of-Day cases result from shifts in the generation mix between the two cases. With the additional demand being spread over a greater number of hours in the Time-of-Day sensitivities, there was a greater tendency for generation to shift from off-peak hours to on-peak hours, thereby creating greater potential for price changes in the off-peak hours. In most provinces, these shifts resulted in little if any change from the Off-Peak Scenario results. In a province such as Ontario, however, with its diverse portfolio of capacity types, the generation mix shifts led to more substantial price changes.

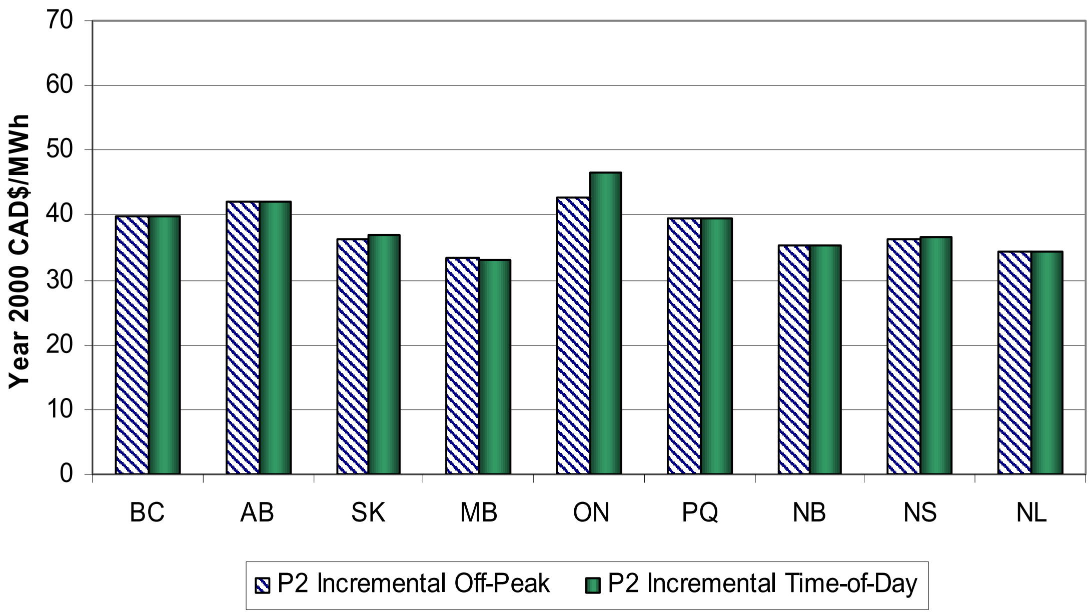


Figure 3-25 Provincial Energy Prices in 2020 – P2 Incremental vs. P2 Incremental Time-of-Day

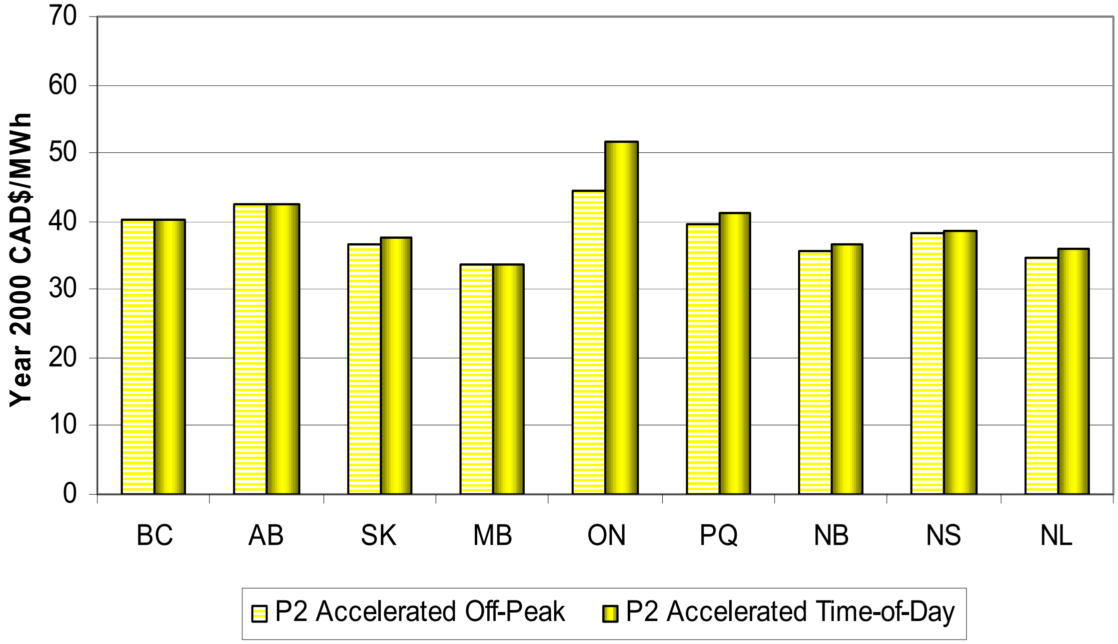


Figure 3-26 Provincial Energy Prices in 2020 – P2 Accelerated vs. P2 Accelerated Time-of-Day

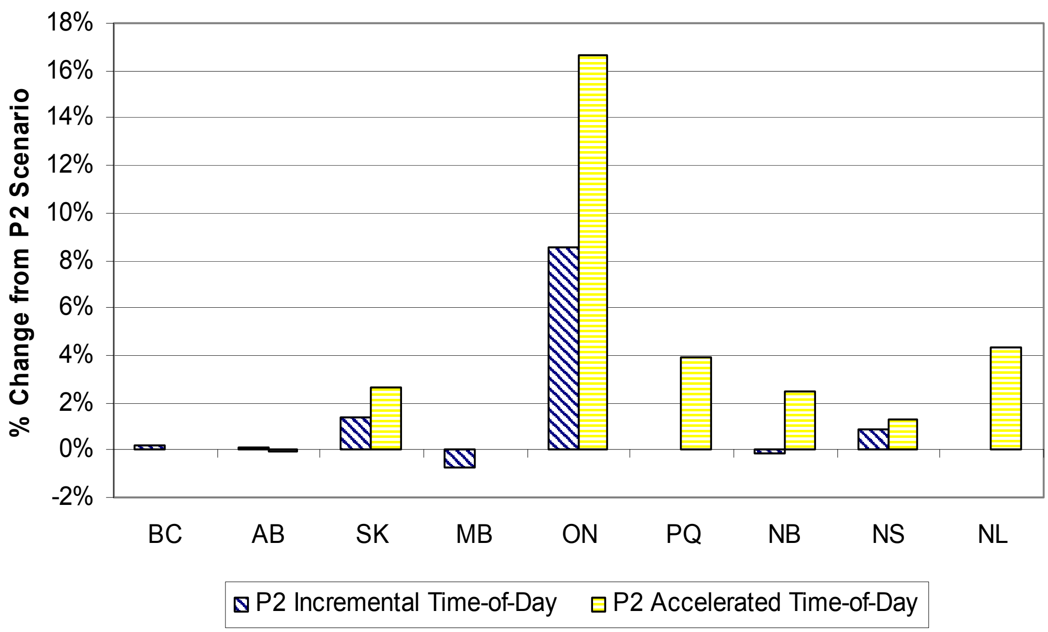


Figure 3-27 Percent Change in 2020 P2 Average Annual Energy Price from P2 Scenario

Analysis of Cost of Hydrogen Production

Figure 3-28 and Figure 3-29 present the energy prices shown in Figure 3-25 and Figure 3-26 translated into costs required per unit of hydrogen produced for the Time-of-Day sensitivities.

Figure 3-28 Electricity Costs in 2020 P2 Incremental Time-of-Day Sensitivity

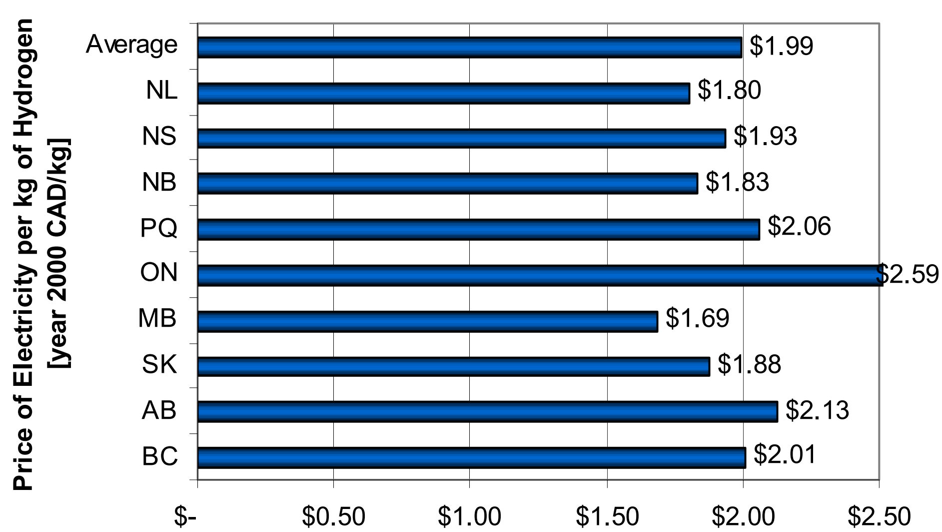


Figure 3-29 Electricity Costs in 2020 P2 Accelerated Time-of-Day Sensitivity

Figure 3-30 and Figure 3-31 show the price of electricity to produce hydrogen required to displace one litre of gasoline when the electricity demand was spread throughout the day (based on forecast fuel efficiencies). In 2020 in the Accelerated Scenario, the price of electricity varied from $0.19 per kilogram of hydrogen in Manitoba to $0.29 in Ontario. These values, while higher than the P2 scenario cases, compared to a current average national market price for gasoline of $0.46/L (pre-tax) and a post-tax price of $0.77 per litre[29]. Note that the regional pre-tax prices varied significantly (from $0.47/L in Toronto to $0.40/L in Charlottetown), albeit all higher than the price for hydrogen. As under the Off-Peak Scenarios, it appears based on this analysis that hydrogen could be an economically viable replacement for gasoline.

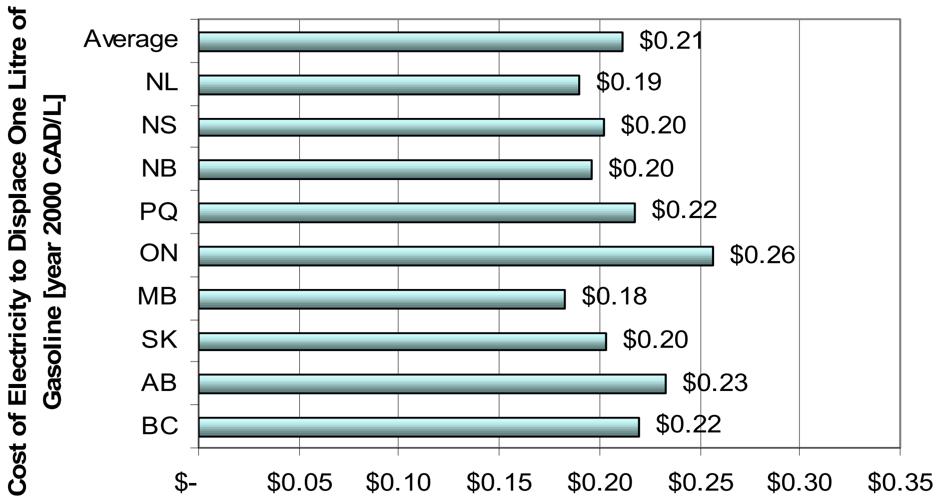


Figure 3-30 Cost of Electricity Required to Displace One Litre of Gasoline (2020 P2 Incremental Time-of-Day)

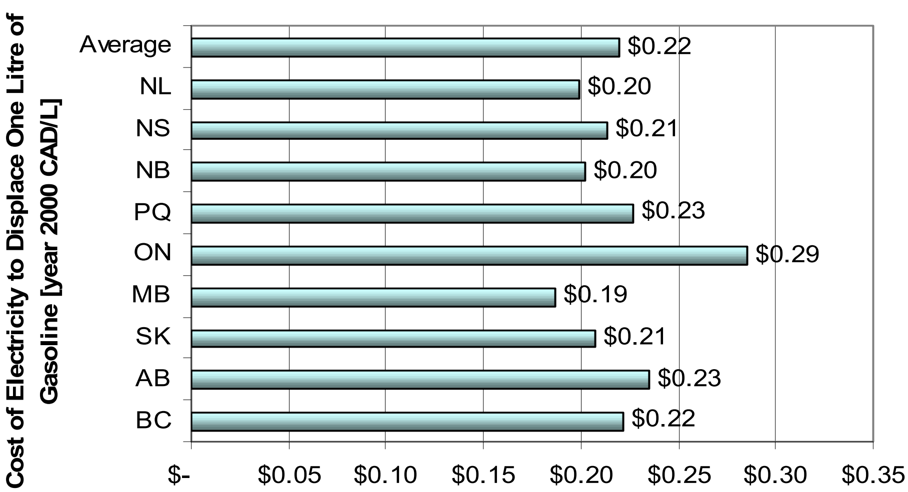


Figure 3-31 Cost of Electricity Required to Displace One Litre of Gasoline (2020 P2 Accelerated Time-of-Day)

[29] www.petro-canada.ca

3.4 PHASE 2 CONCLUSIONS

The Phase 2 analysis provides a refinement of the original inquiry into greenhouse gas impacts related to the power generation sector under a hydrogen vehicle initiative as presented in the Phase 1 section of this report. This follow-up effort also allowed an opportunity to test the robustness of the results to carbon price and demand timing through two sensitivity cases. The work undertaken resulted in a net GHG emission impact estimate from the power generation sector and displacement of gasoline in the light-duty vehicle fleet.

Two key impacts were examined, both of which will have to be considered by government and consumers in determining the value of establishing the hydrogen infrastructure required for electrolysis as a fuelling pathway: GHG impact and power price impact.

Assumptions were revised based on communication with the Canadian Transportation Fuel Cell Alliance's Studies and Assessments Working Group. The refined assumptions included vehicle fleet definition (cars and trucks), forecast fuel efficiencies, life-cycle emission factors, and electrolysis requirements. These assumptions affected the amount of additional electricity that the power generation sector would be required to supply.

Two scenarios, Phase 2 Incremental and Accelerated Off-Peak, were developed with different hydrogen penetration rates than used in Phase 1. Two variables of interest were then chosen to be the focus of sensitivity cases. The carbon price, without which the impetus for the hydrogen initiative would be delayed or lost, and the time of day in which the electricity demand would be increased (peak versus off-peak) were analysed as sensitivities to both scenarios.

The analysis shows that, in 2020 under the Incremental scenario, every kilogram of hydrogen replaces 6.9 L of gasoline in light-duty vehicles and 21.6 kg of CO_2 equivalent emissions. Under the Accelerated scenario, in 2020, every kilogram of hydrogen replaces 9.1 L of gasoline and 28.2 kg of CO_2 equivalent emissions. The inclusion of light-duty trucks in the vehicle fleet contributed to greater gasoline savings and, therefore, greater emissions avoided versus Phase 1.

The modelling efforts provided a breakdown of the fuel mix behind the generation of additional electricity for hydrogen production. This breakdown was used to quantify the GHG emissions impact. A desired GHG impact, that is, a reduction in overall emissions, is achieved in those provinces where electricity emission intensities were 0.39 tonnes CO2e/MWh or lower in 2010 and 0.53 tonnes CO_2e/MWh or lower in 2020. In other words, where power generation produces 0.53 tonnes of CO2e or lower in 2020, the increased emissions from producing electricity to manufacture hydrogen *would be lower than* the emissions displaced from avoiding gasoline combustion, thereby creating a net benefit. As seen in Phase 1, hydro-rich provinces find a net GHG benefit in this analysis. However, across all the provinces studied, the total net GHG impact was a reduction ranging from 0.02 to 5.6 million tonnes of CO_2e reduced in 2010 (Incremental Off-Peak) and 2020 (Accelerated Off-Peak), respectively.

It should be noted that the scope of this analysis focussed only on electrolysis as a fuelling pathway. Other production technologies such as steam methane reforming could also be used to produce hydrogen.

Impacts on electricity prices vary by province based on the generation mix used to meet the additional demand from hydrogen producers for electricity. Provinces with spare capacity to meet the higher demand face lower price increases than the provinces that require significant capacity investments or increased imports to satisfy the requirements. Ontario sees the largest percent increase in prices (approximately 15 percent relative to the Base Case) in the Accelerated Scenario in 2020. Transmission capacity constraints from the U.S. and overburdened transmission lines from

Newfoundland via Quebec leave Ontario in a situation where there is no option for the province but to increase its reliance on fossil-fired generation under provincial SO_2 and NO_X regulation while also facing the national carbon constraint. Most other provinces, however, see price increases of less than 5 percent by 2020. These electric price impacts are only one determinant of the cost of producing hydrogen.

To provide context to the electricity price impacts, it was useful to compare them to the gasoline-equivalent prices. Across all provinces, the cost of electricity for hydrogen production to displace a litre of gasoline averages $0.21/L in the Accelerated Scenario in 2020. This price is lower than the average cost of gasoline, but does not include operational and other costs associated with hydrogen production and distribution. In comparison, the pre-tax price of gasoline is approximately $0.46/L currently and includes cost of crude, refining and marketing.

The sensitivity cases provided some insight into two potentially key drivers of the results. The High Carbon Price sensitivity case showed that a $53.33CDN/tonne CO_2 ($40 USD/tonne CO_2) price was sufficiently high to move the fossil-dependent provinces from coal toward lower-emitting gas-fired or other non-emitting capacity or to increase reliance on imports to meet the additional demand. These shifts resulted in a large increase in country-wide net GHG reductions over the basic scenarios. The 2020 Accelerated High Carbon sensitivity, for example, saw a reduction of 9.0 million tonnes of CO_2.

The Time-of-Day sensitivity case captured the impacts of raising not only the electricity demand, but the peak demand as well. The generation mix was very similar to the corresponding scenarios. However, there was a slight improvement in the net GHG impact with a total national reduction of 6.1 million tonnes CO_2 versus 5.6 million in 2020 Accelerated Off-Peak Scenario. The larger reduction in the Time-of-Day sensitivity was due to a lower percentage of high-emitting coal units when the additional dispatch was considered over the entire day. Electricity prices also were higher under this sensitivity with an average provincial increase of 3.5%.

The Phase 2 analysis adds weight to the finding that there are environmental benefits that can be reaped at costs comparable to gasoline prices today. The sensitivity cases have helped to put the results into context. The high carbon price could represent a “worst price case” where power generation sector response is drastically different from the scenarios. The time-of-day case could represent a first guess of how the fuelling infrastructure could operate where the power generation sector response was encouraging, but very similar to the scenario. Further sensitivity testing on these variables may be an option for Phase 3 of this project. Alternatively, some of the issues that were outside the scope of Phase 1 and 2, but have direct bearing on the GHG impacts could also be incorporated into a Phase 3 component. Lastly, recent announcements in the power generation sector have not been incorporated into the model due to concerns of consistency and also, timing. These may also be valid candidates for a Phase 3 component. Further analysis into these issues could increase the confidence in the results.

4 CONCLUSIONS

Phase 1 of this project was started in the spring of 2003 and Phase 2 followed in the winter of 2003/2004. The overall objective of the project was to consider the viability of using electrolysis to produce hydrogen for fuel-cell vehicles in the context of the power generation sector. Impacts included the net GHG change from increased power requirements and avoided gasoline usage, and changes in electricity prices due to the increased power demand.

Phase 1 was an order-of-magnitude analysis intended to provide a preliminary understanding of the types of changes that might occur in the power generation sector and their impact on the national GHG inventory. It was also intended to elicit recommendations for improvement from the Working Group participants. Both scenarios (Incremental and Accelerated fuel-cell market penetration) showed that there was a possibility of achieving net GHG reductions in substituting hydrogen produced from electrolysis for gasoline in the transportation sector across the country at a price comparable to gasoline. It was noted, however, that several assumptions were “rough” and that better estimates could be produced. Also, key variables were identified to be of interest for sensitivity study. These were carbon price and timing of the additional electricity demand. This led the Canadian Transportation Fuel Cell Alliance’s Studies and Assessments Working Group to re-examine the base assumptions for the hydrogen fuel-cell vehicle penetration in preparation for Phase 2.

Phase 2 used refined inputs to better characterize the vehicle fleet and to represent forecasted vehicle improvements (such as fuel efficiency). This fed into two scenarios that were designed to be more reasonable estimates than those developed in Phase 1. Both scenarios showed that there were GHG savings to be realized with hydrogen fuel-cell vehicles. Electricity prices remained lower then current gasoline pre-tax prices.

Sensitivities of the key variables of interest were run and served to “bound” the scenario results. The High Carbon Price sensitivity used a carbon price of \$53.33CDN/tonne CO_2 (\$40 USD/tonne CO_2), which was substantially higher than the original \$10 CAD/tonne CO_2 and, correspondingly, produced more severe changes in the power generation sector. The sector saw an almost complete shift away from coal towards gas, hydro and imports.

Interestingly, the Time-of-Day sensitivity showed very similar results in the power generation sector as the corresponding scenarios. However, since the net reductions were based on the dispatch for the entire day, a wider variety of capacity types contribute to the dispatch mix, reducing the concentration of the high-emitting coal units and resulting in a greater total reduction in to GHG emissions.

Both Phase 1 and 2 have covered much of the variables in this analysis. Sensitivity around the time of day application of the additional electricity demand has been broached, but a more severe case may help to bound this important issue. Additionally, recent and soon-to-be released announcements in the Ontario (fossil retirement / nuclear expansion) and Quebec power generation markets may have a strong influence on the model outcomes as they change the composition of existing, available capacity in the regions. Future analysis should also be focused at addressing the limitations of the study identified earlier. These include:

- The scope of this analysis focussed only on electrolysis as a fuelling pathway. Other production technologies such as steam methane reforming could also be used to produce hydrogen and could be included in future analysis.

- Electric markets alone were considered in this study. No cost associated with hydrogen production infrastructure was considered, nor was any account made for the cost of water used in electrolysis. These and other associated costs could be included in any future analysis to increase the usefulness of the financial analysis.

The debate around the role of hydrogen fuelled transportation in helping Canada to meet its commitments under the Kyoto Protocol continues. The process has been delayed to a degree during a period of political transition but 2008 is approaching rapidly and there is a general recognition that decisions must be made soon if they are to have any meaningful impact in the first commitment period. The Steering Committee of the CTFCA has the opportunity to make a meaningful contribution to that debate based on solid analysis. Phase III of the study should focus on the gaps in analysis that have been discussed earlier to contribute to bolstering the argument for the role that fuel cells can and should play in the emerging carbon-constrained global market place.

5 REFERENCES

Adams, P. 2000. "Hydro's Future in Canada". Canadian Hydropower Association.

AGRA Monenco. (AGRA.) 1999. "Assessment of Costs and Characteristics of Fossil Fuel Technologies for Electrical Generation". Prepared for National Climate Change Process (NCCP), Electricity Table.

Alberta Power Pool. 2002. Personal Communication.

AMEC. 2001. "Electric Power Generation – Annotated Survey of Selected Cost Estimates for Multi-Pollutant Emissions Reduction Options for the electricity Sector in Canada". Prepared for Environment Canada. Ottawa.

Analysis and Modelling Group (AMG). 2002. "A Guide to the Assumptions and Methodology Underlying the AMG Results". [online] www.nccp.ca

Analysis and Modelling Group (AMG). 2000. "An Assessment of the Economic and Environmental Implications for Canada of the Kyoto Protocol". [online] www.nccp.ca

ATCO. 2002. [website] www.atco.com

Baines, I. 2002. Personal Communication.

Bolen, B. 2002. Personal Communication.

Canadian Hydro Developers homepage. 2002. [online] www.canhydro.com

Canadian Institute for Environmental Law and Policy. 2002. "Green Power Opportunities for Ontario".

Canadian Nuclear Association (CNA). 2002. Electronic Newsletter No. 9. vol III. [online] www.cna.ca

Canadian Nuclear Association (CNA). 2001. "Nuclear Electricity and Canada's Domestic Response to the Kyoto Protocol: Modelling the Economics of Alternative Scenarios".

Canadian Energy Research Institute (CERI). 1996. "Repowering Alberta: Options for Electrical Generating Units; Economics and Emissions Impacts." Study No. 73.

Canadian Forest Service. (CFS.) 1999. "Canada's Wood Residues: A Profile of Current Surplus and Regional Concentrations". [online] www.nccp.ca//NCCP/national_process/issues/forest_e.html Prepared for National Climate Change Process (NCCP), Forest Sector Table.

CANMET Energy Technology Centre, Natural Resources Canada. (CANMET.) 2002. International Small Hydro Atlas.

Courtney Bay Facility. 2002. Personal Communication.

Cowley Ridge homepage. [online] www.cowleyridge.com Accessed 2002.

Cummings, L. 2002. Personal Communication. Environment Canada.

Dunsworth, A. 2002. Personal Communication.

Energy Information Administration (EIA). 2002a. "Annual Energy Outlook."

Energy Information Administration (EIA). 2002b. "Model Documentation Renewable Fuels Module of the National Energy Modelling System".

Energy Technology Futures. 2000a. "2050 Study: Go Your Own Way". Natural Resources Canada.

Energy Technology Futures. 2000b. "2050 Study: Greening the Pump". Natural Resources Canada.

Environment Canada. 2003. "Canada's Greenhouse Gas Inventory 1990-2001".

Environment Canada. 2002a. "Canada's Greenhouse Gas Inventory 1990-2000".

Environment Canada. 2002b. "Energy Generation Analysis (2000-2010)". (unpublished)

Environment Canada. 2002c. Personal Communication.

Environment Canada. 1999. "Identification of Potential Landfill Sites for Additional Gas Recovery and Utilization in Canada". Ottawa.

Environment Canada. 1996. "Background Document for the Development of a National Guideline for NO_X Emissions from New or Modified Commercial/Industrial Boilers and Process Heaters". (REF # FA168-3-7051) Ottawa.

Epcor. 2002. [website] www.epcor.ca

Federal Energy Regulatory Commission (FERC). 1995. Form 714.

Glynn, M. 2002. Personal Communication. Department of the Environment, New Brunswick.

Government of Alberta. 2002. "The Department of Energy". [website] www.energy.gov.ab.ca/Electricity/Key+Numbers/Key+Numbers.htm

Johnson, L. 2002. Personal Communication. Epcor.

Klein, M. 2002. Personal Communication. Environment Canada.

MacDougal, R. 2002. Personal Communication.

Manitoba Hydro. 2002. Personal Communication.

Morris, R.. 2002. Personal Communication. Environment Canada, Atmospheric and Environment Service.

National Climate Change Process (NCCP). 1999. "Canada's Emissions Outlook: an Update."

National Energy Board (NEB). 2001. "Canadian Electricity Trends and Issues: An Energy Market Assessment". Calgary.

National Energy Board (NEB). 2000. "Canadian Natural Gas Market Dynamics and Pricing" [online] www.neb.ca "NatGas_NEB.pdf"

National Energy Board (NEB). 1999. "Canadian Energy Supply and Demand to 2025". [online] www.neb.ca

Natural Resources Canada (NRCan). 2002. "Wind Power Production Incentive". [online] "Wind Power Production Incentive.pdf" www.canren.gc.ca/app/filerepository/ B13F241FE43A4584A993B21ECEFB9ADD.pdf Retrieved June, 2002.

Natural Resources Canada (NRCan). 2001. "Canadian Natural Gas Market Review & Outlook". [online] www.nrcan.gc.ca Retrieved March, 2002. "NatGas_NRCan.pdf"

Natural Resources Canada (NRCan). 1994. "Statistical Review of Coal in Canada".

Neill and Gunter (Nova Scotia) Limited. 1999. "Opportunities for Increased Cogeneration in the Pulp and Paper Industry". [online] www.nccp.ca//NCCP/national_process/issues/forest_e.html Prepared for Industry Economics and Programs Branch, Canadian Forest Service NRCan.

New Brunswick Power. 2002. [website] www.nbpower.com

New Brunswick Power. 2001. "Annual Report".

North American Electricity Reliability Council (NERC). 2001a. "2001 Summer Assessment: Reliability of the Bulk Electricity Supply in North America". [online] http://www.nerc.com

North American Electricity Reliability Council (NERC). 2001b. "2001/2001 Winter Assessment: Reliability of the Bulk Electricity Supply in North America". [online] http://www.nerc.com

North American Electricity Reliability Council (NERC). 2001c. Electricity Supply and Demand Database and Software.

North American Electricity Reliability Council (NERC). 2001d. "Reliability Assessment 2001-2010: The Reliability of Bulk Electric Systems in North America. [online] http://www.nerc.com

Nova Scotia Power. 2002. [website] www.emera.com

Ontario Independent Market Operator. 2002. Personal Communication.

Ontario Ministry of Environment (MOE). 2001. "Coal-Fired Electricity Generation in Ontario".

Ontario Power Generation. (OPG). 2002. [website] www.opg.com

Ontario Power Generation. (OPG). 2001. "Ontario Power Generation and Babcock & Wilcox Team Up for $200 Million Environmental Project." Press release.

Rangi, R. 1992. "Canadian Wind Energy Technical and Market Potential". Prepared for CANMET Energy Technology Centre, Natural Resources Canada.

Reed Wasden Research. June 2002. "Sound Energy." [online] www.reedwasden.com

Robb, G. 2002. Personal Communication. Thermoshare.

Roberts, C. 2002. Personal Communications. National Climate Change Secretariat.

Rose, D., 2002. Personal Communication. Environment Canada.

SaskPower. 2002a. [website] www.saskpower.com

SaskPower. 2002b. Personal Communication.

Senes Consulting. (Senes.) 2002. "Evaluation of Technologies for Reducing Mercury Emissions from the Electric Power Generation Sector". Prepared for the Canadian Council of Ministers of the Environment.

Seney, B. 2002. Personal Communication. National Energy Board.

Shand Generating Station. 2002. Personal Communication.

Statistics Canada. 2002. Cansim II Table 27 "Electric Power Statistics years 1997 to 2001" [online] Accessed June 2002.

Statistics Canada. 2001. "Electric Power Statistics". Ottawa. (Catalogue no. 57-001-XIB).

Statistics Canada. 2001. Catalogue no. 57-202-XPB. "Electric Power Generation, Transmission and Distribution." years 1992 to 1999 Ottawa.

Statistics Canada. 2000a. "Electric Power and Capability and Load". Ottawa. (Catalogue no. 57-204-XIB).

Statistics Canada. 2000b. "Electric Power Generating Stations". Ottawa. (Catalogue no. 57-206-XIB).

Strickland, C. and Nyboer, J. 2002. "A Review of Existing Cogeneration Facilities in Canada". Canadian Industrial Energy End-Use Data and Analysis Centre.

Surtees, N. 2002. Personal Communication. Ministry of the Environment Saskatchewan.

Talbot, R. 2003. Personal Communication. Natural Resources Canada.

TransAlta. 2002. [website] www.transalta.com

U.S. Environmental Protection Agency (EPA). 2002b. "Documentation of EPA Modelling Applications (V.2.1) Using the Integrated Planning Model". Office of Air and Radiation.

U.S. Environmental Protection Agency (EPA). Accessed 2002d. "National Electric Energy System (NEEDS) Database". [online] www.epa.gov/airmarkets/epa-ipm/index.html

Walmsley, J.L. and Morris, R.J. 1992. "Wind Resource Maps for Canada". Report ARD-92-0030-E Environment Canada, Atmospheric and Environment Service. Ottawa.

Welsh, L. 2002. Personal Communication. Environment Canada.

Western Systems Coordinating Council (WSCC). 2002. "2002 WSCC Information Summary". [online] http://www.wecc.biz/documents/publications/info_sum.html

This page intentionally blank.

Appendix A Data and Inputs

This page intentionally blank.

Existing Generation Capacity

IPM® models the power-generating sector based on unit level data and information. For existing generation, all generating units that supply power to the grid were included. This includes fossil-fired steam generating units, combined cycle units, simple cycle combustion turbines, renewables (wind, landfill gas, hydro and biomass) and cogeneration. For this study, an inventory of all electric power generating units supplying power to the grid[1] were developed based on data gathered from a variety of sources.[2] If unit-specific data on the cost and performance characteristics were not available from identified sources, ICF developed estimates of key variables based on judgement or comparable information in the U.S.[3]

Key data required by the model for existing units at the unit level include:

- Net dependable capacity,
- Heat rate (Btu/kWh),
- Fixed and variable O&M costs,
- Existing (or planned) environmental controls,
- Allowable fuels,
- Retirement date, and
- Outage information (forced and planned).

New Generation Technologies

In addition to detailed information on the stock of generating units in each of the nine provinces, IPM® requires information on the availability and characteristics of new generating unit additions to meet growing demand and replace retired capacity. The types of new generation that were allowed include:

- Coal-fired steam units[4]
- Coal-fired Integrated Gasification Gas Combined Cycle (IGCC) [4]
- Natural gas-fired Combined Cycle (CC),
- Natural gas-fired Combustion Turbines (CT),
- Cogeneration (CC and CT),
- Wind,
- Hydro,
- Landfill Gas,
- Biomass (Wood and Wood Waste), and
- Nuclear.

[1] In order to maintain consistency between the demand forecast and the resource data, units not supplying electricity to the grid were not included in the analysis.
[2] Sources included NERC, 2001c; Statistics Canada, 2000, Environment Canada data, and utility website and company literature search.
[3] Electric generation stations in the U.S. are required to report information to the EPA. Sources used included EPA, 2002b and EPA, 2002d.
[4] New coal builds were only allowed in those provinces that have an established coal delivery infrastructure in place. Since there is no or very little existing coal-fired generation in BC, MB, PQ, and NL new coal builds were not provided as new generation options.

Cost and performance characteristics of the alternative unit types, representative of conditions in each of the provinces, were developed. The characteristics were:

- Capital Cost ($/kW), including Interest During Construction (IDC),
- Fixed Operating Cost ($/kW-year),
- Variable Operating Cost ($/MWh),
- Heat Rate (Btu/kWh),
- Resource potential for renewable resources, and
- Energy profile for intermittent resources (seasonal output pattern per 1MW installed).

This information was drawn from a variety of sources as shown in Table A- 1.

Table A- 1 Cost Characteristics Source by Unit Type

Unit Type	Source
Fossil Units	Report to the Electricity Issues Table. AGRA Monenco 1994
Wind	EIA Renewable Energy Documents, 2002b, NRCan, 2002
Small Hydro	CANMET, 2002.
Large Hydro	Personnel Communications. Manitoba Hydro, 2002.
Landfill Gas	Environment Canada "Identification of Potential Landfill Sites for Additional Gas Recovery and Utilization in Canada" with background data (EC, 2002), EIA AEO 2002
Biomass	National Climate Change Process, Forest Sector Table report (NCCP, 1999)
Nuclear	Canadian Nuclear Association. (CNA, 2001)

Cost and Performance of New Generation Technologies

Table A- 2 New Fossil Unit Characteristics (CDN 2000$) – British Columbia

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	**Simple Cycle Gas Turbine with Cogeneration**	**Combine Cycle Gas Turbine**	**Combined Cycle Gas Turbine with Cogeneration**	**Pulverized Coal**	**Atmospheric Fluidized Bed Combustion**	**Integrated Gasification Combined Cycle**
Net Capacity (MW)	107	107	250	124	N/A	N/A	N/A
Heat Rate[1] (BTU/kWh)	10,342	5,270	6,513	4,883	N/A	N/A	N/A
Capital Cost[2] ($/kW)	642	825	870	939	N/A	N/A	N/A
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	N/A	N/A	N/A
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	N/A	N/A	N/A

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Table A- 3 New Fossil Unit Characteristics (CDN 2000$) – Alberta

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	**Simple Cycle Gas Turbine with Cogeneration**	**Combine Cycle Gas Turbine**	**Combined Cycle Gas Turbine with Cogeneration**	**Pulverized Coal**	**Atmospheric Fluidized Bed Combustion**	**Integrated Gasification Combined Cycle**
Net Capacity (MW)	105	105	238	120	400	150	240
Heat Rate[1] (BTU/kWh)	9,975	5,344	6,517	4,886	9,785	10,260	7,938
Capital Cost[2] ($/kW)	798	1,014	1,047	1,115	2,358	2,555	2,305
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	34.9	34.9	40.3
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	0.61	0.68	7.52

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Table A- 4 New Fossil Unit Characteristics (CDN 2000$) – Saskatchewan

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	**Simple Cycle Gas Turbine with Cogeneration**	**Combine Cycle Gas Turbine**	**Combined Cycle Gas Turbine with Cogeneration**	**Pulverized Coal**	**Atmospheric Fluidized Bed Combustion**	**Integrated Gasification Combined Cycle**
Net Capacity (MW)	107	107	242	123	400	150	240
Heat Rate[1] (BTU/kWh)	10,148	5,361	6,541	4,950	9,785	10,260	7,938
Capital Cost[2] ($/kW)	754	962	1,014	1,076	2,312	2,502	2,437
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	34.9	34.9	40.3
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	0.61	0.68	7.52

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Table A- 5 New Fossil Unit Characteristics (CDN 2000$) – Manitoba

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	**Simple Cycle Gas Turbine with Cogeneration**	**Combine Cycle Gas Turbine**	**Combined Cycle Gas Turbine with Cogeneration**	**Pulverized Coal**	**Atmospheric Fluidized Bed Combustion**	**Integrated Gasification Combined Cycle**
Net Capacity (MW)	110	110	250	126	N/A	N/A	N/A
Heat Rate[1] (BTU/kWh)	10,170	5,353	6,531	4,945	N/A	N/A	N/A
Capital Cost[2] ($/kW)	702	896	944	1,002	N/A	N/A	N/A
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	N/A	N/A	N/A
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	N/A	N/A	N/A

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Table A- 6 New Fossil Unit Characteristics (CDN 2000$) – Ontario

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	**Simple Cycle Gas Turbine with Cogeneration**	**Combine Cycle Gas Turbine**	**Combined Cycle Gas Turbine with Cogeneration**	**Pulverized Coal**	**Atmospheric Fluidized Bed Combustion**	**Integrated Gasification Combined Cycle**
Net Capacity (MW)	107	107	247	123	400	150	240
Heat Rate[1] (BTU/kWh)	10,280	5,298	6,517	4,903	9,785	10,260	7,938
Capital Cost[2] ($/kW)	703	903	916	985	2,443	2,555	2,099
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	34.9	34.9	40.3
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	0.61	0.68	7.52

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Table A- 7 New Fossil Unit Characteristics (CDN 2000$) – Quebec

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	**Simple Cycle Gas Turbine with Cogeneration**	**Combine Cycle Gas Turbine**	**Combined Cycle Gas Turbine with Cogeneration**	**Pulverized Coal**	**Atmospheric Fluidized Bed Combustion**	**Integrated Gasification Combined Cycle**
Net Capacity (MW)	110	109	252	126	N/A	N/A	N/A
Heat Rate[1] (BTU/kWh)	10,261	5,309	6,856	4,912	N/A	N/A	N/A
Capital Cost[2] ($/kW)	675	867	897	965	N/A	N/A	N/A
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	N/A	N/A	N/A
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	N/A	N/A	N/A

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Table A- 8 New Fossil Unit Characteristics (CDN 2000$) – New Brunswick

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	Simple Cycle Gas Turbine with Cogeneration	Combine Cycle Gas Turbine	Combined Cycle Gas Turbine with Cogeneration	Pulverized Coal	Atmospheric Fluidized Bed Combustion	Integrated Gasification Combined Cycle
Net Capacity (MW)	110	110	253	127	400	150	240
Heat Rate[1] (BTU/kWh)	10,246	5,318	6,525	4,919	9,785	10,260	7,938
Capital Cost[2] ($/kW)	626	804	858	919	2,129	2,504	2,011
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	34.9	34.9	40.3
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	0.61	0.68	7.52

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Table A- 9 New Fossil Unit Characteristics (CDN 2000$) – Nova Scotia

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	Simple Cycle Gas Turbine with Cogeneration	Combine Cycle Gas Turbine	Combined Cycle Gas Turbine with Cogeneration	Pulverized Coal	Atmospheric Fluidized Bed Combustion	Integrated Gasification Combined Cycle
Net Capacity (MW)	110	109	253	126	400	150	240
Heat Rate[1] (BTU/kWh)	10,261	5,310	6,522	4,913	9,785	10,260	7,938
Capital Cost[2] ($/kW)	665	854	887	951	2,182	2,514	2,026
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	34.9	34.9	40.3
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	0.61	0.68	7.52

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Table A- 10 New Fossil Unit Characteristics (CDN 2000$) – Newfoundland

	Gas-Fired				Coal-Fired		
	Simple Cycle Gas Turbine	**Simple Cycle Gas Turbine with Cogeneration**	**Combine Cycle Gas Turbine**	**Combined Cycle Gas Turbine with Cogeneration**	**Pulverized Coal**	**Atmospheric Fluidized Bed Combustion**	**Integrated Gasification Combined Cycle**
Net Capacity (MW)	109	109	250	126	N/A	N/A	N/A
Heat Rate[1] (BTU/kWh)	10,228	5,325	6,523	4,924	N/A	N/A	N/A
Capital Cost[2] ($/kW)	682	876	906	975	N/A	N/A	N/A
Fixed O&M ($/kW-yr)	9.5	9.5	9.5	9.5	N/A	N/A	N/A
Variable O&M[3] ($/MWh)	3.95	3.95	4.36	4.36	N/A	N/A	N/A

Notes:
[1]Heat Rate includes credit for non-electricity sales for Cogeneration units.
[2]Capital Costs include Interest During Construction.
[3]Variable O&M excludes fuel costs.
Source: AGRA, 1999.

Cost and Performance of Renewable Technologies

Wind Resources

The cost and performance of new wind generating units were developed using several different sources. First, wind performance is based on the quality of wind in each province. Data obtained from the Atmospheric and Environment Service of Environment Canada (Morris, 2002) provided wind speed and generation profile measurements at various monitoring stations across each province. Based on the average annual wind speed, the quality of wind at each station was placed into a specific "wind class" – a measure of the quality of the wind, and, therefore, capacity factor.

Based on the limited data available, each province was assigned one wind class from the station data. The generation profile, which represents the typical energy output over a 24-hour period in a season, as well as the energy available during peak hours at each station, was then scaled to match the capacity factor that corresponds to the assigned wind class. Table A- 11 illustrates the capacity factor for each wind class (EIA, 2002). Provincial capacity factors are specified in Table A- 22.

Table A- 11 Wind Class Characteristics in 2010

Class	Speed (km/hr)	Capacity Factor (%)
4	> 19.95	34 %
5	> 21.56	38 %
6+	> 23.33	42 %

Notes: Measurements taken at 10 m height
Source: EIA, 2002.

Cost assumptions of new wind turbine technologies are based on EIA 2002a. However, the costs of all new wind units built by the model beginning in 2007 reflect the \$0.010/kWh (CDN) incentive that is provided through the Wind Power Production Incentive (WPPI) for the first 10 years of a project's life. The model, in effect, reduces the cost of the option by this incentive amount.

Small Hydro

Cost assumptions for potential small hydro units were developed using the CANMET International Small Hydro Atlas (CANMET, 2002), which provides estimates on the cost and potential for undeveloped small hydro locations in each province. In order to represent the costs and potentials in each province, four cost classes were developed (very low, low, medium, and high cost) that reflect the weighted average cost of all potential sites in each designated class. For hydropower, the model requires an estimate of seasonal energy availability. In the absence of a monthly energy profile, a provincial-level, seasonal capacity factor is used. This data was obtained from generation and capacity figures from Statistics Canada (Statistics Canada, 2002) and applied to the small hydro potential builds.

Potential for large hydro generating stations is considered likely in only 3 of the provinces: Manitoba, Quebec and Newfoundland. Costs for construction of large hydro projects published by Manitoba Hydro were used to characterize potential generation

Landfill Gas

The cost and potential of landfill gas capture and utilization used in this analysis are based on the data collected in a study prepared for Environment Canada called *Identification of Potential Landfill Sites for Additional Gas Recovery and Utilization in Canada* (Environment Canada, 1999). A weighted average cost was calculated for each province based on the reported costs of capture, utilization, and flaring and estimated generation potential at each existing site. The reported operation and maintenance costs were netted by an assumed $0.01/MWh, as used in EIA, 2002, leaving the fixed portion of the O&M costs. A heat rate of 13,648 Btu/kWh was also assumed based on EIA, 2002a assumptions.

Table A- 12 New Renewable Unit Characteristics (CDN 2000$) – British Columbia

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,585	1,313	2,071	1,282	1,777	2,491	4,961	N/A	1,492
Fixed O&M ($/kW-yr)	39.6	39.6	79.1	19.2	26.7	37.4	74.4	NA	182.4
Variable O&M ($/MWh)	N/A	N/A	12.71	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 13 New Renewable Unit Characteristics (CDN 2000$) – Alberta

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,621	1,388	1,630	2,947	3,256	3,894	5,883	N/A	2,027
Fixed O&M ($/kW-yr)	39.6	39.6	65.5	44.2	48.8	58.4	88.2	N/A	151.1
Variable O&M ($/MWh)	N/A	N/A	12.46	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 14 New Renewable Unit Characteristics (CDN 2000$) – Saskatchewan

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,584	1,364	1,319	4,930	N/A	6,757	N/A	N/A	2,402
Fixed O&M ($/kW-yr)	39.6	39.6	51.0	73.9	N/A	101.4	N/A	N/A	188.1
Variable O&M ($/MWh)	N/A	N/A	16.06	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 15 New Renewable Unit Characteristics (CDN 2000$) – Manitoba

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,578	1,352	2,044	3,364	4,036	4,629	5,285		1,849
Fixed O&M ($/kW-yr)	39.6	39.6	79.0	50.5	60.5	69.4	79.3	22.0	174.6
Variable O&M ($/MWh)	N/A	N/A	24.89	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 16 New Renewable Unit Characteristics (CDN 2000$) – Ontario

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,621	1,388	2,637	1,562	2,268	2,748	3,230	N/A	1,900
Fixed O&M ($/kW-yr)	39.6	39.6	24.9	23.4	34.0	41.2	48.5	N/A	204.1
Variable O&M ($/MWh)	N/A	N/A	16.03	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 17 New Renewable Unit Characteristics (CDN 2000$) – Quebec

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,585	1,313	527	2,059	2,769	3,494	4,718		1,861
Fixed O&M ($/kW-yr)	39.6	39.6	13.2	30.9	41.5	52.4	70.8	22.0	286.9
Variable O&M ($/MWh)	N/A	N/A	22.31	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 18 New Renewable Unit Characteristics (CDN 2000$) – New Brunswick

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,585	1,364	1,870	2,899	3,751	4,780	6,098	N/A	3,005
Fixed O&M ($/kW-yr)	39.6	39.6	58.2	43.5	56.3	71.7	91.5	N/A	217.4
Variable O&M ($/MWh)	N/A	N/A	13.96	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 19 New Renewable Unit Characteristics (CDN 2000$) – Nova Scotia

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,587	1,317	1,870	2,422	3,715	3,751	4,783	N/A	1,710
Fixed O&M ($/kW-yr)	39.6	39.6	58.2	36.3	55.7	56.1	71.7	N/A	145.9
Variable O&M ($/MWh)	N/A	N/A	13.96	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 20 New Renewable Unit Characteristics (CDN 2000$) – Newfoundland

	Wind	Wind (adjusted for Incentive)	Biomass	Small Hydro (V. Low)	Small Hydro (Low)	Small Hydro (Med)	Small Hydro (High)	Large Hydro	Landfill Gas[1]
Heat Rate (BTU/kWh)	N/A	N/A	8,654	N/A	N/A	N/A	N/A	N/A	13,648
Capital Cost ($/kW)	1,594	1,332	1,870	1,758	2,518	3,227	4,233		2,515
Fixed O&M ($/kW-yr)	39.6	39.6	58.2	26.4	37.8	48.4	63.5	22.0	194.8
Variable O&M ($/MWh)	N/A	N/A	13.96	N/A	N/A	N/A	N/A	N/A	0.02

Note:
[1]Landfill gas costs include flaring and utilization costs.
Sources:
Small Hydro: CANMET, 2002.
Wind Costs: EIA, 2002.
Biomass Costs: CFS, 1999.
Landfill Gas Costs: EC, 1999.
Heat Rates: EIA, 2002.

Table A- 21 Estimated Provincial Renewable Energy Potential (MW)

	Wind	Biomass	Small Hydro (Very Low)	Small Hydro (Low)	Small Hydro (Medium)	Small Hydro (High)	Large Hydro	Landfill Gas
British Columbia	3,257	483	0	286	290	286	N/A	59
Alberta	2,509	157	19	39	48	32	N/A	46
Saskatchewan	826	15	12	N/A	13	N/A	N/A	4
Manitoba	1,027	6	14	101	117	100	3,187	20
Ontario	8,236	90	0	58	59	54	N/A	153
Quebec	9,777	457	19	347	363	353	2,815	50
New Brunswick	785	34	0	186	180	174	N/A	3
Nova Scotia	574	17	1	54	55	54	N/A	5
Newfoundland	661	4	18	370	387	393	3,200	7

Sources: Rangi, 1992.
CANMET, 2002.
EC, 1999.

Table A- 22 Wind Capacity Factors

Province	Capacity Factor (%)
British Columbia	0.42
Alberta	0.42
Saskatchewan	0.34
Manitoba	0.34
Ontario	0.42
Quebec	0.42
New Brunswick	0.34
Nova Scotia	0.42
Newfoundland	0.42

Source: Morris, 2002.
Walmsley and Morris, 1992.
EIA, 2002b.

Emissions Control Technology

Due to the inclusion of the Ontario NO_X and SO_2 regulation, control technologies were made available to the affected plants. Control options available within the model were chosen based on proven, commercially available technologies.

Sulphur Dioxide Control Technologies

Two types of SO_2 control technologies were included to reduce emissions from coal-fired units: Limestone Forced Oxidation (LSFO) and Magnesium Enhanced Lime (MEL). First, LSFO is a wet scrubber option that is offered to coal units that are greater than 100 MW in size and burn bituminous coals with a 2 percent or higher sulphur content. MEL is also a wet scrubber option that is available for coal plants that are greater than 100 MW in size. Unlike the LSFO, MEL can be applied to units that burn bituminous, subbituminous, or lignite coals that are less than 2.5 percent in sulphur content.[4] The performance of each scrubber is similar. The LSFO is assumed to reduce SO_2 emissions by 95 percent, while the MEL is assumed to reduce SO_2 emissions by 96 percent.

Post-Combustion NO_x Controls

Both Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are available to coal and oil/gas steam units for control of NO_x emissions. SCR is available to coal units that are 100 MW or greater in capacity, and to all oil/gas units. An SCR is assumed to achieve a 90 percent reduction in NO_X emissions on a coal-fired unit, to a limit of 0.02 kg/MMBtu, and 80% on oil/gas units. An SNCR is assumed to achieve a 35 percent reduction in emissions on coal-fired units and a 50 percent reduction on an oil/gas unit.

Reserve Margin Assumptions

The reserve margin represents the system's generating capability over and above the peak load requirement. It is expressed as a percent above system peak load. NERC region's generally target a reserve margin requirement designed to encourage electric suppliers to build beyond peak requirements to meet reliability demands.

In IPM®, these reserve margins were used to represent the reliability standards and were reported by North American Electric Reliability Council (NERC, 2001d) and the Western Systems Coordinating Council (WSCC, 2002). The reserve margins are shown in Table A-23.

[4] EPA, 2002b.

Table A- 23 Reserve Margin Assumptions

Region	Reserve Margin
AB	20%
BC	14%
MB	12%
NB	15%
NL	20%
NS	20%
ON	14%
PQ	12%
SK	14%

Fuel Prices

In determining the optimal capacity expansion and dispatch, IPM® considers current and future fuel price projections. Given the limited availability of public information on the cost and quality of fuels consumed by the fossil generation in Canada, and the lack of consistency across the available data, ICF developed coal-price forecasts based on several sources. Mine mouth coal prices in Alberta and Saskatchewan were based on data provided in StatsCan document *Electric Power Generation, Transmission, and Distribution. 1999.* The remaining coal price projections were based on ICF forecasts of mine mouth coal prices. Each unit that burns coal produced in the U.S. was assigned a transportation price that resulted in a delivered coal price consistent with provincial prices as provided by Natural Resources Canada. Table A- 24 illustrates 2010 delivered coal price projections.

Table A- 24 Weighted Average Coal Price for 2010

Province	Delivered Coal Price 2010 ($ CDN/GJ)
AB	0.48
MB	1.16
NB	1.71
NS	2.55
ON	1.41
SK	0.72

Note: All dollar values in year 2000 CDN

A suitable and consistent natural gas price forecast was not available publicly. Therefore, gas price projections were developed by ICF using the North American Natural Gas Analysis System (NANGAS). NANGAS is a bottom-up optimization model of North American natural gas markets which models production decisions from over 17,000 reservoirs in the U.S and forecasts the equilibrium price and supply given demand, exploration, and production costs, as well as other key drivers. For this study, ICF used the wellhead natural gas prices from its latest forecasts to develop regional estimates of delivered natural gas as illustrated in Table A- 25.

Table A- 25 Base Case Delivered Natural Gas Prices

Province	Natural Gas Price in 2010 ($ CDN/GJ)	Natural Gas Price in 2015 ($ CDN/GJ)
AB	4.71	3.87
BC	4.64	3.81
SK	4.88	4.02
MB	5.16	4.29
ON	5.36	4.70
PQ	6.46	5.52
NB	3.97	3.29
NS	3.97	3.29
NL	3.97	3.29

Source: ICF Forecasts
Note: All dollar values in year 2000 CDN

Financial

IPM® uses a discounted-cash flow calculation to reflect capacity and other investments over time and to capture the time value of money. A key component of this calculation with respect to investment decisions in IPM® is the capital charge rate (CCR). The CCR is used to convert the overnight capital cost of an investment decision (e.g., for a new power plant) into annualized payments that take into account the need to recover the full costs of the initial investment while providing a sufficient return to equity and debt holders. It explicitly considers the following variables:

- Capital structure,
- Pre-tax debt rate (or interest cost),
- Debt life,
- Post-tax return on equity,
- Other costs such as property taxes and insurance,
- State and federal corporate income taxes,
- Depreciation schedule, and
- Book life.

For this analysis, ICF developed provincial-specific capital charge rates based on the market structure of each province for each new capacity option to reflect different risk profiles and financing schemes. The CCRs in this analysis reflected, for example, that investments in regulated markets, such as those in New Brunswick, Nova Scotia and Saskatchewan, can be more highly leveraged because of the backing provided to support the investment. The debt-to-equity ratio also reflects the risk profile of the investment project. Projects such as combustion turbines and renewables, for example, carry with them greater risk because of their expected low capacity factors than would investment in a new combined cycle unit. As a result, riskier investments would be expected to rely more heavily on equity financing than on debt and would, therefore, carry with them the higher required rates of return associated with that equity share. These higher charges are expressed as higher CCRs in IPM®. When possible, the debt-to-equity ratios assumed in this study are based on the ratios used by the provincial utilities.

Appendix B Phase 1 Scenario Assumptions and Calculation Methodology

This page intentionally blank.

Table B - 1 GHG Emissions from Hydrogen Electrolysis - P1 Incremental Scenario 2010 (0.5% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	181,586	164,164	65,093	53,716	530,996	325,014	39,406	41,242	22,646	**1,431,040**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	79%	78%	2%	25%	0%	19%	85%	0%	
NG - Turbine	2%	16%	13%	0%	3%	0%	13%	11%	0%	
Oil	0%	0%	0%	0%	0%	0%	39%	0%	0%	
Hydro	96%	0%	8%	98%	9%	93%	0%	0%	100%	
Nuclear	0%	0%	0%	0%	61%	3%	27%	0%	0%	
Other	2%	4%	1%	0%	2%	4%	2%	4%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	130,350	50,685	1,235	131,126	-	7,514	35,190	-	**356,099**
NG - Turbine	3,511	26,964	8,265	-	16,298	-	4,976	4,421	-	**64,435**
Oil	-	106	-	-	1,225	-	15,491	-	-	**16,823**
Hydro	174,242	411	5,511	52,481	46,207	302,645	-	104	22,646	**604,248**
Nuclear	-	-	-	-	326,001	10,016	10,693	-	-	**346,711**
Other	3,833	6,334	631	-	10,139	12,352	731	1,527	-	**35,549**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	147,816	57,477	1,400	148,697	-	8,521	39,906	-	**403,817**
NG - Turbine	1,740	13,363	4,096	-	8,077	-	2,466	2,191	-	**31,934**
Oil	-	110	-	-	1,272	-	16,087	-	-	**17,469**
Hydro	4,940	12	156	1,488	1,310	8,580	-	3	642	**17,130**
Nuclear	-	-	-	-	4,792	147	157	-	-	**5,097**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**6,680**	**161,302**	**61,729**	**2,888**	**164,148**	**8,727**	**27,231**	**42,100**	**642**	**475,447**

Table B - 2 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.134
NG - Turbine	0.4956
Oil	1.0385
Hydro	0.02835
Nuclear	0.0147
Other	0

Table B - 3 GHG Emissions Displaced by Hydrogen – P1 Incremental Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2010	323.3	292.3	115.9	95.6	945.5	578.7	70.2	73.4	40.3	**2,535.4**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[1] (tonnes of CO_2e)										
2010	**80,965**	**73,197**	**29,023**	**23,951**	**236,758**	**144,916**	**17,570**	**18,389**	**10,098**	**634,867**

Table B - 4 Net GHG Impact (tonnes of CO_2e) – P1 Incremental Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2010	**-74,285**	**88,105**	**32,706**	**-21,063**	**-72,610**	**-136,188**	**9,661**	**23,711**	**-9,455**	**-159,420**

Note: negative numbers represent emission reductions

[1] NRCan emission factor = 250.4 tonnes of CO_2e per KM

Table B - 5 Costs – P1 Incremental Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2010	$41.83	$49.99	$39.71	$30.13	$41.90	$35.88	$34.39	$34.47	$30.94	**$37.70**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2010	$7,596,565	$8,206,173	$2,584,895	$1,618,574	$22,246,876	$11,662,297	$1,355,345	$1,421,705	$700,636	**$57,393,066**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2010	$1.96	$2.34	$1.86	$1.41	$1.96	$1.68	$1.61	$1.61	$1.45	**$1.76**
Forecast price of Hydrogen per km under P1 Incremental scenario - 2010 (2000$CAN)										**Average**
2010	$0.023	$0.028	$0.022	$0.017	$0.024	$0.020	$0.019	$0.019	$0.017	**$0.021**
Forecast price of Hydrogen per litre of gasoline equivalent 2010 (2000$CAN)										**Average**
2010	$0.29	$0.35	$0.28	$0.21	$0.29	$0.25	$0.24	$0.24	$0.21	**$0.26**

Table B - 6 GHG Emissions from Hydrogen Electrolysis - P1 Incremental Scenario 2020 (6% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	1,859,390	1,680,997	666,530	550,038	5,437,248	3,328,045	403,505	422,310	231,893	**14,653,440**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	57%	57%	2%	18%	0%	16%	77%	0%	
NG - Turbine	12%	40%	37%	0%	32%	9%	20%	19%	9%	
Oil	0%	0%	0%	0%	0%	0%	38%	0%	0%	
Hydro	86%	0%	5%	98%	6%	85%	2%	1%	91%	
Nuclear	0%	0%	0%	0%	43%	3%	22%	0%	0%	
Other	2%	3%	1%	0%	1%	3%	2%	3%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	963,433	381,135	12,343	975,155	-	63,350	323,495	-	**2,718,911**
NG - Turbine	219,635	669,453	247,316	-	1,716,675	294,451	81,609	81,093	20,156	**3,330,388**
Oil	-	30	-	-	18,077	-	155,310	-	-	**173,417**
Hydro	1,595,123	-	33,256	536,730	337,655	2,829,237	6,913	4,787	211,738	**5,555,438**
Nuclear	-	-	-	-	2,317,527	91,484	90,156	-	-	**2,499,167**
Other	44,632	48,081	4,823	965	72,159	112,873	6,167	12,935	-	**302,636**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	1,076,347	425,804	13,790	1,089,443	-	70,775	361,409	-	**3,037,567**
NG - Turbine	108,621	331,078	122,310	-	848,982	145,621	40,360	40,104	9,968	**1,647,043**
Oil	-	30	-	-	18,412	-	158,183	-	-	**176,625**
Hydro	45,222	-	943	15,216	9,573	80,209	196	136	6,003	**157,497**
Nuclear	-	-	-	-	31,634	1,249	1,231	-	-	**34,114**
Other	-	-	-	-	-	-	-	-	-	-
TOTAL EMISSIONS	**153,842**	**1,407,456**	**549,057**	**29,006**	**1,998,044**	**227,078**	**270,744**	**401,649**	**15,971**	**5,052,846**

Table B - 7 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.1172
NG - Turbine	0.49455
Oil	1.0185
Hydro	0.02835
Nuclear	0.01365
Other	0

Table B - 8 GHG Emissions Displaced by Hydrogen – P1 Incremental Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2020	3,973.1	3,591.9	1,424.2	1,175.3	11,618.1	7,111.2	862.2	902.4	495.5	**31,153.8**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[2] (tonnes of CO_2e)										
2020	**786,709**	**711,231**	**282,009**	**232,721**	**2,300,504**	**1,408,099**	**170,723**	**178,680**	**98,114**	**6,168,791.3**

Table B - 9 Net GHG Impact (tonnes of CO_2e) – P1 Incremental Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2020	**-632,867**	**696,224**	**267,047**	**-203,715**	**-302,460**	**-1,181,020**	**100,021**	**222,969**	**-82,144**	**-1,115,945**

Note: negative numbers represent emission reductions

[2] NRCan emission factor = 198.0 tonnes of CO_2e per KM

Table B - 10 Costs – P1 Incremental Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2020	$39.68	$42.16	$36.29	$33.37	$45.28	$39.40	$35.57	$36.44	$34.35	**$38.05**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2020	$73,780,592	$70,870,851	$24,185,381	$ 18,355,585	$246,174,103	$131,128,312	$14,353,672	$15,389,172	$7,965,073	**$602,202,740**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2020	$1.86	$1.97	$1.70	$1.56	$2.12	$1.84	$1.66	$1.71	$1.61	**$1.78**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2020	$0.019	$0.020	$0.017	$0.016	$0.021	$0.018	$0.017	$0.017	$0.016	**$0.018**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2020	$0.29	$0.30	$0.26	$0.24	$0.33	$0.28	$0.26	$0.26	$0.25	**$0.27**

Table B - 11 GHG Emissions from Hydrogen Electrolysis - P1 Accelerated Scenario 2010 (1.8% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2010	653,710	590,992	234,334	193,378	1,911,586	1,170,049	141,861	148,472	81,527	**5,151,744**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	78%	78%	2%	25%	0%	19%	85%	0%	
NG - Turbine	2%	18%	13%	0%	3%	0%	12%	11%	0%	
Oil	0%	0%	0%	0%	0%	0%	41%	0%	0%	
Hydro	96%	0%	8%	98%	9%	93%	0%	0%	100%	
Nuclear	0%	0%	0%	0%	61%	3%	27%	0%	0%	
Other	2%	4%	1%	0%	2%	4%	2%	4%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	460,306	181,887	4,377	475,835	-	26,723	126,047	-	**1,275,175**
NG - Turbine	12,360	106,996	30,470	-	65,805	-	16,930	16,745	-	**249,305**
Oil	-	375	-	-	3,991	-	57,576	-	-	**61,942**
Hydro	627,987	821	19,703	189,001	171,207	1,090,007	-	264	81,527	**2,180,516**
Nuclear	-	-	-	-	1,158,700	35,839	38,031	-	-	**1,232,570**
Other	13,364	22,494	2,274	-	36,048	44,203	2,602	5,416	-	**126,402**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	521,987	206,260	4,964	539,596	-	30,304	142,937	-	**1,446,048**
NG - Turbine	6,125	53,027	15,101	-	32,613	-	8,390	8,299	-	**123,555**
Oil	-	389	-	-	4,145	-	59,790	-	-	**64,324**
Hydro	17,803	23	559	5,358	4,854	30,902	-	7	2,311	**61,818**
Nuclear	-	-	-	-	17,033	527	559	-	-	**18,119**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**23,929**	**575,427**	**221,919**	**10,322**	**598,241**	**31,429**	**99,043**	**151,244**	**2,311**	**1,713,864**

Table B - 12 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.134
NG - Turbine	0.4956
Oil	1.0385
Hydro	0.02835
Nuclear	0.0147
Other	0

Table B - 13 GHG Emissions Displaced by Hydrogen – P1 Accelerated Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2010	1,164.0	1,052.3	417.3	344.3	3,403.8	2,083.4	252.6	264.4	145.2	**9,127.3**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[3] (tonnes of CO_2e)										
2010	**291,474**	**263,509**	**104,484**	**86,223**	**852,330**	**521,697**	**63,252**	**66,200**	**36,351**	**2,285,519.9**

Table B - 14 Net GHG Impact (tonnes of CO_2e) – P1 Accelerated Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2010	**-267,545**	**311,918**	**117,435**	**-75,901**	**-254,090**	**-490,268**	**35,791**	**85,043**	**-34,040**	**-571,656**

Note: negative numbers represent emission reductions

[3] NRCan emission factor = 250.4 tonnes of CO_2e per KM

Table B - 15 Costs – P1 Accelerated Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2010	$41.83	$49.99	$40.58	$30.26	$41.91	$35.88	$34.57	$34.86	$30.94	**$37.87**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2010	$27,347,633	$29,542,221	$9,509,022	$5,850,847	$80,118,383	$41,984,270	$4,903,429	$5,175,672	$2,522,291	**$206,953,767**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2010	$1.96	$2.34	$1.90	$1.42	$1.96	$1.68	$1.62	$1.63	$1.45	**$1.77**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2010	$0.023	$0.028	$0.023	$0.017	$0.024	$0.020	$0.019	$0.020	$0.017	**$0.021**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2010	$0.29	$0.35	$0.28	$0.21	$0.29	$0.25	$0.24	$0.24	$0.21	**$0.26**

Table B - 16 GHG Emissions from Hydrogen Electrolysis - P1 Accelerated Scenario 2020 (11.5% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	3,563,831	3,221,912	1,277,516	1,054,239	10,421,391	6,378,753	773,384	809,427	444,462	**28,085,760**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	56%	54%	2%	18%	0%	16%	75%	0%	
NG - Turbine	11%	41%	40%	0%	32%	10%	20%	21%	17%	
Oil	0%	0%	0%	0%	0%	0%	40%	0%	0%	
Hydro	87%	0%	5%	98%	8%	84%	0%	1%	83%	
Nuclear	0%	0%	0%	0%	41%	3%	22%	0%	0%	
Other	2%	3%	1%	0%	1%	3%	2%	3%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	1,802,811	689,058	23,844	1,856,725	-	121,474	606,614	-	**5,100,526**
NG - Turbine	395,793	1,322,042	516,647	-	3,284,610	620,603	155,766	167,820	75,175	**6,538,456**
Oil	-	-	-	-	35,042	-	307,721	-	-	**342,763**
Hydro	3,083,312	743	62,815	1,028,615	785,942	5,380,166	3,722	10,042	369,287	**10,724,644**
Nuclear	-	-	-	-	4,324,218	169,128	172,875	-	-	**4,666,220**
Other	84,726	96,315	8,996	1,780	134,855	208,857	11,826	24,950	-	**572,305**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	2,014,101	769,815	26,639	2,074,333	-	135,710	677,710	-	**5,698,307**
NG - Turbine	195,739	653,816	255,508	-	1,624,404	306,919	77,034	82,995	37,178	**3,233,594**
Oil	-	-	-	-	35,690	-	313,414	-	-	**349,104**
Hydro	87,412	21	1,781	29,161	22,281	152,528	106	285	10,469	**304,044**
Nuclear	-	-	-	-	59,026	2,309	2,360	-	-	**63,694**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**283,151**	**2,667,938**	**1,027,104**	**55,800**	**3,815,734**	**461,756**	**528,624**	**760,990**	**47,647**	**9,648,743**

Table B - 17 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.1172
NG - Turbine	0.49455
Oil	1.0185
Hydro	0.02835
Nuclear	0.01365
Other	0

Table B - 18 GHG Emissions Displaced by Hydrogen – P1 Accelerated Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2020	7,615.0	6,884.4	2,729.7	2,252.6	22,267.9	13,629.8	1,652.5	1,729.5	949.7	**59,711.4**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[4] (tonnes of CO_2e)										
2020	**1,507,860**	**1,363,194**	**540,518**	**446,049**	**4,409,299**	**2,698,856**	**327,219**	**342,469**	**188,052**	**11,823,516.7**

Table B - 19 Net GHG Impact (tonnes of CO_2e) – P1 Accelerated Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2020	**-1,224,709**	**1,304,744**	**486,586**	**-390,250**	**-593,565**	**-2,237,100**	**201,405**	**418,521**	**-140,405**	**-2,174,774**

Note: negative numbers represent emission reductions

[4] NRCan emission factor = 198.0 tonnes of CO_2e per KM

Table B - 20 Costs – P1 Accelerated Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2020	$40.16	$42.55	$36.61	$33.79	$47.46	$39.34	$35.71	$38.13	$34.29	**$38.67**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2020	$143,125,222	$137,084,288	$46,771,145	$35,622,738	$494,609,647	$250,933,782	$27,619,092	$30,863,439	$15,238,832	**$1,181,868,185**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2020	$1.88	$1.99	$1.71	$1.58	$2.22	$1.84	$1.67	$1.78	$1.60	**$1.81**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2020	$0.019	$0.020	$0.017	$0.016	$0.022	$0.018	$0.017	$0.018	$0.016	**$0.018**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2020	$0.29	$0.31	$0.26	$0.24	$0.34	$0.28	$0.26	$0.27	$0.25	**$0.28**

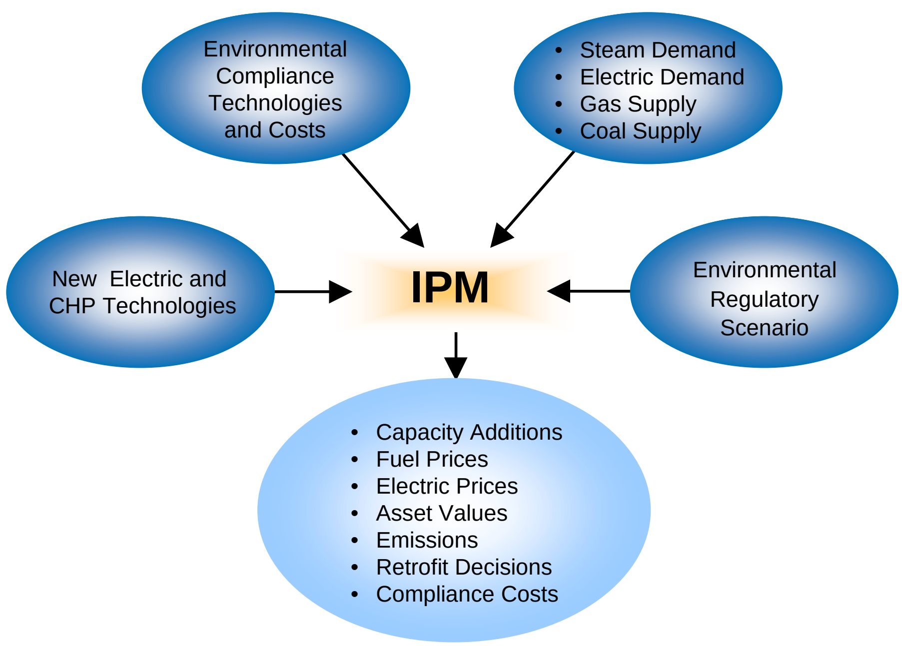
Appendix C Detailed IPM Description

This page intentionally blank.

The **Integrated Planning Model** (**IPM**®) is a culmination of ICF Consulting's 25 years of experience helping private and public sector clients evaluate the complex dynamics of electric, fuel, and environmental markets. IPM is a detailed engineering-economic capacity expansion and production costing model of the power and industrial sectors supported by an extensive database of every boiler and generator in the nation. It is a multi-region model that provides least-cost capacity expansion plans, credible plant dispatch, electric prices forecasts, all based on power market fundamentals. IPM explicitly considers gas, oil, and coal markets, power plant costs and performance characteristics, environmental constraints, and other power market fundamentals.

Unlike purely econometrically driven models, IPM captures the interactions of real world constraints and simulates electric markets based on economic fundamentals rather than trends in historic data. IPM contains the ability to very easily simulate complex phenomena, such a technological advances, unexpected regulatory announcements, and changing risk patterns in capital investments, for example, that is almost impossible to capture with historical data. For example, when Phase I of the US EPA SO_2 trading program effect took effect in 1995, ICF correctly forecasted with IPM that SO_2 allowances prices would peak at $200/ton. By end of 1998, SO_2 allowances prices peaked at $200/ton. Based on IPM analysis, in 1995 ICF warned of energy price spikes such as those observed in Midwestern US power markets in 1998. This model was also used for Ontario's NO_X and SO_2 trading system and, more recently, the federal MERS process. The complex structure of current energy markets requires more than projection from historic data. IPM is particularly successful because it solves for demand-supply equilibrium taking into account the complex interactions with fuel markets, capacity markets, allowance markets, and inter-regional trade. Figure 1 illustrates the key components of IPM

Figure C-1 The Integrated Planning Model Structure



ICF Consulting's IPM uses a dynamic linear programming framework to represent various North American electric power market regions. These regions correspond in most cases to the regions and sub-regions used by the North American Electric Reliability Council (NERC) and the level of detail used depends on the analysis being conducted. IPM models the electric demand, generation, and transmission within each region as well as the transmission grid that connects the regions. Regional representation is flexible and adapted to each project's requirements.

Several factors are taken into account in determining the cost-minimizing planning strategy. Key factors include:

Investment choices are made from among a wide variety of resource options as determined by the user. A unique feature of the IPM is its ability to represent and account for the different characteristics of alternative types of resource options. Options can include demand-side resources (e.g., energy efficiency and load management options), bulk power purchases and cogeneration, increased utilization of existing resources (e.g., life extension, repowering, and relicensing), as well as mature and advanced utility generating technologies (e.g., fluidized bed combustors and integrated gasification combined cycle units).

Generating options are characterized in terms of their capital costs, operating and maintenance (O&M) costs, fuel costs, fuel quality, heat rates, pollution control equipment, reliability, and lead times. In the case of energy efficiency options, characteristics include capital and program administration costs, market penetration rates, and load shape impacts. Load management options (e.g., water heater service interruption or air conditioner cycling) can be dispatched in an optimal manner similar to the dispatch of generating units. The amount and scheduling of available power and its costs characterize possible bulk power purchase options, either for economy or for firm power purchases.

Decisions about fuel conversion, retrofits, repowering, life extension, and economic retirements are based upon trade-offs between capital costs and fuel savings over the planning horizon, as well as how these options compare with other available alternatives.

Selection of fuels for each generating unit are based upon fuel prices and price escalation rates, availability constraints, usage constraints (e.g., an oil or gas plant that is not coal-capable cannot burn coal), emissions characteristics, and environmental regulations. Options can include alternative strategies for meeting environmental constraints (e.g., use of "clean" fuel vs. use of "dirty" fuel with pollution control and/or waste disposal equipment).

The seasonal availability of **reservoir and run-of-river hydro resources** and the cost and operation (e.g., "negative" generation impacts) of pumped storage plants are modelled effectively by IPM.

B. Applications

Its linear programming structure makes IPM particularly well suited for a variety of applications such as assessing planning strategies or regulatory policy options. Among the types of analyses that can be conducted with IPM are:

Power price forecasts. IPM can be used to predict wholesale power prices using scenarios developed through the IPM database interface.

Strategic planning. IPM can be used to assess the costs and risks associated with alternative utility and consumer resource planning strategies as characterized by the portfolio of options included in the input data base.

Analysis of uncertainty. The efficiency of the model's computational algorithms allows it to be used with various techniques for analyzing the potential impacts of uncertain future conditions (e.g., load growth, fuel prices, environmental regulations, costs and performance of resource options) and the risks associated with alternative planning strategies. Alternative approaches that have been used for analyzing uncertainty with IPM include sensitivity analysis, decision analysis, and modelling uncertainty endogenously by incorporating specific factors that are uncertain and the associated probabilities for different values or expectations for these factors directly into the linear programming structure.

Options assessment. IPM can be used to "screen" alternative resource options and option combinations based upon their relative costs and potential earnings.

Environmental Policy Analysis and other operations under system-wide constraints. IPM has been used extensively to model environmental policies and for compliance planning. It was the tool used by EPA in the SIP Call process and is being used extensively for multi-pollutant analyses by parties on all sides of the debate. Various approaches can be evaluated for meeting environmental constraints (e.g., limits on hourly, daily, or annual emissions), fuel use constraints (e.g., optimum allocation of limited fuel supplies to alternative plants).

Multiple emission policies can be modelled simultaneously. For example, the model simulates compliance with SO_2 and NO_X emissions limits, as well as mercury and carbon policies. IPM is particularly well suited to multi-pollutant studies since it can simulate multiple policies that shift over time and geographic areas.

Alternative implementation approaches can be modelled, such as national emissions caps with a trading program, and regional programs within larger programs. Unit, regional (state or province) or multi-regional emissions caps, or cap and trades can also be modelled. More complex aspects of market based programs, such as banking, borrowing, progressive flow control and output updating approaches can also be handled by the model.

Estimation of avoided costs. Shadow prices[1] from the linear programming solution can be used to determine avoided costs by season or time-of-day for pricing purchases from qualifying facilities, independent power producers, or economy and/or firm power purchases from other utilities. Shadow prices also can be used to assess the economic value of relaxing a constraint (e.g., What is the marginal cost of emissions reductions for the utility?), to conduct marginal cost studies, and to determine the cost reductions of alternative options in order for these options to be competitive with those options selected by the model or the "preferred" options. This greatly enhances the capability to use the model and its outputs as a screening tool.

Integrated resource planning. IPM can be used to perform least-cost planning studies that simultaneously optimize demand-side options (load management and energy efficiency options), renewable options, and supply-side options.

Detailed modelling of dispatch. IPM dispatch algorithms are very accurate and have been benchmarked against detailed utility dispatch models.

C. Methodology

[1] Shadow prices provide a measure of the value of incremental capacity and energy or the value of relaxing system operations constraints. Since these costs are not explicitly incurred by utilities or consumers but reflect a willingness to pay for changing binding limitations on their actions or decisions, the term "shadow costs" has been used to characterize these costs (they are not forecast to exist, but can be measured in the "shadow world" that exists in models between forecasted "reality" and the modelling choices not a part of this reality).

IPM uses a long-term dynamic linear program to calculate the minimum system-wide levelized cost for meeting load requirements. IPM makes the dispatch and investment decisions that will minimize system costs based on a linear objective function. The linear equation consists of the present value of the sum of all the costs over the time horizon to be evaluated. The objective function is subject to a series of demand and supply constraints. The supply characteristics such as operating and capital investment costs of resources and their generating availability are user inputs. The effects of resources on regional reserve and reliability requirements also serve as inputs to the model. Several supply-side constraints are outlined below.

> **Capacity Constraints**: These constraints specify how much electricity each plant can generate (a maximum generation level) given its capacity and seasonal availability.
>
> **Turn Down/Area Protection Constraints**: The model can take into account the cycling capabilities of the units, i.e., whether or not they can be shut down at night or on weekends, or whether they must operate at all times, at least at some minimum capacity level.
>
> **Emissions Constraints**: A variety of pollutant constraints, such as SO_2, NO_x and CO_2, and additional constraints can be defined by the user. The constraints can be implemented on either a regional or plant-by-plant basis. The constraints can be defined as either a total tonnage cap, or a maximum rate in lbs./MMBtu [or kg/GJ].
>
> **Transmission Constraints:** Any number of regions transmission links between regions are modelled simultaneously. The constraints define either a maximum MW level on each link, or a maximum level of transmission on two or more links (joint limits) to different regions.

In addition, there are other constraints that are used for dispatching hydro and pumped storage units. The model also has a special structure to account for out-of-system economy and firm purchases.

Demand constraints also restrict the objective function. Demand side inputs and constraints are also user-defined. Several demand side constraints are outlined below.

> **Reserve Margin Constraints**: These constraints define a minimum margin of reserve capacity (in megawatts) per year for each region. If existing plus planned capacity is not enough to satisfy reserve requirement, the model will add the required level of new resources.
>
> **Demand Constraints:** The model divides each year into a number of seasons, which are divided into load segments. Each segment defines the minimum amount of generation required to meet demand at different points in time.

The optimal solution to the linear objective function is the least cost mix of utility resource to satisfy electricity demand on a seasonal basis for each region. The solution is reported in tables that show total generation by region, generation by individual units, variable and fixed costs, transmission levels between regions, and various other tables.

In order to make the modelling more time and cost efficient, the individual boiler and generator data are aggregated into "model" plants. Working with these existing model plants and alternative new power plant options included in the model, IPM determines the least-cost means for supplying electric demand while limiting emissions to specified policy limits.

D. Treatment of Renewables

IPM also models hydro and other renewable technologies. The model captures the unique operating characteristics of the intermittent renewable technologies by specifying 24-hour day-type generation profiles for these technologies. These technologies may be represented as several "vintages" vintage each with unique cost and performance characteristics.

IPM also simulates Renewable Portfolio Standards (RPS). IPM provides the analytical framework for examining the impacts of renewable mandates in isolation and/or in conjunction with other market or regulatory changes. RPS requirements are modelled as regulatory constraints on the power system and can simulate the incentive structure in electricity markets taking into account the geographic scope, time period, and nature of the RPS requirement. IPM will provide a detailed representation of the impact of the RPS regulation on electric power system, emission levels, and fuel markets.

IPM contains detailed representation of renewable resource electricity generating options. These currently include solar (photovoltaic and thermal), wind, electricity generated from landfill gas, geothermal, fuel cells and biomass. Resource base constraints are explicitly taken into account by limiting the potential capacity for each technology by region. IPM appropriately captures the intermittent nature of some renewable technologies, like solar and wind with generation profiles that approximate the capability to generate in any given hour of the year, including the peak hours.

Retrofit Structure

IPM is currently configured to make projects on new capacity builds as well as retrofits to existing plants. This projection will include the types of capacity (i.e. coal, nuclear, combined cycle, combustion turbine, renewable technology, or pollution control technology) to be built and the region in which they are built.

While determining the least cost solution, IPM also determines the optimal compliance strategy for each model plant. A wide range of compliance options are allowed for each affected source including the following:

- Fuel Switching - For example, switching from high sulfur coal to low sulfur coal.
- Repowering - For example, repowering an existing coal plant to a gas combined cycle plant.
- Pollution Control Retrofit - For example, installing selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), gas reburn, or seasonal gas use, to reduce NO_X emissions, or flue gas desulfurization to control SO_2 emissions, to reduce mercury.
- Co-firing – For example, any plant that generates electricity by combusting fuel (coal, gas, or biomass) has the capability in IPM to also co-fire any combination of other fuels, with the portion of fuels co-fired being determined endogenously. This capability extends to endogenously selecting from fuel subtypes, such as different biomass fuel subtypes.
- Economic Retirement - For example, retiring an oil or gas steam plant before its scheduled retirement.
- Dispatch Adjustments - For example, running high SO_2 units less often, and low SO_2 units more often.

Fuel Market Modelling

Natural gas, coal, and biomass fuel supply are also endogenously modelled in IPM. Coal supply is represented by at least 40 coal supply regions and over 15 coal types. Each coal plant is assigned to a coal demand region. The demand regions group plants in a location by coal delivery mode including barge, rail, and truck. These coal supply and demand regions are linked by a coal transportation matrix.

Natural gas markets are similarly represented in the model with a natural gas supply curve (based upon ICF's North American Natural Gas Analysis System), a transportation matrix, and seasonal adjustment factors.

Biomass fuels are similarly treated in IPM with 13 biomass supply regions and 4 biomass fuel types. The transportation matrix also links plants to supply and demand regions. IPM has been used in analyzing the role that biomass might play in energy markets, assessing how biomass technologies and fuels will interact with power, fuel and emissions markets.

E. Outputs of IPM

Many detailed and summary reports can be generated by the IPM. Among the standard reports are:

- Load and generation information.
- Capacity requirements by plant.
- Generation by plant type.
- Retrofit decisions.
- Detailed dispatch information by plant.
- Detailed emissions information by resource type.
- Detailed cost information (capital costs, fixed O&M costs, variable O&M costs, fuel costs).
- Regional energy and capacity prices.
- Power system costs (capital costs, fixed O&M costs, variable O&M costs).
- Allowance prices for controlled pollutants.
- Fuel consumption and fuel prices.

For analysis of policies, such as multipollutant proposals, a business-as-usual scenario is run. Then a policy scenario or scenarios are established. The impact of the policy is the difference between the BAU and the policy runs. Differences in capital, O&M, and fuel costs, and changes in the operation of the system are examined and reflect the cost of the policy. Impacts at the National, regional or more disaggregate levels are possible. Sensitivity analysis is very simple within the IPM framework. Changes in cap levels, year of implementation, economic factors (e.g., demand growth, new technology costs), and control costs, are readily modified.

Appendix D Phase 2 Scenario Assumptions and Calculation Methodology

This page intentionally blank.

Table D - 1 GHG Emissions from Hydrogen Electrolysis – P2 Incremental Off-Peak Scenario 2010 (0.1% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2010	36,212	32,738	12,981	10,712	105,893	64,815	7,858	8,225	4,516	**283,951**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	79%	78%	2%	25%	0%	19%	85%	19%	
NG - Turbine	2%	16%	13%	0%	6%	0%	13%	11%	13%	
Oil	0%	0%	0%	0%	0%	0%	39%	0%	39%	
Hydro	96%	0%	8%	98%	8%	93%	0%	0%	0%	
Nuclear	0%	0%	0%	0%	60%	3%	27%	0%	27%	
Other	2%	4%	1%	0%	2%	4%	2%	4%	2%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	26,027	10,119	247	26,079	-	1,498	7,017	-	**70,988**
NG - Turbine	624	5,388	1,664	-	5,854	-	992	882	-	**15,404**
Oil	-	21	-	-	47	-	3,089	-	-	**3,157**
Hydro	34,832	37	1,072	10,465	8,766	60,397	-	21	4,516	**120,107**
Nuclear	-	-	-	-	63,181	1,978	2,132	-	-	**67,292**
Other	757	1,265	126	-	1,965	2,440	146	305	-	**7,003**
										70,988
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	29,186	11,347	277	29,245	-	1,680	7,869	-	**79,605**
NG - Turbine	309	2,670	825	-	2,901	-	492	437	-	**7,634**
Oil	-	22	-	-	49	-	3,205	-	-	**3,275**
Hydro	878	1	27	264	221	1,522	-	1	114	**3,027**
Nuclear	-	-	-	-	862	27	29	-	-	**919**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**1,187**	**31,880**	**12,199**	**541**	**33,278**	**1,549**	**5,406**	**8,306**	**114**	**94,460**

Table D - 2 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.1214
NG - Turbine	0.4956
NG - Boiler	0.6531
Oil	1.0374
Hydro	0.0252
Nuclear	0.01365
Other	0

Table D - 3 GHG Emissions Displaced by Hydrogen – P2 Incremental Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2010 Car	22.8	20.6	8.2	6.7	66.6	40.8	4.9	5.2	2.8	**178.7**
2010 Truck	18.2	16.5	6.5	5.4	53.4	32.7	4.0	4.1	2.3	**143.1**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[1] (tonnes of CO_2e)										
2010 Car	6,603	5,969	2,367	1,953	19,308	11,818	1,433	1,500	823	**51,773**
2010 Truck	7,658	6,923	2,745	2,265	22,393	13,707	1,662	1,739	955	**60,048**
Total	**14,261**	**12,892**	**5,112**	**4,219**	**41,701**	**25,524**	**3,095**	**3,239**	**1,779**	**111,821**

Table D - 4 Net GHG Impact (tonnes of CO_2e) – P2 Incremental Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2010	**-13,074**	**18,987**	**7,087**	**-3,677**	**-8,422**	**-23,975**	**2,311**	**5,067**	**-1,665**	**-17,361**

Note: negative numbers represent emission reductions

[1] NRCan emission factor = 250.4 tonnes of CO_2e per KM

Table D - 5 Costs – P2 Incremental Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2010	$41.83	$49.99	$39.63	$29.33	$38.05	$35.26	$34.32	$34.38	$30.33	**$37.01**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2010	$1,514,928	$1,636,497	$514,481	$314,146	$4,029,482	$2,285,542	$269,678	$282,755	$136,993	**$10,984,502**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2010	$2.30	$2.75	$2.18	$1.61	$2.09	$1.94	$1.89	$1.89	$1.67	**$2.04**
Forecast price of Hydrogen per km under P2 Incremental scenario - 2010 (2000$CAN)										**Average**
2010	$0.037	$0.044	$0.035	$0.026	$0.034	$0.031	$0.030	$0.030	$0.027	**$0.033**
Forecast price of Hydrogen per litre of gasoline equivalent 2010 (2000$CAN)										**Average**
2010	$0.33	$0.40	$0.32	$0.23	$0.30	$0.28	$0.27	$0.27	$0.24	**$0.29**

Table D - 6 GHG Emissions from Hydrogen Electrolysis - P2 Incremental Scenario 2020 (6% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	1,655,047	1,496,259	593,280	489,590	4,839,704	2,962,299	359,160	375,899	206,409	**12,977,646**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	57%	56%	2%	18%	0%	16%	77%	0%	
NG - Turbine	12%	40%	38%	0%	32%	9%	20%	19%	9%	
Oil	0%	0%	0%	0%	0%	0%	39%	0%	0%	
Hydro	86%	0%	5%	98%	6%	85%	1%	0%	91%	
Nuclear	0%	0%	0%	0%	43%	3%	23%	0%	0%	
Other	2%	3%	1%	0%	1%	3%	2%	3%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	857,553	332,213	10,969	865,092	-	56,940	289,968	-	**2,412,735**
NG - Turbine	192,008	595,882	227,788	-	1,539,509	262,006	73,351	72,688	18,951	**2,982,183**
Oil	-	27	-	-	4,445	-	139,594	-	-	**144,066**
Hydro	1,423,214	-	29,074	477,763	287,596	2,521,212	2,698	1,648	187,457	**4,930,663**
Nuclear	-	-	-	-	2,078,351	80,169	81,034	-	-	**2,239,553**
Other	39,825	42,797	4,204	857	64,712	98,913	5,543	11,594	-	**268,446**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	946,353	366,614	12,105	954,673	-	62,836	319,994	-	**2,662,574**
NG - Turbine	94,957	294,693	112,652	-	761,364	129,575	36,276	35,948	9,372	**1,474,839**
Oil	-	27	-	-	4,518	-	141,884	-	-	**146,429**
Hydro	35,865	-	733	12,040	7,247	63,535	68	42	4,724	**124,253**
Nuclear	-	-	-	-	26,187	1,010	1,021	-	-	**28,218**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**130,822**	**1,241,073**	**479,999**	**24,145**	**1,753,990**	**194,120**	**242,084**	**355,983**	**14,096**	**4,436,313**

Table D - 7 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.10355
NG - Turbine	0.49455
NG - Boiler	0.6195
Oil	1.0164
Hydro	0.0252
Nuclear	0.0126
Other	0

Table D - 8 GHG Emissions Displaced by Hydrogen – P2 Incremental Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2020 Car	1,636.3	1,479.3	586.5	484.0	4,784.8	2,928.7	355.1	371.6	204.1	**12,830**
2020 Truck	1,258.5	1,137.8	451.1	372.3	3,680.2	2,252.6	273.1	285.8	157.0	**9,868**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[2] (tonnes of CO_2e)										
2020 Car	440,643	398,367	157,956	130,349	1,288,534	788,689	95,624	100,080	54,955	**3,455,198**
2020 Truck	494,567	447,118	177,286	146,301	1,446,219	885,206	107,326	112,327	61,680	**3,878,030**
Total	**935,211**	**845,485**	**335,242**	**276,651**	**2,734,753**	**1,673,895**	**202,949**	**212,408**	**116,635**	**7,333,228**

Table D - 9 Net GHG Impact (tonnes of CO_2e) – P2 Incremental Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2020	**-804,388**	**395,588**	**144,757**	**-252,506**	**-980,763**	**-1,479,775**	**39,135**	**143,576**	**-102,538**	**-2,896,915**

Note: negative numbers represent emission reductions

[2] NRCan emission factor = 198.0 tonnes of CO_2e per KM

Table D - 10 Costs – P2 Incremental Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2020	$39.68	$42.16	$36.27	$33.37	$42.86	$39.42	$35.48	$36.33	$34.35	**$37.77**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2020	$65,672,245	$63,082,279	$21,518,258	$16,338,341	$207,417,632	$116,763,475	$12,742,829	$13,657,146	$7,089,726	**$524,281,931**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2020	$1.98	$2.11	$1.81	$1.67	$2.14	$1.97	$1.77	$1.82	$1.72	**$1.89**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2020	$0.023	$0.024	$0.021	$0.019	$0.025	$0.023	$0.020	$0.021	$0.020	**$0.022**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2020	$0.22	$0.23	$0.20	$0.18	$0.24	$0.22	$0.20	$0.20	$0.19	**$0.21**

Table D - 11 GHG Emissions from Hydrogen Electrolysis - P2 Accelerated Scenario 2010 (0.2% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2010	72,425	65,476	25,962	21,424	211,785	129,630	15,717	16,449	9,032	**567,902**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	79%	77%	2%	24%	0%	19%	85%	0%	
NG - Turbine	1%	17%	13%	0%	5%	0%	12%	11%	0%	
Oil	0%	0%	0%	0%	0%	0%	40%	0%	0%	
Hydro	97%	0%	9%	98%	9%	93%	0%	0%	100%	
Nuclear	0%	0%	0%	0%	59%	3%	27%	0%	0%	
Other	2%	4%	1%	0%	2%	4%	2%	4%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	51,872	20,035	476	51,798	-	2,976	13,939	-	**141,097**
NG - Turbine	897	11,001	3,252	-	10,605	-	1,886	1,866	-	**29,507**
Oil	-	42	-	-	32	-	6,321	-	-	**6,396**
Hydro	70,048	25	2,424	20,949	19,626	120,886	8	41	9,032	**243,040**
Nuclear	-	-	-	-	125,810	3,915	4,236	-	-	**133,961**
Other	1,480	2,535	251	-	3,914	4,829	290	603	-	**13,901**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	58,170	22,467	534	58,086	-	3,338	15,631	-	**158,226**
NG - Turbine	444	5,452	1,612	-	5,256	-	935	925	-	**14,624**
Oil	-	44	-	-	34	-	6,558	-	-	**6,635**
Hydro	1,765	1	61	528	495	3,046	0	1	228	**6,125**
Nuclear	-	-	-	-	1,717	53	58	-	-	**1,829**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**2,210**	**63,666**	**24,140**	**1,062**	**65,588**	**3,100**	**10,888**	**16,557**	**228**	**187,438**

Table D - 12 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.1214
NG - Turbine	0.4956
NG - Boiler	0.6531
Oil	1.0374
Hydro	0.0252
Nuclear	0.01365
Other	0

Table D - 13 GHG Emissions Displaced by Hydrogen – P2 Accelerated Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2010 Car	45.6	41.2	16.3	13.5	133.3	81.6	9.9	10.4	5.7	**357**
2010 Truck	36.5	33.0	13.1	10.8	106.7	65.3	7.9	8.3	4.6	**286**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[3] (tonnes of CO_2e)										
2010 Car	13,205	11,938	4,734	3,906	38,615	23,636	2,866	2,999	1,647	**103,547**
2010 Truck	15,316	13,846	5,490	4,531	44,787	27,413	3,324	3,479	1,910	**120,095**
Total	**28,521**	**25,785**	**10,224**	**8,437**	**83,402**	**51,049**	**6,189**	**6,478**	**3,557**	**223,642**

Table D - 14 Net GHG Impact (tonnes of CO_2e) – P2 Accelerated Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2010	**-26,312**	**37,882**	**13,917**	**-7,375**	**-17,814**	**-47,949**	**4,699**	**10,079**	**-3,329**	**-36,204**

Note: negative numbers represent emission reductions

[3] NRCan emission factor = 250.4 tonnes of CO_2e per KM

Table D - 15 Costs – P2 Accelerated Scenario 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2010	$41.83	$49.99	$39.91	$29.33	$37.90	$34.35	$34.15	$34.58	$29.43	**$36.83**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2010	$3,029,856	$3,272,995	$1,036,205	$628,293	$8,026,136	$4,452,537	$536,675	$568,825	$265,865	**$21,817,388**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2010	$2.30	$2.75	$2.20	$1.61	$2.08	$1.89	$1.88	$1.90	$1.62	**$1.82**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2010	$0.037	$0.044	$0.035	$0.026	$0.033	$0.030	$0.030	$0.031	$0.026	**$0.033**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2010	$0.33	$0.40	$0.32	$0.23	$0.30	$0.27	$0.27	$0.28	$0.23	**$0.29**

Table D - 16 GHG Emissions from Hydrogen Electrolysis - P2 Accelerated Scenario 2020 (11.5% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	3,172,172	2,867,830	1,137,120	938,380	9,276,100	5,677,741	688,391	720,472	395,617	**24,873,822**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	56%	53%	2%	17%	0%	16%	75%	0%	
NG - Turbine	11%	41%	40%	0%	32%	10%	19%	21%	12%	
Oil	0%	0%	0%	0%	0%	0%	41%	0%	0%	
Hydro	87%	0%	6%	98%	8%	84%	1%	1%	88%	
Nuclear	0%	0%	0%	0%	42%	3%	22%	0%	0%	
Other	2%	3%	1%	0%	1%	3%	2%	3%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	1,612,293	606,666	20,167	1,617,154	-	107,818	539,285	-	**4,503,382**
NG - Turbine	341,662	1,168,815	450,550	-	2,956,900	573,208	129,078	149,193	48,623	**5,818,029**
Oil	-	-	-	-	6,995	-	280,675	-	-	**287,670**
Hydro	2,756,340	585	71,984	916,642	712,668	4,767,351	6,883	9,814	346,993	**9,589,260**
Nuclear	-	-	-	-	3,861,945	150,870	153,441	-	-	**4,166,256**
Other	74,170	86,137	7,920	1,572	120,439	186,311	10,496	22,181	-	**509,226**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	1,779,246	669,486	22,255	1,784,610	-	118,982	595,128	-	**4,969,707**
NG - Turbine	168,969	578,038	222,819	-	1,462,335	283,480	63,835	73,783	24,047	**2,877,306**
Oil	-	-	-	-	7,110	-	285,278	-	-	**292,388**
Hydro	69,460	15	1,814	23,099	17,959	120,137	173	247	8,744	**241,649**
Nuclear	-	-	-	-	48,661	1,901	1,933	-	-	**52,495**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**238,429**	**2,357,298**	**894,120**	**45,354**	**3,320,674**	**405,518**	**470,203**	**669,158**	**32,791**	**8,433,545**

Table D - 17 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.10355
NG - Turbine	0.49455
NG - Boiler	0.6195
Oil	1.0164
Hydro	0.0252
Nuclear	0.0126
Other	0

Table D - 18 GHG Emissions Displaced by Hydrogen – P2 Accelerated Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2020 Car	3,136.2	2,835.3	1,124.2	927.7	9,170.9	5,613.3	680.6	712.3	391.1	**24,592**
2020 Truck	2,412.2	2,180.7	864.7	713.6	7,053.6	4,317.4	523.5	547.9	300.8	**18,914**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[4] (tonnes of CO_2e)										
2020 Car	844,566	763,537	302,749	249,836	2,469,690	1,511,655	183,279	191,820	105,330	**6,622,463**
2020 Truck	947,921	856,976	339,798	280,410	2,771,920	1,696,644	205,708	215,294	118,220	**7,432,891**
Total	**1,792,487**	**1,620,513**	**642,548**	**530,247**	**5,241,610**	**3,208,299**	**388,986**	**407,114**	**223,550**	**14,055,354**

Table D - 19 Net GHG Impact (tonnes of CO_2e) – P2 Accelerated Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2020	**-1,554,058**	**736,785**	**251,572**	**-484,892**	**-1,920,936**	**-2,802,780**	**81,217**	**262,044**	**-190,759**	**-5,621,808**

Note: negative numbers represent emission reductions

[4] NRCan emission factor = 198.0 tonnes of CO_2e per KM

ICF CONSULTING

Table D - 20 Costs – P2 Accelerated Scenario 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2020	$40.16	$42.55	$36.61	$33.79	$44.38	$39.60	$35.74	$38.16	$34.53	**$38.39**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2020	$127,396,032	$122,018,986	$41,631,085	$31,707,866	$411,640,856	$224,852,721	$24,605,146	$27,493,940	$13,662,227	**$1,025,008,860**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2020	$2.01	$2.13	$1.83	$1.69	$2.22	$1.98	$1.79	$1.91	$1.73	**$1.92**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2020	$0.023	$0.024	$0.021	$0.019	$0.025	$0.023	$0.020	$0.022	$0.020	**$0.022**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2020	$0.22	$0.23	$0.20	$0.19	$0.25	$0.22	$0.20	$0.21	$0.19	**$0.21**

Appendix E Phase 2 Sensitivity Assumptions and Calculation Methodology

This page intentionally blank.

Table E - 1 GHG Emissions from Hydrogen Electrolysis – P2 Incremental High Carbon Price Sensitivity 2010 (0.1% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2010	36,212	32,738	12,981	10,712	105,893	64,815	7,858	8,225	4,516	**283,951**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	9%	0%	0%	3%	0%	0%	4%	0%	
NG - Turbine	0%	84%	90%	0%	13%	0%	42%	81%	0%	
Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Hydro	98%	0%	9%	100%	14%	93%	5%	0%	100%	
Nuclear	0%	0%	0%	0%	68%	3%	47%	0%	0%	
Other	2%	7%	1%	0%	2%	4%	6%	14%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	2,916	-	-	3,007	-	-	321	-	**6,245**
NG - Turbine	-	27,479	11,693	-	13,739	-	3,282	6,696	-	**62,890**
Oil	-	-	-	-	-	-	-	-	-	**-**
Hydro	35,455	83	1,116	10,712	15,136	60,035	393	22	4,516	**127,470**
Nuclear	-	-	-	-	71,777	1,963	3,713	-	-	**77,453**
Other	757	2,260	172	-	2,232	2,817	470	1,186	-	**9,893**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	3,270	-	-	3,372	-	-	360	-	**7,003**
NG - Turbine	-	13,619	5,795	-	6,809	-	1,627	3,318	-	**31,168**
Oil	-	-	-	-	-	-	-	-	-	**-**
Hydro	893	2	28	270	381	1,513	10	1	114	**3,212**
Nuclear	-	-	-	-	980	27	51	-	-	**1,057**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**893**	**16,891**	**5,823**	**270**	**11,543**	**1,540**	**1,687**	**3,679**	**114**	**42,440**

Table E - 2 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.1214
NG - Turbine	0.4956
NG - Boiler	0.6531
Oil	1.0374
Hydro	0.0252
Nuclear	0.01365
Other	0

Table E - 3 GHG Emissions Displaced by Hydrogen – P2 Incremental High Carbon Price Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2010 Car	22.8	20.6	8.2	6.7	66.6	40.8	4.9	5.2	2.8	**179**
2010 Truck	18.2	16.5	6.5	5.4	53.4	32.7	4.0	4.1	2.3	**143**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[1] (tonnes of CO_2e)										
2010 Car	6,603	5,969	2,367	1,953	19,308	11,818	1,433	1,500	823	**51,773**
2010 Truck	7,658	6,923	2,745	2,265	22,393	13,707	1,662	1,739	955	**60,048**
Total	**14,261**	**12,892**	**5,112**	**4,219**	**41,701**	**25,524**	**3,095**	**3,239**	**1,779**	**111,821**

Table E - 4 Net GHG Impact (tonnes of CO_2e) – P2 Incremental High Carbon Price Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2010	**-13,367**	**3,999**	**711**	**-3,949**	**-30,158**	**-23,985**	**-1,407**	**440**	**-1,665**	**-69,381**

Note: negative numbers represent emission reductions

[1] NRCan emission factor = 250.4 tonnes of CO_2e per KM

Table E - 5 Costs – P2 Incremental High Carbon Price Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2010	$43.20	$65.24	$72.73	$30.69	$56.62	$41.91	$49.99	$64.42	$36.78	**$51.29**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2010	$1,564,321	$2,135,819	$944,053	$328,758	$5,995,803	$2,716,530	$392,823	$529,816	$166,113	**$14,774,037**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2010	$2.38	$3.59	$4.00	$1.69	$3.11	$2.31	$2.75	$3.54	$2.02	**$2.82**
Forecast price of Hydrogen per km under P2 Incremental High Carbon Price Sensitivity - 2010 (2000$CAN)										**Average**
2010	$0.038	$0.058	$0.064	$0.027	$0.050	$0.037	$0.044	$0.057	$0.032	**$0.045**
Forecast price of Hydrogen per litre of gasoline equivalent 2010 (2000$CAN)										**Average**
2010	$0.34	$0.52	$0.58	$0.24	$0.45	$0.33	$0.40	$0.51	$0.29	**$0.41**

Table E - 6 GHG Emissions from Hydrogen Electrolysis - P2 Incremental High Carbon Price Sensitivity 2020 (6% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	1,655,047	1,496,259	593,280	489,590	4,839,704	2,962,299	359,160	375,899	206,409	**12,977,646**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	2%	0%	0%	6%	0%	0%	7%	0%	
NG - Turbine	0%	93%	90%	5%	35%	2%	55%	82%	0%	
Oil	0%	0%	0%	0%	0%	0%	2%	0%	0%	
Hydro	97%	0%	9%	95%	8%	87%	6%	2%	100%	
Nuclear	0%	0%	0%	0%	45%	3%	33%	0%	0%	
Other	3%	6%	1%	1%	5%	9%	4%	10%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	23,766	-	-	296,257	-	-	25,196	-	**345,218**
NG - Turbine	-	1,387,425	535,623	23,512	1,713,871	51,823	196,759	307,966	-	**4,216,978**
Oil	-	-	-	-	4,893	-	5,838	-	-	**10,731**
Hydro	1,611,759	710	51,235	462,900	405,924	2,571,830	22,325	6,235	206,212	**5,339,131**
Nuclear	-	-	-	-	2,182,705	81,606	119,162	-	-	**2,383,473**
Other	43,287	84,358	6,422	3,177	236,054	257,041	15,076	36,502	197	**682,115**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	26,227	-	-	326,934	-	-	27,805	-	**380,965**
NG - Turbine	-	686,151	264,892	11,628	847,595	25,629	97,307	152,305	-	**2,085,507**
Oil	-	-	-	-	4,973	-	5,934	-	-	**10,907**
Hydro	40,616	18	1,291	11,665	10,229	64,810	563	157	5,197	**134,546**
Nuclear	-	-	-	-	27,502	1,028	1,501	-	-	**30,032**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**40,616**	**712,396**	**266,183**	**23,293**	**1,217,233**	**91,467**	**105,305**	**180,267**	**5,197**	**2,641,957**

ICF CONSULTING

Table E - 7 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.10355
NG - Turbine	0.49455
NG - Boiler	0.6195
Oil	1.0164
Hydro	0.0252
Nuclear	0.0126
Other	0

Table E - 8 GHG Emissions Displaced by Hydrogen – P2 Incremental High Carbon Price Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2020 Car	1,636.3	1,479.3	586.5	484.0	4,784.8	2,928.7	355.1	371.6	204.1	**12,830**
2020 Truck	1,258.5	1,137.8	451.1	372.3	3,680.2	2,252.6	273.1	285.8	157.0	**9,868**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[2] (tonnes of CO_2e)										
2020 Car	440,643	398,367	157,956	130,349	1,288,534	788,689	95,624	100,080	54,955	**3,455,198**
2020 Truck	494,567	447,118	177,286	146,301	1,446,219	885,206	107,326	112,327	61,680	**3,878,030**
Total	**935,211**	**845,485**	**335,242**	**276,651**	**2,734,753**	**1,673,895**	**202,949**	**212,408**	**116,635**	**7,333,228**

Table E - 9 Net GHG Impact (tonnes of CO_2e) – P2 Incremental High Carbon Price Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2020	**-894,594**	**-133,090**	**-69,059**	**-253,358**	**-1,517,519**	**-1,582,428**	**-97,644**	**-32,141**	**-111,438**	**-4,691,271**

Note: negative numbers represent emission reductions

[2] NRCan emission factor = 198.0 tonnes of CO_2e per KM

ICF CONSULTING

Table E - 10 Costs – P2 Incremental High Carbon Price Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2020	$41.26	$62.87	$66.46	$48.96	$64.96	$50.89	$55.97	$64.67	$45.48	**$55.72**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2020	$68,288,874	$94,066,810	$39,431,747	$23,972,513	$314,389,618	$150,741,050	$20,102,383	$24,307,855	$9,386,849	**$744,687,699**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2020	$2.06	$3.14	$3.32	$2.45	$3.25	$2.54	$2.80	$3.23	$2.27	**$2.79**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2020	$0.024	$0.036	$0.038	$0.028	$0.037	$0.029	$0.032	$0.037	$0.026	**$0.032**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2020	$0.23	$0.35	$0.37	$0.27	$0.36	$0.28	$0.31	$0.36	$0.25	**$0.31**

Table E - 11 GHG Emissions from Hydrogen Electrolysis - P2 Accelerated High Carbon Price Sensitivity 2010 (0.2% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2010	72,425	65,476	25,962	21,424	211,785	129,630	15,717	16,449	9,032	**567,902**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	9%	0%	0%	3%	0%	0%	4%	0%	
NG - Turbine	0%	83%	88%	0%	13%	0%	39%	82%	0%	
Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Hydro	98%	0%	10%	100%	15%	93%	10%	1%	100%	
Nuclear	0%	0%	0%	0%	67%	3%	46%	0%	0%	
Other	2%	7%	1%	0%	2%	4%	6%	14%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	6,176	-	-	5,329	-	-	590	-	**12,095**
NG - Turbine	-	54,672	22,911	-	28,404	-	6,108	13,460	-	**125,555**
Oil	-	-	-	-	-	-	-	-	-	**-**
Hydro	70,957	139	2,712	21,424	32,269	120,023	1,530	134	9,032	**258,221**
Nuclear	-	-	-	-	141,384	3,944	7,171	-	-	**152,499**
Other	1,468	4,490	339	-	4,399	5,663	907	2,265	-	**19,531**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	6,925	-	-	5,976	-	-	662	-	**13,563**
NG - Turbine	-	27,095	11,355	-	14,077	-	3,027	6,671	-	**62,225**
Oil	-	-	-	-	-	-	-	-	-	**-**
Hydro	1,788	3	68	540	813	3,025	39	3	228	**6,507**
Nuclear	-	-	-	-	1,930	54	98	-	-	**2,082**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**1,788**	**34,024**	**11,423**	**540**	**22,797**	**3,078**	**3,164**	**7,336**	**228**	**84,377**

Table E - 12 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.1214
NG - Turbine	0.4956
NG - Boiler	0.6531
Oil	1.0374
Hydro	0.0252
Nuclear	0.01365
Other	0

Table E - 13 GHG Emissions Displaced by Hydrogen – P2 Accelerated High Carbon Price Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2010 Car	45.6	41.2	16.3	13.5	133.3	81.6	9.9	10.4	5.7	**357**
2010 Truck	36.5	33.0	13.1	10.8	106.7	65.3	7.9	8.3	4.6	**286**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[3] (tonnes of CO_2e)										
2010 Car	13,205	11,938	4,734	3,906	38,615	23,636	2,866	2,999	1,647	**103,547**
2010 Truck	15,316	13,846	5,490	4,531	44,787	27,413	3,324	3,479	1,910	**120,095**
Total	**28,521**	**25,785**	**10,224**	**8,437**	**83,402**	**51,049**	**6,189**	**6,478**	**3,557**	**223,642**

Table E - 14 Net GHG Impact (tonnes of CO_2e) – P2 Accelerated High Carbon Price Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2010	**-26,733**	**8,239**	**1,199**	**-7,897**	**-60,605**	**-47,970**	**-3,026**	**858**	**-3,329**	**-139,264**

Note: negative numbers represent emission reductions

[3] NRCan emission factor = 250.4 tonnes of CO_2e per KM

Table E - 15 Costs – P2 Accelerated High Carbon Price Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2010	$43.20	$65.32	$72.71	$30.69	$56.65	$41.94	$49.99	$64.56	$36.81	**$51.32**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2010	$3,128,643	$4,276,713	$1,887,704	$657,516	$11,998,171	$5,437,078	$785,646	$1,061,927	$332,507	**$29,565,905**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2010	$2.38	$3.59	$4.00	$1.69	$3.12	$2.31	$2.75	$3.55	$2.02	**$2.82**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2010	$0.038	$0.058	$0.064	$0.027	$0.050	$0.037	$0.044	$0.057	$0.032	**$0.045**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2010	$0.34	$0.52	$0.58	$0.24	$0.45	$0.33	$0.40	$0.51	$0.29	**$0.41**

Table E - 16 GHG Emissions from Hydrogen Electrolysis - P2 Accelerated High Carbon Price Sensitivity 2020 (11.5% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	3,172,172	2,867,830	1,137,120	938,380	9,276,100	5,677,741	688,391	720,472	395,617	**24,873,822**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	4%	0%	0%	6%	0%	0%	6%	0%	
NG - Turbine	0%	91%	89%	5%	35%	2%	57%	81%	0%	
Oil	0%	0%	0%	0%	0%	0%	1%	0%	0%	
Hydro	98%	0%	10%	94%	9%	86%	5%	3%	100%	
Nuclear	0%	0%	0%	0%	43%	3%	33%	0%	0%	
Other	2%	6%	1%	1%	7%	10%	4%	9%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	106,858	-	-	548,581	-	-	45,748	-	**701,187**
NG - Turbine	-	2,595,689	1,010,963	50,485	3,253,458	93,303	395,667	586,842	-	**8,058,464**
Oil	-	-	-	-	6,647	-	5,083	-	-	**12,656**
Hydro	3,093,029	4,221	114,047	882,001	831,402	4,875,714	32,322	21,648	395,231	**10,255,503**
Nuclear	-	-	-	-	4,016,448	150,466	226,644	-	-	**4,434,833**
Other	79,143	161,062	12,109	5,894	619,564	558,257	28,675	66,235	386	**1,536,546**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	117,923	-	-	605,386	-	-	50,485	-	**773,795**
NG - Turbine	-	1,283,698	499,972	24,967	1,608,998	46,143	195,677	290,223	-	**3,985,313**
Oil	-	-	-	-	6,756	-	5,167	-	-	**12,864**
Hydro	77,944	106	2,874	22,226	20,951	122,868	815	546	9,960	**258,439**
Nuclear	-	-	-	-	50,607	1,896	2,856	-	-	**55,879**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**77,944**	**1,401,727**	**502,846**	**47,194**	**2,292,699**	**170,907**	**204,514**	**341,253**	**9,960**	**5,086,290**

Table E - 17 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.10355
NG - Turbine	0.49455
NG - Boiler	0.6195
Oil	1.0164
Hydro	0.0252
Nuclear	0.0126
Other	0

Table E - 18 GHG Emissions Displaced by Hydrogen – P2 Accelerated High Carbon Price Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2020 Car	3,136.2	2,835.3	1,124.2	927.7	9,170.9	5,613.3	680.6	712.3	391.1	**24,715.5**
2020 Truck	2,412.2	2,180.7	864.7	713.6	7,053.6	4,317.4	523.5	547.9	300.8	**19,009.6**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[4] (tonnes of CO_2e)										
2020 Car	844,566	763,537	302,749	249,836	2,469,690	1,511,655	183,279	191,820	105,330	**6,655,840.6**
2020 Truck	947,921	856,976	339,798	280,410	2,771,920	1,696,644	205,708	215,294	118,220	**7,470,353.3**
Total	**1,792,487**	**1,620,513**	**642,548**	**530,247**	**5,241,610**	**3,208,299**	**388,986**	**407,114**	**223,550**	**14,126,194**

Table E - 19 Net GHG Impact (tonnes of CO_2e) – P2 Accelerated High Carbon Price Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2020	**-1,714,543**	**-218,786**	**-139,702**	**-483,053**	**-2,948,911**	**-3,037,392**	**-184,472**	**-65,861**	**-213,590**	**-9,039,904**

Note: negative numbers represent emission reductions

[4] NRCan emission factor = 198.0 tonnes of CO_2e per KM

Table E - 20 Costs – P2 Accelerated High Carbon Price Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2020	$41.88	$63.10	$67.19	$50.17	$65.32	$51.13	$56.48	$64.70	$45.73	**$56.19**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2020	$132,853,755	$180,961,490	$76,405,907	$47,081,818	$605,887,031	$290,328,425	$38,881,680	$46,612,391	$18,089,573	**$1,437,102,070**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2020	$2.09	$3.16	$3.36	$2.51	$3.27	$2.56	$2.82	$3.23	$2.29	**$2.81**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2020	$0.024	$0.036	$0.038	$0.029	$0.037	$0.029	$0.032	$0.037	$0.026	**$0.032**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2020	$0.23	$0.35	$0.37	$0.28	$0.36	$0.28	$0.31	$0.36	$0.25	**$0.31**

Table E - 21 GHG Emissions from Hydrogen Electrolysis – P2 Incremental Time-of-Day Sensitivity 2010 (0.1% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2010	36,212	32,738	12,981	10,712	105,893	64,815	7,858	8,225	4,516	**283,951**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	74%	69%	2%	22%	0%	15%	80%	0%	
NG - Turbine	1%	19%	12%	0%	7%	0%	10%	9%	0%	
Oil	0%	0%	0%	0%	0%	0%	38%	0%	0%	
Hydro	97%	3%	18%	98%	20%	94%	13%	8%	100%	
Nuclear	0%	0%	0%	0%	50%	3%	22%	0%	0%	
Other	2%	4%	1%	0%	2%	3%	2%	3%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	24,064	8,992	212	23,002	-	1,216	6,548	-	**64,034**
NG - Turbine	451	6,260	1,545	-	6,996	3	822	746	0	**16,824**
Oil	-	55	-	-	92	-	2,984	-	-	**3,132**
Hydro	35,155	1,052	2,325	10,500	21,135	61,100	987	652	4,516	**137,421**
Nuclear	-	-	-	-	53,009	1,660	1,731	-	-	**56,400**
Other	606	1,306	118	-	1,659	2,053	118	279	-	**6,141**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	26,986	10,084	238	25,794	-	1,364	7,343	-	**71,808**
NG - Turbine	224	3,103	766	-	3,467	1	407	370	0	**8,338**
Oil	-	58	-	-	95	-	3,096	-	-	**3,249**
Hydro	886	27	59	265	533	1,540	25	16	114	**3,463**
Nuclear	-	-	-	-	724	23	24	-	-	**770**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**1,109**	**30,172**	**10,908**	**502**	**30,613**	**1,564**	**4,915**	**7,729**	**114**	**87,627**

Table E - 22 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.1214
NG - Turbine	0.4956
NG - Boiler	0.6531
Oil	1.0374
Hydro	0.0252
Nuclear	0.01365
Other	0

Table E - 23 GHG Emissions Displaced by Hydrogen – P2 Incremental Time-of-Day Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2010 Car	22.8	20.6	8.2	6.7	66.6	40.8	4.9	5.2	2.8	**179**
2010 Truck	18.2	16.5	6.5	5.4	53.4	32.7	4.0	4.1	2.3	**143**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[5] (tonnes of CO_2e)										
2010 Car	6,603	5,969	2,367	1,953	19,308	11,818	1,433	1,500	823	**51,773**
2010 Truck	7,658	6,923	2,745	2,265	22,393	13,707	1,662	1,739	955	**60,048**
Total	**14,261**	**12,892**	**5,112**	**4,219**	**41,701**	**25,524**	**3,095**	**3,239**	**1,779**	**111,821**

Table E - 24 Net GHG Impact (tonnes of CO_2e) – P2 Incremental Time-of-Day Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2010	**-13,151**	**17,280**	**5,797**	**-3,716**	**-11,088**	**-23,961**	**1,821**	**4,490**	**-1,665**	**-24,194**

Note: negative numbers represent emission reductions

[5] NRCan emission factor = 250.4 tonnes of CO_2e per KM

Table E - 25 Costs – P2 Incremental Time-of-Day Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2010	$41.83	$49.99	$40.18	$29.33	$38.04	$35.28	$34.30	$34.36	$30.35	**$37.07**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2010	$1,514,928	$1,636,497	$521,523	$314,146	$4,027,840	$2,286,547	$269,556	$282,628	$137,063	**$10,990,728**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2010	$2.30	$2.75	$2.21	$1.61	$2.09	$1.94	$1.89	$1.89	$1.67	**$2.04**
Forecast price of Hydrogen per km - 2010 (2000$CAN)										**Average**
2010	$0.037	$0.044	$0.035	$0.026	$0.034	$0.031	$0.030	$0.030	$0.027	**$0.033**
Forecast price of Hydrogen per litre of gasoline equivalent 2010 (2000$CAN)										**Average**
2010	$0.33	$0.40	$0.32	$0.23	$0.30	$0.28	$0.27	$0.27	$0.24	**$0.30**

Table E - 26 GHG Emissions from Hydrogen Electrolysis - P2 Incremental Time-of-Day Sensitivity 2020 (6% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	1,655,047	1,496,259	593,280	489,590	4,839,704	2,962,299	359,160	375,899	206,409	**12,977,646**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	55%	52%	2%	16%	0%	14%	72%	0%	
NG - Turbine	8%	40%	34%	0%	29%	8%	18%	18%	11%	
Oil	0%	0%	0%	0%	0%	0%	35%	0%	0%	
Hydro	90%	2%	13%	98%	15%	87%	11%	7%	89%	
Nuclear	0%	0%	0%	0%	38%	2%	20%	0%	0%	
Other	2%	3%	1%	0%	1%	3%	1%	3%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	823,320	305,604	9,677	792,961	-	49,994	271,712	-	**2,253,268**
NG - Turbine	137,015	591,563	204,546	-	1,424,021	228,612	65,202	66,894	22,701	**2,740,554**
Oil	-	718	-	-	11,585	-	127,357	-	-	**139,660**
Hydro	1,484,472	35,987	79,100	479,156	728,233	2,577,104	40,590	26,102	183,707	**5,634,451**
Nuclear	-	-	-	-	1,825,769	70,001	71,150	-	-	**1,966,921**
Other	33,559	44,671	4,030	756	57,136	86,582	4,867	11,190	-	**242,792**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	908,575	337,250	10,680	875,072	-	55,171	299,847	-	**2,486,594**
NG - Turbine	67,761	292,557	101,158	-	704,249	113,060	32,246	33,083	11,227	**1,355,341**
Oil	-	730	-	-	11,775	-	129,446	-	-	**141,951**
Hydro	37,409	907	1,993	12,075	18,351	64,943	1,023	658	4,629	**141,988**
Nuclear	-	-	-	-	23,005	882	896	-	-	**24,783**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**105,170**	**1,202,769**	**440,401**	**22,754**	**1,632,452**	**178,885**	**218,782**	**333,588**	**15,856**	**4,150,657**

Table E - 27 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.10355
NG - Turbine	0.49455
NG - Boiler	0.6195
Oil	1.0164
Hydro	0.0252
Nuclear	0.0126
Other	0

Table E - 28 GHG Emissions Displaced by Hydrogen – P2 Incremental Time-of-Day Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2020 Car	1,636.3	1,479.3	586.5	484.0	4,784.8	2,928.7	355.1	371.6	204.1	**12,830**
2020 Truck	1,258.5	1,137.8	451.1	372.3	3,680.2	2,252.6	273.1	285.8	157.0	**9,868**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[6] (tonnes of CO_2e)										
2020 Car	440,643	398,367	157,956	130,349	1,288,534	788,689	95,624	100,080	54,955	**3,455,198**
2020 Truck	494,567	447,118	177,286	146,301	1,446,219	885,206	107,326	112,327	61,680	**3,878,030**
Total	**935,211**	**845,485**	**335,242**	**276,651**	**2,734,753**	**1,673,895**	**202,949**	**212,408**	**116,635**	**7,333,228**

Table E - 29 Net GHG Impact (tonnes of CO_2e) – P2 Incremental Time-of-Day Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2020	**-830,041**	**357,284**	**105,159**	**-253,896**	**-1,102,301**	**-1,495,010**	**15,833**	**121,180**	**-100,778**	**-3,182,571**

Note: negative numbers represent emission reductions

[6] NRCan emission factor = 198.0 tonnes of CO_2e per KM

Table E - 30 Costs – P2 Incremental Time-of-Day Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2020	$39.77	$42.21	$36.78	$33.12	$46.52	$39.42	$35.43	$36.66	$34.35	**$38.25**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2020	$65,826,165	$63,151,855	$21,821,720	$16,216,923	$225,121,270	$116,763,475	$12,726,128	$13,779,501	$7,089,726	**$542,496,764**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2020	$1.99	$2.11	$1.84	$1.66	$2.33	$1.97	$1.77	$1.83	$1.72	**$1.91**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2020	$0.023	$0.024	$0.021	$0.019	$0.027	$0.023	$0.020	$0.021	$0.020	**$0.022**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2020	$0.22	$0.23	$0.20	$0.18	$0.26	$0.22	$0.20	$0.20	$0.19	**$0.21**

Table E - 31 GHG Emissions from Hydrogen Electrolysis - P2 Accelerated Time-of-Day Sensitivity 2010 (0.2% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2010	72,425	65,476	25,962	21,424	211,785	129,630	15,717	16,449	9,032	**567,902**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	74%	69%	2%	22%	0%	15%	79%	0%	
NG - Turbine	1%	19%	12%	0%	7%	0%	10%	9%	0%	
Oil	0%	0%	0%	0%	0%	0%	38%	0%	0%	
Hydro	97%	3%	18%	98%	20%	94%	13%	8%	100%	
Nuclear	0%	0%	0%	0%	50%	3%	22%	0%	0%	
Other	2%	4%	1%	0%	2%	3%	2%	3%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	48,321	18,000	424	45,982	-	2,435	13,067	-	**128,230**
NG - Turbine	961	12,308	3,071	-	14,503	6	1,626	1,521	0	**33,997**
Oil	-	111	-	-	165	-	5,976	-	-	**6,253**
Hydro	70,252	2,112	4,654	21,000	42,138	122,199	1,977	1,303	9,032	**274,667**
Nuclear	-	-	-	-	105,690	3,319	3,465	-	-	**112,474**
Other	1,212	2,623	237	-	3,307	4,106	237	558	-	**12,281**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	54,188	20,185	476	51,564	-	2,730	14,654	-	**143,797**
NG - Turbine	476	6,100	1,522	-	7,188	3	806	754	0	**16,849**
Oil	-	116	-	-	172	-	6,200	-	-	**6,487**
Hydro	1,770	53	117	529	1,062	3,079	50	33	228	**6,922**
Nuclear	-	-	-	-	1,443	45	47	-	-	**1,535**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**2,247**	**60,456**	**21,825**	**1,005**	**61,428**	**3,128**	**9,834**	**15,440**	**228**	**175,590**

Table E - 32 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.1214
NG - Turbine	0.4956
NG - Boiler	0.6531
Oil	1.0374
Hydro	0.0252
Nuclear	0.01365
Other	0

Table E - 33 GHG Emissions Displaced by Hydrogen – P2 Accelerated Time-of-Day Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2010 Car	45.6	41.2	16.3	13.5	133.3	81.6	9.9	10.4	5.7	**357**
2010 Truck	36.5	33.0	13.1	10.8	106.7	65.3	7.9	8.3	4.6	**286**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[7] (tonnes of CO_2e)										
2010 Car	13,205	11,938	4,734	3,906	38,615	23,636	2,866	2,999	1,647	**103,547**
2010 Truck	15,316	13,846	5,490	4,531	44,787	27,413	3,324	3,479	1,910	**120,095**
Total	**28,521**	**25,785**	**10,224**	**8,437**	**83,402**	**51,049**	**6,189**	**6,478**	**3,557**	**223,642**

Table E - 34 Net GHG Impact (tonnes of CO_2e) – P2 Accelerated Time-of-Day Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2010	**-26,274**	**34,671**	**11,601**	**-7,432**	**-21,974**	**-47,921**	**3,644**	**8,962**	**-3,329**	**-48,052**

Note: negative numbers represent emission reductions

[7] NRCan emission factor = 250.4 tonnes of CO_2e per KM

Table E - 35 Costs – P2 Accelerated Time-of-Day Sensitivity 2010

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2010	$41.83	$49.99	$39.57	$29.33	$37.91	$34.36	$34.30	$34.36	$29.45	**$36.79**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2010	$3,029,856	$3,272,995	$1,027,352	$628,293	$8,029,419	$4,454,546	$539,112	$565,256	$266,005	**$21,812,834**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2010	$2.30	$2.75	$2.18	$1.61	$2.09	$1.89	$1.89	$1.89	$1.62	**$2.02**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2010	$0.037	$0.044	$0.035	$0.026	$0.033	$0.030	$0.030	$0.030	$0.026	**$0.032**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2010	$0.33	$0.40	$0.32	$0.23	$0.30	$0.27	$0.27	$0.27	$0.23	**$0.29**

Table E - 36 GHG Emissions from Hydrogen Electrolysis - P2 Accelerated Time-of-Day Sensitivity 2020 (11.5% Penetration)

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
Electricity Required to meet Hydrogen Demand (MWh)										
2020	3,172,172	2,867,830	1,137,120	938,380	9,276,100	5,677,741	688,391	720,472	395,617	**24,873,822**
IPM Output - Dispatch by Fuel Type Required to meet Increased Electricity Demand (% of base segment)										
Coal	0%	54%	51%	2%	16%	0%	13%	75%	0%	
NG - Turbine	8%	41%	35%	0%	30%	7%	21%	15%	16%	
Oil	0%	0%	0%	0%	0%	0%	35%	0%	0%	
Hydro	90%	2%	13%	98%	15%	88%	11%	7%	84%	
Nuclear	0%	0%	0%	0%	37%	2%	19%	0%	0%	
Other	2%	3%	1%	0%	1%	3%	1%	3%	0%	
Dispatch by Fuel Type, Calculated from IPM Dispatch Output, Required to meet Increased Electricity Demand (MWh)										
Coal	-	1,551,625	585,490	21,827	1,513,849	-	90,786	539,953	-	**4,303,531**
NG - Turbine	253,971	1,162,830	392,547	-	2,772,754	392,221	145,019	106,410	63,375	**5,289,126**
Oil	-	1,353	-	-	22,039	-	240,836	-	-	**264,228**
Hydro	2,853,688	67,821	151,370	915,109	1,385,398	4,982,769	73,708	51,871	332,242	**10,813,977**
Nuclear	-	-	-	-	3,473,366	135,346	129,204	-	-	**3,737,915**
Other	64,513	84,200	7,712	1,444	108,694	167,405	8,838	22,237	-	**465,045**
GHG Emissions by Fuel Type, based on NRCan Emission Factors, Associated with Increased Electricity Demand (tonnes of CO_2e)										
Coal	-	1,712,296	646,118	24,087	1,670,608	-	100,187	595,865	-	**4,749,162**
NG - Turbine	125,601	575,077	194,134	-	1,371,265	193,973	71,719	52,625	31,342	**2,615,737**
Oil	-	1,376	-	-	22,401	-	244,785	-	-	**268,562**
Hydro	71,913	1,709	3,815	23,061	34,912	125,566	1,857	1,307	8,372	**272,512**
Nuclear	-	-	-	-	43,764	1,705	1,628	-	-	**47,098**
Other	-	-	-	-	-	-	-	-	-	**-**
TOTAL EMISSIONS	**197,514**	**2,290,458**	**844,067**	**47,148**	**3,142,951**	**321,244**	**420,177**	**649,798**	**39,715**	**7,953,071**

Table E - 37 NRCan Emission Factors

Fuel Type	Emission Factor (tonnes CO_2e/MWh delivered)
Coal	1.10355
NG - Turbine	0.49455
NG - Boiler	0.6195
Oil	1.0164
Hydro	0.0252
Nuclear	0.0126
Other	0

Table E - 38 GHG Emissions Displaced by Hydrogen – P2 Accelerated Time-of-Day Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
LDV (gasoline powered) Kilometers Displaced by Hydrogen (million kilometers)										
2020 Car	3,136.2	2,835.3	1,124.2	927.7	9,170.9	5,613.3	680.6	712.3	391.1	**24,592**
2020 Truck	2,412.2	2,180.7	864.7	713.6	7,053.6	4,317.4	523.5	547.9	300.8	**18,914**
TOTAL DISPLACEMENT - GHG Emissions Associated with LDV Gasoline Usage Displaced by Hydrogen, based on NRCan Emission Factor[8] (tonnes of CO_2e)										
2020 Car	844,566	763,537	302,749	249,836	2,469,690	1,511,655	183,279	191,820	105,330	**6,622,463**
2020 Truck	947,921	856,976	339,798	280,410	2,771,920	1,696,644	205,708	215,294	118,220	**7,432,891**
Total	**1,792,487**	**1,620,513**	**642,548**	**530,247**	**5,241,610**	**3,208,299**	**388,986**	**407,114**	**223,550**	**14,055,354**

Table E - 39 Net GHG Impact (tonnes of CO_2e) – P2 Accelerated Time-of-Day Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	Total
2020	**-1,594,973**	**669,945**	**201,519**	**-483,099**	**-2,098,659**	**-2,887,055**	**31,191**	**242,683**	**-183,835**	**-6,102,283**

Note: negative numbers represent emission reductions

[8] NRCan emission factor = 198.0 tonnes of CO_2e per KM

Table E - 40 Costs – P2 Accelerated Time-of-Day Sensitivity 2020

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	Nova Scotia	Newfoundland	
Forecast price of electricity required to meet increased electricity demand (2000$CAN/MWh)										**Average**
2020	$40.18	$42.53	$37.57	$33.79	$51.75	$41.15	$36.63	$38.66	$36.04	**$39.81**
Forecast price of electricity required to meet increased electricity demand (2000$CAN)										**Total**
2020	$127,445,201	$121,974,534	$42,723,857	$31,707,866	$480,079,923	$233,653,219	$25,213,340	$27,851,294	$14,257,036	**$1,104,906,270**
Forecast price per kg of Hydrogen (2000$CAN)										**Average**
2020	$2.01	$2.13	$1.88	$1.69	$2.59	$2.06	$1.83	$1.93	$1.80	**$1.99**
Forecast price of Hydrogen per km (2000$CAN)										**Average**
2020	$0.023	$0.024	$0.021	$0.019	$0.030	$0.024	$0.021	$0.022	$0.021	**$0.023**
Forecast price of Hydrogen per litre of gasoline equivalent (2000$CAN)										**Average**
2020	$0.22	$0.23	$0.21	$0.19	$0.29	$0.23	$0.20	$0.21	$0.20	**$0.22**

Appendix F Hydrogen Model Input for Phase 1 and 2

This page intentionally blank.

Hydrogen Model Input for Phase 1

Note: Numbers may not match due to rounding.

Vehicle Kilometres Forecasts

Information *(A)* provided by NRCan	**Car Gasoline Usage (million litres of gasoline equivalent)**	
	Year	**Total Gas (million L)**
	2000	36,860
	2010	41,280
	2020	33,920
Information (*B*) provided by Greening the Pump	**Car Kilometers per Litre**	
	Year	**Efficiency (L/100 km)**
	2000	8.18
	2010	8.1
	2020	6.5
Calculation *D = A x B*	**Total Car Kilometers**	
	Year	**Total 1,000,000 km**
	2000	450,611
	2010	509,630
	2020	521,846

Hydrogen Consumption Forecasts

Information *(F)* provided by NRCan	**Mass of Hydrogen required to meet demand associated with displaced gasoline (tonnes H_2 / 1,000,000 km)**	
	Year	**tonnes H_2 / 1,000,000 km**
	2010	12
	2020	10
Calculation *(G) = D x F*	**Mass of Hydrogen**	
	Year	**H_2 (tonnes)**
	2010	6,115,556
	2020	5,218,462

Electricity Consumption Forecasts

Calculation	**Electricity required to meet Hydrogen demand (MWh)**	
***(H)* = *G* x 46.80 MWh/tonne (information on the amount of electricity required per tonne of H_2 provided by NRCan**	**Year**	**MWh**
	2010	286,208,000
	2020	244,224,000

The above numbers are national. The penetration rates and regional percentages as shown in Figure 2-1 are then applied.

Hydrogen Model Input for Phase 2

Note: Numbers may not match due to rounding.

Vehicle Kilometres Forecasts

	Total Number of LDVs by type per year			
Information *(A)* provided by NRCan	**LDV Type**	**Car (number)**	**Truck (number)**	**Total (number)**
	2010	9,956,000	7,755,000	17,711,000
	2020	11,579,000	8,927,000	20,506,000
	Kilometers driven per LDV by type per year			
Information *(B)* provided by NRCan	**LDV Type**	**Car (kms/LDV)**	**Truck (kms/LDV)**	
	2010	18,038	18,542	
	2020	18,561	18,517	
	Total Kilometers driven by LDV type per year			
Calculation *(C) = A x B*	**LDV Type**	**Car (kms)**	**Truck (kms)**	**Total (kms)**
	2000	-	-	-
	2010	179,586,328,000	143,793,210,000	323,379,538,000
	2020	14,917,819,000	165,301,259,000	380,219,078,000

Fuel Consumption Forecasts

	Fuel consumption (L of gasoline) by LDV type per km per year			
Information *(D)* provided by NRCan	**LDV Type**	**Car (L/km)**	**Truck (L/km)**	
	2010	0.093	0.133	
	2020	0.087	0.125	
	Total Fuel consumption (thousand L of gasoline) by LDV type per year			
Calculation *(E)* = C x *D*	**LDV Type**	**Car (1000L)**	**Truck (1000L)**	**Total (1000L)**
	2010	16,701,529	19,124,497	35,826,025
	2020	18,697,850	20,662,657	39,360,508

Hydrogen Cosumption Forecasts

	Hydrogen consumption (kg) by LDV type per 100km per year			
Information *(F)* provided by NRCan	**LDV Type**	**Car (kg H_2/100km)**	**Truck (kg H_2/100km)**	
	2010	1.400	1.860	
	2020	1.000	1.330	
	Total Hydrogen consumption (tonne) by LDV type per year (assuming 100% H_2 adoption)			
Calculation *(G)* = C x *F*	**LDV Type**	**Car (tonne H_2)**	**Truck (tonne H_2)**	**Total (tonne H_2)**
	2010	2,514,209	2,674,554	5,188,762
	2020	2,149,178	2,198,507	4,347,685

Electricity Consumption Forecasts

Information *(H)* provided by NRCan	**Electricty required to meet hydrogen demand (MWhr/Tonne H_2) per year**			
	LDV Type	**Car (MWh/Tonne H_2)**	**Truck (MWh/Tonne H_2)**	
	2010	55.0	55.0	
	2020	50.0	50.0	
Calculation *(J)* = G *x H*	**Total Additional Electricty demand (MWh) by LDV type per year (assuming 100% H_2 adoption)**			
	LDV Type	**Car (tonne H_2)**	**Truck (tonne H_2)**	**Total (tonne H_2)**
	2010	138,281,473	147,100,454	285,381,926
	2020	107,458,910	109,925,337	217,384,247

The above numbers are national. The penetration rates and regional percentages as shown in Figure 2-1 are then applied.