Arctic Development Library

Canada's Energy Outlook - 1992 - 2020
Type of Study: Analysis/review
Mining/oil/energy, Energy General
Date of Report: 1993
Author: Canada - Natural Resources
Catalogue Number: 6-5-23

2020

CANADA'S ENERGY OUTIOOK

1992

Natural Resources Resources naturelles
Canada Canada

Canada

1992 2020

CANADA'S ENERGY OUTIOOK

Working Paper

Prepared By

Energy and Fiscal Analysis Division
Economic and Financial Analysis Branch
Energy Sector

September 1993

Natural Resources Canada
Ressources naturelles Canada

Canada

TABLE OF CONTENTS

PREFACE

This study provides a long term outlook for energy demand and supply in Canada, and for related greenhouse gas emissions. While not an official forecast by Natural Resources Canada (NRCan), it is a considered view of the evolution of energy markets in Canada over the next three decades. It should be emphasized that the projection is a reference scenario in that current federal and provincial energy and related policies are held constant over the period under consideration,

Within NRCan, the outlook serves a number of purposes. First, it provides a focal point for assembling the views of the department on energy matters within a consistent framework. Second, the outlook identifies pressure points and emerging issues in Canadian energy markets. And finally, it is used to assess the need for, and the form of policies to address such issues. It is for the same reasons that the outlook is also offered to analysts, policy makers and interested parties outside of NRCan. It is hoped that the analysis and projections will contribute to an informed public discussion of energy and related environmental issues.

In its role of assembling views within the department, the outlook has benefited considerably from the input of other branches and sectors. We would particularly like to thank our colleagues in the Energy Policy, Efficiency and Alternative Energy, Oil and Gas, and Electricity Branches, the Office of Energ y Research and Development and the Coal and Ferrous Division for their significant contributions to the anal ysis. We also are grateful for the comments received during presentations to the Department's Executive Committee, to the Deputy Minister's Advisory Committee on CANMET, to the Minister's National Advisory Council to CANMET and to the Minister's National Industrial Advisory Committee to the Geological Survey of Canada.

Given the variety and complexity of the issues covered in this outlook we have attempted to consult very widely with experts in the public and private sectors. Some of the organizations to which we have made presentations and solicited views include: Environment Canada, External Affairs and International Trade Canada and the National Energy Board within the federal government; the energy departments of Alberta, Ontario and Quebec and Alberta's Energy Resources Conservation Board and Oil Sands Technology Research Authority (AOSTRA); Ontario Hydro, Hydro Québec and, more informally, other utilities; industry associations such as CPA and IPAC (now combined as the Canadian Association of Petroleum Producers - CAPP), the Canadian Gas Association and the Coal Association of Canada; and companies such as TransCanada Pipelines Ltd. and Petro-Canada. While these organizations were not in total agreement with the views presented in this document, their assistance was very valuable and their comments caused us, in many cases, to revise our views. We are grateful for the input of these groups and acknowledge that any remaining errors of omission and interpretation are our responsibility.

Canada's Energy Outlook is a product of the talents and work of a team of analysts within the Energy and Fiscal Analysis Division. The credit for the successful completion of this long and complex undertaking belongs to Al Coombs, Ram Sahi, and Alan Webster who supervised the analysis, to Jai Persaud who coordinated the drafting and production of the document and to the other members of the team - Michel Bérubé, Julia Brown, Erik Brunet, Joycelyn Exeter, Wally Geekie, Hertsel Labib, Cristobal Miller, Louis Theriault, Co Tran and Hy-Hiên Tran - who made invaluable contributions to the study and to the many presentations of its results.

As noted earlier, this document has been produced to stimulate discussion of energy issues. In that context, we would be pleased to receive questions, comments or requests for further information. Please write, fax or telephone me at the address below. We are also most interested in ascertaining your views on the document as to its usefulness to your work, its scope, and the timeliness and quality of the analysis. For this purpose, a short questionnaire is enclosed.

Neil McIlveen
Director
Energy and Fiscal Analysis Division
Economic and Financial Analysis Branch
Natural Resources Canada
580 Booth Street
Ottawa, Ontario
KIA 0E4
Tel: 613995-8762
Fax: 613996-7837

— EXECUTIVE SUMMARY

The paper provides a reference outlook for energy demand and supply, and for energy related emissions of the principal greenhouse gases over the next three decades. The outlook has been developed based on extensive consultations with experts in the private and public sectors and a careful examination of the relationships between energy consumption and production and price, economic, demographic and technological factors. It should be noted that the outlook is not a forecast, in the strict sense of that term, since one important set of variables - the energy and related policies of the federal and provincial governments - is held constant throughout the projection period. It should also be recognized that the view presented in this document is only one of many possible energy scenarios for Canada. It is, in effect, a judgement of what might happen under a set of plausible assumptions about the future. Obviously, also, the outlook results are more reliable in the shorter to mid-term rather than in the longer term given the difficulty of envisioning specific changes in technology over such a span of time.

For the reasons outlined above, the results should not be construed as the official forecast of either Natural Resources Canada or the Government of Canada. Indeed, the outlook has been developed to identify pressure points and facilitate the analysis of alternative assumptions and policy initiatives. In order to supplement the reference case projection, various impact analyses are carried out to gauge the consequences of different price and macroeconomic assumptions on the reference case results.

Framework Assumptions

Chapter 2 presents the assumptions concerning energy prices, the macroeconomy, climate and policy which provide the framework for the projections. The most important of these framework assumptions include:

- World oil prices (WTI at Cushing in US$ 199 1/bbl) remain in the $20-22 range until 1995, then rise slowly to $24 by 2005 and remain constant thereafter. The outlook assumes that world oil demand will grow by about only 170 per year due to continuing substitution to natural gas, efficiency improvements and environmental initiatives. Non-OPEC supply is expected to remain fairly stable over the outlook period, with declines in U.S. production being offset by increases from other parts of the world including the former USSR in the late 1990s. OPEC capacity is expected to show major increases in the next 10-15 years, to 40 MMB/D by 2005, thus comfortably exceeding the call on OPEC of about 32 MMB/D.

- Canadian plant-gate natural gas prices (in 1991 C$) increase to $2.00/mcf by 2000 and $3.00/mcf by 2020. These prices reflect a significant North American resource base characterized by a relatively flat supply curve.

- Electricity prices incorporate announced prices until 1994, are flat until about 2005, then increase by 170 real per year, thereafter. This projection reflects the current excess capacity situation of the electricity industry and the consequent absence of need to construct new plants.

- Coal and uranium prices remain flat in real terms reflect] ng a significant availability of supply.

- The Canadian economy grows at an annual average rate of 2.5% implying a doubling of

Canada's gross domestic product by 2020. In contrast to the trend in the 1970s and 1980s, growth in the service sector is expected to lag that of the industrial sector. The macroeconomic outlook also assumes a population growth rate of 1 %, due mainly to immigration, and an inflation rate of 2.9% per year over the projection period.

- The reference case results assume that the current federal and provincial energy and related policies prevail over the entire projection period. This is referred to as the "business as usual" assumption. Government policies currently in the process of being established are included under business as usual depending on the degree to which sufficient information is available as to their tangible expression. Thus, judgments are made concerning the likely scope of federal energy efficienc y programs as well as related provincial initiatives. The Canada-U. S. Air Quality Agreement (March 199 1) has also been incorporated despite the fact that the sulphur dioxide (SO_2) cap for the Western provinces has yet to be determined. However, the initiatives to achieve the greenhouse gas stabilization commitment are not judged to be sufficiently far advanced, in terms of legislation and regulation, to be included under business as usual.

Energy Demand

Chapter 3 provides projections of secondary energy demand for the four principal energy-using sectors: residential. commercial, industrial and transportation Plus non-combustion energy use (e.g., petrochemical feedstocks) and consumption by energy producing industries. The latter two, when combined with secondary use, provide estimates of total primary energy demand. The long term energy demand projections by sector and province were developed using the econometric Inter-Fuel Substitution Demand (IFSD) model and process/end-use models. Highlights of the demand projections include:

- Total secondary energy demand will be 16% higher in 2000 and 61% higher in 2020 than in 1991.
- Energy demand in the industrial sector grows the fastest because of strong industrial growth. Its share of total secondary energy demand increases from 37% in 1991 to 42% in 2020.
- The residential sector experiences the weakest growth, due largely to slower household growth and the impact of energy efficiency programs and regulations. The share for this sector drops from 22% in 1991 to 17% by 2020,
- The shares for both the transportation and commercial sectors remain relatively constant over the entire outlook period.
- Alternative fuels make only modest inroads into the transportation sector.
- The shares of the major fuels in secondary demand do not change appreciably over the long term reflecting modest changes in relative end-use energy prices over the outlook period.
- Energy intensity is projected to decline by O. 8% per year. The declines in energy intensity are considerably less than those experienced in the 1980s. This is due to modest energy price increases and a reduction in government spending on energy conservation and substitution programs compared to the 1980s.

Energy Supply

Chapter 4 presents the outlook with respect to oil and natural gas supply; electricity generation and the related capacity expansions; and coal supply and demand. Major results of the projections are noted below:

Oil and Gas

- The oil and gas industry will reduce its domestic reinvestment of cashflow from 80-85 percent historically to 70-75 percent during the projection period. This reduction reflects industry restructuring and increased international investment. Nonetheless, oil and gas investment, over the long term, will increase from the current level of about $5.6 billion (real 1991$) to an average of $12 billion per year in the last decade of the projection.

- Total crude oil production falls from 1 734 rob/d in 1992 to 1585 rob/d in 1995 but rebounds to 1 740 rob/d by 2020. The reduction in the 1990s is due to the decline in western conventional oil. Over the long term, this decline will be more than offset by production from the frontier and oil sands.

- Canada remains a net oil exporter until 2008. Thereafter, net oil imports increase to 385 rob/d, or 18% of total demand by 2020. Over the projection period, Canada continues to export about 75% of its total heavy oil production. By 2020, Canada's heavy oil exports will be 425 rob/d while light net oil imports will be 810 rob/d.

- Total natural gas demand increases by 50% from the current level of 4.0 Tcf to 6.1 Tcf by 2020. Domestic demand increases from the current level of about 2 Tcf to 3.4 Tcf in 2020. Gas exports increase from about 2 Tcf in 1992 to 2.7 Tcf by 2001 and remain at this level for the rest of the period. The U.S. West Coast and the Northeast markets are likely to account for most of the increase in exports.

Electricity

- Electricity demand in Canada is projected to increase at an annual average rate of 1.5% for the next three decades or half the rate experienced in the 1980s. As a consequence, the current excess generating capacity being experienced by most provincial utility systems is projected to last until 2000 to 2005. It is only after this point that significant new generating capacity will be required. Over the thirty year period, Canada will continue to depend on conventional sources of electricity supply such as hydro, coal and nuclear to meet its growing electricity demand.

Coal

- Canadian domestic supply increases from 65 megatonnes in 1992 to 111 megatonnes by 2020, reflecting modest increases in both domestic and export demand. Approximately 60% of this production will be used in domestic coal fired electricity generation.

Greenhouse Gas Emissions

Chapter 5 outlines the projections for energy related greenhouse gas (GHG) emissions. Energy consumption is the chief source of GHG in Canada accounting for 78% of total emissions or about 91% excluding chloroflourocarbons (CFCs). Canada has committed to stabilizing non-CFC gas emissions at 1990 levels by the year 2000. As CO_2 is the largest energy related GHG, the study focusses on trends in emissions of this gas. Highlights of the analysis include:

- CO_2 emissions increase from 461 megatonnes in 1990 to 510 in 2000 and 716 in 2020. The growth over the 1990s is 1% compared to 1.79o per year after 2000 partly reflecting an expanded use of coal for electricity generation in the latter period. Over the entire 1992-2020 period, $C0_2$ emissions from natural gas grow at 1.8 percent annually compared to 1.5 percent for coal and 1.2 percent for oil.

- Electricity generation, and the transportation and industrial sectors will account for most of the increase in CO_2 emissions over the next three decades. By contrast, CO_2 emissions by the residential and commercial sectors increase modestly, reflecting slower population and household growth and improvements in energy efficiency. On a provincial basis, Ontario and the Prairies are expected to continue to account for most of the CO_2 emissions in Canada over the projection period.

- The "gap", of approximately 50 megatonnes, behveen the 2000 and 1990 emission levels is extremely sensitive to changes in underlying assumptions. A 1 % change in total emissions in 2000, will generate a 10% change in the "gap". Modest changes in energy prices and macro assumptions thus have a significant impact on the size of the "gap".

- Although only a partial analysis of GHG emissions (i.e., non-energy related emissions are not included), the results suggest that additional measures will probably be required to attain the stabilization goal by 2000. Maintaining stabilization beyond 2000 would appear to pose a major challenge and require significant technological, structural and life style changes.

Impact Analysis

Chapter 6 provides an assessment of the impacts for demand, supply and CO_2 emissions under alternate assumptions for price, macroeconomic and industrial structure variables. The reference case projection over the medium term (up to 2000) is only moderately altered by changes in key variables. Over the longer term, however, the impact is, in some cases, quite sizeable. Key highlights are:

A $5/bbl increase in oil prices or a 20% increase in electricity prices results in a reduction of about 3 % in energy demand as compared to reference case levels. In the oil price increase case, crude oil supply grows by almost 30% by 2020, and in the electricity price increase case, electricity generation decreases by about 12%.

Higher annual economic growth of 1 percentage point above the reference scenario level leads to a significant increase in energy demand - 4.2% in 2000 and 22.5% in 2020.

Assuming a stronger growth in services relative to industry, but the same total economic output, results in lower secondary energy demand of 2.870 in 2000 and 9.4% in 2020. Industrial energy demand is down by 26% in 2020 while commercial demand is up by 18%.

1. INTRODUCTION

The art of prophecy is very difficult
- especially with respect to the future
Mark Twain

The objective of this paper is to provide a reference outlook for energy demand and supply, and for energy related emissions of the principal greenhouse gases over the next three decades. The outlook has been developed based on extensive consultations with experts in the private and public sectors and a careful examination of the relationships between energy consumption and production and price, economic, demographic and technological factors. It should be noted that the outlook is not a forecast, in the strict sense of that term, since one important set of variables - the energy and related policies of the federal and provincial governments - is held constant throughout the projection period. It should also be recognized that the view presented in this document is only one of many possible energy scenarios for Canada. It is, in effect, a judgement of what might happen under a set of plausible assumptions about the future. Obviously, also, the outlook results are more reliable in the shorter to mid-term rather than in the longer term given the difficulty of envisioning specific changes in technology over such a span of time. For the reasons outlined above, the results should not be construed as the official forecast of either Natural Resources Canada or the Government of Canada. Indeed, the outlook has been developed to identify pressure points and facilitate the analysis of alternative assumptions and policy initiatives.

This paper not only constitutes a significant update of the last EMR projection, contained in a paper entitled "2020 VISION" published in January 1990[1], but it also represents a considerable expansion and enhancement of the earlier effort in several areas. First, reflecting increasing concern about the relationship between energy use and the environment, the study provides projections of energy-related emissions of the principal greenhouse gases - carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N, O). Second, the current analysis incorporates many important methodological advances. The specifications for energy demand in the industrial sector, for example, have been restructured to focus more precisely on trends in particular industries. More generally, the forecasting exercise also makes use of process/end-use models to ensure that the econometric results reflect technological and regulator y realities. Third, reflecting the greater amount of information now available, views are explicitly incorporated concerning the prospects for alternate transportation fuels, and for non-utility generation (NUG) and demand-side management (DSM) programs in the electricity sector.

The current study also differs importantly from its predecessor in that only one scenario is presented. The decision to proceed with only one case is due, in part, to the greater consensus, in the aftermath of the Gulf War, on world oil prices, the variable on which alternate scenarios are generally constructed, However, it is important for the reader to understand the implications for changing different assumptions. Accordingly, the paper also includes projections for energy supply and demand and emissions under different hypotheses for major variables such as oil prices and economic growth.

---

[1] Energy, Mines and Resources Canada, "2020 VISION: Canada's Long Term Energy Outlook 1988-2020", Energy and Fiscal Analysis Division, Economic and Financial Analysis Branch, Winter 1990.

The paper is organized as follows:

- Chapter 2 provides the major framework assumptions used in the subsequent analysis. Included are our assumptions on such important variables as world oil prices, North American natural gas prices and Canadian macroeconomic, demographic and climatic trends over the next thirty years. Also included in this section is a discussion of what constitutes the current policy framework.

- Chapter 3 provides projections of secondary energy demand for the four principal energy consuming sectors: residential, commercial, industrial and transportation plus non-combustion energy use (e.g., petrochemical feedstocks) and consumption by energy producing industries - and a summary of aggregate results for secondary and primary energy.

- Chapter 4 presents the outlook for oil and natural gas supply, electricity generation and related capacity expansions and coal supply and demand.

- Chapter 5 outlines the projections for energy related greenhouse gas emissions, concentrating on carbon dioxide.

- Chapter 6 offers several impact analyses obtained by varying important assumptions such as world oil prices, economic growth and industrial structure.

Statistical appendices are also included in the paper providing detailed results at the Canada level for the reference scenario and summaries for the various impact analyses. Full reference case results, at the national and regional levels, are available in diskette form, on request.

2. FRAMEWORK ASSUMPTIONS

The levels and composition of energy demand and supply are heavily influenced by many factors which are external to domestic energy markets. Among the most important are fossil fuel prices, which, in a deregulated pricing environment are largely determined in international or, at least, in North American markets. Energy consumption, in particular, is also significantly influenced by demographic trends, macroeconomic performance, and the structure of the Canadian economy. Recent concern regarding global warming suggests that, over a period of thirty years, climate may also change, and that such a change may influence energy use. According y, the projection incorporates rough estimates of temperature changes over the period. Finally, government energy and related policies will influence energy consumption and production decisions. Even though in this analysis government policy is held constant, it is important to specify carefully the parameters of current policy.

Collectively, these factors - international energy prices, demography, economics, climate and policy - constitute the framework within which future energy demand and supply in Canada are analyzed. The assumptions used to construct this framework are described in the remainder of this chapter.

2.1 World Oil Prices

Since the Gulf War, international oil prices have remained relatively stable in the US$20 per barrel range. As shown in Table 2.1.1, most forecasters anticipate only modest increases from this level over the next two decades. Reflecting these views and our own internal analysis, the assumption underlying the projections in this document is that world oil prices will, on average, remain in the US$20-22 range until 1995, subsequently rise slowly to US$24 by 2005 and remain constant thereafter (all prices are expressed in 1991 US$ and refer to the marker crude West Texas Intermediate (WTI) delivered to Cushing, Oklahoma).

This assumed trend is based on a number of considerations. First, world oil demand is expected to grow about 1 % per year, being constrained by continuing substitution to natural gas, efficienc y improvements in energy consumption and environmental initiatives. The growth in oil demand in industrialized countries is expected to be slightly below 1 %, while in developing countries it is expected to be stronger due to increased urbanization and transportation

Table 2.1.1
Oil Price Projections
WTI at Cushing
(1991 US$/bbl)

	1995	2000	2005	2010
Chevron	17-28 from 1990 to 2005			
Royal Dutch Shell	20-25 from 1990 to 2005			
PEL	20	21	21	21
PIRA	21	23	23	
IEA	21	26	29	29
US DOE - REF.	20	23	26	29
CERI	23	23	25	
NEB	22	24	26	28
NRCan	21	23	24	24

Sources: Chevron & Royal Dutch Shell - Recent Company Reports.
PEL, Petroleum Economics *Ltd* Presentation *at NRCan*, March 29, 1993.
PIRA, Petroleum Industry Research Associates, Presentation *at NRCan, February* 22.1993.
IEA, *World* Energy Outlook *to* 2010, Spring 1993.
U.S. DOE, Energy Outlook. *January* 1993.
CERI, Challenging OPEC: World Oil Market Projections, 1992-2007, July 1992.
NEB, *Canadian Energy* Supply and Demand, 1990-2010, June 1991.

-— fuel-requirements, and rapid population growth.

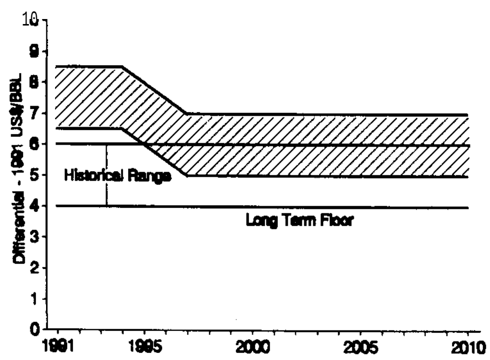
Second, technology is assumed to continue to improve on the supply side, leading to no major real cost increases for crude oil. Non-OPEC supply is expected to be fairly stable over the projection horizon, with declines in U.S. production being offset by increases in other parts of the world. In particular, production in and, to a lesser extent, exports from the former USSR are expected to decline through the earl y 1990s, but both are expected to rebound in the late 1990s.

Third, OPEC capacity is expected to show major increases in the next 10-15 years. Productive capacity, including Kuwait and Iraq, should exceed 35 MMB/D by 1995, and 40 MMB/D by 2005. As such, capacity should comfortably exceed the call on OPEC's production of about 32 MMB/D in 2005.

The price outlook assumes that the major OPEC producers will prefer stable increases in revenues through increased production coupled with moderate price policies, rather than through sharp price increases as in the past twenty years, This is not to say, however, #at there will be no volatility in oil prices over the period or uncertainties about the path of future world crude oil prices. Any attempt to significant y raise oil prices by the major OPEC producing countries is believed, however, to be sustainable for only brief periods.

Canadian crude price differentials between light and heavy crudes are largely determined in the international market. These differentials between the cost of light sweet and heavy sour crudes are critically important for the economics of upgraders. Figure 2.1.1 shows the assumption for the differential between WTI and Maya crudes, expressed in 1991 US$. The differentials between light and heavy crude oil are expected to fall somewhat from the high levels attained in 1991, but are likely to stay at the upper end of the historical range. The major reason for the higher differentials than in the past is the anticipated surplus in residual fuel oil. Other factors, such as the competition from natural gas in the boiler fuel market, serve to reinforce the higher differentials. On the other hand, if differentials become very wide, additional investment in hydrocracking will be attractive for refineries, which will tend to lower the differential.

Figure 2.1.1
Oil Price Differentials
WTI VS Maya
(1991 US$/bbl)



2.2 North American Natural Gas Prices

In spite of the tightening of the natural gas markets in the later part of the year, Canadian wellhead prices in 1992 averaged about $1 .35/mcf, or 50% below the peak attained in 1984. Several factors have caused this significant decline in prices including surplus deliverability, small growth in gas demand, increased storage, pipeline constraints and high rates of reserve replacement, Although all of these factors are likely to continue to be instrumental in determining long term prices, the most critical will be the level of gas supply. Both Canada and the U.S. have significant gas reserves and resource potential as shown in Table 2.2.1. Mexico with its large gas reserves and potential, could also become a player in the North American natural gas market hence limiting long term price increases. The established reserves in North America are equivalent to 13 years of production at current rates. This, however, would be considerably higher if one considers potential reserves.

Table 2.2.1
Natural Gas Reserves and Potential [1]
(Tcf)

	Remaining Established	Remaining Potential
U.S	172	1 140
Canada	71	450
Mexico	73	290

[1] *Excludes* coal seam gas
Sources: *U.S. DOE, PGC, CPA, NEB, NRCan, PEMEX*

According to Petroleum Industry Research Associates, Inc. (PIRA), new gas supply from sources such as coal seam and tight sands in the U.S. could be brought on stream rapidly by the mid-1990s.[2] The output of coal seam gas in the U.S. is currently small, but it is considered to have enormous potential for increasing rapidly and representing a larger share of total gas production. According to PIRA, coalbed methane gas output in 1991 was 350 Bcf or 2% of total gas production in the U.S. This is expected to increase to about 800 Bcf or 4.5% of U.S. gas production by 1995.[3] In the San Juan basin of new Mexico, coal seam gas is believed to be economic even without the government tax credit of about $0.90/mcf in US$ which was available for wells drilled before Dec 31, 1992.[4] Production from these wells will continue to qualify for the tax credit until Dec 31, 2002.

The coal seam resource base in Canada is believed to be vast, and could represent a major source of supply over the long term. There has been a wide range of estimates of the Canadian coal seam resource base, some even as high as 2600 Tcf. A more realistic recoverable potential could be in the neighborhood of about 150-200 Tcf. Currently, some pilot projects are underway to assess the feasibility of the development of coal seam gas on the east coast of Canada. There has also been some preliminary drilling in western Canada to assess the resource base.

Another important factor limiting long term price increases is the development of LNG that is taking place around the world. Due to the significant availability of natural gas worldwide, and the estimated costs associated with existing and new facilities, LNG could be viewed as a backstop supply source for the North American markets

Overall, the view is for faster increases in prices in the 1990s, and modest and continuous improvements over the medium to long term (see Table 2.2.2). The increase in prices is expected to

---

[2] PIRA, The Gas Market Outlook, June 1991.

[3] PIRA, 1993 preliminary estimates.

[4] For a detailed discussion on coal seam gas refer to: "Coal Seam Gas Development in the Continental U.S.", prepared by the Natural Gas Exports Division, Oil and Gas Branch, EMR, January 1991.

[5] A recent announcement by a consortium including Shell, Exxon, and the Venezuelan company Lagoven suggests that LNG could be shipped to the U.S. east coast for a landed cost of no more than US$2.40/mcf. See International Petroleum Finance, Volume 16, No 16, March 31.1993, page 3.

result from the decline in the excess productive capacity, increasing natural gas demand, and therefore, the development and connection of new higher cost reserves. Considering these views as well as analysis within the Department, Canadian plantgate natural gas prices, in 1991 C$, are assumed for this outlook to increase to $2.00/mcf in 2000 and $3.00/mcf in 2020. This is expected to be the general trend but there may be short term perturbations due to deliverability constraints. The natural gas and oil price projections used in this analysis imply a long term oil/gas price relationship of about 9 at the wellhead. This value is at the lower end of the historical range of 8-15, reflecting a relatively optimistic view for gas prices by 2020.

Table 2.2.2
Alberta Plantgate Natural Gas Price Projections
(1991 C$/mcf)

	1995	2000	2010
Coles	1.52	2.05	2.40
TCPL	1.75	2.05	2.70
NEB	2.25	3.15	4.50
Power West	1.55	2.20	n.a.
Chenery Dobson (17 Consultants)	1.45	2.05	2.35
NRCan	1.55	2.00	2.50

Sources: Co[es *Gilbert* Associates Lid., March 1993.
TCPL, 1994r95 Facilities Application to *the* NEB, March 1993.
NEB, Canadian *Energy Supply* and Demand 1990-2010, June 1991.
Power West Financial *Ltd.*, Monthly Energy Update, March 1993.
Chenery Dobson Resource Management Ltd., January 1993.

2.3 Coal and Uranium Prices

International coal prices have fallen on average over the last few years, and while there has been some firming recently, the expectation is that they will remain flat in real terms over the foreseeable future. Low sulphur coals, however, may begin to command higher prices as utilities endeavor to meet new environmental standards. To the extent utilities decide to install desulphurization equipment, this upward pressure in prices would be attenuated. In this study, the price of coal used by electric utilities is assumed to remain constant in real terms at 1992 levels.

The uranium market has suffered an oversupply situation since the late 1970s, when inventories began to accumulate due to delays and cutbacks in reactor construction. The situation has worsened recently as a result of the availability of low-priced uranium from the German uranium stockpile and non-traditional suppliers, especiall y Russia, Eastern European countries and China. The emergence of these non-traditional suppliers, the availability of surplus inventory and the large world wide resource base will put downwards pressure on price, but over the long term the price of uranium should remain flat in real terms.

2.4 Macroeconomic and Demographic Assumptions

The economic and demographic assumptions underlying the energy demand and supply projections are based on the Informetrica National and Provincial Reference Outlook[6]. It should be noted that the major energy price and investment assumptions underlying the Informetrica National/Provincial projection are consistent with the energy outlook presented in this document.

[6] Informetrica Ltd., November/December 1992 Reference Case Outlook,

Canadian economic growth over the long term will be driven chiefly by demographics and U.S. economic growth. Population in Canada is projected to grow at an annual rate of 1.070 between 1991 and 2020 largely due to immigration (see Table 2.4.1). In line with recent government policy, the

Table 2.4.1
Economic Prospects
(Average Annual Growth Rates (%))

	1972-1991	1991-2000	2OW-2O1O	2010-2020	1991-2020
Canada					
Real GDP	3.1	2.5	2.5	2.5	2.5
Industrial RDP	1.2	3.2	3.2	3.0	3.1
Services RDP	3.4	2.2	2.2	2.2	2.2
CPI	7.1	2.8	2.8	3.1	2.9
Ten year Bond Rate	10.5 (1991)	6.50 (2000)	5.90 (2010)	6.90 (2020)	6.9 (2020)
Population	1.1	1.2	0.9	0.8	1.0
Us.					
Real GDP	2.5	2.2	2.0	1.5	1.9

Source: *Statistics Canada and Informetrica.*

forecast assumes an immigration level of about 250,000 persons per year. The U.S. economy is assumed to grow by 2.2% per year up to 2000, eroding modestly thereafter as a result of slowing labor force growth and little change in long term productivity performance. Based on these assumptions, the Canadian economy is projected to expand at an annual average rate of 2.5% between 1991 and 2020. This implies that real GDP will be approximate y 257~ larger in 2000 relative to 1991 and twice as large by 2020. On the financial front, monetary policy is expected to continue to ease somewhat with interest rates falling from 9.4% in 1992 to 6.570 in 2000. The rate of inflation, as measured by the Consumer Price Index, is 2.9% on average over the period.

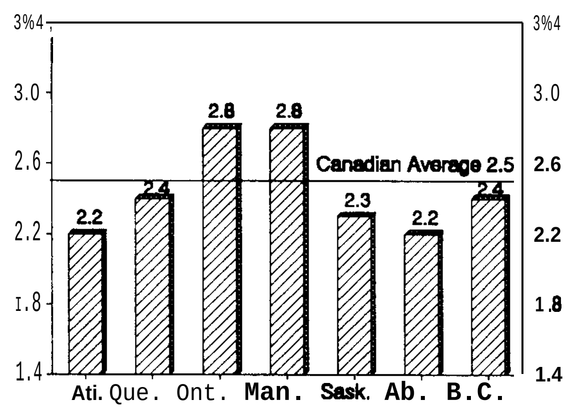
In contrast to the experience of the 1970s and 1980s, Informetrica expects higher growth in the industrial sector than in the service sector (3.1 % vs 2,2 %). This is a particularly important assumption given the considerable y greater energy intensity of the former. Underlying this greater industrial sector growth is the view that Canada's macroeconomic future will be determined primarily by export performance. Improved export performance will stem from the increased competitiveness of Canadian industry which, in turn, will result in lower cost increases compared to the U.S. and other producers. This improved competitiveness reflects the restructuring of Canadian industries in the late 1980s and earl y 1990s. It will also be stimulated by several policy developments such as the Free Trade Agreement and tax reform (e.g., the removal of sales tax from exports under the GST). Within the sector, pulp and paper, chemical products, electrical equipment and metallic minerals and products are industries likely to experience above average growth.

The intriguing question, however, is not why the industrial sector will grow more rapidly, but rather why the service sector will grow so slowly. The answer lies in the fact that about 4070 of the output of this sector is accounted for by non-commercial services: education, public administration and

— health care. With the possible exception of the latter, the growth in these services will be considerably reduced as population growth slows and as governments retrench to address deficit and debt problems. Non-business commercial services such as restaurants, recreation and accommodation are also related to population and, in consequence, will grow more slowly in the future. By contrast, services to business are expected to expand more or less in line with the growth in the industrial sector.

According to the Informetrica projections, economic growth will vary somewhat across regions. Some of the more important regional trends are noted below:

Figure 2.4.1
Gross Domestic Product
(Average Annual Growth Rate 1990-2020)



- The Atlantic provinces are projected to experience relatively slower economic growth because of lower population growth relative to the national average. Newfoundland, however, will, outperform the Maritime Provinces because of the Hibernia and Terra Nova projects (see Chapter 4).

- Economic growth in Quebec will closely track the national average. While the province is expected to benefit from increased exports, the non-durable goods portion of industrial production will experience weaker performance as a result of low population growth.

- Despite current problems, Ontario is projected to outperform all other provinces except Manitoba over the projection period. Healthy gains are expected in capital investments in manufacturing as this sector strives to increase its competitiveness. These investments will lead to large productivity gains. As well, exports will contribute to Ontario's overall economic growth given the provincial economy's close ties to export markets.

- Economic growth varies widely among the Western provinces. Manitoba's relatively high economic growth will come mainly from the construction sector, notably from major utility developments by Manitoba Hydro coupled with continued investment in the manufacturing and mining sectors. Economic growth in Saskatchewan and Alberta will come mainly from the manufacturing and construction sectors (i.e., pulp and paper, chemicals, upgrading of heavy crude oil) which are expected to compensate for moderate growth in the traditional agricultural and mining sectors.

- In British Columbia, population and household growth, fuelled by immigration, will exceed the national average significantly. Growth in the forestry and wood products sectors and other resource industries will decelerate as a result of the declining North American demand for housing. On balance, provincial growth is projected to be slightly below the national average.

2.5 Climate

Table 2.5.1
Projected Levels of Mean Annual Temperatures
(Degrees Celsius)

Selected Canadian Cities	1951-1980 Normal	1980 Decade	2005 Projection	2020 Projection
Vancouver	9.8	10.0	10.3	10.7
Edmonton	3.1	4.4	4.7	5.1
Saskatoon	1.6	2.8	3.1	3.5
Winnipeg	2.2	3.2	3.5	3.9
Toronto	8.9	9.0	9.3	9.7
Montreal	6.2	6.3	6.6	7.0
Halifax	6.1	6.0	6.3	6.7
St. Johns	4.8	4.7	5.0	5.4

Source: Environment Canada, *Climate* Change *Centre*

In earlier projections by the Department, future temperatures in Canada were assumed to be the same as the 30 year average experienced over the 1951-1980 period. With increasing discussions concerning global warming, it no longer seems appropriate to forecast over a thirty year period using a constant temperature assumption. For this projection, the Canadian Climate Centre of Environment Canada has provided estimates of the changes in mean annual temperatures and heating degree days (HDDs) associated with estimated warming. The temperature estimates are given in Table 2.5.1 for selected Canadian cities for the normal 1951-80 period, the 1980 decade and the years 2005 and 2020. The temperature projections, relative to the 1951-80 normals, range from only very slight increases in coastal cities by the year 2005 to increases of almost 2 degrees for inland cities such as Edmonton by 2020 from the 1951-80 normal.[7]

These changes impact largely on the energy demands of the residential and commercial sectors, and particularly on natural gas demand, since gas is the predominant fuel for space heating in Ontario and Western Canada where the changes are concentrated.

The impact of the higher temperature on energy use is, however, not large. An analysis, made assuming that future temperatures in the projection period remain the same as the 30 year averages for 1951-1980, reveals that total energy demand would be only 0.6 and 1.3 percent higher in 2000 and 2020 respectively. In other words, the global warming trend underlying the energy outlook has only a small impact on overall energy demand and CO_2 emissions. Finally, it should be noted that the present analysis does not include the effect of warmer temperatures on cooling degree days and the consequent effect on electricity demand for increased air conditioning use.

[7] Heating degree days (HDDs) are a measure of periods during the year in which the mean daily temperature is below 18 degree Celsius. An increase in temperature will, other things being equal, reduce annual HDDs. Analysis by the Climate Change Center suggests that the negative relationship between temperature changes and HDDs is basically linear.

2.6 The Policy Framework: Business as Usual

Government policy also exerts an important influence on energy markets. As noted in the introduction, the assumption underlying the reference case projection is that current federal and provincial energy policies and related policies affecting Canadian energy trends, remain unchanged over the projection period. This is usually, and perhaps inappropriately, referred to as the "business as usual" assumptions

The reader will have noted that our business as usual assumption allows us to speculate on changes in the policies of other governments which might materially impact future Canadian energy developments. Obviously, it is desirable to minimize the instances of such speculation to those which are both critical and for which there is sufficient information to develop an informed judgement. One such international example concerns automobile fuel efficiency standards. Given the integrated nature of the North American automobile market, the regulatory decisions of the U.S. government in this field will continue to have a decisive impact on the efficiency of new cars sold in Canada. Our assumptions concerning U.S. auto fuel efficiency standards are provided in Chapter 3.

Some aspects of current energy and related policy are relatively straightforward to define. Thus, for example, we assume that, consistent with agreements reached with the provinces in the mid- 1980s, Canadian oil and natural gas prices and markets will remain deregulated. Similarly, the elements of the tax system that affect energy - royalties, corporate income tax, excise taxes on motive fuels and the GST - are assumed to remain in place. More generally, Informetrica's macroeconomic projections incorporate the deficit and debt reduction policies of the Government of Canada and provincial governments.

There are, however, several recent policy initiatives, particularly in the environmental area, for which some judgement is required concerning their inclusion in the business as usual assumption. These include the NO_x/VOC Management Plan, the Canada-U.S. Air Quality Agreement (March 1991), the measures stemming from the Energy Efficiency and Alternative Energy Program, and the greenhouse gas stabilization commitment. The process common to each of these initiatives is for the government to announce targets for emission levels, to be achieved at some point in the future, and then to follow-up with legislation, regulations and programs to attain the objectives. The process to develop such legislation, regulations and programs is typically quite protracted, involving lengthy consultation and negotiation with provincial governments and stakeholder groups. At the time of writing, none of these initiatives can be considered to be fully developed.

The question, therefore, is whether to include these statements of intent in the current policy framework. Our approach to this question is to include a particular initiative if the process of giving legislative or regulatory expression is sufficiently far advanced that an informed outside observer could discern the direction and implications of the policy. Using this approach we include, under current policy, the Canada-U.S. Air Quality Agreement (March 1991) despite the fact that the allocation of the SO_2 cap across the Western provinces has yet to be determined. In a similar vein, judgments are made concerning the likely evolution of the initiatives contained within federal and provincial energy

---

[8]"Business as usual" does not imply that the behavior of Canadian energy producers and consumers necessarily remains unchanged. Certainly any change by business or consumers - a re-orientation of markets, changes in investment patterns or an adoption of a new technology - is incorporated in the projection if sufficient information is available.

efficiency and alternative energy programs, i.e., about the level of energy efficiency standards for equipment likely to be put into legislation over the projection period. In doing so, it is acknowledged that the final form of such initiatives may be somewhat different than that assumed.

We do not, however, incorporate either the NO_x/VOC Management Plan or the greenhouse gas stabilization commitment in the business as usual definition. Although there has been extensive consultation on the former, there is, as yet, little agreement between federal and provincial governments as to the implementation of appropriate regulations governing NO_x and VOC emissions. It is likely that additional rounds of negotiations will be required before the Plan assumes final form. Consequently, there is insufficient information, at this point, to incorporate measures into the projections. The greenhouse gas commitment to stabilize greenhouse gas emissions at 1990 levels by the year 2000 was made in the Green Plan and is implicitly in the Climate Change Convention which Canada ratified in December 1992. It is recognized, however, that legislation and programs to achieve this goal are still in their infancy. In fact, as emphasized in the Green Plan[9], the approach of the government is to start by undertaking first those measures that make economic sense in their own right - such as those following from the Efficiency and Alternative Energy Program - before determining whether additional initiatives are necessary. In the absence of information concerning such initiatives it would be inappropriate, in this document, to speculate on their likely scope and direction.

[9] Government of Canada, Canada's Green Plan, 1990, p. 102-103.

3. ENERGY DEMAND

In this chapter, we provide projections and analysis of secondary energy demand for the four principal energy-using sectors: residential, commercial, industrial and transportation. We also present projections of non-combustion energy use (e.g., petrochemical feedstocks) and consumption by energy producing industries which, when combined with secondary use, provide estimates of total primary energy demand. To set the stage, the chapter commences with a discussion of projected trends in consumer energy prices.

The long term energy demand projection is developed using the econometric Inter-Fuel Substitution Demand (IFSD) model and process/end-use models. One of the main strengths of IFSD is that it emphasizes the relationship of energy demand, on a provincial basis, to economic and demographic variables such as prices, output, population and households. However, as with any econometric model, IFSD cannot adequately forecast technological improvements or changes other than those based on historical trends. In order to better capture the penetration of new technologies, and the impact of standards and regulations, end-use or process models, maintained by the Efficiency and Alternative Energy Branch, were used to complement the initial IFSD econometric forecasts. In addition, adjustments were made to the estimates following consultation with experts within NRCan, provincial governments, the petroleum industry and electricity and natural gas utilities.

3.1 Domestic Energy Prices

Consumer energy prices are a crucial determinant of both the level and composition of secondary energy demand. Translating the crude oil and natural gas wellhead price projections of the previous chapter to the consumer level requires assumptions concerning a variety of charges - transportation, refining and distribution margins - and commodity taxes. Usually, these charges and taxes must be specified on a regional basis.

In almost all cases, we have adopted conservative assumptions concerning the trends in transportation, refining and distribution margins, namely that they increase only by the rate of inflation. In particular, we have assumed, consistent with the "business as usual" assumption, that Canada does not impose regulations concerning reformulated gasoline and "clean" fuels similar to those in the U.S. Clean Air Act.

Concerning commodity taxes, it is assumed that the rates for all applicable ad valorem taxes - most provincial fuel taxes and the GST - remain constant. Per unit levies - such as the federal excise tax on selected motive fuels, increase by the rate of inflation. The GST applies to residential and passenger transportation energy consumption only. No new energy taxes are assumed for the reference scenario.

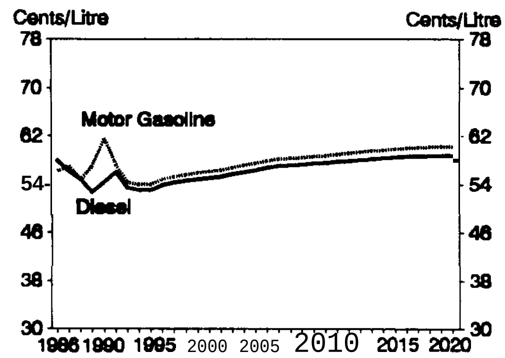
Important features of the methodology used to calculate consumer prices for refined petroleum products (RPPs), natural gas and electricity and the results are provided below.

Refined Petroleum Product Prices

Domestic oil prices are calculated on the basis of the prices for WTI at Cushing (see Section 2.1) adjusted for the exchange rate and quality differentials with the appropriate transportation costs to determine equivalent crude prices at Edmonton, Montreal, Toronto and Halifax. The Canadian costs of crude oil are then translated into petroleum product prices, with the appropriate taxes for each province.

In brief, heavy fuel oil, light fuel oil and motor gasoline prices are directly tied to crude oil prices. Taxes and margins escalate at the rate of inflation as measured by the CPI. Given the uncertainty of the cost impact of environmental programs on oil product prices, these costs were not factored into the price projection. On balance, real prices for light and heavy fuel oil are expected to increase at roughly the same rate and are not projected to reach their 1985 peak over the entire 30 year projection period. Motor gasoline and diesel fuel prices are also projected to follow similar paths. The price (in 1991 cents) for regular unleaded gasoline, for example, increases from 54 cents per litre in 1992 to 58 cents per litre in 2005 and then remains relatively stable through to 2020 (see Figure 3.1. 1). It should be noted that because taxes make up about 50 percent of the price of gasoline and diesel, a one percent change in the price of crude oil leads only to about a 0.5 percent change in the price of gasoline and diesel.

Figure 3.1.1
Fuel Prices - Transportation Sector
(1991 Cents per Litre)



Natural Gas **Prices**

As a result of market deregulation, it is no longer reasonable to assume domestic natural gas prices are tied to other fuel prices. As discussed in Section **2.2, the** field price of natural gas is determined on the basis of North American reserve and resource levels. Sectoral end-use prices are determined regionally for the residential, commercial and industrial sectors (i.e., by type of sales contract) by adjusting for appropriate pipeline charges and distributor margins. For forecasting purposes, pipeline charges and distributor margins are assumed to remain constant in real terms. As depicted in Figure 3.1.2, natural gas prices, adjusted for inflation, have experienced notable declines between 1985 and 1991. Under our pricing assumptions, natural gas end-use prices are expected to increase in real terms such that the y reach their previous 1984 peak by the year 2010.

Electricity Prices

Electricity prices reflect the utilities' announced prices or proposed price increases up to the end of 1994. Between 1995 and 2005, electricity prices are assumed to increase only at the rate of inflation, due to considerable excess capacity in most regions. Post-2005, real electricity prices increase by 1.0% per year, as new generation capacity is required to meet the additional demand. The rationale for this projection is explained more fully in Chapter 4.

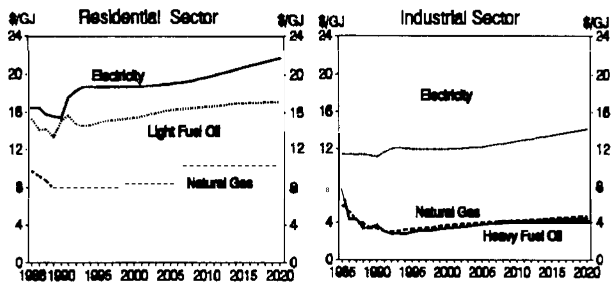
Inter-Fuel Competition

Energy end-use prices (i.e., prices at the burner tip) vary considerably by sector. Figure 3.1.2 displays end-use prices by fuel for the residential and industrial sectors at the national level. These prices are adjusted for the energy efficiency content of each fuel. It should be noted that market shares are sensitive to relative price changes and not to absolute changes in price levels.

In the residential sector, prices for all fuels increase at roughly the same rate except for a sharper increase in electricity prices in the short term (see Figure 3. 1.2). Light fuel oil and natural gas remain more competitive than electricity during the projection horizon. In some instances, technological changes and relative capital costs of alternative systems can favor the use of electricity. But, the high price of electricity suggests that there will be only limited substitution towards this fuel.

In the industrial sector, the price of electricity y increases moderately faster than heavy fuel and natural gas. Due to the high degree of substitution between heavy fuel and natural gas in the industrial sector, heavy fuel prices track closely natural gas prices and hence, prices for both these fuels are projected to be almost identical over the projection horizon. Overall, the fuel price projection indicates that inter-fuel competition will continue to be relatively intense as it has been since 1985 (see Figure 3. 1.2).

Figure 3.1.2
Inter-Fuel Price Competition
(1991 C$/GJ)



In summary, the consumer energy price projection calls for electricity prices to increase faster than other fuels in the short term thereby favoring the use of other fuels, notably natural gas. Over the longer term, however, substitution among major fuels will be somewhat limited given that the prices for oil, natural gas and electricity increase at roughly the same pace.

3.2 Residential Sector

The residential sector accounts for about 20 percent (1348 petajoules[10]) of total secondary energy demand. End-uses in the residential sector include space heating, water heating, appliances and lighting, and space cooling. As depicted in Figure 3.2.1, space and water heating account for the lion's share of total residential energy consumption.

The residential sector demand projection is based not only on economic and demographic factors, but also on the introduction of specific federal and provincial standards and programs that impact on the thermal shell of the housing stock, space heating systems, water heaters and appliances. The main standards and programs underlying the residential projections are briefly described below:

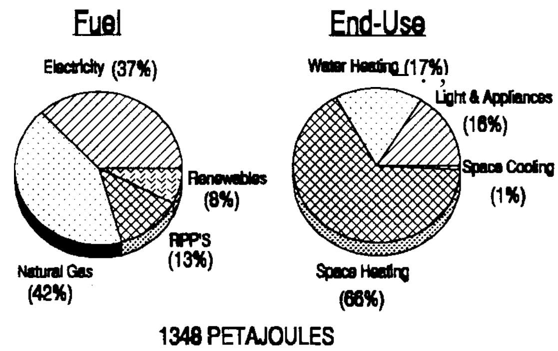
- By 1995, ninety percent of new houses will be 11 to 20% more efficient (depending on location) than levels prescribed in the 1983 Measures for Energy Conservation, and the

[10] A petajoule (or 10^{15} joules) is a measure of energy content and is employed to combine energy use of different fuels on a comparable basis. As an illustration, the city of Toronto consumes, on average, approximately 1.5 petajoules per day for its heating, lighting and transportation needs.

remaining 10 percent will meet the R-2000 standards. Post 2005, 90 percent of new houses will satisfy the current R-2000 standards and the remaining 10% are assumed to be more efficient than current R-2000 houses.

- In 1994, standards for natural gas furnaces in Canada are assumed to match the levels of the U.S. 1992 standards. Revisions are also assumed post 1994 such that the annual fuel utilization efficiency (AFUE) for the stock of natural gas furnaces is 84% in 2020 compared to 70% in 1990. Standards for oil furnaces are assumed to be implemented in 1995 and correspond to the U.S. 1992 standards. These standards are assumed to remain constant over the projection period.

Figure 3.2.1
Residential Energy Demand
1991



Source: Statistics Canada and NRCan.

- In 1994, Canada wide standards are assumed to be implemented for electric, natural gas and oil-fired water heaters. These standards are set equal to current Ontario standards.

- Standards for major appliances are assumed to be introduced in 1994 and match closely the U.S. 1993/94 standards. The standards are revised every five years over the forecast period.

- Standards for space cooling systems are assumed to be implemented in 1994 and are set equal to current Ontario standards.

- The information/suasion components of Electric Utility DSM and Energy Management programs are judgmentally incorporated in the projection. It should be noted that one cannot disentangle the impact of DSM programs from the federal and provincial programs given their similar means and objectives.11

Since space heating and water heating account for more than 80% of the total residential energy demand, efficiency measures are chiefly concentrated in these end-use categories.

[11] Even though DSM programs are difficult to assess quantitative y, specific assumptions are made concerning their amounts, their effect on the redistribution of peak demand and their impact on electricity prices. See Chapter 4 on electricity generation and capacity for a more detailed explanation of the above elements.

Table 3.2.1 summarizes the residential energy demand forecast and underlying factors. Energy intensit y, as measured by total energy demand divided by total households, is projected to fall by an average rate of 1.0% per year, which corresponds closely to intensity changes experienced over the last ten years. In previous years, high energy prices and energy conservation and substitution programs were the main contributors to the declines in energy intensity. The declines over the projection period are due to the introduction of new standards, the economic attractiveness of more efficient technology, as well as energy efficiency programs.

Table 3.2.1
Residential Energy Demand
(Average Annual Growth Rates (%))

	1981/1991	1991 /2000	2000/2010	2010/2020	1991 /2020
Total Demand[1]	0.9	0.6	0.2	0.4	0.4
Energy Intensity[2]	-0.9	-1.1	-1.1	-0.8	-1.0
Key Determinants:					
Households	1.8	1.7	1.3	1.2	1.4
Household Income	0.3	-0.2	0.5	1.1	0.5
Real Energy Prices	0.9	0.5	0.7	0.9	0.7

[1] Adjusted for weather fluctuations.
[2] Energy demand per household.

Table 3.2.2 provides our projection of selected residential sector energy end-use intensities over the projection period. It should be noted that these intensities reflect the efficiency of the new stock. The total intensity displayed in Table 3.2.1 includes old and new stock, and as such, it is not directly comparable with end-use intensities.

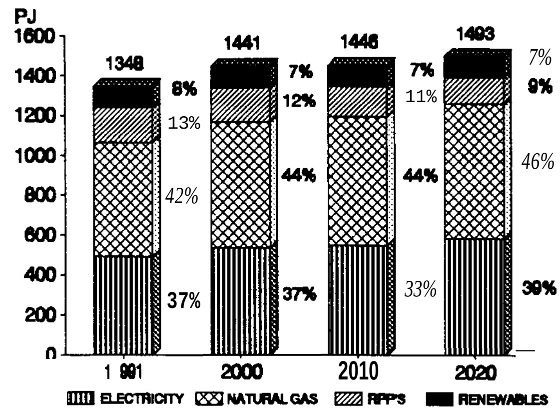
Table 3.2.2
Selected Residential End-Use Intensities
(Gigajoules/Household)

	1990	2000	2020	1990/2020 (AAGR)[1]
Space Heating (Ontario)	43.6	30.2	21.6	-2.3
Electric Water Heaters	21.1	19.5	18.0	-0.5
Refrigerators	4.1	2.3	2.2	-2.0
Freezers	2.3	1.1	1.2	-2.1

[1] *Average Annual Growth Rate*

Figure 3.2,2 summarizes the residential energy demand projection by fuel over the 1991 to 2020 period. In terms of level, the most interesting point is that post-2000, residential energy demand remains almost constant. This result is related both to the decline in the growth rate of household formation and to the increasing impact of the energy efficiency standards and programs as housing and appliance stocks turn over. Fuel shares for the residential sector change only modestly, with natural gas increasing its share slightly at the expense of fuel oil chiefly in space heating applications.

Figure 3.2.2
Residential Energy Demand by Fuel
1991-2020

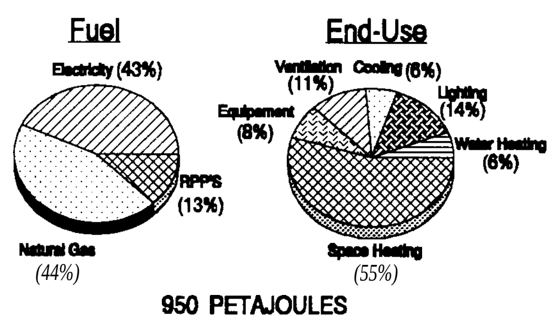


3.3 Commercial Sector

The commercial sector includes a diverse group of service industries and institutions, such as: office buildings, retail establishments, hotels, motels, restaurants, warehouses, recreational buildings, schools, hospitals, religious and other institutional and service industries. Collective y, these industries and institutions consume about 15 percent of total secondary energy demand. In 1991, the largest energy users in the commercial sector were office buildings (21 %), retail stores (18%) and educational facilities (18%).

Space heating is the largest component of commercial energy use, being responsible for more than half of the total. In comparison, lighting, ventilation, and equipment account for 14, 11 and 8% respectively. Space cooling accounts for the lowest level of energy use in the commercial sector (see Figure 3.3. 1).

Figure 3.3.1
Commercial Energy Demand by Fuel
1991



Sources: Statistics Canada.
NRCan, Efficiency and Alternate Energy Branch.

Commercial energy demand is largely driven by commercial RDP growth, real energy prices (see Table 3.3. 1) and structural changes within the sector. Such changes include a declining growth of office building stock and a rising growth in health services. In addition, government and utility programs are also expected to play a role in promoting energy conservation. The following programs are incorporated in the energy demand outlook for this sector:

- Federal Buildings Energy Efficiency nitiatives (on going)
- Introduction of a Federal and Provincial building Energy Code (commencing in 1995)
- Energy Efficiency Standards for Equipment (starting in 1995)

Table 3.3.1
Commercial Energy Demand
(Average Annual Growth Rates (%))

	1981/1991	1991/2000	2000/2010	2010/2020	1991 /2020
Total Demand'	0.7	1.2	1.8	1.5	1.6
Energy Intensity[2]	-2.1	-0.9	-0.4	-0.7	-0.7
Key Determinants:					
Commercial RDP	2.8	2.2	2.2	2.2	2.2
Real Energy Prices	0.8	0.9	0.6	1.0	0.8

[1] *Adjusted* for weather fluctuations.
[2] Energy *demand* per commercial *RDP*.

The development of equipment and building standards in the commercial sector is not as advanced as in the residential sector. Therefore, it is not possible to point to specific standard levels. Nevertheless, the commercial sector energy use projections reflect a broad range of equipment and building standard setting activities.

Table 3.3.2 presents the evolution of selected commercial sector energy end-use intensities over the projection period. As in the residential sector, these intensities reflect the efficiency of the new buildings and equipment. As a result, the end-use intensities and the total stock intensity displayed in Table 3.3.1 are not directly comparable.

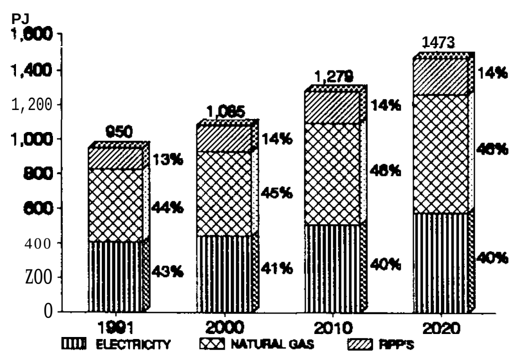
As highlighted in Figure 3.3.2, the market share for natural gas is expected to increase slightly over the outlook period as relative energy prices favor the use of this fuel. For the opposite reason, electricity's fuel market share is expected to decline from 43 percent in 1991 to 40 percent by 2020. The share of oil is expected to remain relatively stable at roughly 14 percent throughout the outlook period.

Energy intensity in the commercial sector is projected to decline by 0,7% per year over the 1991 to 2020 period, substantiall y lower than the **2.1 %** per year decline experienced over the 1981 to 1991 period.

Table 3.3.2
Selected Commercial End-Use Intensities
(Average Annual Growth Rates (%))

	1990i20m	2000/2020
Space Heating	-0.8	-1.9
Lighting	-1.8	-4.4
Cooling	-1.2	-2.9
Motors	-1.1	-2.6

Figure 3.3.2
Commercial Energy Demand
1991-2020



Three factors are responsible for the smaller decline in energy intensity:

- the slower turnover in capital stock as indicated by the lower projected growth in commercial RDP;

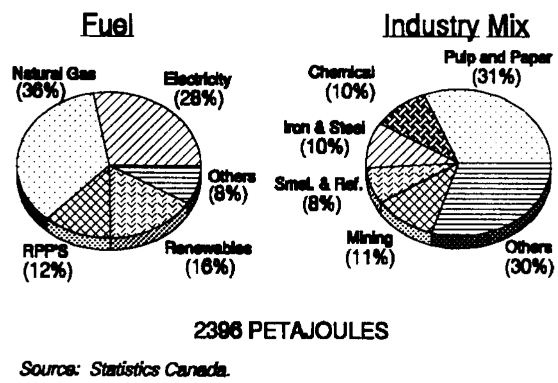
- the slower rate of fuel substitution to more efficient fuels - as most of this substitution took place during the last decade when there was a significant switch away from oil; and

- the projected rapid growth in energy using equipment such as computers and communication equipment.

3.4 Industrial Sector

The industrial sector is the largest energy user, accounting for just under 40 percent (2396 petajoules in 1991) of total secondary demand. The sector includes the manufacturing, mining, construction and forestry industries. As shown in Figure 3.4.1, four energy-intensive industries - pulp and paper, iron and steel, smelting and refining and chemicals - account for about 60% of the energy requirements of this sector. In contrast, their share in industrial production, as measured by RDP, is only 15%. According y, changes in the composition of industrial production should be considered together with overall industrial RDP growth when projecting industrial energy demand. Reflecting this crucial relationship, total industrial energy demand in the IFSD model is disaggregated into seven industries. Demand for these industries is determined by energy prices, output, and investment[12].

Figure 3.4.1
Industrial Energy Demand
1991



Our overall results suggest that energy intensity, the ratio of industrial energy demand to industrial RDP, in the industrial sector will decline by about 1.0% per year over the 1991-2020 period (see Table 3.4. 1). This intensity projection is similar to the latest NEB and U.S. DOE/EIA forecasts.[13] Despite these energy intensity declines, energy demand is projected to increase by about 2.1% per annum over the next thirty years. By historical standards, this energy demand growth is relatively high. For the most part, it is explained by the macroeconomic scenario which calls for sharp increases in industrial production.

---

[12] For a discussion of this analysis, please see: Erik Brunet and Michel Bérubé, "Modeling Industrial Energy Demand", EMR, April 1992.

[13] National Energy Board, Canadian Energy Supply and Demand 1990-2010, June 1991; and U.S. Department of Energy, Annual Energy Outlook, 1993.

Table 3.4.1
Industrial Energy Demand
(Average Annual Growth Rates (%))

	1981/1991	1991/2000	2000/2010	2010/2020	1991/'2020
Total Demand	0.8	2.1	2.2	2.1	2.1
Energy Intensity[1]	-0.7	-1.1	-1.0	-0.8	-1.0
Key Determinants:					
Industry RDP	1.5	3.2	3.2	3.0	3.1
Real Energy Prices	1.0	1.7	1.3	1.6	1.5

[1] *Energy demand* per industrial *RDP*.

As highlighted in Table 3.4.2, the pace of energy intensity change is expected to differ considerably among industries. The differences are partially explained by movements in energy prices relative to other factor input prices.

Key factors affecting energy intensity are described below:

Table 3.4.2
Energy Demand by Major Industries
(Average Annual Growth Rate (%) 1991-2020)

	RDP	Demand	Intensity
Pulp & Paper	2.8	1.5	-1.3
Chemicals	4.0	2.8	-1.1
Iron & Steel	4.1	2.4	-1.6
Smelting& Refining	3.9	2.8	-1.0
Other Manufacturing	3.6	1.8	-1.8
Mining	2.2	1.6	-0.6
Forestry & Construction	2.5	1.4	-1.1
Total Industrial	3.1	2.1	-1.0

- In the new era of increased international competitiveness and greater preoccupation with environmental concerns, energy conservation is expected to be a prominent factor in investment plans.

- The RDP growth rates in Table 3.4.2 imply that all industries, except mining, will double their output over the outlook period. Significant additions to new productive capacity will be required, implying a high rate of capital stock turnover, Typically, installation of new equipment provides a major opportunity to introduce new efficiency processes.

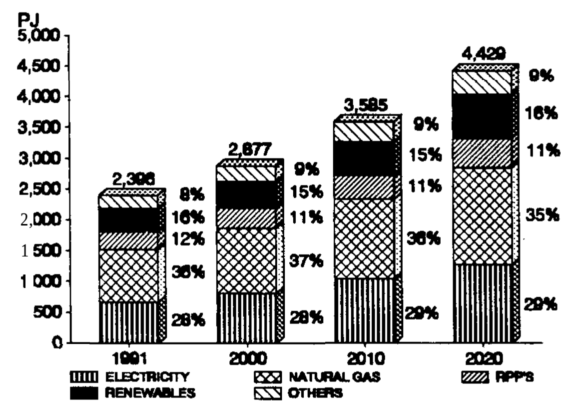
- Due to environmental concerns and regulations (e.g., several states in the U.S. have introduced legislation forcing newspaper publishers to use more recycled paper), there will be an increasing use of metal and paper recycling. The manufacturing process using recycled products (e.g., waste paper) requires less energy than the manufacturing process using virgin products (e.g., wood).

- The U.S. Clean Air Act amendments of 1990 will result in technology transfers. For instance, these amendments will result in major changes to the coke ovens of the U.S. iron and steel industry because the production of domestic coke will become uneconomic as a result of regulations. Several new processes that provide alternatives to the traditional blast furnace have been developed. These more energy efficient processes are both more economic and environmentally more benign than the coke oven/blast furnace method.

- Energy efficiency gains in the mining sector stemming from new efficient machinery and equipment will be offset by declining ore grades (i.e., more machinery and hence more energy are required to extract minerals).

- Federal and provincial information and suasion initiatives will heighten awareness of energy efficiency potential in industrial processes. These initiatives include the Minister of Energy, Mines and Resources' high profile "National Advisory Council on Industrial Energy Efficiency". The industrial projection also includes the programs to encourage the development and adoption of highly energy efficient technologies.

Figure 3.4.2
Industrial Energy Demand by Fuel
1991-2020

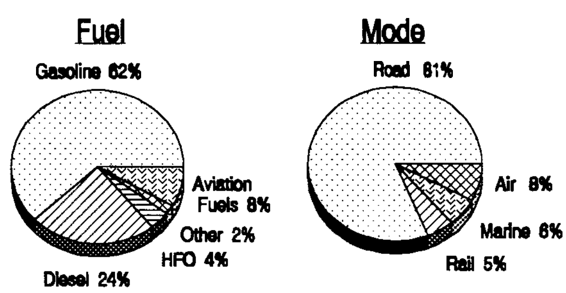


As a result of stable relative fuel prices, fuel market shares remain almost constant over the outlook horizon (see Figure 3.4.2). The slight price advantage favoring natural gas use is offset by the increased use of newer processes and technologies based on electricity. In effect, industry will use electricity for precision processes but substitute gas for traditional uses (i.e., heating the factories).

3.5 Transportation Sector

The chief sources of energy for the transportation sector are motor gasoline for automobiles, diesel fuel for trucks and trains, turbo fuel and aviation gasoline for aircraft, and heavy fuel oil for ships. As shown in Figure 3.5.1, total energy consumption for transportation was 1737 petajoules in 1991, representing 26 percent of total secondary energy demand. Approximately 81 percent of energy consumed in this sector in 1991 was used on the road, while air, marine and rail accounted for 7.5, 6.5 and 5 percent respective y.

Figure 3.5.1
Transportation Energy Demand
1991



1737 PETAJOULES

Source: Statistics Canada.

Road Energy Demand

Gasoline and Diesel Demand

The chief determinants of road energy demand are the stock of vehicles, the average fuel efficiency of the vehicle stock and the average distance travelled per vehicle.

Over the outlook period, car stock is projected to increase modestly at 1.8% per year. Key factors affecting this growth are low interest rates and stable fuel prices, notwithstanding slow growth in households and personal disposable income. The ratio of cars to households is expected to increase from 1.1 currently to 1.2 in 2020.

The fuel efficiency of new automobiles sold in Canada is perhaps the most critical assumption underlying the projection of road transport energy demand. Further, given the integrated nature of the North American automobile market, the assumption is very sensitive to views concerning regulatory initiatives by the U.S. government. During 1978-1985, the U.S. government imposed Corporate Average Fuel Economy (CAFE) standards, regulating the fuel efficiency of new automobiles. Since 1986, these standards have not been changed.[14] The Clinton Administration seems to favor raising the CAFE standards. But, it is not clear that action will be taken given the desire to stimulate the U.S. economy. Despite the uncertainty surrounding this issue, we assume that a modest CAFE program, requiring a three percent per annum improvement in new vehicle fuel efficiency, will be introduced by the U.S. government for the years 1996-2001 and that a comparable program is implemented in Canada. This improvement is about one-half that achieved under the 1978-1985 CAFE program.

Table 3.5.1
New Car Fuel Efficiency
(litres per 100 kilometres) "

	1990	2010	AAGR 1990-2010
CANADA			
NRCan	9.7	8.0	-0.9
NEB	10.3	8.0	-1.2
DRI	10.2	8.2	-1.1
UNITED STATES			
DOE (low price)	9.7	8.9	-0.4
DOE (reference)	9.7	7.9	-1.0
Proposed U.S. Legislation			
Bryan Bill	9.7	6.8 (2001)	-3.2
Johnston Bill	9.7	7.4 (2006)	-1.7

Sources: NEB. Canadian *Energy* Supply & Demand, 1990-2020, June 1991.
DRI/McGraw-Hill, Canadian *Energy* Review, *Fall/Winter* 1992-1993.
U.S. DOE, Energy Outlook January 1993.
U.S. Senate, Bryan Bill and Johnston Bill by Senators Bryan and Johnston, 1991.

Product plans of manufacturers suggest no improvement in new vehicle fuel efficiency can be expected before 1996. With the new CAFE program, an improvement in automobile efficiency, averaging 0.9% per year, (i.e., from 9.7 litres per 100 Km in 1990 to 8.0 in 2010) is assumed through to 2010 (see Table 3.5.1). Thereafter, the improvement in new car fuel efficiency slows to 0.4% per year. It should be noted that these improvements are significantly lower than those contained in proposed legislation introduced, but not passed, in the last U.S. Congress.

The distance travelled per car is expected to grow at 0.4% per year over the forecast period, considerably below the rate of 1.6% that prevailed in the 1980s. This change reflects the expectation of lower income growth, reduced growth in the number of licensed drivers, a decline in the ratio of high mileage young drivers to those of retirement age, and government programs to encourage ride sharing and use of less fuel intensive (on a per passenger basis) mass transit,

[14] In 1989 there was a temporary modification to these standards.

— Over the outlook period, the stocks of trucks are also projected to increase modestly, at average annual rates of 2.6% for gasoline and 1.4% for diesel trucks, based on an outlook with modest economic growth and stable prices for motor gasoline and diesel. But, trends in fuel efficiency and average distance travelled are expected to differ from passenger cars. Truck fuel efficiency is expected to improve at a slower rate than cars -0. 3% per year for gasoline trucks and 0.570 per year for the heavier diesel trucks. The average distance travelled for gasoline trucks is expected to grow at a rate similar to cars, while virtually no growth is expected for diesel trucks.

Alternate Fuels

In response to security of supply and environmental concerns, governments and utilities have been researching, demonstrating and providing incentives to encourage the use of alternate transportation fuels for over a decade. We project that these programs and vehicle technology improvements will be successful in maintaining the attractiveness of alternative transportation fuels for the high mileage fleet market.

Internal analyses, at NRCan, have been carried out in order to compare the payback periods for recovering additional expenditures (excluding infrastructure costs) in switching from conventional fuels. Natural gas has the shortest pay back while electricity has the longest. The reduction in the payback period for methanol over this time-frame reflects the expected trend of methanol being used in flexible-fuel vehicles in the early years to its use in dedicated-fuel vehicles during the last decade when a wide distribution network is expected (methanol use requires fewer changes to the existing fuel distribution network). Consequently by the end of the outlook period, methanol becomes almost as competitive as natural gas and propane. In spite of the favorable economics of natural gas, the major drawbacks limiting its penetration in the car market are: the extra weight of fuel storage cylinders; the reduction of trunk space due to the size of the cylinders; and the very high cost of the compressors at refueling stations. Methanol and propane will be the most widely used alternatives by 2020. Methanol begins penetrating the new automobile and light truck market in the late 1990s and its share of total road demand reaches 2.5% by 2020. The share of propane almost doubles from its current level of 1.690. Without a major breakthrough in the cost and performance of electric vehicles, the use of electricity will not become much more attractive than it is today. Research and development efforts, however, by U.S. car manufacturers to create an economic electric car will likely intensify to meet the 1998 deadline to produce zero emission vehicles for the California market, and that development will influence the use of electric vehicles in Canada. The demand for ethanol will increase mainly to satisfy oxygenate blending in gasoline.

In summary, on the basis of the economics of using alternate fuels and some consideration of non-economic factors influencing their acceptance by consumers, it is expected that the alternative fuels share of total energy demand for road transportation will continue to be small (see Table 3.5.2), increasing from 2% in 1991 to 6% by 2020.

Table 3.5.2
Alternate Transportation Fuels
(Per Cent of Road Transport Demand)

	1991	2000	2010	2020
Natural Gas	0.30	0.55	0.60	0.51
Propane	1.61	1.89	2.80	2.80
Methanol	0.00	0.12	0.25	2.50
Electricity	0.00	0.00	0.01	0.02
Ethanol	0.04	0.46	0.41	0.45
Total	1.95	3.02	4.07	6.28

Given these trends, road transportation energy is projected to increase 60% over the outlook period, representing an average growth of 1.6% per year. Motor gasoline will continue to be the dominant fuel, growing at 1.6% per year while diesel demand increases at 1.1% per year.

Other Transportation Modes

As shown in Table 3.5.3, demand for aviation fuels is expected to grow by 3.1% over the outlook period, notwithstanding some improvement in aircraft efficiency. This trend reflects a stable real price for turbo fuel and a strong demand for air travel. Aircraft fuel efficiency is expected to improve at an average annual rate of about 1.57o during the 1990s as new aircraft are put into service and older less fuel efficient aircraft are retired. After 2000, fuel efficiency improves at a slower rate to 2010 and then levels off over the remaining years. The strong projected demand for air travel is partially attributed to the increase in leisure travel by the senior segment of the population, and the increase in air cargo volumes generated by improved access for Canadian exports to foreign markets as a result of lower trade barriers.

Table 3.5.3
Transportation Energy Demand
(Average Annual Growth Rates (%))

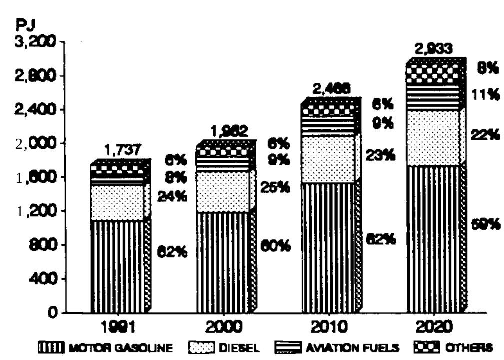
Mode	1981/1991	I 99 1/2000	2000/2010	2010/2020	I 99 1/2020
Road	-0.1	1.0	2.3	1.4	1.6
Air	-0.1	3.4	2.5	3.5	3.1
Rail	-1.0	3.4	2.6	2.7	2.9
Marine	-2.5	0.6	1.6	2.0	1.4
Total	-0.3	1.3	2.3	1.7	1.8

Rail and marine energy demands, are projected to increase at 2.9% and 1.4% per year respectively over the next three decades. Energy demand in these sectors reflects relatively fast RDP growth in the industrial sector, stable fuel prices, and little potential for further improvements in energy efficiency.

Summarv of Transportation Demand

Transportation energy demand is projected to increase about 69% over the 1991 to 2020 period, representing an average annual growth of 1.87o per year. Figure 3.5.2 also illustrates the slight change in fuel composition in the transportation sector during this period. The shares of motor gasoline and diesel are expected to fall, chiefly as a result of increased use of alternative fuels for road transport. Accompanying this fuel shift will be a minor shift in the shares of the various modes of transportation. Rail and marine shares are essentially stable throughout the years. Air increases its share, however, from 8 to 1 l% at the expense of the road sector whose share declines from 80 to 777o.

Figure 3.5.2 -
Transportation Energy Demand
1991-2020

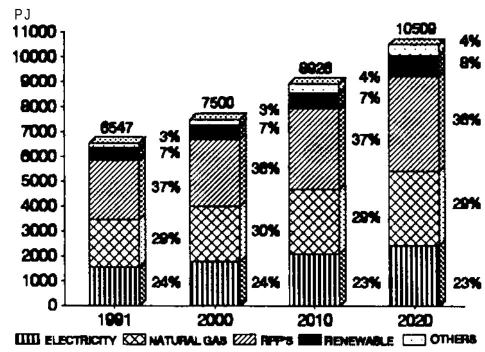


.3.6 Total Secondary Energy Demand

Total secondary demand (the sum of energ y use in the residential, commercial, industrial and transportation sectors) will be 15% higher in 2000 than in 1991 and 61% higher in 2020.

As discussed in the earlier sections, the industrial sector will experience the strongest demand growth and the residential the weakest. Accordingly, the industrial sector's share in total secondary demand is projected to increase from 37% in 1991 to 42% in 2020 while the share for the residential sector drops from 22 to 17% over the same period. The shares for both the commercial and transportation sectors remain relatively stable.

Figure 3.6.1
Secondary Energy Demand by Fuel
1991-2020



As depicted in Figure 3.6.1, market shares for major fuels are projected to remain relatively constant over the outlook period, thereby implying similar demand growth for all the major fuels. It is interesting to note that the historical one-to-one growth relationship between the economy and electricity demand is not expected to continue in this projection (i.e., 2.5% average annual economic growth between 1991-2020 vs 1.5% in electricity demand). The two major factors dampening electricity demand growth are utilities' DSM programs and the projected high cost of electricity relative to natural gas.

As a result of different demographic and economic growth patterns, secondary energy demand growth varies across provinces (see Table 3.6. 1). Due to slower residential and commercial demand growth reflecting relatively slower population and household formation growth, the Atlantic provinces, Quebec and Alberta are expected to experience slower growth than the national average. In the case of Saskatchewan, the slower growth stems chiefly from slower industrial growth. For Ontario, Manitoba and British Columbia, the higher than national average growth derives from higher demographic and industrial production growth,

Table 3.6.1
Secondary Demand by Region
(Average Annual Growth Rates: 1991-2020)

	Electricity	Natural Gas	Oil	Total Demand
Atlantic	1.3	0.0	1,4	1.4
Quebec	1.6	1.8	1.3	1.5
Ontario	1,4	1.7	1.9	1.8
Manitoba	2.0	1.8	1.9	1.9
Saskatchewan	0.8	0.3	1.5	1.3
Alberta	1.3	1.5	1.6	1.5
British Columbia	1.8	1.6	1.5	1.7
CANADA	1.5	1.6	1.6	1.6

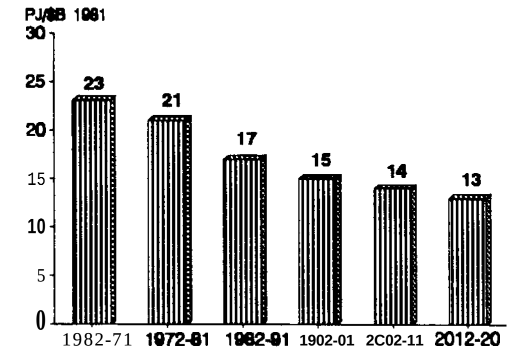
Energy intensity, defined as the ratio of secondary energy consumption to real gross domestic product, is projected to decline by an annual rate of 0.8% between 1991 and 2020 (see Figure 3.6.2). This decline in energy intensity is considerable y less than that experienced in the 1980s (a decrease of 1.8% per year occurred between 1981 and 1991). The smaller intensity decline is mainly attributed to:

a structural shift to more rapid growth in the industrial sector relative to the less-energy intensive commercial sector. In the 1970s and 1980s, growth in service-producing industries out-paced growth in goods-producing industries;

a modest projected increase in energy prices over the 1991-2020 period, whereas in the 1970s and 1980s energy prices rose sharply; and

a reduction in government spending on energy conservation and substitution programs compared to that of the 1980s.

Figure 3.6.2
Energy Intensity: Canada
(Secondary Energy Demand/Real GDP)



3.7 Total Primary Energy Demand

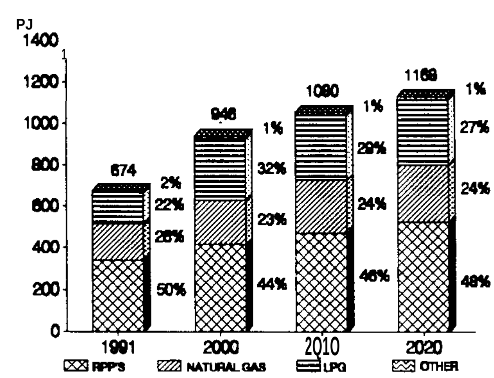
Primary energy demand[15] includes secondary energy demand, non-combustion use, and energy industry supply requirements. Electricity demand is disaggregated by fuels (e.g., nuclear and hydro, etc.). Each component is briefly described below except for electricity generation which is covered in Section 4.2.

<u>Non-Combustion Use</u>

Non-combustion energy use consists of oil-based petrochemical feedstocks, asphalt, lubricating oils and greases, naphtha specialties, petroleum coke and other products. There are also petrochemical feedstock uses for natural gas and natural gas liquids (NGLs), and some non-energy uses for coal and coke. In 1991, non-combustion energy use accounted for 9% of total end-use demand (secondary plus non-combustion energy use) with petrochemical feedstocks and asphalt representing about 70 and 20% respective y of the total.

Petrochemicals are used to manufacture several products namely, fertilizers, plastics, cosmetics, textiles, transportation equipment, rubber and forest products and, therefore, are closely tied to the growth prospects of the economy. Non-combustion energy use is projected to

Figure 3.7.1
Non-Combustion Energy Demand by Fuel
1991-2020



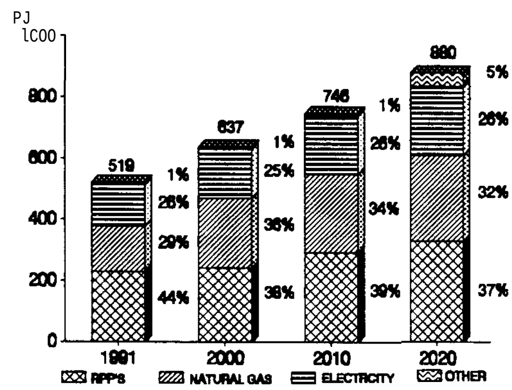
[15] For more details see Appendix A.

increase at an annual rate of 1.8% between 1991 and 2020 and will account for 10% of total end-use demand (see Figure 3.7. 1).

Own-Use

This category relates to the energy consumed by the energy supply industry for its own use. It includes fuels used by pipelines and refineries, and transmission and distribution losses. In 1991, own-use consumption represented 6% of total primary energy demand. On a fuel-by-fuel basis (see Figure 3.7.2), refined petroleum products (RPPs) accounted for approximately 44% of total own-use demand in 1991, natural gas and electricity for 29% and 26% respective y (See Figure 3.7.2).

Figure 3.7.2
Own-Use Energy Demand by Fuel
1991-2020

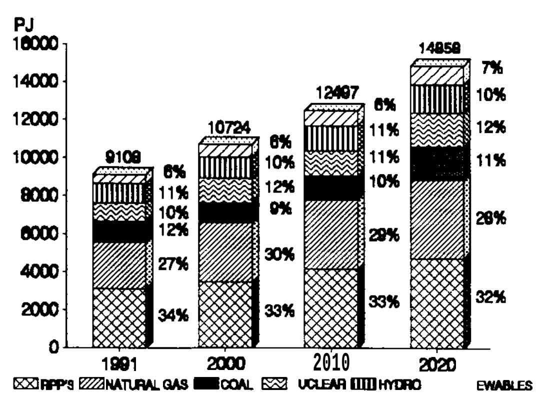


In general, own-use energy requirements are largely driven by domestic and export demand for energy products. Reflecting the increase in natural gas export demand over the period, natural gas is projected to experience the fastest growth followed by electricity and RPPs. More specifically, overall own-use energy requirements are projected to expand at an average annual rate of 1.8% with natural gas growing at 2.070, electricity at 1.8% and RPPs at 1.3%.

Total Primary **Energy**

Total primary energy demand is projected to increase at an annual rate of 1.790 over the 1991-2020 period which corresponds closely to the projected growth for secondary demand. As depicted in Figure 3.7.3, the share of oil in total primary demand will continue to decline but at a much lower rate than in the past because of the limited potential for further substitution and slower progress in efficiency improvements, particularly in the transportation sector.

Figure 3.7.3
Primary Energy Demand by Fuel
1991-2020



Natural gas consumption is expected to increase by 2.5% per year during the 1990s, reflecting strong demand for this fuel in the industrial sector and by utilities. The demand for natural gas then slows down to 1.2% per amum over the period 2000 to 2020, when natural gas becomes relatively more expensive than coal. Accordingly, the share of natural gas in total primary demand rises from 27% in 1991 to 30% by 2000 and then declines to **28%** by 2020.

The share of coal drops from 12% in 1991 to 9% in 2000 due to substitution of nuclear for coal in electricity generation in Ontario. The share for nuclear is projected to increase from 10% in 1990 to 12% in 2000, declining back to 10% in 2020 (see Section 4.2 for details on electricity generation and capacity).

Renewable energy, mainly wood and alcohol fuels, increases its share modestly from 6 to 7% over the 30-year period due to the increased role of wood wastes in the pulp and paper industry and alcohol fuels for transportation.

4. ENERGY SUPPLY

This chapter provides our reference case energy supply outlook. The first section describes the methodology and results for oil and natural gas supply. The second section examines electricity generation and the required capacity expansions to satisfy domestic and export demand. The third and final section discusses coal supply and demand.

4.1 Oil and Gas Supply

Unlike energy demand, for which econometric techniques are available, the approach to projecting oil and gas supply is more eclectic. Available information on the geology, engineering and economics of various potential sources of supply are assembled to arrive at oil and gas resource estimates consistent with the framework assumptions. The approach, which ensures the overall consistency and reasonableness of the oil and gas projections, relates production and price levels to industry cash flow. First, industry investment is projected for petroleum exploration and development. The next step is to project reserve additions given assumptions on oil and gas replacement costs. The final step is to calculate future production based on the estimate of reserve additions as well as the production from established reserves. This approach ensures that projected supply can be achieved with funds available to the industry.

Our assumptions regarding the oil and gas resource bases, industry investment decisions, and replacement costs are provided below. The resulting supply profiles for oil and gas are presented next. Also discussed are the implications of the domestic demand and supply projections for external petroleum trade.

4.1.1 Key Factors Affecting Oil and Gas Supply

Conventional Oil and Natural Gas Resource Base

At the end of 1991, established conventional oil and natural gas reserves were estimated at 4.1 billion barrels and 71.2 Tcf respectively (see Table 4.1.1). These estimates imply reserve-production ratios (R/P) of 10 years for oil and 18 years for natural gas. In terms of resource potential, the conventional resource base for oil and gas is estimated at 13.3 billion barrels and 181.4 Tcf respectively. It must also be recognized, however, that only a portion of the potential resource base would be commercially attractive, particularly given the price projections assumed in this study. Studies by the Geological Survey of Canada[16] (GSC) suggest that 60 to 80% of undiscovered resources of Western Canada may ultimately become commercial supply. Applying a 70% factor to the discovered and undiscovered resource base, would imply a total commercial oil resource, including established reserves, of 10.5 billion barrels or 25 years of supply. Applying the same analysis to gas, implies a commercial resource base of about 148.3 Tcf or an R/P of 37 years.

One can expect that these estimates will continue to be revised upwards because of improvements in

[16] GSC, Conventional Oil Resources of the Western Canada Sedimental Basin, GSC Paper 87-26 (1988); and GSC, Devonian Gas Resources of the Western Canada Sedimentary Basin, Bulletin 452 (1993).

Table 4.1.1
Conventional Reserves and Resource Estimates
Year End 1991

	Oil (10^9bbl)	Gas (Tcf)
Remaining Established Reserves	4.1	71.2
Other Discovered Resources	3.9	
Undiscovered Recoverable Resources	5.3	110.2
Total	13.3	181.4
Commercial Resources [2]	10.5	148.3
R/Ps		
Remaining Established Reserves	10	18
Commercial Resource Base	25	37

Notes: [1] Excludes coal seam gas resources. Established reserve estimates are for 1991 but resource estimates are for 1989.

[2] Established reserves plus *70% of* discovered and undiscovered resources.

Sources: NEB, 1990 Annual Report.
NEB, *Canadian Energy Supply* and *Demand* 1990-2010, 1991.
CPA, Handbook, 1992.

technology and knowledge of the resource base. A recent comprehensive study by the ERCB[17] for example shows continuous upward revisions in the ultimate potential of natural gas: from 110 Tcf in 1973, to 140 Tcf in 1979, 170 Tcf in 1987 and 200 Tcf in 1992 (see Table 4.1 .2).

Table 4.1.2
Alberta's Ultimate Gas Potential

Year of Estimate	TCF
1964	100
1973	110
1979	130 to 140
1985	150
1987	170
1992	200

Source: *ERCB, Report 92-A, 1992.*

Recent studies by EMR and the NEB [18] also support the conclusion that the resource base of the Western Canada Sedimentary Basin (WCSB) is significantly larger than previously estimated. These analyses suggest that there does not seem to be a tightly binding resource constraint on oil and gas supply.

The frontier resource base is also immense. Frontier oil and gas resources are estimated at 22 billion barrels and 275 Tcf respectively. Production of these resources, however, depends on major projects, as discussed below.

Investment

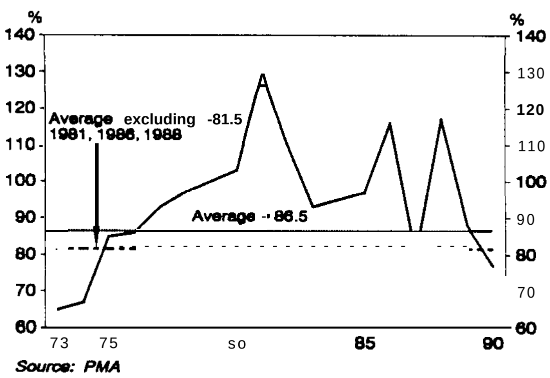
Investment in the Canadian oil and gas industry depends chiefly upon the availability of profitable opportunities and cashflow. Over the past two decades, the ratio of investment to cashflow

[17] ERCB, Ultimate Potential and Supply of Natural Gas in Alberta (Report 92-A), June 1992.

[18] GSC, Devonian Gas Resources of the Western Canada Sedimentary Basin, Bulletin 452 (1993); and NEB, Canadian Energy Supply and Demand 1990-2010, 1991.

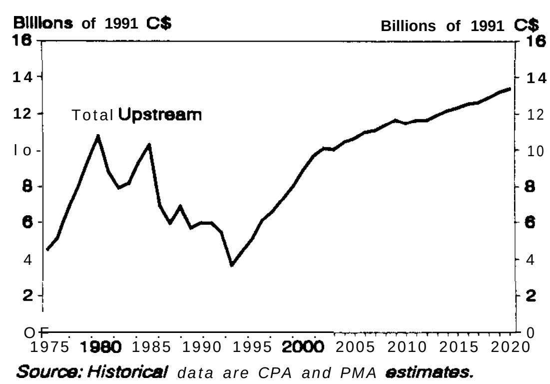
(reinvestment ratio), excluding the years 1981, 1986 and 1988,[19] averaged 81 .5% (see Figure 4.1.1). This high reinvestment ratio is not believed to be sustainable in the future, due to the restructuring of the industry, a higher desired level of dividend payments, and a greater emphasis by some companies on foreign investment. The study assumes that the industry reinvestment ratio in Canada over the projection period averages between 70 and 75%. These ratios yield investments of about $5-6 billion (real 1991$) per year over the short term. However, over the medium to long term, total investment more than doubles, due mainly to an increased number of megaprojects and larger expenditures on natural gas.

Figure 4.1.1
Reinvestment Ratio
(Per Cent)



Since the beginning of 1992, oil-directed and gas-directed activity accounted for about 70% and 30% of total industry investment respectively. The relatively low level of gas-directed expenditures reflects the gas surplus which has plagued the industry for the past several years. As natural gas markets tighten over the next two to five years, gas-directed expenditures are assumed to increase to about 50% of total industry investment by 2010.

Figure 4.1.2
Upstream Oil and Gas Investment
(Billions of 1991 C$)



Megaprojects

Major oil and gas projects are an integral part of overall industry investment and are expected to represent a large share of future supply in Canada. In projecting the timing and size of these projects, many factors are considered, including economic and technical feasibility and related risks, announced industry plans, and industry comments on start-up dates. The major assumptions are as follows:

---

[19] Reinvestment ratios in these years were abnormally high due to the introduction of the National Energy Program (198 1), the oil price collapse (1986), and the combined availability of short-term federal and provincial exploration and development incentives which expired in 1988. Including the cashflow and investment for these years results in a weighted average reinvestment ratio of 86.5%.

Frontiers

Cohasset/Panuke, Hibernia and Terra Nova are assumed to come on stream during the outlook period. The Cohasset/Panuke project which commenced in 1992 is expected to continue for six years with a flat production level of about 20 rob/d. Hibernia is assumed to commence in 1997 with production peaking at 126 rob/d in 1999. Terra Nova is assumed to commence in 1999 with production attaining its maximum level of 80 rob/d in 2001. Later in the period, production from other discoveries such as White Rose, Ben Nevis and Hebron is expected to offset the declines in supply from the Hibernia and Terra Nova projects.

For the Beaufort/Mackenzie Delta region, no major oil or gas prospects are incorporated in the projection. On the oil side, the major constraint is resources - results, to date, indicate that there are insufficient reserves to warrant field development and pipeline construction. In the case of natural gas, a consortium involving Imperial Oil, Shell and Gulf has already received approvals from the NEB to export 9 Tcf from the Delta. An analysis of the data submitted for the export application, however, suggests that these projects are only marginally economic at natural gas prices assumed in this outlook. Further, recent EMR studies[20] indicate that the assumed prices would be insufficient to stimulate further reserve additions and thus ensure the economic feasibility of major development of Delta gas.

Oil Sands Plants and Upgraders

Improvements in technology, and the increase in real oil prices will be key factors in determining the pace of oil sands developments. The projection assumes an incremental 70 rob/d of oil sands production beginning in 2005. This could be brought about by a major expansion, a new plant or a series of smaller plants. Although there are many technical hurdles to overcome, there are reasons for believing that ongoing development of new technologies will be characterized by significant cost reductions. S yncrude for instance, has managed to reduce operating costs to about C$15.40/bbl or 37% below 1982 levels.

The outlook also assumes two new upgraders of 50 rob/d capacity to be operational in 2002 and 2016. Here again, technological advances will be key in determining the pace of development. Upgrader development, will also be contingent on heavy oil market expansion and oil price differentials over the period.

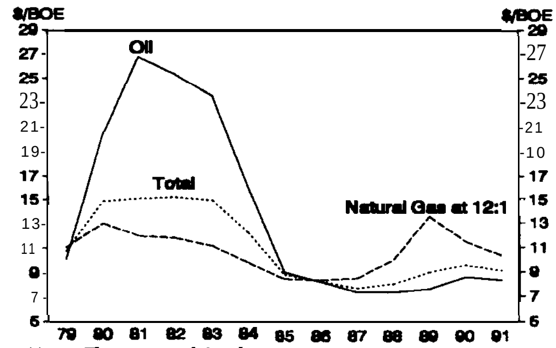
Oil and Gas Replacement Costs

Replacement cost is defined as the dollar cost of finding and developing a unit of crude oil or natural gas. On the surface this appears to be a fairly simple calculation. However, there are a number of interpretations of what constitutes costs, and the reserves associated with those costs. The result is a wide range of estimates that make comparisons difficult and sometimes misleading. The major problem is allocating expenditures to the reserves booked in any particular year.

20 GSC, An Economic Analysis of Beaufort Sea - Mackenzie Delta Oil Resources, GSC Petroleum Resource Supply Economics Committee, September, 1988; and R.F. Corm, S.M. Dallaire, J.A. Christie, G.C. Taylor and R.M. Procter, Natural Gas Resource Assessment and Economic Potential of Undiscovered Natural Gas Resources of the Mackenzie Delta - Beaufort Sea, GSC Open File 2378, 1991.

The study employs the methodology used by companies, namely that replacement costs[21] are the weighted average over five years on unappreciated reserves (see Figure 4.1.3). This methodology reduces distortions caused by price fluctuations and the yearly variations in the size of discoveries.

Figure 4.1.3
Western Canada Finding and Development Costs
(1991 C$/BOE)



Note: Five year weighted average.

It is worthwhile noting, that the relatively high costs of adding oil reserves during the early eighties reflect mainly high cost exploration ventures which were, to a great extent, due to government incentives and the relatively high prices paid for “new oil”. Since 1985, oil replacement costs have remained relatively flat at about $8-9/bbl ($1991). Over the same period, natural gas replacement costs were less stable and averaged $0.75-1. 10/Mcf ($9- 13 per barrel of oil equivalent). In an environment of industry restructuring, low oil prices, unregulated markets, and continuous improvement in technology, a significant run-up in costs appears unlikely. Based on the above considerations, this study assumes an oil replacement cost of $10. 80/bbl (199 1$) over the entire outlook period, while that for gas is assumed to be $0.70/mcf (1991$) until 2000, increasing at 2% per year thereafter, to reflect the exploitation of more expensive resources.

4.1.2 Projection Highlights

Reserve Additions

Assumptions regarding oil and natural gas prices, level of investment and replacement costs result, on average, in oil reserve additions, including bitumen, of 400 million barrels per year and gas reserve additions of 5.2 Tcf per year. These reserve additions as well as the megaproject assumptions have significant implications for the reference case oil and gas supply projections, provided below.

Crude Oil Supply and Trade

- Total crude oil supply declines from 1734 rob/d in 1992 to 1585 rob/d by 1995 before increasing and levelling off at about 1740 rob/d over the remainder of the outlook period (see Figure 4.1.4 & Table 4.1.3). The fall in production in the short term is due to declining conventional production. Over the long term, this decline is more than offset by frontier and oil sands production. By 2020 more than 55% of total crude oil production will be from non-conventional, high cost resources, compared with only 23% in 1992.

---

[21] For an analysis of different finding costs methodologies see for example: Hertsel Labib and Peter Clelford, “Finding Costs of Crude Oil and Natural Gas”, Economic and Financial Analysis Branch, EMR, December 1992.

Figure 4.1.4
Crude Oil Supply*
(Millions of Barrels per Day)

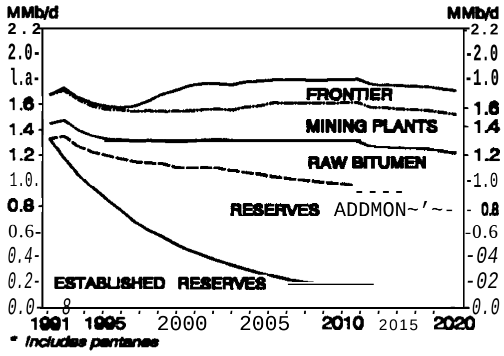


Table 4.1.3
Crude Oil Supply Forecast
(Thousands of Barrels per Day)

	Conventional		Synthetic	Raw Bitumen	Offshore	Total
	Light[1]	Heavy				
1992	977	373	237	126	21	1734
1995	908	291	236	129	21	1585
2000	822	285	236	199	170	1712
2010	720	262	306	305	190	1783
2020	579	194	306	465	190	1734

[1] *Includes pentanes*

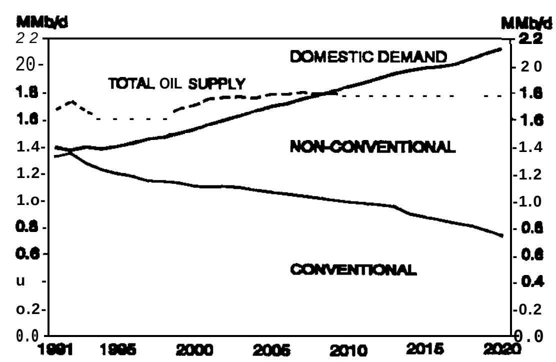
- Conventional oil supply is expected to continue to decline. Light oil supply falls from 977 rob/d in 1992 to 579 rob/d by 2020. Heavy oil supply drops from 373 mb/d in 1992 to 194 rob/d in 2020.

- Total frontier production peaks at 206 rob/d in 2001 and falls to 190 rob/d by 2005, remaining at this level until 2020.

- Synthetic oil supply from mining plants is projected to increase from the current level of 237 rob/d to 306 rob/d in 2007 and remain at this level until 2020.

- Bitumen production is projected to remain flat at the 1992 level of about 130 rob/d until 1995 before increasing to 200 rob/d in 2000 and to 465 rob/d in 2020. The growth in supply for the rest of the 1990s is expected to come mainly from the existing Cold Lake, Wolf Lake and Peace River projects. The increase in supply over the period is expected to satisfy mainly U.S. market expansions and Canadian upgrader feedstock requirements.

Figure 4.1.5
Crude Oil Balance in Canada
(Millions of Barrels per Day)



- Canada is expected to remain a net oil exporter until 2008 (see Figure 4.1.5). Thereafter, net oil imports (the difference between domestic demand and total domestic production) will increase to 385 rob/d, or 18% of total demand by 2020. Throughout the period, Canada will continue to export about 75% of its total heavy oil production. By 2020, Canada's heavy oil net export will be 425 rob/d, considerably less than light oil imports of about 810 rob/d.

Natural Gas Supply and Trade

- As shown in Figure 4.1.6, relatively high surplus productive capacity will continue to exist over the next few years. This surplus, however, will diminish over the medium and long term due to increasing demand. Over the long term, natural gas supply capability is expected to exceed total domestic and export demand by only about 10% or well below the levels experienced in recent years. Any surge in gas demand above the level projected in the outlook will certainly narrow this band. Total gas demand is expected to increase by 50% from the current level of 4.0 Tcf to 6.1 Tcf by 2020.

- Gas export volumes are expected to increase from about 2 Tcf in 1992 to 2.7 Tcf by 2001 and remain at this level for the remainder of the outlook period. Canadian gas exports are expected to continue to account for 10 to 12% of U.S. domestic consumption. The U.S. West Coast and North East markets are likely to account for most of the increase in exports (see Figures 4.1.7).

In general, the oil and natural gas supply projections presented in this section are highly sensitive to the assumptions on industry's reinvestment ratio. For example, a drop of 10 percentage points in the reinvestment ratio (assuming all other parameters remain unchanged including prices) would result in lower oil and gas production of about 12% and 21% respectively by 2020. Additional impact analysis affecting oil and gas supplies are provided in Chapter 6.

Figure 4.1.6
Natural Gas Supply and Demand
(Trillions of Cubic Feet per Year)

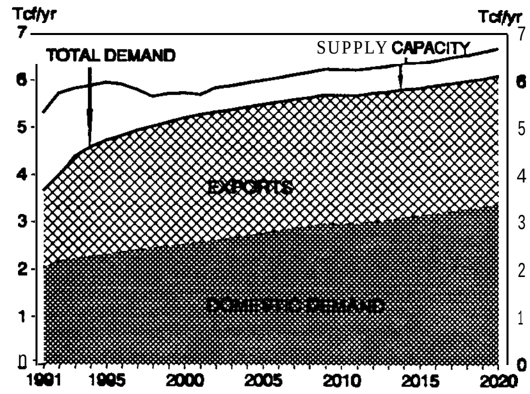
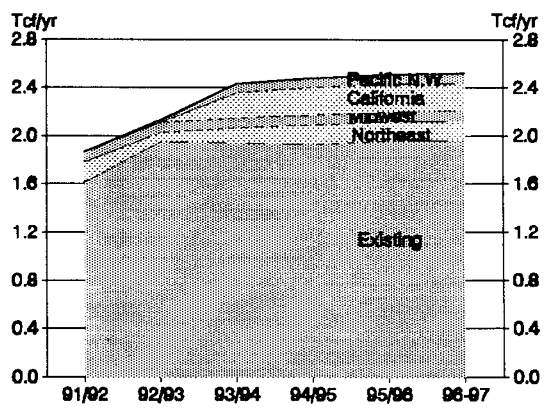


Figure 4.1.7
Natural Gas Exports
(Trillions of Cubic Feet per Year)



Source: EMR, An Evaluation of 1991/92 Canadian Natural Gas Exports with a Mid-Term Forecast, Oil and Gas Branch, 1993, p 48.

— _ 4.2 Electricity Generation and Capacity

This section examines the level and mix of generating capacity required to satisfy the total projected electricity demand presented in Chapter 3 and the expected electricity exports discussed below. At the outset, it should be noted that the required additional capacity will come not only from utilities but also from industrial self-generation and independent power producers (IPPs). Total demand for electricity, coupled with information on the major utilities' long term generation expansion programs, provide an electricity supply scenario for each province and territory.

Table 4.2.1
Provincial Electricity Demand
(GW.h)

	1992	2020	AAGR(%)[1]	
			1992-2020	1981-91
Newfoundland	11317	16261	1.3	2.0
Nova Scotia	9579	13764	1.3	3.3
P.E.I.	745	1070	1.3	3.6
New Brunswick	13836	19881	1.3	4.0
Quebec	166753	262187	1.6	2.8
Ontario	145619	214629	1.4	2.6
Manitoba	18680	31439	1.9	2.4
Saskatchewan	12586	17120	1.1	3.1
Alberta	44865	64 951	1.3	5.9
British Columbia	57716	97136	1.9	2.7
Yukon	470	791	1.9	1.8
Northwest Territories	588	989	1.9	-0.3
Canada	482754	740218	1.5	3.0

[1] *AAGR: Annual Average Growth Rate.*

Assumptions

Domestic Electricity Demand

As a result of the recent recession and structural changes in the economy, electricity demand in Canada is projected to grow at an annual rate of only 1.5% for the next thirty years, half of the prevailing growth rate in the 1980s (see Table 4.2.1). As a result, a significant amount of surplus capacity exists in most regions of Canada; the power plants were planned and built during the high growth period of the 1970s and 1980s. This excess capacity, in conjunction with utilities' DSM programs (see discussion below), will result in most provinces not requiring additional power plants to meet increasing electricity demand until after the year 2000.

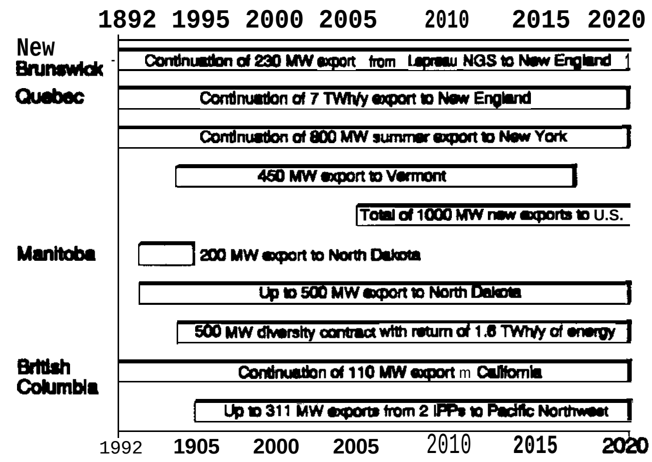
Electricity Exports

In 1991, total gross electricity exports to the U.S. were 19.8 TW.h (8.8 TW.h firm), mostly from New Brunswick, Quebec, Manitoba and British Columbia; by 2020, gross exports will increase to 50.5 TW.h (24.1 TW.h firm). Figure 4.2.1 shows the projected firm exports; more specifically, the assumptions call for the continuation and renewal of existing firm and interruptible contracts and agreements with few new ones.

Demand Side Management Programs

Utilities pursue Demand Side Management (DSM) initiatives in order to maximize efficiency in their existing operations and to reduce the need for capacity additions. DSM programs aim at changing the

Figure 4.2.1
Firm Electricity Exports
Canada 1992-2020



pattern and magnitude of electricity use through such actions as load reduction (improve electrical end-use by promoting more efficient appliances), load shifting (move the use from peak time to periods of lighter demand by adopting time-of-use rates) and peak clipping (reduce demand at peak time without shifting it to another period by offering preferential rates for interruptible load).

Over the past several years, Canadian utilities have announced ambitious DSM programs designed to save over 12 GW **(about 10% of capacity) by 2000.** Announced DSM expenditures to 2000 by the three largest utilities - Ontario Hydro, Hydro Quebec and B.C. Hydro - were on the order of $8 billion.

With the existence of significant overcapacity during the next decade, DSM expenditures of this magnitude are no longer credible. While DSM is an attractive alternative to building new capacity, it is probably less so when assessed against the mothballing of existing operating plants, Ontario Hydro has already reduced its planned DSM spending for the 1990s by $2.7 billion from a total of $4.5 billion and, in June 1993, announced significant restrictions on its industrial rebate programs. Reflecting these developments, our own, very speculative estimate is that utilities' DSM spending to 2000 will be on the order of $2.5 billion.

Both the utilities and other anal ysts of the electricity market find it difficult to assess the costs and benefits of DSM programs[22]. These difficulties relate, in part, to uncertainty concerning the rate of penetration of such programs into the electricity market. Further, the assessment of load reduction measures, typically a major element of the DSM effort, is complex.

Our approach to incorporating DSM in the projections is probably too simplistic and does not address all the features of such initiatives. It attempts to capture the information/suasion elements of DSM by judgmentally increasing the rate of penetration of energy-efficient technologies. These effects are incorporated in the secondary demand projections of Chapter 3. To address the load reduction measures, we include our estimate of DSM expenditures to 2000, $2.5 billion, in the rate bases of the utilities. This produces a reduction in the demand of electrical energy via an increase in the price of electricity. Finally, to address the load shifting component, we judgmentally reduce the peaking requirement.

The above approach to DSM is, admittedly, not comprehensive, although the resulting error is probably not very large in a situation of significant overcapacity. The consequences of the methodology y are likely, however, to be more serious in the post-2000 period, when the need for new capacity should bring DSM programs under active consideration. For this reason, NRCan would be

22 For a discussion of this point, see EMR, Electric Power in Canada, 1991, p. 108.

most interested in working with the utilities and provincial energy ministries to develop a better means of evaluating DSM potential.

Independent Power Production

Most utilities have indicated a willingness to buy electrical energy from non-utility producers at prices which reflect their avoided production costs. Some provinces, such as British Columbia, Alberta, Ontario and Quebec, have called on the non-utility sector for proposals to supply electricity to meet the anticipated additional demand. The private sector is increasingly interested in cogeneration, that is producing heat and electricity for their own-use and/or for sale to utilities. Combined cycle cogeneration technology results in up to an 80% efficiency versus 35% for a traditional power plant.

For the most part, non-utility generation (NUG) will come from natural gas, followed by biomass/refuse and small scale hydro. By 2000, IPPs are projected to sell about 25 TW.h to utilities representing 5% of total electricity demand (see Appendix C for projected NUG capacity).

Projection Highlights by Province

Utilities require ample production capability to satisfy winter peak demand and to provide reliable service. In addition to respecting environmental constraints and standards, provincial utilities develop resources which are the most economical and reliable and result in the least long term cost to their customers. Canadian utilities also aim to maximize the use of in-province resources. These factors were taken into account in developing the electricity expansion programs discussed below. The timing of the capacity additions is designed to meet the projected electricity demands, exports and NUG assumptions discussed earlier, as well as the expected decommissioning of older power plants.

Newfoundland and Labrador

Long term electricity needs are assumed to be supplied from the Lower Churchill development in Labrador via an 800 MW high voltage direct current submarine cable. The transmission line, expected to be completed by the year 2000, will be linked to the construction of the Gull Island (2 264 MW) and Muskrat Falls (824 MW) hydro generating stations by 2002 and 2006 respectively, and the sale of some 2200 MW of the output to Quebec under long term contracts.

Nova Scotia

The 165 MW Point Aconi 1 Circulating Fluidized Bed (CFB) coal combustion plant is expected to be in service in 1993. Nova Scotia Power is expected to add new base-load power plants at the Point Aconi site by the year 2000, when provincial load requirements are projected to exceed available capacity. These new plants are expected to use the CFB technology burning indigenous coal.

Prince Edward Island

For economic reasons, Prince Edward Island has been purchasing most of its electrical energy from New Brunswick via a submarine cable, although it has oil-fired power plants to meet its needs. As electricity demand grows, the Island will continue to purchase most of its requirements from New Brunswick, and possibly from Nova Scotia starting in 1995. Over the outlook period, Maritime Electric will also build new oil-fired combined cycle power plants to replace decommissioned units.

New Brunswick

After the completion of the 440 MW Belledune 1 in 1993, the next base-load addition is assumed to be a 450 MW CANDU 3 nuclear unit at the Lepreau site by the year 2005. Additional coal-fired plants are assumed to be built at the Belledune site in the late 2010s as total demand will exceed available capacity. To meet stringent federal and provincial emission standards and acid rain constraints, New Brunswick (NB) Power will install flue gas desulphurization systems on all new fossil fuel-fired power plants and use low sulphur coal at some existing stations. Coal from various sources (domestic as well as imported) and a Venezuelan emulsion of water and bitumen called "Orimulsion" will be used at NB Power's thermal generating stations.

Quebec

Hydro-Quebec is committed to complete the development of the "La Grande" hydro complex with the construction of Eastmain 1 by 2001. The development of the 3 168 MW Grande Baleine complex is assumed to occur by the year 2005, followed by Sainte-Marguerite in 2008, and then the 8440 MW Nottaway-Broadback-Ruppert (NBR) hydroelectric system during the 2010 decade. Beginning in 2003, Quebec is expected to purchase up to 2 200 MW from the Lower Churchill hydro development in Labrador, in addition to production from Churchill Falls station. This expansion program is designed to satisfy 2250 MW of firm exports to the U.S. by 2005. However, this long term supply strategy may be affected by the environmental review currently being conducted.

Ontario

With lower than anticipated domestic demand, some of Ontario Hydro's excess capacity is likely to last until the middle of the next decade. Additional purchases from NUG (1 000 MW) and from Manitoba Hydro (1 000 MW) are assumed by 2005 and 2008 respectively, with the redevelopment of several old hydroelectric power plants (Niagara station, Mattagami complex) in 2005-07, when provincial load is projected to exceed available capacity. Ontario Hydro is expected to pursue a long term supply strategy consisting of building coal-fired plants using clean coal technologies, such as the Integrated Coal Gasification Combined Cycle (IGCC), and CANDU nuclear generating stations, when old nuclear and coal-fired units are decommissioned during the 2006-2020 period. The present nuclear power plants will likely be retubed during their lifetime and existing coal-tired units will be life-extended and equipped with scrubbers. It should be noted, however, that Ontario Hydro's plans are currently in flux. It is possible, for example, that the utility will decide to mothball part of its nuclear capacity (i.e., some of the units at the Bruce complex) and shift production to coal-fired generation.

Manitoba

Manitoba is expected to continue to develop its rich hydroelectric potential once total demand exceeds available capacity, starting with the 352 MW Wukswatim power plant anticipated to be built by the year 2000. The recent cancellation of the 1 000 MW long term purchase by Ontario Hydro will postpone the completion of the 1 290 MW Conawapa station until the year 2008, when it is assumed that Manitoba Hydro will sell 1 000 MW to Ontario under a new long term contract. other Lower Nelson developments are projected to occur during the 2010 decade.

Saskatchewan

A second 280 MW coal-fired unit is projected to be built at the Shand site by the year 2001. Saskatchewan Power will add new base-load capacity, using clean coal technologies, as electricity demand grows. The 300 MW Wintego hydro generating station is assumed to be built by 2009.

Alberta

The 386 MW Genesee 1 is anticipated to be built by 1994. Medium term load growth in the province will be met by the Alberta Interconnected System (AIS), with increased purchases from IPPs (up to 1200 MW by 2006). Alberta is expected to pursue a long term strategy consisting of building new power plants, using clean coal technologies when old thermal generating units are decommissioned during the 2000-2020 period.

British Columbia

The provincial government and British Columbia Hydro have announced plans to fully utilize all available resources (Power Smart Programs, NUG, Columbia River Downstream Benefits) in the province or abroad, before committing to any new construction of power plants. BC is expected to need additional base-load capacity to meet increased domestic demand by the year 2005, with the addition of a fourth unit at the existing Seven Mile station, followed by the development of the Waneta Expansion, Keenle yside and Peace Site C hydro projects during the 2005-2010 period. The 2000 MW Hat Creek coal-fired power plants are assumed to be developed during the 2010s.

Yukon and Northwest Territories

Unlike the provinces, the Yukon and Northwest Territories have no integrated network; the total electricity demand is a combination of isolated loads. Small diesel combustion turbines are projected to be built when and where required to provide a secure and adequate supply for the isolated communities. Small hydro projects could replace some of these diesel turbines.

National Trends

The long term outlook for electricity in terms of generation mix is presented in Table 4.2.2. Overall, electricity y production will increase by a modest 17 percent by 2000, about three quarters the growth of the economy. By 2020, electricity production will be approximately 59 percent higher than 1991 levels. In 1991, hydro accounted for 62 percent of total electricity generation, coal for 17 percent, nuclear for 16 percent and oil and gas for 2 percent each. Hydro power will largely retain its share in the future, accounting for 60 percent of total generation in 2020. Coal's share will initially decline, reflecting overcapacity, additional nuclear power plants, and the increasing use of natural gas. Post 2000, however, it will experience a renaissance, as a base-load alternative to nuclear, and it will be based on clean coal technologies. By 2020, its share, 15 percent, will remain at about the 1991 level. After the construction of Darlington, generation by nuclear power will remain nearly flat until the 2010 decade when Ontario brings new capacity on line. Oil-fired generation, by contrast, will virtually disappear as oil capacity is increasingly relegated to reserve status or to satisfying peaking requirements.

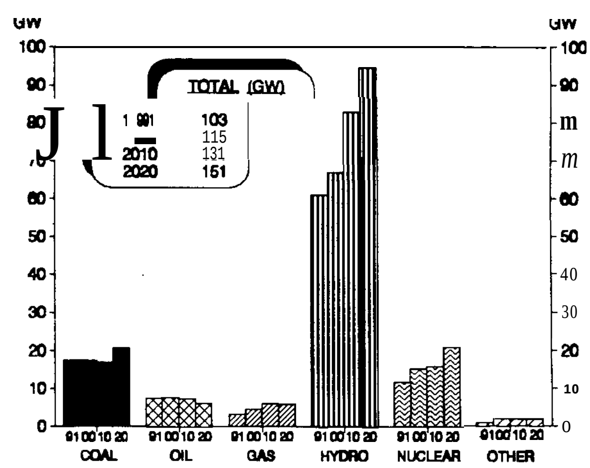
The generation estimates for natural gas require some explanation. Gas-fired generation is projected to increase, relative to 1991, by almost 2 1/2 times by 2000 and to triple by 2010 before stabilizing at about 35 TW.h. These increases, while impressive, are considerably below plans announced over the past several years. The reason is that, although improved turbine technology and low natural gas prices make non-utility gas-fired generation very competitive, IPPs are attempting to break into an industry already experiencing significant surplus capacity. By the time that new capacity is required (i.e., post 2005), rising natural gas prices will have partly eroded that competitive advantage.

The thirty year outlook for capacity (see Figure 4.2.2) shows that Canada will continue to depend on conventional sources of supply, such as hydro, coal and nuclear to meet its growing electricity demand, even with increased IPPs and DSM programs. During the 2000-2020 period major hydro generating stations will be developed in Labrador, Quebec, Manitoba and British Columbia. After the completion of Darlington in 1994, Ontario will not put into service any new nuclear or coal-fried plants until 2010. Over the following decade, however, several CANDU and coal-fired stations are projected to be built. Coal-fired power plants of the conventional type, as well as those using clean coal technologies (such as CFB, IGCC), will be built in New Brunswick, Nova Scotia, Saskatchewan, Alberta and British Columbia during the 2010s. While more natural gas will be used in electricity generation, mostly by the NUG/IPPs, the fuel is still projected to play a small part in the electric power industry.

Table 4.2.2
Electricity Production by Fuel
(TW.h)

	1991	2000	2010	2020
Coal	82.6	63.8	80.4	113.0
Oil	12.4	11.7	11.8	3.2
Natural Gas	9.5	22.0	30.7	35.4
Fossil Fuels	104.5	97.5	122.9	151.6
Hydro	305.5	354.8	423.0	471.0
Nuclear	80.1	113.4	111.7	149.9
Other	2.5	12.1	12.1	12.1
Totat	492.6	577.8	669.7	784.6

Figure 4.2.2
Generating Capacity by Fuel



_ 4.3 Coal Supply and Markets

This section begins with a review of Canadian coal reserves and is followed by a discussion of the supply and demand projections. It concludes with an overview of the resulting coal trade balance to 2020.

Reserve Base

At the end of 1985, recoverable coal reserves in Canada were estimated at over 6.5 billion tonnes (see Table 4.3. 1), which represents approximate y 75 % of mineable coal reserves. Of the recoverable coal reserves, 53 percent are bituminous, 15 percent are sub-bituminous and the remaining 32 percent are lignite. At current levels of production, these reserves translate into approximately 90 years of supply for bituminous, 40 years for sub-bituminous and 250 years for lignite. Therefore, we have more than adequate reserves for the foreseeable future.

Coal is commonly classified by its end use, either thermal or metallurgical. In Canada, thermal coals are essentially combusted to produce steam for electric power generation while metallurgical coals are used to produce metallurgical coke for the steel industry.

Of the 6.5 billion tomes of recoverable coal reserves in Canada, two-thirds are thermal and the remainder are metallurgical.

Of the bituminous coal reserves shown in Table 4.3.1, some are suitable for metallurgical uses. The remainder of the bituminous, along with all of the sub-bituminous and lignite are suitable for thermal applications.

Table 4.3.1
Recoverable Coal Reserves in Canada
as of December 31, 1985
(Megatonnes)

	Bituminous'	Sub-Bituminous	Lignite	Total
British Columbia	1998		566	2564
Alberta	1 040	872		1912
Saskatchewan			1 670	1670
New Brunswick	21			21
Nova Scotia	415			415
Canada	**3474**	**872**	**2236**	**6 582**
R/P Ratios[2] (years)	90	40	250	90

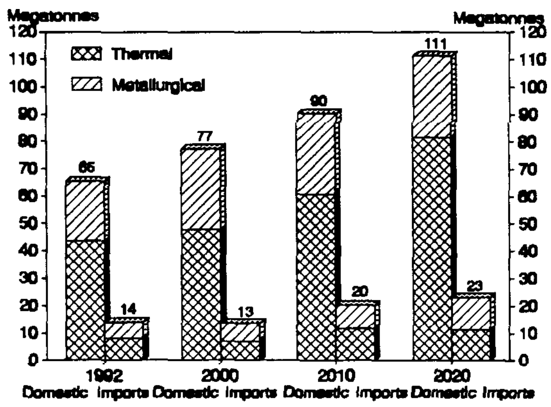
Notes: [1] *Small amounts of anthracite are included in the bituminous category.*
[2] *R/P ratios are estimated based on 1991 production data as reported by Statistics Canada.*
Source: Compiled from information contained in *Coal Resources of Canada, GSC, 1989, p.* 25.

Supply

In 1992, the total supply of coal amounted to 79 megatonnes (see Figure 4.3. 1). Of this total, 65 megatonnes (Mt) were produced domestically y and 14 Mt were imported. The domestic production comprised 32 Mt of bituminous, 23 Mt of sub-bituminous and 10 Mt of lignite. Grouped by thermal and metallurgical, domestic production was 43 Mt and 22 Mt respectively.

Domestic thermal coal, by type of coal, is produced regionally as follows: lignite - 100% from Saskatchewan; sub-bituminous - 100% from Alberta; and, bituminous -3970 from Alberta, 34% from Nova Scotia, 23% from British Columbia and 4% from New Brunswick. Domestic metallurgical production is mainly from British Columbia at 67%, Alberta accounts for 29% and the remainder is from Nova Scotia. Of the 14 Mt of imported coal in 1992, 8 Mt were thermal and 6 Mt were metallurgical. Over 95% of the imports are destined for the Ontario market with the remainder to Quebec and New Brunswick. The United States is the principal supplier of Canadian import requirements.

Figure 4.3.1
Total Coal Supply
(Megatonnes)

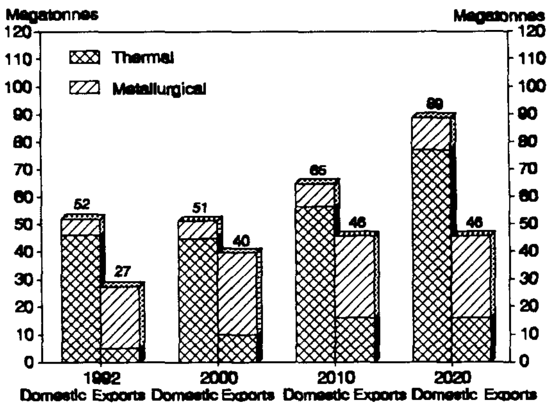


Over the projection period, total Canadian coal supply is expected to increase to 134 Mt by 2020, reflecting an increase of slightly less than 2% per year. Both the domestic and import components are expected to grow at approximately the same rate. Domestic production will increase to 111 Mt and imports to 23 Mt. The growth in the thermal and metallurgical components of the imports will be approximate y the same, whereas for domestic production most of the growth will be in thermal coal. Metallurgical coal production is expected to return to its peak level of about 29 Mt by 1995 and remain flat thereafter.

Demand

Figure 4.3.2 depicts domestic and export demand for metallurgical and thermal coal. In 1992, total demand was 79 Mt, of which 52 Mt were for domestic requirements and 27 Mt were for export. Some of the key factors underpinning the coal consumption projections are: production and transportation costs, environmental concerns and, in some regions, coal's availability relative to other indigenous energy resources.

Figure 4.3.2
Total Coal Demand
(Megatonnes)



Over the projection period, domestic demand for thermal coal is expected to rise from 46 Mt in 1992 to 77 Mt by 2020. Electric utilities account for more than 95% of Canadian thermal coal consumption.[23] In 1992, electric utilities consumed 45 Mt of coal, of which 38 Mt came from domestic sources and the remainder from the U.S.

Provinces with indigenous coal resources will continue to rely on these deposits to generate their electricity requirements. The only exception to this is British Columbia, where it has been assumed

23 Based on information provided by Statistics Canada and the Coal and Ferrous Division of EMR.

that coal will not be used for power generation until after 2010.

Alberta is the largest consumer of coal for electrical power generation in Canada. Most of this demand is met with its sub-bituminous production and a small portion from its bituminous production. The majority of its bituminous thermal coal, approximately 40% of its total bituminous production, is either shipped to Ontario, for use by Ontario Hydro or exported. The remaining bituminous production is metallurgical quality and is exported.

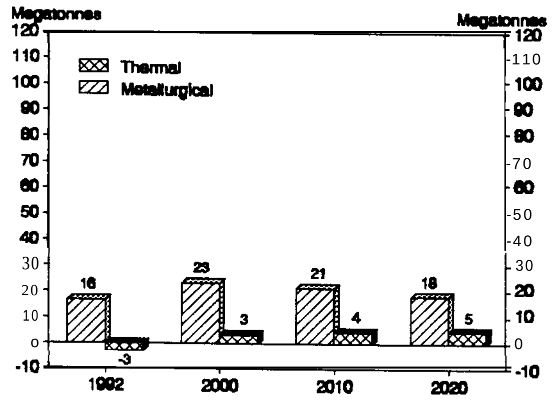
Ontario is the second largest consumer of thermal coal but has no coal production. U.S. sources are expected to account for about two-thirds of Ontario's thermal coal requirements with the remainder being met from western Canada. Bituminous coal from British Columbia, Alberta and the eastern United States meets some of the requirements of power stations in southern Ontario, while lignite from Saskatchewan fuels the coal-fired stations in northern Ontario.

Domestic demand for metallurgical coal is mainly by the steel industry in Ontario, and its requirements are met by imports from the U.S. Demand for metallurgical coal is expected to increase from approximately 6 Mt in 1992 to 12 Mt by 2020.

Of the 27 Mt of coal exported from Canada in 1992, 22 Mt were metallurgical and 5 Mt were thermal. The majority of demand for Canadian metallurgical coal comes from abroad, with most of the exports going to the Asia-Pacific region, primarily Japan, South Korea and Taiwan. Metallurgical exports are projected to rise to 29 megatonnes by 1995 and to remain at this level until 2020. Exports of thermal coal are expected to rise to 16 megatonnes by 2010 and remain flat thereafter. To reach these export levels, Canada will have to be an aggressive marketer, particularly in the Asia-Pacific region.

World thermal coal import demand, particularly in the Asia-Pacific region and Europe, is expected to expand whereas metallurgical coal markets are expected to be stable at best. The immediate challenge for Canadian producers will be to recapture metallurgical export sales lost as a result of production disruptions in 1992. In the longer term, expanding thermal coal markets should provide opportunities for Canadian producers. However, our ability to capture a portion of the expanding thermal market will depend on the future world price of coal. Due to a surplus of coal, world prices have fallen, and many exporters are making unacceptable rates of return. Coupled with low prices, producers shipping coals to export or to central Canadian markets face long and costly rail hauls.

Figure 4.3.3
Net Exports
(Megatonnes)



Coal Trade Balance

Currently, Canada is a net exporter of metallurgical coal and a net importer of thermal coal (see Figure 4.3.3). In 1992, net exports of metallurgical coal were 16 Mt and net imports of thermal coal were 3 Mt.

Net exports of metallurgical coal are anticipated to increase to 23 Mt by 1995 and decline slightly afterwards. In the case of thermal coal, it is expected that by 2000 Canada will attain a net export position and maintain it over the projection period.

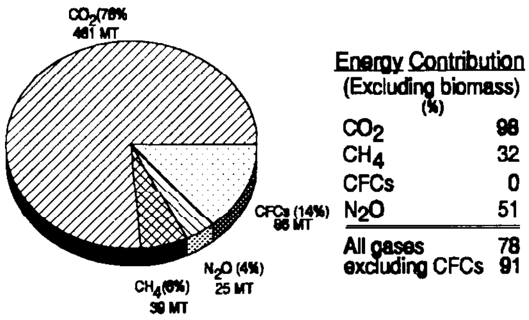
By *2020,* Canada's total net exports of coal are anticipated to increase to 23 Mt, of which 5 Mt will be thermal coal and 18 Mt will be metallurgical, compared to a 1992 total net export of 13 Mt.

5. _GREENHOUSE GAS EMISSIONS

Over the past several years, environmental issues, particularly those relating to atmospheric pollution, have attracted increasing public concern. Global warming and urban air quality have joined acid rain as critical items on local, national and international political agendas.

It is also increasingly recognized that energy use, notably the combustion of fossil fuels, is the major source of anthropogenic emissions (i.e., emissions related to human activities) responsible for atmospheric pollution. As shown in Figure 5.1, fossil fuel use accounts for almost all of Canada's CO_2 emissions - the principal greenhouse gas (GHG). On a radiative equivalent basis, fossil fuel combustion accounts for 78% of the total of all greenhouse gases, but this estimate rises to 91% if chloroflourocarbons (CFCs) are excluded.

Figure 5.1
Anthropogenic Emissions of Greenhouse Gases in Canada for 19901



[1] *Estimated using 100 year global warming potential (GWP).*
Source: Environment Canada and NRCan.

In addition to the greenhouse gases, fossil fuel use contributes approximately 80% of nitric oxides (NO_x) and 35% of volatile organic compound (VOC) emissions, which in combination are responsible for urban smog, and approximately 6070 of energy-related sulphur dioxide emissions, chiefly from the burning of coal for electricity generation.[24]

Given the important role of fossil fuel use in the contribution of atmospheric emissions, future energy trends will be a significant determinant of emissions trends. Technological developments, to reduce the volume of emissions per unit of fuel, may also have an important impact on emissions trends, but their role will be somewhat limited in the case of carbon dioxide. The purpose of this section is to provide reference scenario projections for the energy-related portion of greenhouse gas emissions. It is important to note that we have <u>not</u> imposed the greenhouse gas stabilization target in the results reported below.

5.1 Carbon Dioxide

Carbon dioxide is an integral product of fossil fuel combustion, and emissions of this gas are directly related to the carbon content of such fuels. Details on the factors used to derive $C0_2$ emissions from fuel data are provided in Appendix B. As a rule of thumb, coal emits almost twice as much and

---

[24] Estimates of NO_x, VOCS and SO_2 have been made by NRCan for those emissions which are energy-related. The accuracy of these estimates is highly questionable because of their technological dependence, particularly when projected over long time periods. Therefore, the estimates are not included in this report. NRCan intends to improve upon the estimation methodology and would welcome discussion with others on this matter.

refined petroleum products emit 40 percent more CO_2, per unit of energy, than does natural gas.

CO_2 emission levels, by fuel source, for 1990 and the projection period are shown in Figure 5.1.1.[25] In 1990, petroleum products accounted for just under one-half of the 461 megatonnes of CO_2 emissions. Natural gas and coal were responsible for 30 and 21 percent respectively. Raw CO_2 commingled with natural gas production has been included with the natural gas share. The remaining two percent, labelled industrial processes, are mainly from cement and lime production.

Our reference projection suggests that total CO_2 emissions will increase over time, from 461 megatonnes in 1990 to 510 in 2000 and to 716 in 2020. The growth rate over the 1990s is slightly lower (1.0 percent per annum) than that for the following two decades, (1.7 percent per annum) reflecting the expanded use of coal for electricity generation in the latter period. The share of emissions generated by combustion of oil products declines gradually over time. Over the entire 1992-2020 period, CO_2 emissions from natural gas grow at 1.8 percent compared to 1.5 percent for coal and 1.2 percent for oil.

Table 5.1.1 gives the CO_2 results on a sectoral basis. In 1990, total industrial emissions (i.e., from industry, producer consumption and industrial processes) were responsible for 32 percent of CO_2 emissions, while transportation and electric utilities (conversion requirements) were responsible for a further 27 and 21 percent respectively. Residential, commercial and non-energy use accounted for the remaining 20 percent. The largest increments in CO_2 emissions over the next three decades are from electric utilities and the transportation and

Figure 5.1.1
CO_2 Emissions by Fuel
1990-2020

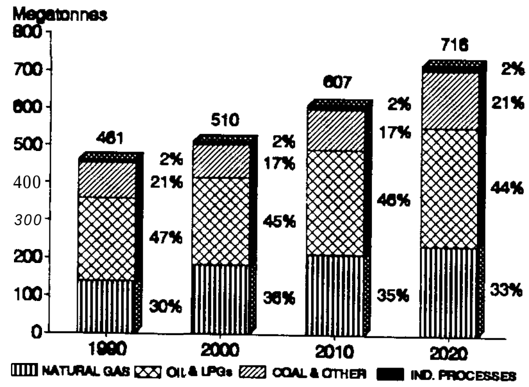


Table 5.1.1
CO_2 Emissions by Sector
1990-2020
(Megatonnes)

SECTOR	1990	2000	2010	2020
Residential	52	53	54	56
Commercial	31	36	43	50
Industrial	83	97	118	144
Transportation	124	135	169	198
Non-Energy	14	23	26	28
Producer Consumption	47	61	69	78
Industrial Processes!	15	19	23	26
Conversion Requirements	96	87	107	136
TOTAL	461	510	607	716

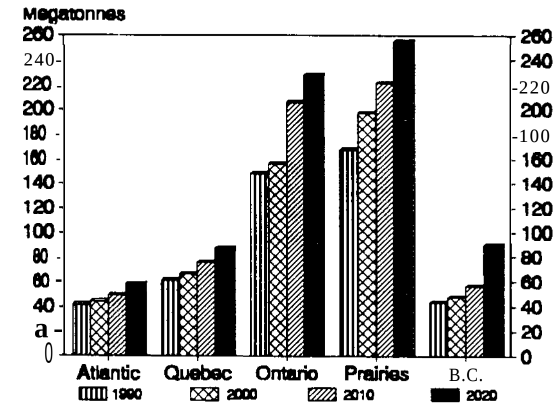
[1] *Raw CO_2 has* been included here, *to* be consistent with the treatment in *Environment* Canada's publication on greenhouse gas estimates *for 1990,* but it is included with natural *gas in* Figure 5.1.1.

[25] Emissions from biomass combustion are not included in the total. Using conventions developed by international organizations such as OECD, CO_2 emissions from biomass are not counted if a nation's forests are managed in a sustainable manner. If this is the case, the regenerated forest will sequester the same volume of CO_2 as is emitted by biomass combustion. Analysis by Forestry Canada suggests that under current management practices, Canada's forests are a slight net sink.

industrial sectors. To the year 2000, emissions from the electrical utility sector decline reflecting the substitution of nuclear for coal; this is reversed after 2000, reflecting the increased use of coal for existing and new capacity. Emissions from the residential sector are projected to show only modest increases over the 30-year period, reflecting lower population and household growth and, in particular, the increasing impact of energy efficiency programs.

The regional distribution of CO_2 emissions is shown in Figure 5.1.2. Ontario and the Prairies dominate in terms of level - each accounting for about 35 percent of emissions in 1990- and continue to dominate over time reflecting the high utilization of fossil fuel energy. The results for the Prairies also reflect the heavy fossil fuel energy requirements for the oil sands and bitumen projects in Alberta.

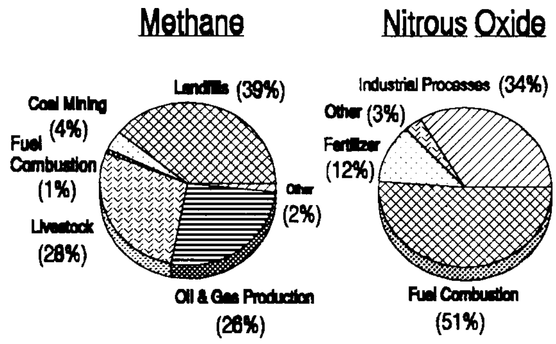
Figure 5.1.2
CO_2 Emissions by Region
1990-2020



5.2 Other Greenhouse Gases

In addition to carbon dioxide, direct greenhouse gases include chloroflourocarbons (CFCs), methane (CH_4) and nitrous oxide (N_2O). CFC emissions are not related to energy use,[26] and energy plays a smaller role in the generation of CH_4 and N_2O emissions than is the case for carbon dioxide. As shown in Figure 5.2.1 energy is responsible for about 32 percent of methane emissions chiefly from oil and gas production, coal mining and incomplete fuel combustion. The majority of methane emissions are from cattle (enteric fermentation) and landfills. Just over one-half of N_2O emissions are related to energy. The remainder is due mainly to chemical processes and fertilizer use.

Figure 5.2.1
Anthropogenic Emissions of Methane and Nitrous Oxide by Source in 1990



Source: NRCan and Environment Canada.

Our projections of energy related CH_4 and N_2O emissions are provided in Table 5.2.1. They are constructed by relating the emissions to a projected source variable (i. e., in the case of methane, the volume of oil and gas production). This procedure assumes, in effect, that technology influencing

[26] CFC emissions are used in refrigeration and aerosols. CFC emissions, in addition to their role in global warming, are responsible for stratospheric ozone depletion. Under the 1985 Montreal Protocol, Canada and other signatories committed to phase out production of CFCS by 2000. Canada has since advanced this deadline to 1997.

Table 5.2.1
Energy Related Emissions Estimates
for Methane and Nitrous Oxide
(Kilotonnes)

	1990	2000	2010	2020
CH_4	1 140	1 290	1 360	1 400
N_2O	47	52	65	76

emissions per unit remains unchanged over the projection period. For this reason, among others, the methane and nitrous oxide estimates are subject to wider ranges of uncertainty than are the CO_2 results.

With this caveat in mind, our projections indicate that energy-related methane emissions will increase from 1 140 kilotonnes (kt) in 1990 to 1 290 kt in 2000 and to 1400 kt by 2020 for an overall growth of 0.7 percent per year, This trend mainly reflects the increase in natural gas production. In the medium term, emissions from coal mining are projected to be lower than in 1990 because of reductions in production in Nova Scotia. Nitrous oxide emissions from energy grow from 47 (kt) in 1990 to 76 kt by 2020 largely reflecting the increase in motor gasoline and diesel fuel usage.

Methane and nitrous oxide are more powerful greenhouse gases than CO_2 reflecting their longer residence in the atmosphere (for N_20 in particular) and their greater heat absorptive capacity. These effects are captured by multiplying the volume of emissions by a global warming potential factor (GWP). For a 100 year time scale, the GWPs used here are 11 for methane and 270 for nitrous oxide, indicating that a molecule of each gas is respectively 11 and 270 times more powerful in trapping heat than a molecule of carbon dioxide.

Figure 5.2.2
Energy Related Greenhouse Gases on a CO_2 Equivalent Basis[1]
1990-2020

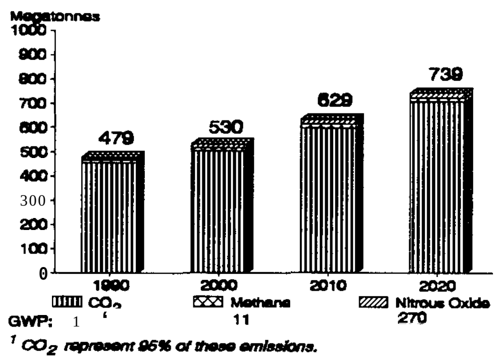


Figure 5.2.2 summarizes our projections of energy related GHG emissions (plus the small contribution of industrial processes to CO_2) on a $C0_2$ equivalent basis. Annual GHG emissions from energy increase from 479 megatonnes in 1990, to 530 in 2000 and to 739 megatonnes by 2020 for an overall growth rate of 1.5 percent per annum. CO_2 contributes by far the largest share, very nearly 95 percent for all years. Methane and nitrous oxide each contribute about half of the remainder.

5.3 The Greenhouse Gas Stabilization Goal

The Government of Canada committed, in the Green Plan, to stabilize greenhouse gas emissions, other than those covered by the Montreal Protocol (i.e., CFCs), at 1990 levels by the year 2000. The goal is also a part, although the language is somewhat imprecise, of the Climate Change Convention signed at the 1992 Rio Conference. Canada ratified the Convention in December 1992, but the document does not become legally binding until 50 countries have ratified it.

What are the implications of the current analysis for the greenhouse gas (GHG) stabilization goal?

Addressing this question requires the elaboration of several points to place the analysis in context. First, the projections in Figure 5.2.2 do not provide a complete picture of GHG emissions. About 9 percent of emissions, those related to the non-energy sources of methane and nitrous oxide, are not included. Work is underway at Environment Canada to develop projections for these components but, at the time of writing, results are very preliminary. A similar point can be made concerning man made "sinks". The best known example of such a sink is the use of CO_2 as an injectant for enhanced oil recovery. Knowledge concerning the potential for man-made sinks is very rudimentary. A comprehensive projection of net GHG emissions will, therefore, be somewhat different than the partial results portrayed in this analysis.

Second, the stabilization goal, because it is expressed as a difference between the 1990 and 2000 emissions levels - the so-called "gap" - is extremely sensitive to changes in the underlying assumptions. A one percent change in total emissions in 2000 (e.g., about 5 megatonnes), translates into a 10 percent change in the "gap" which is 50 megatonnes in the reference scenario. As shown in the next chapter, plausible changes in energy prices or macroeconomic assumptions can give rise to significant differences in the size of the gap. For this and other reasons, the projection of emissions relative to the stabilization goal should be viewed as representative only.

Third and most important, it must be emphasized that this is a reference scenario. Under the business as usual assumption, current federal and provincial energy and environment policies are held constant throughout the projection. Only those policies and programs currently in place or close to implementation are incorporated in the estimates. We do not speculate in the projections upon future climate change policies. In fact, the purpose of the projections is to provide a base against which to evaluate the need for, and form of such policies.

Within the context and limitations noted above, the emissions projections presented in this paper suggest that additional measures will be required to attain the stabilization goal by the year 2000. Further, maintaining stabilization beyond 2000 would appear to pose a major challenge and require significant technological, structural and life style changes. These conclusions are not particularly startling. Climate change is an enormously complex issue, characterized by scientific uncertainty, unusually high requirements for international cooperation and divergent opinions concerning appropriate responses. Reflecting these complexities, the approach of the government, as outlined in the 1990 Green Plan, has been to focus its initial actions on initiatives, such as certain energy efficiency measures, that make economic sense in their own right, or that serve multiple policy objectives, such as the elimination of CFCs[27]. As the consequences of the initiatives already undertaken become clearer, the situation will be assessed to determine whether additional measures are required and the form of any such initiatives.

27 Government of Canada, Canada's Green Plan, 1990, p. 102-103.

prices. Consequently, at the retail level, the $5 world oil price decrease translates into decreases of approximately 5¢/liter ($1991) for gasoline and light fuel. Nonetheless, lower crude oil and natural gas prices do have an impact. Total secondary demand is up by 2.9% and 4.1% in 2000 and 2020 respectively. The lion's share of the increase comes from the transportation sector followed by the industrial and residential sectors. By fuel, the main impact is on RPPs reflecting the effect of lower oil prices on transportation demand. The decline in natural gas demand is due to fuel substitution (see Table 6.1.1).

Table 6.1.1
Impact of Lower Oil Prices
(Level and % Change Relative to Reference Case)

	2000		2020	
	Levels	%	Levels	%
Demand (PJ)				
RPPs	265	9.8	519	13.7
Natural Gas	-22	-1.1	-34	-1.2
Total Energy	214	2.9	431	4.1
Oil & Gas Investment (Billion $)	-3.3	-27.8	-8.5	-27.7
Crude Oil Supply (mb/d)	-211	-12.3	-328	-19.1
Natural Gas Supply (BCF)	-26	-0.5	-41	-0.7
CO_2 Emissions (Mt)	15.5	3.0	31.2	4.4

In line with higher demand, CO_2 emissions are 3.0 percent or 15.5 megatonnes higher in 2000 relative to reference case levels. The combined effects of lower production and higher demand results in Canada becoming a net oil importer by 1997 compared to 2007 in the reference case. The lower bitumen production results in an excess supply of diluent.

6.2 Higher World Oil Prices

In this scenario, world oil prices are assumed to be US $5/bbl higher commencing in 1995. Over the long term, prices average about $30/bbl and represent the upper end of expert views (see Table 2.1. 1). Natural gas prices also increase, but at a slower pace than oil prices (assuming similar increases would result in an excess supply situation in the North American market). As a result, the oil/gas price parity, at the wellhead, is roughly 10:1 by 2020 in the higher oil price case versus 8:1 in the reference case.

Table 6.2.1
Impact of Higher Oil Prices
(Level and % Change Relative to Reference Case)

			2020	
	Levels	%	Levels	%
Demand (PI)				
RPPs	-202	-7.3	-430	-11.3
Natural Gas	-31	-1.5	119	4.2
Total Energy	-202	-2.7	-297	-2.8
Oil & Gas Investment (Billion $)	2.5	21.0	7.0	23.0
Crude Oil Supply (rob/d)	42	2.4	527	30.7
Natural Gas Supply (BCF)	-22	-0.4	118	2.0
$C0_2$ Emissions (Mt)	-13.7	-2.7	-24.1	-3.4

Higher oil prices stimulate a significant increase in oil and gas investment, resulting from higher industry cashflow which would then lead to more oil and natural gas discoveries and supplies (see Table 6.2. 1). Given the reference case natural gas market conditions, these additional supplies have a depressing effect on natural gas prices and explain the 10:1 parity instead of 8:1.

As for major projects, the higher world oil price case would bring on stream additional oil sands mining capacity of 70,000 b/d in both 2002 and 2005, two additional upgraders of 50,000 b/d, one in 2009 and the other in 2020. Offshore production (East Coast) would increase over the period reaching 241,000 b/d by 2020. Overall, oil supply would increase by 2.4 percent in 2000 and 30.7 percent in 2020.

As highlighted in Table 6.2.1, total energy demand is down by 2.7 and 2.8 percent in 2000 and 2020 respectively relative to reference case levels. CO_2 emissions also experience similar percentage decreases. It is interesting to note that the impact results are not symmetric to those in the lower world price case. The latter is explained mainly by the different relationships assumed between natural gas prices and oil prices in the two cases.

The higher oil production coupled with lower oil demand renders Canada a net exporter of oil over the entire outlook period. The impact of higher prices on oil supply is not entirely beneficial since higher bitumen production is not matched by equivalent increases in diluent production and diluent shortages occur by 2000.

6.3 Higher Electricity Prices

This case examines the implications of higher electricity prices. Specifically, electricity prices are assumed to be 20 percent above baseline levels over the entire outlook period commencing in 1995. As shown in Table 6.3.1, the impact on demand is relatively small except for the price sensitive commercial sector. Total secondary demand is approximately 3 percent below reference case levels in both 2000 and 2020. As expected, electricity demand is the most adversely affected. At the national level, electricity demand is 9.7 and 12.2 percent lower in 2000 and 2020 respectively relative to reference case levels. These sizable declines imply that several electrical projects would be postponed or delayed. Grande Baleine would be delayed by 7 years to 2012, Bruce A-1 and A-2 would be mothballed in 1997-1998 and Conawapa would be delayed until 2010.

Overall, the impact of a 20 percent increase in electricity prices on energy

Table 6.3.1
Impact of Higher Electricity Prices
(Level and % Change Relative to Reference Case)

	2000		2020	
	Levels (PJ)	%	Levels (PJ)	%
Secondary Demand By Sector				
Residential	-55	-3.5	-39	-2.3
Commercial	-61	-5.6	-97	-6.6
Industrial	-102	-3.5	-158	-3.6
Transportation	o	0.0	0	0.0
Total	-218	-2.9	-294	-2.8
Secondary Demand by Fuel				
RPPs	-2	-0.1	23	0.6
Natural Gas	-31	-1.5	-1.4	0.0
Electricity	-172	-9.7	-298	-12.2
Total	-218	-2.9	-294	-2.8
CO_2 Emissions (Mt)	-13	-2.5	-19	-2.7

demand and CO_2 emissions is similar to the impact of $5 bbl increase in world oil prices. The CO_2 reduction is almost the same in both cases in 2000 but it is moderately higher in 2020 in the higher oil price case.

6.4 Higher Economic Growth

Our higher economic growth case assumes that overall growth in the economy is 1 percentage point per annum above the reference case levels (i.e., GDP growth averages about 3.5 percent rather than 2.5 percent per year) .28 By 2020, this implies that the economy's output would be about 35% larger. While this might appear overly optimistic, the 3.5% annual growth is roughly in line with economic growth experienced between 1970 and 1991.

Table 6.4.1
Impact of Higher Economic Growth
(Level and % Change Relative to Reference Case)

	2000		2020	
	Levels (PJ)	%	Levels (PJ)	%
Secondary Demand By Sector				
Residential	22	1.4	88	5.3
Commercial	66	6.0	400	27.2
Industrial	179	6.2	1355	30.6
Transportation	46	2.3	517	17.6
Total	313	4.2	2360	22.5
Primary Demand by Fuel				
RPPS	133	3.8	876	18.5
Natural Gas	113	3.6	754	18.4
Hydro	22	2.0	231	15.4
Nuclear	0	0.0	639	36.5
Coal & Other	162	9.6	829	29.9
Total	422	4.0	3329	22.2
CO_2 Emissions (Mt)	30	5.7	163	22.7

Relative to reference case levels, primary demand and secondary demand are up by 4.2 and 4.0% respectively in 2000 and by 22.5 and 22.7% in 2020. On a sectoral basis, the residential and transportation sectors exhibit the smallest increases, reflecting the fact that demand in these sectors is driven chiefly by demographic variables (i.e., population is about 1.8% higher in 2000 compared with 9.4% for total GDP). In line with the sectoral impacts, nuclear, hydro and renewable display the largest increases whereas RPPs show the smallest increases.

Given the substantial increase in electricity demand, some major electricity projects were assumed to come on stream earlier than in the reference case. However, the impact on electricity prices is relatively small over the period.

As a result of higher economic growth, CO_2 emissions are 30 and 163 megatonnes above reference case levels in 2000 and 2020 respectively. The higher relative increase in CO_2 emissions compared with total primary energy demand in 2000 reflects the greater use of coal to meet the additional electricity requirements. Over the longer term, however, CO_2 emissions and total primary energy

---

28 In order to accommodate this additional growth, population, labor force and labor productivity were also altered. More specifically, annual labor force and labor productivity growth were increased from their reference case levels of 1.0 and 1.4% to 1.3 and 1.870 respective y.

demand experience similar relative increases.

6.5 Modified Sectoral Growth Profile

Unlike the 1970s and 1980s, the reference case macroeconomic scenario is characterized by the industrial sector growing at a much faster pace than the service sector. This structural shift in economic activity has significant implications for energy demand because the industrial sector is a more energy intensive sector than the commercial sector.

To assess the impact of the continuation of the historical trend, industrial real domestic product (RDP) growth was reduced from 3.1 to 2.1% per annum over the 1991/2020 period while commercial RDP growth was increased from 2.2 to 2.890 over the same period. The shift in sectoral RDP growth leaves overall GDP roughly the same as projected for the reference case.

This modified sectoral growth profile results in reductions of 2.8 and 2.3% in total primary and secondary demand respectively in 2000, and of 9.4 and 8.8% respectively in 2020. As shown in Table 6.5.1, the energy demand increase in the less energy intensive commercial sector is not sufficient to compensate for the decrease in industrial energy demand. Since the demographic and energy price projections remain unchanged at their reference case level, the impact on residential and transportation energy demand is negligible. Demand for all fuels decreases. Coal, hydro and renewable display the largest decreases whereas nuclear experiences the smallest.

Table 6.5.1
Impact of Different Sectoral Growth Profile
(Level and % Change Relative to Reference Case)

	2000		2020	
	Levels (PJ)	%	Levels (PJ)	%
Secondary Demand By Sector				
Residential	o	0	6	0.4
Commercial	58	5.3	267	18.1
Industrial	-243	-8.4	-1138	-25.7
Transportation	-26	-1.3	-118	-4.0
Total	-211	-2.8	-983	-9.4
Primary Demand by Fuel				
RPPs	-76	-2.2	-259	-5.5
Natural Gas	-73	-2.3	-335	-8.1
Hydro	-1o	-0.9	-113	-7.5
Nuclear	-8	-0.6	-8	-0.5
Coal & Other	-75	-4.8	-594	-22.9
Total	-243	-2.3	-1310	-8.8
$C0_2$ Emissions (MT)	-13	-2.5	-74	-10.3

As a result of lower primary energy demand, CO_2 emissions are 13 and 74 megatonnes lower in 2000 and 2020 relative to reference case levels.

APPENDICES

		Projections									
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
	REAL DOMESTIC PRO UCT 'RDP ($1981 BILDIONS'										
RDPC	TOTAL........L...........	410.5	406.4	414.6	428.0	440.7	455.1	508.5	577.1	651.9	834.4
RDPAGC	AGRICULTURE............	11.8	12.2	12.1	12.0	12.2	12.4	13.5	14.8	16.5	20.5
RDPINC	INDUSTRIAL............:	129.6	123.5	126.6	132.6	138.4	144.7	164.0	192.2	224.0	300.8
RDPCPC	COMMERCIAL & PUBLIC ADMIN	220.2	221.4	225.1	231.0	236.6	243.0	269.7	301.4	335.1	418.2
RDPAVC	AVIATION................	2.9	2.5	2.5	2.5	2.6	2.7	3.0	3.4	3.9	5.6
RDPRLC	RAIL....................	3.5	3.5	3.6	3.7	3.8	3.9	4.4	5.0	5.7	7.5
	INDUSTRIAL RDP ($1981 MILLIONS)										
RDPPPC	PULP & PAPER............	6627.	6487.	6663.	6921.	7147.	7399.	8285.	9483.	10943.	14524.
RDPCHC	CHEMICAL................	5506.	5339.	5736.	6030.	6311.	6614.	7710.	9438.	11462.	16576.
RDPISC	IRON & STEEL............	2642.	2609.	2807.	2944.	3034.	3111.	3536.	4426.	5595.	8324.
RDPNFC	SMELTING & REFINING......	3262.	3383.	3458.	3542.	3694.	3851.	4613.	5663.	6949.	10121.
RDPMIC	MINING..................	22809.	23048.	23059.	23396.	23675.	24048.	26469.	30563.	34935.	43455.
RDPOMC	OTHER MANUFACTURING......	55858.	51347.	53630.	57248.	60096.	63263.	72145.	86628.	.03493.	142544.
RDPCFC	CONSTRUCTION & FORESTRY..	33313.	31609.	31450.	32488.	34319.	36218.	41047.	45931.	50008.	63936.
	REAL PERSONAL DISPOSABLE INCOME										
YPDKC	($1981 .	300.	295.	298.	302.	306.	312.	336.	368.	404.	505.
	PERSONAL DISPOSABLE INCOME										
YPDPCC	PER CAPITA ($1981)...........	11282.	10939.	10898.	10901.	10892.	10965.	11163.	11645.	12201.	14055.
YPDHHC	PER HOUSEHOLD ($1981)........	31118.	30002.	29710.	29584.	29439.	29518.	29492.	30148.	30992.	34580.
	PRICES AND COSTS: (1981=1.0										
PWPIUS	U.S. PRODUCER PRICE (1982=100).	119.1	121.7	123.9	127.5	131.8	135.9	159.1	190.2	228.6	326.6
PGDP	GDP DEFLATOR - TOTAL...........	1.468	1.521	1.551	1.591	1.636	1.671	1.925	2.200	2.505	3.339
PGDPAG	AGRICULTURAL....	0.849	0.907	0.934	0.970	1.000	1.032	1.313	1.554	2.022	4.239
PGDPIN	INDUSTRIAL......	1.380	1.363	1.357	1.377	1.417	1.440	1.614	1.811	2.029	2.583
PGDPCP	COMMERCIAL......	1.577	1.667	1.711	1.762	1.814	1.859	2.169	2.509	2.877	3.859
CPI	CONSUMER PRICE INDEX...........	1.582	1.671	1.715	1.767	1.819	1.860	2.149	2.470	2.840	3.836
PCXDE	CONSUMER PRICE INDEX EX. ENERGY	1.579	1.669	1.714	1.762	1.811	1.851	2.140	2.455	2.812	3.799
RIPRVB	AVG. YIELD-10 PROV'L BONDS (%).	11.6	10.5	9.4	8.8	7.9	7.0	6.5	5.9	5.9	6.9
	DEMOGRAPHIC: ('000)										
POPC	TOTAL POPULATION..............	26584.	26978.	27348.	27721.	28093.	28463.	30133.	31621.	33080.	35957.
HHC	TOTAL HOUSEHOLDS..............	9638.	9836.	10032.	10214.	10394.	10574.	11406.	12214.	13023.	14615.
	LABOUR MARKET:										
LFC	LABOUR FORCE ('000)...........	13680.	13757.	13868.	14104.	14344.	14587.	15654.	16565.	17274.	18096
EMPC	TOTAL EMPLOYMENT ('000).......	12572.	12344.	12433.	12635.	12862.	13128.	14076.	15171.	15916.	17081.
URATEC	UNEMPLOYMENT RATE (%).........	8.10	10.27	10.35	10.42	10.33	10.00	10.08	8.42	7.86	5.61
RDPPEC	LABOUR PROD. (RDP/EMP) $1981...	32655.	32924.	33346.	33873.	34261.	34666.	36123.	38040.	40957.	48848.
DDAYSC	HEATING DEGREE DAYS (NORM=1	0.930	0.935	1.000	0.996	0.991	0.987	0.965	0.944	0.932	0.908

Appendix A-2: Reference Scenario - World and Domestic Crude Oil Prices ($/Cubic Metre)

		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
				Projections							
	WEST TEXAS INTERMEDIATE : ($US)										
PWTCU	CASHING	153.81	135.99	128.14	131.82	136.35	147.64	185.13	236.08	283.74	405.29
PWTCUR	REAL ($1991) $/BBL	24.96	21.61	20.00	20.00	20.00	21.00	22.50	24.00	24.00	24.00
TOCUCH	TRANSPORTATION TO CHICAGO	4.28	4.32	4.35	4.39	4.45	4.51	4.79	5.15	5.55	6.44
PWTCH	CHICAGO	157.57	139.79	131.97	135.70	140.29	151.62	189.40	240.71	288.77	411.21
	BRENT ($US)										
PBRN S	NORTH SEA(F.O.B)	148.80	130.28	122.69	126.45	130.86	141.93	178.62	228.51	275.11	394.09
TOLOSS	OCEAN LOSS	0.60	0.52	0.49	0.51	0.52	0.57	0.71	0.91	**1.10**	1.58
TONSPO	TRANSPORTATION TO PORTLAND.	5.79	5.85	5.90	5.99	6.09	6.19	6.70	7.33	8.04	9.63
TOPOMO	TRANSPORTATION TO MONTREAL.	4.61	4.66	4.70	4.77	4.85	4.93	5.33	5.84	6.40	7.67
PBRMO	MONTREAL (C.I.F)	159.79	141.31	133.78	137.71	142.33	153.61	191.36	242.59	290.66	412.95
	CANADIAN PAR:										
PPACH	CHICAGO (GUS)	157.02	138.39	130.65	134.35	138.89	150.11	187.51	238.30	285.89	407.10
TRFPAU	U.S. IMPORT TARIFFS	1.53	1.09	0.91	0.74	0.74	0.74	0.74	0.74	0.74	0.74
TOBOCH	TRANSPORTATION TO U.S. BORDER.	2.96	2.99	3.01	3.06	3.11	3.16	3.42	3.74	4.11	4.91
TOBOED	TRANSPORTATION TO EDMONTON.	3.44	3.50	3.54	3.58	3.63	3.67	3.94	4.22	4.50	5.20
PPAED	EDMONTON ($CDN)	173.94	149.89	145.79	150.26	155.52	168.69	212.32	271.72	327.27	468.93
	REFINERY CRUDE COST ($CDN) :										
PCRATA	ALBERTA	172.75	148.86	144.79	149.23	154.45	167.54	210.87	269.87	325.03	465.72
PCRATO	ONTARIO	171.29	166.58	159.27	162.01	167.25	178.76	223.89	283.15	339.68	481.85
PCRATQ	QUEBEC	170.64	178.20	173.46	175.94	181.33	192.63	238.98	299.14	356.86	501.49
PCRATF	ATLANTIC	176.78	151.71	148.01	152.44	157.64	170.50	213.36	271.56	326.08	464.97

To convert $/cubic metre to $/barrel, divide by 6.293

Appendix A-3: Reference Scenario - Domestic and Export Natural Gas Price ($/Gigajoule) *Region: Canada*

		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
				Projections							
	DOMESTIC PRICE AT ALTA. BORDER:										
PRNGAE	AVERAGE REAL ($1991)	1.82	1.51	1.47	1.57	1.71	1.76	2.18	2.39	2.60	3.02
PNGAB	AVERAGE NOMINAL	1.72	1.50	1.51	1.66	1.86	1.96	2.80	3.53	4.41	6.93
PNGABR	RESIDENTIAL	1.90	1.66	1.68	1.84	2.06	2.16	3.11	3.94	4.94	7.79
PNGABC	COMMERCIAL	1.85	1.60	1.61	1.77	1.97	2.07	2.88	3.61	4.52	7.14
PNGABI	INDUSTRIAL (DIRECT SALES) . .	1.53	1.33	1.35	1.50	1.69	1.78	2.60	3.28	4.11	6.49
GoPAR	TORONTO GAS/OIL PARITY	0.58	0.55	0.58	0.60	0.63	0.61	0.64	0.63	0.64	0.69
	EXPORT PRICE AT US BORDER:										
PNGXT	NOMINAL ($CDN)	2.12	1.81	1.80	1.92	2.12	2.21	3.03	3.76	4.65	7.18
PNGXU	NOMINAL ($US)	1.82	1.58	1.52	1.62	1.79	1.87	2.56	3.18	3.93	6.07
PNGFX	FIELDGATE-NATURAL GAS EXPORTS.	1.47	1.23	1.22	1.33	1.52	1.61	2.40	3.10	3.96	6.42
	REAL AVERAGE FIELD GATE PRICE ALL CANADIAN & EXPORT SALES										
PNGFIR	($1991CDN)/MCF	1.66	1.32	1.27	1.35	1.50	1.55	2.00	2.25	2.50	3.00

To convert $/gigajoule to $/mcf, multiply by 1.07

		1990	1991	Projections 1992	1993	1994	1995	2000	2005	2010	2020
	ENERGY PRICE INDEXES (1981=1.0)										
PDIRAC	RESIDENTIAL	1.57	1.82	1.87	1.96	**2.03.**	2.07	2.44	2.88	3.46	5.08
PDICPC	COMMERCIAL	1.64	1.78	1.96	2.05	**2.10**	2.16	2.53	2.96	3.56	5.25
PDIINC	INDUSTRIAL	1.42	1.50	1.57	1.63	**1.69**	1.73	2.07	2.45	2.96	4.40
PDITRC	TRANSPORTATION	1.58	1.59	1.55	1.58	**1.63**	1.70	2.02	2.41	2.81	3.89
PDISDC	TOTAL SECONDARY DEMAND. . .	1.54	1.64	1.69	1.76	**1.81**	1.86	2.21	2.62	3.12	4.53
	REGIONAL SECTORAL PRICES: ($/GJ - EFFICIENCY ADJUSTED)										
PULFRC	LFO - RESIDENTIAL	14.23	15.68	14.99	15.36	**15.83**	16.54	19.81	23.94	28.15	39.04
PULFCC	- COMMERCIAL	11.27	11.68	11.18	11.46	**11.80**	12.33	14.78	17.85	20.98	29.10
PUHFIC	HFO - INDUSTRIAL	3.55	3.06	2.89	2.95	**3.06**	3.33	4.32	5.63	6.91	10.12
PUHFCC	- COMMERCIAL	3.94	3.35	3.18	3.31	**3.49**	3.81	4.90	6.21	7.59	11.04
PUNGRC	NATURAL GAS - RESIDENTIAL.	7.24	7.74	7.91	8.32	**8.82**	9.10	11.46	13.78	16.53	24.32
PUNGCC	- COMMERCIAL	5.15	5.05	5.23	5.51	**5.86**	6.04	7.55	9.06	10.89	16.07
PUNGIC	- INDUSTRIAL.	3.17	3.07	3.12	3.29	**3.54**	3.69	4.83	5.92	7.20	10.84
PUELRC	ELECTRICITY - RESIDENTIAL.	14.55	17.56	18.35	19.24	**19.57**	20.02	23.12	26.99	32.52	48.24
PUELCC	- COMMERCIAL.	18.64	20.79	23.28	24.47	**24.86**	25.43	29.39	34.19	41.23	61.22
PUELIC	- INDUSTRIAL	10.57	11.68	12.34	12.85	**13.09**	13.36	15.45	18.06	21.77	32.40
	PRICE RATIOS: (EFFICIENCY ADJ'D)										
	RESIDENTIAL :										
RPEORC	ELECTRICITY / LIGHT FUEL OIL	1.02	1.12	1.22	1.25	**1.24**	1.21	1.17	1.13	1.16	1.24
RPEGRC	ELECTRICITY / NATURAL GAS...	2.01	2.27	2.32	2.31	**2.22**	2.20	2.02	1.96	1.97	1.98
RPOGRC	LIGHT FUEL OIL / NATURAL GAS	1.97	2.03	1.90	1.85	**1.80**	1.82	1.73	1.74	1.70	1.61
	COMMERCIAL:										
RPEOCC	ELECTRICITY / LIGHT FUEL OIL	1.65	1.78	2.08	2.14	**2.11**	2.06	1.99	1.92	1.96	2.10
RPEGCC	ELECTRICITY / NATURAL GAS. . .	3.62	4.12	4.45	4.44	**4.25**	4.21	3.89	3.77	3.79	3.81
RPOGCC	LIGHT FUEL OIL / NATURAL GAS	2.19	2.31	2.14	2.08	**2.01**	2.04	1.96	1.97	1.93	1.81
	INDUSTRIAL:										
RPEOIC	ELECTRICITY / HEAVY FUEL OIL	2.98	3.81	4.27	4.35	**4.28**	4.02	3.58	3.21	3.15	3.20
RPEGIC	ELECTRICITY / NATURAL GAS...	3.33	3.81	3.96	3.90	**3.69**	3.62	3.20	3.05	3.02	2.99
RPOGIC	HEAVY FUEL OIL / NATURAL GAS	1.12	1.00	0.93	0.90	**0.86**	0.90	0.89	0.95	0.96	0.93

Appendix A-5: Reference Scenario - Light and Heavy Crude Oil Balances (KCM/D)

		1990	1991	Projections 1992	1993	1994	1995	2000	2005	2010	2020
	LIGHT CRUDE OIL:										
QLMPN	CONVENTIONAL (INCL. E.O.R.)	142.1	137.0	137.4	130.3	123.2	118.5	102.7	94.7	84.1	59.8
QSOPN	SYNTHETIC	33.1	36.1	37.7	37.1	37.1	37.5	37.5	42.3	48.6	48.6
QCRFR	FRONTIERS	0.0	0.0	0.0	3.3	3.3	3.3	27.0	32.7	30.2	30.2
QPPPN	PENTANES	18.0	18.8	20.6	23.7	24.9	25.8	28.1	29.4	30.4	32.2
QLPDL	LESS DILUENT REQUIREMENTS	13.4	13.5	13.8	12.5	11.2	11.2	15.2	15.2	18.5	23.7
QCRUP	UPGRADER OUTPUT	7.0	7.0	8.0	11.5	15.0	15.0	15.0	22.0	22.0	29.0
QCTLT	TOTAL SUPPLY	186.8	185.4	189.9	193.4	192.3	188.9	195.1	205.9	196.8	176.1
VCRDD	TOTAL DOMESTIC DEMAND	229.9	214.4	217.9	222.0	219.8	223.0	243.3	271.2	294.2	333.4
VHVDD	LESS: DEMAND FOR HEAVY	18.3	19.5	25.3	13.7	14.4	15.2	18.1	20.9	23.5	29.1
VLMDD	DOMESTIC DEMAND FOR LIGHT	211.6	194.9	192.6	208.4	205.3	207.9	225.2	250.3	270.7	304.3
VLMSD	SUPPLY/DEMAND BALANCE FOR LIGHT OIL AND NET IMPORTS. . . .	-24.8	-9.5	-2.7	-14.9	-13.1	-18.9	-30.1	-44.5	-74.0	-128.2
	HEAVY CRUDE OIL:										
QHVPN	CONVENTIONAL (INCL. E.O.R.)	49.8	53.0	59.4	48.1	46.9	46.4	45.3	44.8	41.7	30.9
QOCNT	IN-SITU AND BITUMEN	21.5	19.5	20.1	20.5	20.5	20.5	31.7	39.1	48.4	73.9
QCRUC	LESS: UPGRADER INPUT-CONV	7.0	7.0	8.0	10.0	12.0	12.0	12.0	12.0	12.0	12.0
QCRUB	UPGRADER INPUT-BITUMEN.	0.0	0.0	0.0	2.0	4.0	4.0	4.0	12.0	12.0	20.0
QLPDL	DILUENT (PENTANES AND OTHER)	13.4	13.5	13.8	12.5	11.2	11.2	15.2	15.2	18.5	23.7
QCTHV	TOTAL SUPPLY	77.7	79.0	85.3	69.1	62.6	62.1	76.2	75.1	84.6	96.6
VHVDD	DEMAND FOR DOMESTIC HEAVY. . .	18.3	19.5	25.3	13.7	14.4	15.2	18.1	20.9	23.5	29.1
VHVXS	SUPPLY/DEMAND BALANCE (EXPORTABLE SURPLUS)	59.4	59.5	60.0	55.4	48.2	46.9	58.1	54.3	61.1	67.4

Appendix A-6: ReferenceScenario- Supply and demand - petroleum (thousands of cubic metres per day)

				Projections							
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
	DOMESTIC CRUDE OIL PRODUCTION:										
VCRPN	TOTAL	265.0	264.9	275.7	262.5	254.9	251.0	**271.3**	281.0	**281.4**	272.6
	DOMESTIC CRUDE OIL DEMAND:										
VRPDDC	PETROLEUM PRODUCTS DEMAND	239.9	226.2	228.7	233.0	230.6	234.0	**254.6**	283.1	**306.6**	346.6
VCRRG	REFINERY GAIN AND ADJUSTMENTS.	11.8	13.7	12.7	12.8	12.8	12.8	**13.3**	13.8	**14.3**	15.1
QLPRN	NET REFINERY PROD'N OF LPG'S.	1.8	1.9	1.9	1.9	1.9	1.9	**1.9**	1.9	**1.9**	1.9
QLPPR	TOTAL REFINERY LPG PROD'N.	6.2	6.2	6.2	6.2	6.2	6.2	**6.2**	6.2	**6.2**	6.2
VLPRP	REFINERY LPG CONSUMPTION	4.3	4.3	4.3	4.3	4.3	4.3	**4.3**	4.3	**4.3**	4.3
VCRDD	DOMESTIC CRUDE OIL DEMAND	229.9	214.4	217.9	222.0	219.8	223.0	**243.3**	271.2	**294.2**	333.4
	PETROLEUM EXPORTS:										
VPEXT	TOTAL	142.3	164.4	170.9	123.4	112.2	106.9	**108.1**	94.3	**101.1**	107.4
VCRXT	CRUDE OIL - TOTAL	104.0	121.2	133.1	83.4	72.2	66.9	**68.1**	64.3	**76.1**	87.4
VLMXS	LIGHT & MEDIUM	44.7	61.7	73.1	28.0	24.0	20.0	**10.0**	10.0	**15.0**	20.0
VHVXS	HEAVY (INCL. DILUENT)	59.4	59.5	60.0	55.4	48.2	46.9	**58.1**	54.3	**61.1**	67.4
VCRXE	EXCHANGES	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	**0.0**	0.0
VRPXT	PRODUCTS - TOTAL	38.3	43.2	37.8	40.0	40.0	40.0	**40.0**	30.0	**25.0**	20.0
	PETROLEUM IMPORTS:										
VPEMT	TOTAL	108.3	110.4	105.0	82.9	77.1	78.9	**80.1**	84.5	**114.0**	168.2
VCRMT	CRUDE OIL	85.6	86.8	81.5	57.9	52.1	53.9	**55.1**	59.5	**84.0**	118.2
VRPMT	PRODUCTS - TOTAL	22.7	23.6	23.5	25.0	25.0	25.0	**25.0**	25.0	**30.0**	50.0
VPEMN	NET PETROLEUM IMPORTS	-34.0	-54.0	-65.9	-40.5	-35.1	-28.0	**-28.0**	-9.8	**12.9**	60.8

		Projections									
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
	MARKETABLE NATURAL (MCM)										
VNGPN	TOTAL PRODUCTION..	98987.	105372.	116775.	123594.	129198.	133174.	146213.	153927.	159536.	171118.
VNGDD	DOMESTIC DEMAND..	57325.	58449.	62277.	63465.	64899.	66162.	72348.	78706.	84365.	96147.
VNGSC	STOCK CHANGE.....	1615.	-445.	-3004.	0.	0.	0.	0.	0.	0.	0.
VNGXT	EXPORTS...........	40689.	47687.	57953.	60480.	64699.	67512.	74545.	75951.	75951.	75951.
VNGMT	IMPORTS...........	641.	319.	452.	350.	400.	500.	680.	730.	780.	980.
	NATURAL GAS DISTRUBITION										
KGDSC	CAPACITY (MCM)........	856	865	866.	868	872	877.	897	917	935	968
	GAS PLANT NGLS (KCM/D)										
QLPRN	NET REFINERY PRODUCTION.	1.80	1 90	1.90	1 90	1.90	1 90	1.90	1.90	1.90	1.90
VGPPN	GAS PLANT PROD (EXCL SOL FLD)	47.70	49.00	55.61	60.90	63.57	65.46	71.68	75.35	78.03	83.55
VPBPN	PROPANE & BUTANE...........	28.50	28.50	32.77	35.90	37.49	38.61	42.29	44.47	46.05	49.32
VETPN	ETHANE.....................	19.30	20.50	22.84	25.00	26.08	26.86	29.39	30.88	31.97	34.22
VGPDD	DOMESTIC DEMAND.............	29.[illegible]0	32.70	30.51	31.68	32.84	37.02	49.64	51.04	54.21	57.40
VGPXT	NET EXPORTS (POTENTIAL).....	18.70	18.50	27.00	31.12	32.63	30.34	23.94	26.21	25.71	28.05

Appendix A-8: Reference Scenario- Electricity Supply &

		1990	1991	Project 1992
	GENERATING CAPACITY (MEGAWATTS) .			
KEGCTC	TOTAL	103815.	103790.	104193
KEGCUC	UTILITIES	97395.	97627.	97832
KEGCIC	INDUSTRIES	6420.	6163.	6361
	CANGEN PLANNED GENERATION:			
	TOTAL :			
VEUPXC	UTILITIES	427604.	446334.	477204
VEIPXC	INDUSTRY	40015.	40423.	38257
	FOR DOMESTIC DEMAND:			
VELDXC	TOTAL	467163.	482661	483697
	CANGEN PLANNED CAPACITY FACTOR:			
RGCUPC	UTILITIES	0.501	0.522	0.55
RGC I PC	INDUSTRY	0.712	0.749	0.68
	EXTERNAL SALES & PURCHASES:			
VELENC	NET EXTERNAL SALES	350.	4096.	31764
VELXNC	NET EXPORTS TOURS	350.	4096.	31764
VELESC	EXTERNAL SALES	18128.	4969.	31767
VELXTC	EXPORTS	16494.	4969.	31767
VELEPC	EXTERNAL PURCHASES	17779.	873.	3
VELMTC	IMPORTS	16494.	873.	3
	GENERATION FOR DOMESTIC DENAND: (INC. OWN-USE)			
VELDDC	TOTAL	4673.63.	474131.	483094
VEUDDC	UTILITIES	427148.	433708.	444837
VEIDDC	INDUSTRY	40015.	40423.	38257
	TOTAL GENERATION:			
VELPNC	TOTAL	467619.	490419.	515799
VEUPNC	UTILITIES	427604.	449996.	477542
VEIPNC	INDUSTRY	40015.	40423.	38257
	CAPACITY FACTOR:			
RGCUAC	UTILITIES	0.501	0.526	0.55
RGC IAC	INDUSTRY	0.712	0.749	0.68

				Projections							
		1990	1993.	1992	1993	1994	1995	2000	2005	2010	2020
HTSSDC	SECONDARY DEMAND BY FUEL:	6654.0	6547.1	6656.0	6737.5	6811.3	6917.1	7500.2	8196.4	8925.6	**10509.1**
HRPSDC	RPP' S	2550.4	2405.6	2432.1	2446.6	2470.8	2503.6	2693.6	2975.9	3262.8	**3797.3**
HNGSDC	NATURAL GAS	1789.9	1787.3	1844.7	1876.0	1897.3	1929.4	2106.7	2271.1	2446.8	**2826.9**
HELSDC	ELECTRICITY	1551.6	1570.7	1594.9	1608.8	1624.9	1651.1	1786.2	1939.7	2096.7	**2442.9**
HCCSDC	COAL	46.9	38.2	38.3	39.2	40.0	41.0	45.1	48.4	50.2	**60.8**
HLPSDC	LPG'S	90.7	88.3	94.0	97.0	99.3	100.6	110.2	121.8	133.3	**159.6**
HKGSDC	COKE AND COKE OVEN GAS.	130.7	147.0	151.2	158.4	160.8	163.3	181.6	207.4	234.9	**291.9**
HSTSDC	STEAM	21.0	24.8	25.1	25.0	25.0	25.1	27.9	31.0	34.5	**42.6**
HOFSDC	OTHER	368.0	382.9	372.8	383.3	389.8	399.3	444.5	496.0	561.4	**782.4**
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.6	105.0	105.0	**104.9**
	PRIMARY DEMAND BY SECTOR:										
HTSPDC	TOTAL	9081.8	9104.9	9323.5	9504.1	9632.3	9859.5	10723.9	11617.0	12496.6	**14857.5**
HTSEUC	END-USE DEMAND	7299.3	7221.5	7353.7	7453.7	7547.6	7698.7	8446.3	9213.0	10005.1	**11676.9**
	SECONDARY DEMAND.	6654.0	6547.1	6656.0	6737.5	6811.3	6917.1	7500.2	8196.4	8925.6	**10509.1**
HTSRAC	RESIDENTIAL	1506.7	1463.8	1510.4	1518.9	1530.7	1541.6	1576.4	1594.8	1595.9	**1673.8**
HTSCPC	COMMERCIAL	945.4	950.3	963.6	967.2	976.2	993.1	1084.6	1194.7	1279.0	**1473.4**
HTSINC	INDUSTRIAL	2404.6	2395.9	2429.8	2492.1	2527.2	2580.6	2877.4	3200.9	3584.8	**4429.2**
HTSTRC	TP.ANSPORTATION	1796.9	1736.9	1752.3	1759.3	1777.1	1801.7	1961.8	2206.0	2465.9	**2932.7**
HTSNEC	NON-ENERGY USE	645.3	674.4	697.7	716.2	736.3	781.6	946.1	1016.6	1079.5	**1167.7**
HELIRC	ADJUST. (IMPORTS AND OTHERS)	0.0	0.0	3.4	3.4	4.0	5.4	-34.3	-24.8	-10.6	**13.2**
HTSPCC	PRODUCER CONSUMPTION	504.0	519.3	542.0	561.1	568.5	580.9	636.6	693.9	746.2	**879.6**
HTSCLC	INTERMEDIATE CONVERSION LOSS	1278.5	1364.1	1434.7	1497.6	1538.0	1607.2	1713.6	1805.7	1850.8	**2382.9**
HNGCSC	LESS SAVINGS FROM NUGS. .	0.0	0.0	10.4	11.6	25.8	32.6	38.2	70.7	95.0	**95.0**
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL	9081.8	9104.9	9323.5	9504.1	9632.3	9859.5	10723.9	11617.0	12496.6	**14857.5**
HRPPDC	RPP'S	3279.3	3107.5	3137.7	3191.5	3151.7	3197.6	3483.2	3872.2	4183.4	**4721.4**
HNGPDC	NATURAL GAS	2164.9	2191.0	2348.8	2397.7	2451.9	2499.6	2733.3	2973.5	3187.3	**3632.4**
HLPPDC	LPG'S	232.3	237.5	254.2	263.3	272.9	307.7	412.5	424.2	450.6	**477.0**
HCCPDC	COAL	1077.5	1120.7	1010.8	1081.4	885.6	857.9	993.7	1117.6	1254.9	**1748.2**
HENPDC	NUCLEAR ELECTRICITY (11.654	802.2	933.7	1003.2	976.5	1237.3	1338.9	1330.9	1340.3	1311.8	**1754.6**
HEHPDC	HYDRO ELECTRICITY (3.6) . . .	1053.0	1029.5	1046.9	1049.9	1068.5	1058.7	1085.8	1152.8	1306.9	**1501.7**
HOFPDC	OTHER (RENEWABLE). . '...'....	368.0	382.9	418.9	440.7	461.0	495.4	579.8	631.4	696.7	**917.3**
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.6	105.0	105.0	**104.9**
	RATIOS :										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	143.11	135.73	138.57	136.56	135.10	133.68	126.38	119.02	111.08	**102.16**
RCDPRC	COM. DEMAND / COM. RDP	4.07	4.09	4.08	3.99	3.92	3.88	3.82	3.77	3.63	**3.34**
RIDPRC	IND. DEMAND / IND. RDP	18.55	19.40	19.19	18.80	18.26	17.84	17.55	16.65	16.01	**14.73**
RSDPCC	SECONDARY DEMAND / POP (GJ) .	246.36	242.29	243.38	243.05	242.46	243.02	248.90	259.20	269.81	**292.27**
RSDPRC	/mP/	15.95	16.08	16.06	15.74	15.46	15.20	14.75	14.20	13.69	**12.60**
REUPCC	END-USE DEMAND / POP (GJ) . .	270.63	267.29	268.89	268.88	268.67	270.47	280.30	291.35	302.45	**324.74**
REUPRC	" /RAP	17.52	17.74	17.74	17.42	17.13	16.92	16.61	15.96	15.35	**13.99**
RPDPCC	PRIMARY DEMAND / POP (GJ) . . .	341.63	337.59	340.91	342.85	342.88	346.39	355.89	367.38	377.76	**413.20**
RPDPRC	/RAP	22.12	22.41	22.49	22.21	21.86	21.67	21.09	20.13	19.17	**17.81**

				Projections							
		1990	1991	1992	1993	1994	1995	**2000**	**2005**	**2010**	**2020**
HTSSDF	SECONDARY DEMAND BY FUEL:	514.3	502.3	499.8	499.5	502.2	506.2	**549.0**	604.7	649.0	742.8
HRPSDF	RPP'S	320.2	305.4	302.4	301.9	303.4	305.6	**333.8**	368.3	398.1	451.6
HNGSDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0
HELSDF	ELECTRICITY	112.8	114.4	115.5	115.4	116.1	117.1	**126.6**	140.4	148.6	165.8
HCCSDF	COAL	2.0	2.4	2.8	2.8	2.9	3.0	**3.3**	3.6	3.5	3.2
HLPSDF	LPG'S	6.7	6.3	5.9	6.0	6.2	6.3	**7.0**	7.9	7.9	8.6
HKGSDF	COKE AND COKE OVEN GAS......	1.3	2.1	2.1	2.0	2.0	1.9	**2.9**	3.6	3.8	4.4
HSTSDF	STEAM	1.4	1.6	1.5	1.5	1.5	1.5	**1.8**	2.3	2.2	2.7
HOFSDF	OTHER	46.1	46.6	45.9	46.0	46.2	46.8	**49.4**	54.4	60.7	92.2
HWDRAF	RESIDENTIAL WOOD............	23.8	23.5	23.7	23.8	23.9	24.0	**24.2**	24.3	24.2	24.2
	PRIMARY DEMAND BY SECTOR...										
HTSPDF	TOTAL	848.1	826.9	793.2	807.7	822.4	842.4	**909.9**	1016.5	1088.4	1215.9
HTSEUF	END-USE DEMAND	540.3	522.3	521.3	521.6	525.0	529.6	**574.8**	632.9	679.4	777.9
HTSSDF	SECONDARY DEMAND..........	514.3	502.3	499.8	499.5	502.2	506.2	**549.0**	604.7	649.0	742.8
HTSRAF	RESIDENTIAL	124.1	120.7	124.6	126.5	127.9	128.6	**133.2**	136.4	135.5	135.3
HTSCPF	COMMERCIAL	70.3	65.6	67.3	68.4	69.6	71.0	**77.1**	86.1	92.5	104.2
HTSINF	INDUSTRIAL	146.1	146.4	145.2	143.4	143.5	144.8	**164.9**	187.1	202.6	250.4
HTSTRF	TRANSPORTATION	173.8	169.6	162.6	161.2	161.3	161.8	**173.7**	195.1	218.3	253.0
HTSNEF	NON-ENERGY USE	26.0	20.0	21.6	22.1	22.8	23.4	**25.8**	28.2	30.4	35.1
HELIRF	INTER-REG'L ELEC. TRANSFERS.	88.6	87.8	96.4	101.0	100.9	105.9	**106.0**	139.3	151.8	143.3
HTSPCF	PRODUCER CONSUMPTION	53.0	55.5	36.0	36.8	36.3	37.3	**41.2**	45.4	46.3	49.0
HTSCLF	INTERMEDIATE CONVERSION LOSS	166.2	161.3	139.5	148.3	160.1	169.5	**187.9**	198.9	211.0	245.6
HNGCSF	LESS SAVINGS FROM NUGS.......	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0.0	0.0
HTSPDF	PRIMARY DENAND BY FUEL - TOTAL.	848.1	826.9	793.2	807.7	822.4	842.4	**909.9**	1016.5	1088.4	1215.9
HRPPDF	RPP'S	499.0	473.8	415.0	429.4	419.4	435.1	**484.4**	530.6	530.8	542.7
HNGPDF	NATURAL GAS	0.0	0.0	0.1	0.1	0.2	0.2	**0.2**	0.2	0.2	0.2
HLPPDF	LPG'S	7.5	6.5	6.9	7.0	7.2	7.3	**8.0**	8.9	8.9	9.6
HCCPDF	COAL	83.1	81.9	90.8	90.2	118.4	116.8	**125.9**	137.2	148.6	247.7
HENPDF	NUCLEAR ELECTRICITY (11.654)	62.2	63.4	51.9	51.9	51.9	51.9	**52.0**	52.0	89.0	88.6
HEHPDF	HYDRO ELECTRICITY (3.6) ...	126.5	131.1	155.2	155.5	150.5	152.1	**153.7**	196.8	213.7	208.4
HOFPDF	OTHER (RENEWABLES)	46.1	46.6	49.7	49.8	50.9	55.1	**61.6**	66.6	73.0	94.5
HWDRAF	RESIDENTIAL WOOD	23.8	23.5	23.7	23.8	23.9	24.0	**24.2**	24.3	24.2	24.2
	RATIOS :										
RRDPHF	RES. DEMAND / HOUSEHOLD (GJ)	155.07	142.28	153.80	153.40	152.39	150.89	**145.24**	138.30	128.93	115.87
RCDPRF	COM. DEMAND / COM. RDP	3.83	3.71	3.75	3.71	3.69	3.67	**3.58**	3.55	3.41	3.02
RIDPRF	IND. DEMAND / IND. RDP	24.10	24.75	24.24	23.26	22.65	22.14	**22.60**	22.88	22.61	22.13
RSDPCF	SECONDARY DEWD / POP (GJ) .	207.38	212.44	211.75	209.38	208.06	207.38	**213.22**	222.97	229.08	244.29
RSDPRF	" /mP/	19.19	19.57	19.43	18.94	18.58	18.23	**17.73**	17.30	16.64	15.01
REUPCF	END-USE DEWAND / POP (GJ) ...	218.36	221.01	220.90	218.66	217.49	216.95	**223.23**	233.37	239.82	255.85
REUPRF	" " /mP	20.21	20.36	20.26	19.77	19.42	19.07	**18.57**	18.10	17.41	15.72
RPDPCF	PRIMARY DEMAND / POP (GJ) ...	358.56	351.68	336.08	338.57	340.69	345.07	**353.38**	374.83	384.20	399.88
RPDPRF	" /mP	33.18	32.39	30.83	30.62	30.43	30.33	**29.39**	29.08	27.90	24.57

Appendix A-9: Reference Scenario - Summary Results - Energy Demand (Petajoules)   Region: Quebec

		Projections									
		1990	1991	1992	1993	1994	1995	2000	2005		2020
HTSSDQ	SECONDARY DEMAND BY FUEL	459.0	1407.0	1453.4	1470.4	1489.2	1521.5	1633.8	1768.2	1898.4	2190.9
HRPSDQ	RPP'S	582.0	534.5	557.3	561.6	567.3	574.9	598.5	638.5	671.8	767.4
HNGSDQ	NATURAL GAS	211.0	206.1	217.2	218.0	219.0	224.8	245.3	273.2	299.8	349.8
HELSDQ	ELECTRICITY	531.6	537.9	549.9	559.3	568.0	583.1	637.1	691.1	749.7	860.6
HCCSDQ	COAL	14.4	8.6	8.7	9.2	9.6	10.1	11.8	12.1	10.6	12.5
HLPSDQ	LPG'S	9.3	9.1	10.0	10.7	11.5	11.8	14.0	16.6	16.5	18.9
HKGSDQ	COKE AND COKE OVEN GAS	4.4	5.1	5.1	15.2	5.3	5.6	6.5	7.4	8.5	11.4
HSTSDQ	STEAM	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
HOFSDQ	OTHER	69.7	68.8	68.1	69.3	71.3	73.9	82.9	91.4	103.5	131.9
HWDRAQ	RESIDENTIAL WOOD	36.4	36.8	36.9	36.9	37.0	37.1	37.4	37.7	37.9	38.1
	PRIMARY DEMAND BY SECTOR:										
HTSPDQ	TOTAL	1573.5	1522.3	1554.8	1571.0	1617.3	1653.7	1774.4	1861.3	2032.3	2405.9
HTSEUQ	END-USE DEMAND	1537.2	1494.0	1544.0	1563.2	1584.6	1619.5	1770.1	1912.5	2050.6	2361.1
HTSSDQ	SECONDARY DEMAND	1459.0	1407.0	1453.4	1470.4	1489.2	1521.5	1633.8	1768.2	1898.4	2190.9
HTSRAQ	RESIDENTIAL	318.4	307.0	314.7	318.1	320.4	322.4	327.3	326.2	320.9	333.6
HTSCPQ	COMMERCIAL	196.6	191.3	193.5	194.2	195.8	199.0	217.0	234.9	247.1	286.1
HTSINQ	INDUSTRIAL	558.1	544.5	563.5	578.2	592.6	617.9	692.7	777.9	865.2	1027.6
HTSTRQ	TRANSPORTATION	384.9	363.1	381.8	379.9	380.3	382.2	396.8	429.2	465.2	543.6
HTSNEQ	NON-ENERGY USE	78.2	87.0	90.6	92.8	95.4	98.0	136.2	144.2	152.2	170.2
HELIRQ	INTER-REG'L ELEC. TRANSFERS	-86.6	-85.6	-90.0	-94.7	-94.0	-99.6	-123.5	-148.3	-145.5	-113.3
HTSPCQ	PRODUCER CONSUMPTION	78.1	80.3	92.9	94.0	95.3	97.4	105.2	114.1	122.9	141.7
HTSCLQ	INTERMEDIATE CONVERSION LOSS	44.8	33.7	8.5	9.1	36.1	44.7	32.1	-7.4	13.8	25.9
HNGCSQ	LESS SAVINGS FROM NUGS	0.0	0.0	0.5	0.5	4.7	8.3	9.5	9.5	9.5	9.5
HTSPDQ	PRIMARY DEMAND BY FUEL - TOTAL	1573.5	1522.3	1554.8	1571.0	1617.3	1653.7	1774.4	1861.3	2032.3	2405.9
HRPPDQ	RPP'S	705.3	643.2	673.6	680.1	687.3	696.5	728.7	779.2	822.2	940.5
HNGPDQ	NATURAL GAS	211.5	206.6	222.1	223.1	231.2	243.0	266.0	294.3	321.3	372.1
HLPPDQ	LPG'S	17.4	23.7	18.7	19.7	20.9	21.6	54.6	57.2	57.1	59.5
HCCPDQ	COAL	27.0	20.2	21.0	21.6	22.3	23.4	26.5	28.3	28.7	35.2
HENPDQ	NUCLEAR ELECTRICITY (1.654)	48.3	45.6	55.9	55.9	55.9	55.8	56.0	56.0	56.0	55.8
HEHPDQ	HYDRO ELECTRICITY (3.6)	457.9	477.4	457.9	459.3	482.0	482.0	498.1	493.0	581.4	748.8
HOFPDQ	OTHER (RENEWABLES)	69.7	68.8	68.7	74.3	80.6	94.3	107.1	115.7	127.7	156.0
HWDRAQ	RESIDENTIAL WOOD	36.4	36.8	36.9	36.9	37.0	37.1	37.4	37.7	37.9	38.1
	RATIOS:										
RRDPHQ	RES. DEMAND / HOUSEHOLD (GJ)	122.08	114.91	115.65	114.82	113.77	112.73	107.35	101.24	94.34	87.82
RCDPRQ	COM. DEMAND / COM. RDP	3.67	3.49	3.48	3.40	3.36	3.33	3.35	3.33	3.21	3.00
RIDPRQ	IND. DEMAND / IND. RDP	20.15	20.41	20.60	20.39	19.97	19.84	19.86	19.13	18.29	15.96
RSDPCQ	SECONDARY DEMAND / POP (GJ)	211.23	205.57	209.82	209.74	210.02	212.26	217.80	227.23	235.33	251.06
RSDPRQ	" " / RDP	15.18	15.01	15.19	14.93	14.71	14.57	14.24	13.81	13.27	11.99
REUPCQ	END-USE DEMAND / POP (GJ)	222.84	218.27	222.90	222.97	223.48	225.94	235.97	245.76	254.20	270.57
REUPRQ	" " / RDP	16.02	15.93	16.14	15.87	15.65	15.51	15.42	14.94	14.34	12.92
RPDPCQ	PRIMARY DEMAND / POP (GJ)	233.62	222.42	224.45	224.09	228.09	230.71	236.54	239.19	251.93	275.71
RPDPRQ	" " / RDP	16.79	16.24	16.25	15.95	15.97	15.83	15.46	14.54	14.21	13.17

Appendix A-9: Reference Scenario - Summary Results -

		1990	1991	Projec 199
HTSSDO	SECONDARY DEMAND BY FUEL:	2288.4	2272.0	232
HRPSDO	RPP'S	781.6	729.1	73
HNGSDO	NATURAL GAS	750.0	763.9	79
HELSDO	ELECTRICITY.	476.5	476.8	48
HCCSDO	COAL	20.5	17.0	1
HLPSDO	LPG'S	29.3	33.4	3
HKGSDO	COKE AND COKE OVEN GAS.	124.2	138.5	14
HSTSDO	SAW	19.1	22.9	2
HOFSDO	OTHER	61.6	67.8	6
HWDRAO	RESIDENTIAL WOOD	25.5	22.7	2
	PRIMARY DEMAND BY SECTOR:			
HTSPDO	TOTAL	3332.3	3415.8	357
HTSEUO	END-USE DEMAND	2501.7	2488.9	255
HTSSDO	SECONDARY DEMAND.	2288.4	2272.0	232
HTSRAO	RESIDENTIAL	539.7	526.0	53
HTSCPO	COMMERCIAL	325.8	346.8	35
HTSINO	INDUSTRIAL	799.9	797.8	82
HTSTRO	TRANSPORTATION.	622.4	600.9	60
HTSNEO	NON-ENERGY USE	213.3	216.9	22
HELIRO	INTER-REG'L ELEC. TRANSFERS.	-7.9	-7.6	-
HTSPCO	PRODUCER CONSUMPTION	171.5	175.2	18
HTSCLO	INTERMEDIATE CONVERSION LOSS	667.0	759.3	86
HNGCSO	LESS SAVINGS FROM NUGS.	0.0	0.0	
HTSPDO	PRIMARY DEMAND BY FUEL - TOTAL.	3332.3	3415.8	357
HRPPDO	RPP'S	1046.7	999.9	105
HNGPDO	NATURAL GAS	824.6	841.4	90
HLPPDO	LPG'S	57.6	60.0	7
HCCPDO	COAL	439.2	468.6	41
HENPDO	NUCLEAR ELECTRICITY (11.654)	691.7	824.8	89
HEHPDO	HYDRO ELECTRICITY (3.6) . . .	185.5	130.8	13
HOFPDO	OTHER (RENEWABLE)	61.6	67.8	8
HWDRAO	RESIDENTIAL WOOD	25.5	22.1	2
	RATIOS :			
RRDPHO	RES. DEMAND / HOUSEHOLD (GJ)	149.65	141.96	144.
RCDPRO	COM. DEWAND / COM. RDP	3.74	3.98	4.
RIDPRO	IND. DEMAND / IND. RDP	14.93	16.16	16.
RSDPCO	SECONDARY DEMAND / POP (GJ) .	232.06	229.48	231.
RSDPRO	" /Rap/	14.55	14.93	14.
REUPCO	END-USE DEMAND / POP (GJ) . . .	253.93	251.40	254.
REUPRO	/RAP	15.92	16.35	16.
RPDPCO	PRIMARY DEMAND / POP (GJ) . . .	341.73	345.41	357.
RPDPRO	/RAP	21.43	22.47	22.

		Projections									
		1990	1991	1992	1993	1994	1995	2000		2010	2020
HTSSDM	SECONDARY DEMAND BY FUEL:	231.5	224.2	231.4	232.6	235.8	239.9	263.0	288.6	316.9	387.6
HRPSDM	RPP'S........	93.7	90.1	89.7	89.1	90.2	92.0	101.4	112.2	123.5	153.7
HNGSDM	NATURAL GAS..	73.5	70.0	73.6	74.1	74.8	75.9	82.8	89.3	97.4	117.7
HELSDM	ELECTRICITY..	55.2	55.9	58.7	59.5	60.4	61.4	67.3	73.6	81.0	98.7
HCCSDM	COAL.........	2.1	1.8	2.0	2.1	2.2	2.2	2.4	2.8	2.9	3.8
HLPSDM	LPG'S......................	3.7	3.0	3.6	4.1	4.4	4.5	5.0	6.2	7.5	8.6
HKGSDM	COKE AND COKE OVEN GAS.. ...	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDM	STEAM........	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDM	OTHER...............	0.3	0.4	0.7	0.7	0.8	0.8	1.1	1.3	1.4	1.9
HWDRAM	RESIDENTIAL WOOD....	2.8	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2
	PRIMARY DEMAND BY SECTOR:										
HTSPDM	TOTAL.........................	269.3	265.2	276.3	280.0	283.4	288.6	321.0	348.7	401.2	480.8
HTSEUM	END-USE DEMAND.............	235.4	228.4	235.5	236.8	240.2	244.5	268.2	294.4	323.2	395.3
HTSSDM	SECONDARY DEMAND.........	231.5	224.2	231.4	232.6	235.8	239.9	263.0	288.6	316.9	387.6
HTSRAM	RESIDENTIAL...........	73.3	69.6	73.7	74.9	75.8	76.4	79.0	80.0	81.8	87.8
HTSCPM	COMMERCIAL............	46.8	46.2	47.2	47.1	47.5	48.2	52.2	57.7	64.0	80.7
HTSINM	INDUSTRIAL............	43.6	42.1	46.3	47.7	49.2	50.9	59.6	68.6	78.4	102.3
HTSTRM	TRANSPORTATION........	67.8	66.1	64.2	62.9	63.3	64.3	72.2	82.2	92.7	116.7
HTSNEM	NON-ENERGY USE..........	3.9	4.2	4.1	4.3	4.4	4.6	5.2	5.8	6.3	7.8
HELIRM	INTER-REG'L ELEC. TRANSFERS.	5.9	6.0	4.5	4.8	3.4	3.2	7.7	5.9	26.1	26.1
HTSPCM	PRODUCER CONSUMPTION........	24.4	28.0	36.0	38.0	39.4	40.5	44.7	48.0	51.5	59.0
HTSCLM	INTERMEDIATE CONVERSION LOSS	3.6	2.8	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
HNGCSM	LESS SAVINGS FROM NUGS......	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HTSPDM	PRIMARY DEMAND BY FUEL - TOTAL.	269.3	265.2	276.3	280.0	283.4	288.6	321.0	348.7	401.2	480.8
HRPPDM	RPP'S......................	98.2	94.8	100.3	99.8	101.2	103.2	113.9	126.1	138.8	172.6
HNGPDM	NATURAL GAS.........	90.0	89.0	94.4	96.9	98.9	100.8	110.2	118.3	128.0	151.0
HLPPDM	LPG'S......................	3.7	3.1	3.6	4.1	4.4	4.5	5.0	6.3	7.5	8.6
HCCPDM	COAL.......................	7.1	5.3	2.0	2.1	2.2	2.2	2.4	2.8	2.9	3.8
HENPDM	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDM	HYDRO ELECTRICITY ...	67.3	69.6	71.7	72.9	72.5	73.5	84.7	[illegible]	118.8	139.2
HOFPDM	OTHER (RENEWABLES).......	0.3	0.4	1.1	1.1	1.2	1.3	1.6	1.8	1.9	2.4
HWDRAM	RESIDENTIAL WOOD........	2.8	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2
	RATIOS:										
RRDPHM	RES. DEMAND / HOUSEHOLD (GJ)	150.20	142.99	146.58	143.91	141.81	140.24	133.52	124.49	117.32	105.38
RCDPRM	COM. DEMAND / COM. RDP......	4.86	4.90	5.01	4.88	4.81	4.77	4.67	4.59	4.52	4.29
RIDPRM	IND. DEMAND / IND. RDP......	13.16	13.53	14.36	14.37	14.29	14.18	14.44	14.37	14.20	13.54
RSDPCM	SECONDARY DEMAND / POP (GJ)	208.61	203.83	208.00	206.48	206.88	208.54	217.15	226.79	237.41	258.74
RSDPRM	" " / RDP/	14.30	14.23	14.45	14.19	14.01	13.84	13.53	13.01	12.49	11.23
REUPCM	END-USE DEMAND / POP (GJ)..	212.19	207.66	211.70	210.26	210.76	212.51	221.41	231.32	242.16	263.92
REUPRM	" " / RDP.	14.54	14.50	14.71	14.45	14.27	14.11	13.79	13.27	12.74	11.46
RPDPCM	PRIMARY DEMAND / POP (GJ)..	245.63	241.26	248.36	248.59	248.66	250.88	264.99	274.02	300.57	320.96
RPDPRM	" " / RDP.	16.84	16.85	17.26	17.08	16.84	16.65	16.51	15.72	15.82	13.93

		1990	1991	Project 1992
HTSSDS	SECONDARY DEMAND BY FUEL:	280.1	295.1	**277.**
HRPSDS	RPP'S	113.8	112.4	**108.**
HNGSDS	NATURAL GAS	100.6	115.1	**104.**
HELSDS	ELECTRICITY	44.0	44.7	**41.**
HCCSDS	COAL	3.6	3.8	**3.**
HLPSDS	LPG'S	4.6	3.7	**3.**
HKGSDS	COKE AND COKE OVEN GAS	0.0	0.0	**0.**
HSTSDS	STEAM	0.0	0.0	**0.**
HOFSDS	OTHER	11.1	13.3	**14.**
HWDRAS	RESIDENTIAL WOOD	2.5	2.2	**2.**
	PRIMARY DEMAND BY SECTOR:			
HTSPDS	TOTAL	413.3	429.5	**419.**
HTSEUS	END-USE DEMAND	293.0	307.1	**288.**
HTSSDS	SECONDARY DEMAND	280.1	295.1	**277.**
HTSRAS	RESIDENTIAL	102.4	97.9	**102.**
HTSCPS	COMMERCIAL	39.7	38.9	**39.**
HTSINS	INDUSTRIAL	78.1	95.0	**74.**
HTSTRS	TRANSPORTATION	60.0	63.2	**60.**
HTSNES	NON-ENERGY USE	12.9	12.0	**11.**
HELIRS	INTER-REG'L ELEC. TRANSFERS.	-0.2	-1.0	**-0.**
HTSPCS	PRODUCER CONSUMPTION	37.3	39.8	**52.**
HTSCLS	INTERMEDIATE CONVERSION LOSS	83.3	83.6	**78.**
HNGC S S	LESS SAVINGS FROM NUGS. . . .	0.0	0.0	**0.**
HTSPDS	PRIMARY DEMAND BY FUEL - TOTAL.	413.3	429.5	**419.**
HRPPDS	RPP'S	126.9	124.4	**120.**
HNGPDS	NATURAL GAS	137.3	153.6	**167.**
HLPPDS	LPG'S	4.9	4.0	**3.**
HCCPDS	COAL	115.5	117.0	**95.**
HENPDS	NUCLEAR ELECTRICITY (11.654)	0.0	0.0	**0.**
HEHPDS	HYDRO ELECTRICITY (3.6) . . .	15.1	15.0	**13.**
HOFPDS	OTHER (RENEWABLES)	11.1	13.3	**16.**
HWDRAS	RESIDENTIAL WOOD	2.5	2.2	**2.**
	RATIOS :			
RRDPHS	RES. DEMAND / HOUSEHOLD (GJ)	174.14	171.68	**181.5**
RCDPRS	COM. DEMAND / COM. RDP	5.04	4.99	**5.0**
RIDPRS	IND. DEMAND / IND. RDP	21.98	27.35	**21.4**
RSDPCS	SECONDARY DEWD / POP (GJ)	276.20	295.54	**278.1**
RSDPRS	" /RAP/	16.83	17.54	**16.5**
REUPCS	END-USE DEMAND / POP (GJ)	289.00	307.59	**289.9**
REUPRS	/ RDP.	17.61	18.26	**17.2**
RPDPCS	PRIMARY DEMAND / POP (GJ) .	411.19	430.40	**420.9**
RPDPRS	/RAP	25.06	25.55	**24.9**

Appendix A-9: Reference Scenario Summary Results - Energy Demand (Petajoules) — *Region: Alberta/*

				Projections							
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
HTSSDA	SECONDARY DEMAND BY FUEL:	955.4	907.5	939.2	960.1	965.6	971.6	1041.7	1121.4	1227.6	1412.4
HRPSDA	RPP'S	323.6	298.5	309.1	312.1	314.3	315.9	345.4	379.7	419.1	466.6
HNGSDA	NATURAL GAS	442.0	411.1	428.9	442.5	445.9	450.3	483.0	515.2	559.2	626.6
HELSDA	ELECTRICITY	140.2	147.8	148.6	150.8	150.5	150.4	155.0	163.2	178.4	216.1
HCCSDA	COAL	0.9	0.9	0.6	0.7	0.8	0.8	0.6	0.5	0.6	0.6
HLPSDA	LPG'S	23.3	18.7	20.9	21.8	22.5	22.7	24.0	24.9	27.6	33.9
HKGSDA	COKE AND COKE OVEN GAS... .	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
HSTSDA	STEAM	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
HOFSDA	OTHER	21.8	25.9	26.6	27.6	27.1	27.0	29.3	33.5	38.5	64.5
HWDRAA	RESIDENTIAL WOOD..	3.4	4.3	4.3	4.3	4.3	4.3	4.2	4.1	4.0	3.8
	PRIMARY DEMAND BY SECTOR:										
HTSPDA	TOTAL	1627.2	1613.7	1680.9	1716.3	1729.4	1768.9	1904.9	2010.0	2176.5	2490.6
HTSEUA	END-USE DEMAND	1241.9	1219.1	1258.9	1286.4	1299.3	1337.9	1455.3	1570.8	1705.9	1917.6
HTSSDA	SECONDARY DEMAND	955.4	907.5	939.2	960.1	965.6	971.6	1041.7	1121.4	1227.6	1412.4
HTSRAA	RESIDENTIAL	204.7	197.4	207.5	209.3	210.9	212.2	215.6	217.8	221.5	230.7
HTSCPA	COMMERCIAL	151.3	141.0	142.5	142.8	143.5	145.6	159.7	175.0	186.9	207.4
HTSINA	INDUSTRIAL	361.5	351.2	365.0	382.4	383.4	385.1	412.9	441.6	498.0	611.2
HTSTRA	TRANSPORTATION	238.5	218.5	224.2	225.6	227.7	228.7	253.5	287.0	321.2	363.1
HTSNEA	NON-ENERGY USE	286.5	311.6	319.7	326.3	333.7	366.3	413.5	449.4	478.3	505.2
HELIRA	INTER-REG'L ELEC. TRANSFERS.	3.0	1.4	8.8	8.8	8.8	8.8	8.8	11.0	8.5	10.4
HTSPCA	PRODUCER CONSUMPTION	81.2	77.6	81.7	84.8	86.6	88.0	95.7	103.4	111.9	125.4
HTSCLA	INTERMEDIATE CONVERSION LOSS	301.1	315.6	331.4	336.3	334.7	334.1	345.1	349.1	379.8	466.9
HNGCSA	LESS SAVINGS FROM NUGS.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.3	29.7	29.7
HTSPDA	PRIMARY DEMAND BY FUEL - TOTAL.	1627.2	1613.7	1680.9	1716.3	1729.4	1768.9	1904.9	2010.0	2176.5	2490.6
HRPPDA	RPP'S	414.9	385.8	394.3	399.5	403.7	407.2	447.0	492.0	542.9	610.1
HNGPDA	NATURAL GAS	655.1	647.2	712.4	727.0	732.9	735.4	799.8	881.4	922.3	980.0
HLPPDA	LPG'S	127.0	125.4	136.7	140.6	145.3	175.8	192.2	193.1	210.8	217.2
HCCPDA	COAL	397.5	417.7	385.6	396.2	392.6	395.7	408.8	380.1	434.7	589.9
HENPDA	NUCLEAR ELECTRICITY (11.654)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDA	HYDRO ELECTRICITY (3 .6)...	7.4	7.3	15.0	15.0	15.5	15.5	15.5	17.7	15.2	17.3.
HOFPDA	OTHER (RENEWABLES)	21.8	25.9	32.6	33.6	35.2	35.1	37.4	41.6	46.6	72.5
HWDRAA	RESIDENTIAL WOOD	3.4	4.3	4.3	4.3	4.3	4.3	4.2	4.1	4.0	3.8
	RATIOS :										
RRDPHA	RES. DEMAND / HOUSEHOLD (GJ)	192.34	182.19	188.28	184.85	181.22	177.73	161.80	149.43	139.33	124.08
RCDPRA	COM. DEMAND / COM. RDP	5.37	5.02	5.04	4.92	4.82	4.76	4.70	4.65	4.48	4.22
RIDPRA	IND. DEMAND / IND. RDP	18.09	17.80	18.75	18.99	18.57	18.17	17.31	16.32	15.98	15.89
RSDPCA	SECONDARY DEMAND / POP (GJ) .	390.78	359.88	366.30	366.22	360.18	355.00	350.57	356.30	369.95	398.44
RSDPRA	/RAP/	17.59	16.75	17.29	17.17	16.83	16.47	15.76	15.14	14.71	13.95
REUPCA	END-USE DENAND / POP (GJ)	508.38	483.47	490.98	490.68	484.67	488.83	489.72	499.10	514.09	540.96
REUPRA	/ RDP	22.88	22.50	23.17	23.00	22.65	22.68	22.02	21.20	20.45	18.94
RPDPCA	PRIMARY DEMAND / POP (GJ)	667.94	639.94	655.54	654.67	645.11	646.29	641.02	638.66	655.89	702.61
RPDPRA	" / RDP	30.06	29.78	30.94	30.69	30.15	29.99	28.82	27.13	26.09	24.60

		1990	1991	Projections 1992	1993	1994	1995	2000	2005	2010	2020
HTSSDZ	SECONDARY DEMAND BY FUEL:	925.3	939.0	931.7	942.3	954.2	968.6	1040.2	1143.4	1254.1	1535.2
HRPSDZ	RPP'S	335.4	335.6	331.5	332.1	334.5	338.1	352.3	390.8	431.8	522.2
HNGSDZ	NATURAL GAS	212.7	221.1	223.5	228.8	233.3	238.2	260.0	280.0	296.4	348.7
HELSDZ	ELECTRICITY	191.4	193.2	194.1	195.7	197.7	200.0	215.7	240.7	267.1	325.8
HCCSDZ	COAL	3.3	3.8	3.8	3.9	4.1	4.2	4.2	4.8	5.4	6.9
HLPSDZ	LPG'S	13.7	14.0	14.2	14.9	“15.3	15.3	16.7	18.7	20.9	25.1
HKGSDZ	COKE AND COKE OVEN GAS.	0.8	1.3	1.3	1.4	1.4	1.4	1.6	2.1	2.4	3.6
HSTSDZ	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDZ	OTHER	157.4	160.1	153.3	155.5	158.0	161.3	179.5	196.2	220.0	292.7
HWDRAZ	RESIDENTIAL WOOD	10.6	9.8	9.9	9.9	10.0	10.0	10.2	10.2	10.2	10.2
	PRIMARY DEMAND BY SECTOR:										
HTSPDZ	TOTAL	1018.1	1031.4	1019.6	1036.8	1054.3	1080.7	1166.5	1271.4	1391.2	1896.8
HTSEUZ	END-USE DEMAND	949.8	961.7	954.3	965.5	978.3	993.3	1067.6	1173.7	1286.8	1574.5
HTSSDZ	SECONDARY DEMAND	925.3	939.0	931.7	942.3	954.2	968.6	1040.2	1143.4	1254.1	1535.2
HTSRAZ	RESIDENTIAL	144.2	145.0	147.9	149.7	150.5	151.0	151.7	154.5	155.3	165.7
HTSCPZ	COMMERCIAL	114.9	120.4	117.4	117.6	118.5	120.4	129.2	143.2	153.9	178.3
HTSINZ	INDUSTRIAL	417.2	418.8	412.3	418.5	424.7	431.9	470.7	524.1	587.6	755.2
HTSTRZ	TRANSPORTATION	249.5	255.5	254.1	256.4	260.6	265.4	288.6	321.6	357.4	435.9
HTSNEZ	NON-ENERGY USE	24.6	22.'7	22.5	23.3	24.0	24.8	27.4	30.3	32.7	39.3
HELIRZ	INTER-REG'L ELEC. TRANSFERS.	-2.8	-1.1	-8.6	-8.6	-8.6	-6.6	-22.6	-24.8	-22.3	-24.2
HTSPCZ	PRODUCER CONSUMPTION.	58.5	63.0	59.2	61.7	63.5	65.0	70.0	76.3	82.3	134.3
HTSCLZ	INTERMEDIATE CONVERSION LOSS	12.5	7.8	14.7	18.2	24.0	34.0	57.9	52.6	50.8	218.7
HNGCSZ	LESS SAVINGS FROM NUGS.	0.0	0.0	0.0	0.0	2.8	5.0	6.5	6.5	6.5	6.5
HTSPDZ	PRIMARY DEMAND BY FUEL - TOTAL.	1018.1	1031.4	1019.6	1036.8	1054.3	1080.7	1166.5	1271.4	1391.2	1896.8
HRPPDZ	RPP'S	388.4	385.5	381.8	383.3	386.2	390.6	409.3	454.7	501.2	599.4
HNGPDZ	NATURAL GAS	246.4	253.1	250.2	257.9	268.2	277.4	303.9	325.1	342.3	451.1
HLPPDZ	LPG'S	14.2	14.9	14.7	15.4	15.8	15.8	17.2	19.3	21.0	25.3
HCCPDZ	COAL	8.2	10.0	6.3	6.5	6.7	6.9	7.1	8.4	9.6	226.1
HENPDZ	NUCLEAR ELECTRICITY (11.654)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDZ	HYDRO ELECTRICITY (3.6)	193.3	198.2	194.2	194.5	193.1	192.6	182.0	200.3	229.8	235.0
HOFPDZ	OTHER (RENEWABLES)	157.4	160.1	162.4	169.3	174.2	187.3	236.7	253.4	277.1	349.6
HWDRAZ	RESIDENTIAL WOOD	10.6	9.8	9.9	9.9	10.0	10.0	10.2	10.2	10.2	10.2
	RATIOS :										
RRDPHZ	RES. DEWD / HOUSEHOLD (GJ)	115.51	111.17	110.74	109.40	107.63	105.89	97.87	92.24	86.00	79.76
RCDPRZ	COM. DEMAND / COM. RDP	4.12	4.26	4.14	4.04	3.96	3.91	3.82	3.81	3.70	3.37
RIDPRZ	IND. DEMAND / IND. RDP	26.36	27.59	26.15	25.45	24.88	24.46	24.60	23.66	23.57	22.58
RSDPCZ	SECONDARY DEWD / POP (GJ) .	286.38	284.89	276.65	275.03	273.85	273.78	275.82	286.27	296.87	325.86
RSDPRZ	" /mP/	18.62	19.32	18.66	18.27	17.98	17.73	17.39	17.00	16.79	16.02
REUPCZ	END-USE DEMAND / POP (GJ)	294.07	291.78	283.34	281.82	280.75	280.78	283.08	293.86	304.61	334.19
REUPRZ	/ RDP	19.12	19.79	19.11	18.73	18.43	18.18	17.85	17.45	17.22	16.43
RPDPC Z	PRIMARY DEMAND / POP (GJ)...	318.75	312.95	302.75	302.63	302.57	305.48	309.29	318.32	329.31	402.60
RPDPRZ	" " /mP	20.73	21.23	20.42	20.11	19.86	19.78	19.50	18.90	18.62	19.80

		1990	1991	Projections 1992	1993	1994	1995	2000	2005	2010	2020
	RESIDENTIAL :										
HTSRAC	TOTAL	1506.7	1463.8	1510.4	1518.9	1530.7	1541.6	1576.4	1594.8	1595.9	1673.8
HTSORC	RESIDENTIAL (EXCL. FARM)	1379.3	1348.2	1390.1	1394.8	1404.3	1413.5	1441.5	1453.8	1446.5	1493.1
HELRAC	ELECTRICITY.	503.0	495.4	509.3	513.3	517.9	522.6	538.5	545.2	549.5	586.3
HNGRAC	NATURAL GAS	551.6	555.1	578.2	578.9	583.0	588.7	607.8	619.5	621.7	649.0
HRPORC	TOTAL RPP'S	197.7	178.9	180.6	179.2	178.7	177.9	170.7	165.4	150.2	130.7
HCCRAC	COAL	2.5	2.0	2.2	2.4	2.6	2.7	2.6	2.4	2.4	2.2
HLPRAC	LPG' S	19.6	14.3	16.9	17.9	18.6	17.9	17.3	16.3	17.7	19.9
HSTRAC	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HWDRAC	WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.6	105.0	105.0	104.9
HDFAGC	FARM DIESEL	71.4	67.2	67.7	68.5	69.2	70.0	75.2	81.4	88.9	108.1
HMGAGC	FARM MOTOR GASOLINE.	56.1	48.4	52.6	55.6	57.3	58.1	59.7	59.6	60.5	72.7
	COMMERCIAL:										
HTSCPC	TOTAL	945.4	950.3	963.6	967.2	976.2	993.1	1084.6	1194.7	1279.0	1473.4
HTSOCC	MAJOR COMMERCIAL	895.7	905.3	917.8	920.4	928.4	944.2	1031.4	1136.4	1215.4	1397.4
HELOCC	ELECTRICITY.	384.6	398.3	398.5	397.6	399.5	404.8	433.0	468.5	494.0	566.1
HNGCPC	NATURAL GAS	387.8	403.5	405.4	405.9	408.4	415.3	460.3	512.9	557.2	644.4
HRPOCC	TOTAL RPP'S	101.7	86.3	94.8	97.0	99.9	102.7	113.1	125.6	132.5	148.7
HCCCPC	COAL	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
HLPCPC	LPG' S	21.3	16.9	18.7	19.4	20.1	20.8	24.5	28.7	31.0	37.3
HSTCPC	STEAM	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
HOFCPC	NES FUELS	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.5	0.6	0.7
HELSLC	STREET LIGHTING	9.4	9.6	9.7	9.9	10.0	10.2	10.8	11.4	11.9	12.8
HTFCPC	AVIATION TURBO FUEL.	35.0	32.5	33.0	33.9	34.7	35.6	39.1	43.4	47.9	58.7
HAGCPC	AVIATION GASOLINE.	3.9	3.0	3.0	3.0	3.1	3.2	3.3	3.6	3.9	4.5
	INDUSTRIAL:										
HTSINC	TOTAL	2404.6	2395.9	2429.8	2492.1	2527.2	2580.6	2877.4	3200.9	3584.8	4429.2
HTSOIC	MAJOR INDUSTRIAL.	1905.9	1866.0	1907.5	1952.7	1979.6	2021.7	2258.5	2508.0	2800.1	3415.7
HELINC	ELECTRICITY	654.7	667.4	677.3	688.0	697.4	713.6	804.0	914.7	1041.3	1277.6
HNGINC	NATURAL GAS	847.8	826.0	858.1	887.7	901.9	921.0	1032.1	1130.2	1257.3	1523.1
HRPINC	TOTAL RPP'S	314.6	284.0	282.3	286.0	288.5	293.9	319.4	350.7	381.8	468.1
HCCINC	COAL	44.2	36.0	36.0	36.7	37.3	38.2	42.3	45.9	47.7	58.5
HLPINC	LPG'S	23.8	28.2	28.8	29.3	29.5	30.0	32.8	35.5	37.5	45.8
HSTINC	STEAM	20.8	24.6	25.0	25.0	24.9	25.0	27.8	31.0	34.4	42.5
HKGINC	COKE & COKE OVEN GAS	130.7	147.0	151.2	158.4	160.8	163.3	181.6	207.4	234.9	291.9
HOFINC	RENEWABLES	368.0	382.9	371.1	381.0	386.8	395.6	437.3	485.5	549.8	721.7

		Projections									
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
	ROAD TRANSPORTATION:										
HTSRTC	TOTAL	1454.	1412.	1425.	1420.	1424.	1433.	1555.	1753.	1957.	2257.
HMGRTC	MOTOR GASOLINE	1120.	1088.	1103.	1097.	1094.	1093.	1181.	1353.	1529.	1730.
HDFRTC	DIESEL FUEL	305.	293.	287.	287.	292.	300.	324.	340.	360.	400.
HLPRTC	PROPANE	26.	29.	30.	30.	31.	32.	36.	41.	47.	57.
HNGRTC	COMPRESSED NATURAL GAS	3.	3.	3.	4.	4.	4.	6.	9.	11.	10.
HOFRTC	OTHER FUELS	0.	0.	1.	2.	3.	3.	7.	10.	11.	60.
	PASSENGER VEHICLES:										
NPVSTC	SALES - VOLUME . . . .('000)	885.	874.	919.	978.	1073.	1161.	1301.	1467.	1585.	1764.
ENPVS	- EFFICIENCY . . . .L/lOOKN	9.70	9.73	9.67	9.68	9.68	9.68	8.33	8.23	8.01	7.70
KTPVSC	CAR STOCK (ALL FUELS) . . . .. (.000)	10422.	10507.	10463.	10458.	10536.	10700.	12048.	13958.	15520.	17804.
EKTPVC	CAR STOCK EFFICIENCY. . . .L/100KM	10.57	10.41	10.25	10.12	10.00	9.90	9.13	8.51	8.20	7.81
KMDPCC	DISTANCE TRAVELLED PER CAR...	20845.	20537.	21243.	21396.	21405.	21242.	21657.	22341.	22873.	23183.
KTPVHC	PASSENGER VEHICLES/HOUSEHOLD..	1.08	1.07	1.04	1.02	1.01	1.01	1.06	1.14	1.19	1.22
	TRUCKS :										
NTKSTC	SALES GASOLINE TRUCKS. .('000)	409.	320.	349.	373.	404.	439.	510.	604.	689.	838.
NCVSTC	SALES - DIESEL TRUCKS . . ..('OOO)	24.	16.	19.	22.	25.	28.	29.	31.	34.	40.
KTTKSC	GASOLINE TRUCKS STOCK. ('000)	3953.	3897.	3934.	3981.	4044.	4126.	4684.	5563.	6464.	8156.
KTCVSC	DIESEL TRUCKS STOCK. . . ('000)	274.	273.	273.	274.	277.	282.	305.	328.	357.	419.
ENTKS	GASOL. TRUCK SALES EFF. .L/100KM	12.13	12.10	12.10	12.10	12.10	12.09	11.59	11.44	11.30	11.10
	GASOLINE TRUCK STOCK										
EKTTKC	EFFICIENCY. L/100KM	12.82	12.67	12.53	12.41	12.32	12.25	11.91	11.62	11.43	11.18
	DISTANCE TRAVELLED PER										
KMDTKC	GASOLINE TRUCK	23423.	23128.	23731.	23905.	23929.	23741.	24278.	24988.	25594.	25908.
	RAIL TRANSPORTATION:										
HTSRLC	TOTAL	89.	83.	87.	92.	97.	101.	112.	127.	144.	187.
HDFRLC	DIESEL FUEL OIL	89.	83.	87.	92.	97.	101.	112.	127.	144.	187.
	AVIATION TRANSPORTATION:										
HTSAVC	TOTAL	146.	130.	130.	134.	141.	151.	175.	197.	224.	316.
HTFAVC	AVIATION TURBO FUEL..	145.	129.	129.	133.	140.	149.	173.	195.	221.	312.
HAGAVC	AVIATION GASOLINE	2.	1.	1.	2.	2.	2.	2.	2.	2.	3.
	MARINE TRANSPORTATION:										
HTSMAC	TOTAL	107.	112.	110.	112.	115.	117.	120.	129.	141.	172.
HHFMAC	HEAVY FUEL OIL	60.	66.	64.	65.	67.	68.	69.	74.	81.	100.
HDFMAC	DIESEL FUEL OF....... . . .	47.	45.	46.	47.	48.	49.	51.	54.	59.	72.
HCCMAC	COAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
HOFMAC	OTHER	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
HTSTRC	TOTAL TRANSPORTATION.	1797.	1737.	1752.	1759.	1777.	1802.	1962.	2206.	2466.	2933.
HDFTRC	TOTAL DIESEL	442.	421.	420.	426.	437.	450.	487.	521.	563.	660.
HHFTRC	TOTAL HEAVY FUEL OIL.	60.	66.	64.	65.	67.	68.	69.	74.	81.	100.

		1990	1991	Projections 1992	1993	1994	1995	2000	2005	203.0	2020
	NON-COMBUSTION ENERGY:										
HTSNEC	TOTAL	645.3	674.4	697.7	716.2	736.3	781.6	946.1	1016.6	1079.5	1167.7
HRPNEC	REFINED PETROLEUM PRODUCTS.	335.2	338.6	351.5	361.2	371.4	381.5	422.6	459.6	496.5	562.4
HASNEC	ASPHALT	124.3	122.1	122.1	127.3	133.1	138.7	160.8	181.8	201.8	244.7
HLGNEC	LUBES &GRF.ASES	36.6	33.9	34.4	35.2	36.0	36.8	39.3	42.6	46.0	53.4
HNSNEC	NAPTHA SPECIALTIES.	9.4	9.9	10.1	10.4	10.6	10.9	11.7	12.7	13.9	16.2
HPFNEC	PETROCHEMICAL FEEDSTOCKS.	133.9	124.7	136.6	139.0	141.3	143.6	156.1	163.5	171.3	174.6
HPCNEC	PETROLEUM COKE	18.3	31.2	31.5	32.2	32.9	33.6	35.6	38.4	41.4	48.0
HOPNEC	OTHER PRODUCTS	12.8	16.6	16.7	17.1	17.5	17.9	19.1	20.5	22.1	25.5
HNGNEC	NATURAL GAS (FEEDSTOCKS) . .	155.8	177.3	178.2	180.8	183.3	185.0	213.8	246.3	256.8	276.8
HLPNEC	LIQUEFIED PETROLEUM GASES.	139.2	148.5	157.9	163.9	171.1	204.3	298.2	298.2	312.8	312.8
HKGNEC	COKE & COKE OVEN GASES. . .	9.2	4.9	4.9	5.1	5.2	5.3	5.7	6.2	6.7	7.9
HCCNEC	COAL	5.8	5.1	5.1	5.2	5.3	5.5	5.8	6.3	6.8	7.9
	PRODUCER CONSUMPTION :										
HTSPCC	TOTAL	504.0	519.3	542.0	561.1	568.5	580.9	636.6	693.9	746.2	879.6
HRPPCC	REFINED PETROLEUM PRODUCTS.	234.0	229.6	216.6	220.6	217.4	220.5	241.1	268.8	291.5	329.2
HNGPCC	NATURAL GAS	133.1	147.7	177.6	191.5	200.5	207.2	228.1	242.4	256.4	282.2
HLPPCC	LPGS	2.4	0.7	2.3	2.4	2.5	2.8	4.2	4.2	4.4	4.7
HCCPCC	COAL	4.4	5.0	1.4	1.4	1.5	1.5	1.6	1.8	2.0	38.3
HELPCC	ELECTRICITY	130.1	136.2	144.2	145.2	146.5	148.8	161.7	176.6	191.8	225.2
HOFPCC	OTHER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

eference Scenario Conversion Requirement Demands (Petajoules, Region: Canada

	1990	1991	Projections 1992	1993	1994	1995	2000	2005	2010	2020
ION REQUIREMENTS...	3122.	3358.	3493.	3590.	3657.	3765.	4004.	4314.	4614.	5612.
NERATION:										
(INC. EXPORTS)										
....	2817.	2996.	3130.	3210.	3269.	3368.	3617.	3889.	4144.	5054.
....	874.	913.	795.	857.	657.	625.	736.	827.	931.	1313.
UEL OIL....	137.	111.	115.	139.	70.	71.	104.	144.	111.	12.
ATES.(DFO & LFO)...	10.	11.	11.	12.	12.	13.	14.	16.	15.	15.
GAS......	51.	43.	109.	107.	140.	152.	163.	224.	260.	279.
....	802.	34.	1003.	976.	1237.	1339.	1331.	1340.	1312.	1755.
....	943.	84.	1074.	1085.	1106.	1097.	1167.	1236.	1412.	1580.
UELS.	0.	0.	23.	34.	47.	71.	102.	102.	102.	102.
ES:(DOMESTIC)										
....	2816.	2930.	2970.	2997.	3045.	3138.	3398.	3649.	3934.	4848.
....	874.	913.	795.	857.	657.	625.	736.	827.	931.	1313.
UEL OIL..........	137.	111.	115.	139.	70.	71.	104.	144.	111.	12.
ATES..............	10.	11.	11.	12.	12.	13.	14.	16.	15.	15.
GAS..............	51.	43.	109.	107.	140.	152.	163.	224.	260.	279.
....	802.	34.	978.	909.	1166.	1267.	1273.	1273.	1311.	1754.
....	941.	18.	939.	938.	953.	939.	1006.	1063.	1203.	1374.
UELS..............	0.	0.	23.	34.	47.	71.	102.	102.	102.	102.
OWER										
....	154.	154.	188.	196.	201.	205.	215.	215.	215.	215
....	1.	1.	0.	0.	0.	0.	0.	0.	0.	0.
UEL OIL..........	7.	7.	12.	12.	12.	12.	12.	12.	12.	12.
ATES.............	2.	2.	0.	0.	0.	0.	0.	0.	0.	0.
GAS..............	33.	33.	49.	53.	54.	54.	55.	55.	55.	55.
....	111.	111.	104.	108.	112.	115.	115.	115.	115.	115.
UELS..............	0.	0.	23.	23.	24.	25.	33.	33.	33.	33.
RATION:										
....	6.	5.	2.	2.	2.	2.	3.	3.	3.	4.
....	0	0.	1.	1.	1.	1.	2.	2.	2.	2.
EL OIL............	3	3.	1.	1.	1.	1.	1.	1.	2.	2.
GAS...............	2	2.	0.	0.	0.	0.	0.	0.	0.	0.
ELS...............	0	0.	0.	0.	0.	0.	0.	0.	0.	0.
VEN GAS GENERATION:										
....	145.	158.	170.	178.	180.	183.	204.	232.	263.	326.

Appendix A-14: Reference Scenario - Summary Results - Carbon Dioxide *Region: Canada*

CO2-Emissions (Kilotonnes)

				Projections							
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
	C02 EMISSIONS BY FUEL:										
AECANC	TOTAL EXCLUDING BIOMASS. . .	461189.	455406.	457361.	473353.	457815.	462617.	510000.	561474.	607261.	716465.
ANGSCC	NATURAL GAS (INCL. FLARING)	131276.	133247.	143450.	148577.	153196.	156775.	171657.	186908.	199946.	224698.
AFLOCC	NATURAL GAS FLARING. .	26178.	25140.	26839.	29487.	30824.	31773.	34883.	36724.	38062.	40825.
ARPSCC	REFINED PETROLEUM PRODUCTS.	207045.	195927.	197396.	200672.	197175.	199881.	217180.	241892.	261003.	294212.
AMGSCC	MOTOR GASOLINE	79999.	77253.	78614.	78403.	78322.	78294.	84397.	96081.	108059.	122577.
AAGSCC	AVIATION GASOLINE.	382.	290.	310.	317.	325.	337.	368.	402.	439.	555.
ATFSCC	AVIATION TURBO	12724.	11422.	11468.	11812.	12354.	13090.	15038.	16890.	19064.	26279.
AHFSCC	HEAVEY FUEL OIL.....	28336.	25100.	25063.	26967.	22054.	22344.	26104.	31122.	31000.	28612.
AKRSCC	KEROSENE	1756.	1664.	1762.	1753.	1756.	1762.	1809.	1865.	1808.	1777.
ALFSCC	LIGHT FUEL OIL	18169.	16228.	16448.	16488.	16591.	16685.	16593.	16711.	15970.	15777.
ADFSCC	DIESEL FUEL OIL.....	46345.	43832.	44164.	44943.	45906.	47202.	51019.	54950.	58972.	69274.
APCSCC	PETROLEUM COKE	5264.	6322.	6527.	6705.	6764.	6879.	7329.	7681.	8132.	9527.
ANSNCC	NAPHTHA SPECIALTIES.	134.	141.	143.	147.	151.	154.	166.	181.	196.	229.
ARPOCC	RPP OWN USE	13935.	13676.	12899.	13137.	12951.	13134.	14358.	16010.	17363.	19604.
APFNCC	PETROCHEMICAL FEEDSTOCKS.	1898.	1769.	1937.	1971.	2004.	2036.	2213.	2318.	2429.	2476.
ALGNCC	LUBES AND GREASES	1318.	1223.	1240.	1270.	1298.	1328.	1416.	1535.	1657.	1924.
AOPNCC	OTHER PETROLEUM PRODUCTS.	470.	610.	615.	629.	643.	657.	701.	754.	812.	939.
ALPSCC	LIQUID PETROLEUM GASES..	7240.	7107.	7675.	7930.	8162.	8659.	3.0451.	11151.	12030.	13612.
ACCSCC	COAL	84949.	87784.	76876.	82404.	65258.	62684.	72953.	81098.	90761.	131111.
AKGSCC	COKE AND COKE OVEN GAS.	12031.	13064.	13426.	14058.	14274.	14502.	16105.	18369.	20783.	25781.
AINDPC	INDUSTRIAL PROCESSES. . . .	14963.	14674.	15271.	16429.	17116.	17756.	19272.	21015.	22627.	26506.
ANGCSC	LESS SAVINGS FROM NUGS.	0.	0.	526.	586.	1310.	1663.	1947.	3566.	4790.	4794.
	C02 EMISSIONS BY SECTOR:										
AECANC	TOTAL EXCLUDING BIOMASS. .	461189.	455406.	457361.	473353.	457815.	462617	510000.	561474.	607261.	716465.
ATRC2C	RESIDENTIAL	52019.	49636.	51403.	51674.	52065.	52371.	53227.	53779.	53452.	55700.
ATCC2C	COMMERCIAL	30601.	29657.	30659.	30956.	31389.	32050.	35507.	39600.	42774.	49471.
ATIC2C	INDUSTRIAL	82460.	80039.	81937.	84415.	85577.	87254.	96792.	106659.	117957.	143993.
ATSTCC	TRANSPORTATION	123906.	119710.	120647.	121099.	122310.	123993.	134757.	151236.	168986.	197947.
ATSNCC	NON-ENERGY USE	13923.	17710.	18114.	18470.	18836.	19488.	22544.	24711.	26043.	28249.
ATSOCC	PRODUCER CONS. (INC. FLARING)	47284.	46676.	48830.	52418.	54031.	55516.	60972.	65202.	68621.	78343.
ATGVCC	CONVERSION REQUIREMF.NTS. .	96034.	97302.	91025.	98479.	77801.	75853.	88877.	102837.	111589.	141051.
AINDPC	INDUSTRIAL PROCESSES.	14963.	14674.	15271.	16429.	17116.	17756.	19272.	21015.	22627.	26506.
ANGCSC	LESS SAVINGS FROM NUGS.	0.	0.	526.	586.	1310.	1663.	1947.	3566.	4790.	4794.
AOFSCC	BIOMASS	48071.	49464.	48269.	49355.	50002.	50967.	55530.	60743.	67652.	86112.
ATSSCC	TOTAL INCLUDING BIOMASS. .	509261.	504870.	505631.	522708.	507816.	513585.	565531.	622217.	674913.	802577.
	CO2 INTENSITIES:										
CPPD1C	CO2/PRIMARY DEMAND (TONNES/TJ)	53.57	52.82	51.83	52.87	50.47	49.81	50.38	51.23	51.28	51.06
CPPRDC	CO2 /RDP (TONNES/$1981M)	1123.37	1120.53	1103.21	1106.04	1038.92	1016.55	1003.03	972.91	931.57	858.68
CPPPOC	C02/Population (TOnnes/person)	17.35	16.88	16.72	17.08	16.30	16.25	16.93	17.76	18.36	19.93

Appendix B - Emission Conversion Factors

	co2		CH_4		N_2O	
COMBUSTION SOURCES						
Gaseous Fuels	([/ML)[b]	(t/TJ)	(kg/ML)	(kg/TJ)	(kg/ML)	(kg/TJ)
Natural Gas	1.88	49.68	(4.8 to 48)	(0.13 [o 1.27)	0.02	0.62
Still Gas	2.07	49.68			0.02	0.62
Coke Oven Gas	1.60	86.00				
Liquid Fuels	(t/kL)	(t/TJ)	(kg/kL)	(kg/TJ)	(kg/KL)	(kg/TJ)
Motor Gasoline	2.36	67.98	(0.24 [0 4.20)	(6.92 to 121.11)	(0.23 [o1.65)	(6.6 to 47.60)
Kerosene	2.55	67.65	0.21	5.53	0.23	6.10
Aviation Gas	2.33	69.37	2.19	60.00	0.23	6.86
LPGs	(1.11 to 1.76)	(59.84 to 61.38)	0.03	1.18	0.23	(9.00 to 12.50)
Diesel Oil	2.73	70.69	(0.06 to 0.25)	(1.32 to 5.7)	(0. 1310 0.40)	(3.36 to 10.34)
Light Oil	2.83	73.11	(0.01 to 0.21)	(0.16 to 5.53)	(o. 13 to 0.40)	(3.36 to 10.34)
Heavy Od	3.09	74.00	(0.03 to 0.12)	(0.72 10 2.88)	(0. 13 to 0.40)	(3.11 to 9.59)
Aviation Jet Fuel	2.55	70.84	0.08	2.00	0.23	6.40
Petroleum Coke	4.24	1CQ.10	0.02	0.38		
Solid Fuels	(t/t)	([/J'J)	(g/kg)	(kg/J'J)	(g/kg)	(kg/TJ)
Anthracite	2.39	86.20	0.02	varies	(0.1 to 2.11)	varies
U.S. Bituminous	(2.46 [o 2.50)	(81.6 to 85.9)	0.02	Varies	(0.1 to 2.11)	varies
Cdn. Bituminous	(1.70 to 2.52)	(94.3 [o 83.0)	0.02	varies	(0.1 102.11)	varies
Sub-Bituminous	1.74	94.30	0.02	varies	(0.1 to 2.11)	varies
Lignite	(1.34 to 1.52)	(93.8 [o 95.0)	0.02	varies	(0.1 to 2 .11)	varies
Coke	2.48	86.00				
Fuel Wood	1.47	81.47	(0.15 to 0.5)	(0.01 to 0.03)	(), 16	8.89
Slash Burning	1.47	81.47	5.00	001		
Incineration						
Municipal Solid Wrote	0 91	85.85	0.23	0.02		
Wood Waste	1.50	83.33	0.15	0.01		

[a] Note: Where ranges are given for emission factors, please consult the report cited below for details
[b] The S1 abbreviations M for mega (x 10^6); G for giga (x 10^9); and T for tera (x 10").

Source: A. P. Jaques Canada's Greenhouse Gas Emissions: Estimates for 1990, Environment Canada December 1992

Appendix B - Emission Conversion Factors (Cent'd)

	CO_2		CH_4		N_2O	
PROCESS SOURCES	(t/t)	(t/TJ)	(g/kg)	(t/TJ)	(g/kg)	(kg/TJ)
Cement Production	0.50					
Lime Production	0.79					
Ammonia Production	1.58					
Spent Pulping Liquor	1.43	107.38				
Adipic Acid Production					0.03	
Nitric Oxide Production					(2.0 to 20)	
Natural Gas Production	0.07		2.67			
Coal Mining			(1.20 to 16.45)			
Non-Energy Uses	(t/KL)	(t/TJ)				
Petrochemical Feedstocks	0.50	14.22				
Naphthas	0.50	14.22				
Lubricants	1.41	36.01				
Other Products	1.45	28.88				
Coke	2.48	86.00				
	(t/ML)					
Natural Gas	1.26	33.35				
Coke Oven Gas	1.6	86.00				
Agriculture	(kg/head/year)		(kg/head/year)		(g/kg)	(kg/TJ)
Livestock	(36 to 3 960)		(0.01 to 120)			
Fertilizer Use					(1 to 50)	
Miscellaneous	(kg/t)		(kg/t)		(g/kg)	(kg/TJ)
Landfills	182.00		66.00			

Source: A. P. Jaques, Canada's Greenhouse Gas Emissions: Estimates for 1990, Environment Canada. December 1992

Appendix C - Non-Utility Generation (NUG) Projected Capacity: Canada (M W)

		1992	2000	2010	2020	Capacity Factor %
Atlantic	Hydro	0	10	10	10	80
	Oil	0	15	15	15	75
	Other	0	100	100	100	80
	Total	0	125	125	125	
Quebec	Hydro	10	106	106	106	80
	Natural Gas	20	351	351	351	80
	Other	7	300	300	300	75
	Total	37	757	757	757	
Ontario	Hydro	132	182	182	182	80
	Natural Gas	366	824	1824	1824	80
	Other	250	329	329	329	80
	Total	748	1335	2335	2335	
Manitoba	Total	0	0	0	0	
Saskatchewan	Hydro	0	40	40	40	24
	Other	15	25	25	25	55
	Total	15	65	65	65	
Alberta	Hydro	20	49	49	49	50
	Natural Gas	0	0	1100	1100	80
	Other		39	39	39	50
	Total	22	88	1188	1188	
B.C	Hydro	6	887	887	887	55
	Natural Gas	0	245	245	245	78
	Other	0	450	450	450	80
	Total	6	1582	1582	1582	
Canada	Hydro	168	1274	1274	1274	
	Natural Gas	386	1420	3520	3520	
	Oil	0	15	15	15	
	Other	274	1243	1243	1243	
	Total	828	3952	6052	6052	

		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
				Projections							
	SECONDARY DEMAND BY FUEL:										
HTSSDC	TOTAL SECONDARY DEMAND. . . .	6654.0	6547.1	6656.0	6737.5	6811.3	6917.1	7500.2	8196.4	8925.6	10509.1
HRPSDC	RAPS	2550.4	2405.6	2432.1	2446.6	2470.8	2503.6	2693.6	2975.9	3262.8	3797.3
HNGSDC	NATURAL GAS	1789.9	1787.3	1844.7	1876.0	1897.3	1929.4	2106.7	2271.1	2446.8	2826.9
HELSDC	ELECTRICITY	1551.6	1570.7	1594.9	1608.8	1624.9	1651.1	1786.2	1939.7	2096.7	2442.9
HCCSDC	COAL	46.9	38.2	38.3	39.2	40.0	41.0	45.1	48.4	50.2	60.8
HLPSDC	LPGS	90.7	88.3	94.0	97.0	99.3	100.6	110.2	121.8	133.3	159.6
HKGSDC	COKE AND COKE OVEN GAS. . . .	130.7	147.0	151.2	158.4	160.8	163.3	181.6	207.4	234.9	291.9
HSTSDC	STEAM	21.0	24.8	25.1	25.0	25.0	25.1	27.9	31.0	34.5	42.6
HOFSDC	OTHER	368.0	382.9	372.8	383.3	389.8	399.3	444.5	496.0	561.4	782.4
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.6	105.0	105.0	104.9
	SECONDARY DEMAND BY SECTOR:										
HTSSDC	TOTAL SECONDARY DEMAND	6654.0	6547.1	6656.0	6737.5	6811.3	6917.1	7500.2	8196.4	8925.6	10509.1
HTSRAC	RESIDENTIAL	1506.7	1463.8	1510.4	1518.9	1530.7	1541.6	1576.4	1594.8	1595.9	1673.8
HTSCPC	COMMERCIAL	945.4	950.3	963.6	967.2	976.2	993.1	1084.6	1194.7	1279.0	1473.4
HTSINC	INDUSTRIAL	2404.6	2395.9	2429.8	2492.1	2527.2	2580.6	2877.4	3200.9	3584.8	4429.2
HTSTRC	TRANSPORTATION	1796.9	1736.9	1752.3	1759.3	1777.1	1801.7	1961.8	2206.0	2465.9	2932.7
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL.	9081.8	9104.9	9323.5	9504.1	9632.3	9859.5	10723.9	11617.0	12496.6	14857.5
HRPPDC	RPPS	3279.3	3107.5	3137.7	3191.5	3151.7	3197.6	3483.2	3872.2	4183.4	4721.4
HNGPDC	NATURAL GAS	2164.9	2191.0	2348.8	2397.7	2451.9	2499.6	2733.3	2973.5	3187.3	3632.4
HLPPDC	LPGS	232.3	237.5	254.2	263.3	272.9	307.7	412.5	424.2	450.6	477.0
HCCPDC	COAL	1077.5	1120.7	1010.8	1081.4	885.6	857.9	993.7	1117.6	1254.9	1748.2
HENPDC	NUCLEAR ELECTRICITY **(11.654)**	802.2	933.7	1003.2	976.5	1237.3	1338.9	1330.9	1340.3	1311.8	1754.6
HEHPDC	HYDRO ELECTRICITY (3.6) . . .	1053.0	1029.5	1046.9	1049.9	1068.5	1058.7	1085.8	1152.8	1306.9	1501.7
HOFPDC	OTHER (RENEWABLES)	368.0	382.9	418.9	440.7	461.0	495.4	579.8	631.4	696.7	917.3
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.6	105.0	105.0	104.9
	ENERGY RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	143.11	135.73	138.57	136.56	135.10	133.68	126.38	119.02	111.08	102.16
RCDPRC	COM. DEMAND / COM. RDP	4.07	4.09	4.08	3.99	3.92	3.88	3.82	3.77	3.63	3.34
RIDPRC	IND. DEMAND / IND. RDP	18.55	19.40	19.19	18.80	18.26	17.84	17.55	16.65	16.01	14.73
RSDPCC	SECONDARY DEMAND / POP. . .	246.36	242.29	243.38	243.05	242.46	243.02	248.90	259.20	269.81	292.27
RSDPRC	SECONDARY DEMAND / RDP	15.95	16.08	16.06	15.74	15.46	15.20	14.75	14.20	13.69	12.60
VCRPN	CRUDE OIL SUPPLY (MCM/DAY) . . .	265.	265.	276.	263.	255.	251.	271.	281.	281.	273.
VNGPN	NATURAL GAS SUPPLY (MCM)	98987.	105372.	116775.	123594.	129198.	133174.	146213.	153927.	159536.	171118.
AECANC	C02 EMISSIONS EXC. BIOMASS (KT)	461189.	455406.	457361.	473353.	457815.	462617.	510000.	561474.	607261.	716465.

				Projections							
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
	SECONDARY DEMAND BY FUEL:										
HTSSDC	TOTAL SECONDARY DEMAND.	6654.0	6547.1	6656.0	6737.5	6811.3	6819.2	7297.9	7907.1	8606.1	10211.7
HRPSDC	RPPS	2550.4	2405.6	2432.1	2446.6	2470.8	2435.7	2497.0	2716.9	2947.5	3366.6
HNGSDC	NATURAL GAS	1789.9	1787.3	1844.7	1876.0	1897.3	1906.7	2075.7	2197.0	2396.1	2946.1
HELSDC	ELECTRICITY	1551.6	1570.7	1594.9	1608.8	1624.9	1645.9	1811.2	1982.7	2142.8	2457.1
HCCSDC	COAL	46.9	38.2	38.3	39.2	40.0	40.5	44.4	47.5	49.2	60.0
HLPSDC	LPGS	90.7	88.3	94.0	97.0	99.3	99.9	108.9	120.1	131.6	158.1
HKGSDC	COKE AND COKE OVEN GAS. . . .	130.7	147.0	151.2	158.4	160.8	161.1	180.5	206.5	234.1	291.2
HSTSDC	STEAM	21.0	24.8	25.1	25.0	25.0	24.8	27.5	30.4	33.8	42.2
HOFSDC	OTHER	368.0	382.9	372.8	383.3	389.8	400.8	448.2	501.0	566.1	785.5
HWDRAC	RESIDENTIAL WOOD.	104.9	102.3	102.9	103.2	103.5	103.8	104.7	105.1	105.1	104.9
	SECONDARY DEMAND BY SECTOR:										
HTSSDC	TOTAL SECONDARY DEMAND	6654.0	6547.1	6656.0	6737.5	6811.3	6819.2	7297.9	7907.1	8606.1	10211.7
HTSRAC	RESIDENTIAL	1506.7	1463.8	1510.4	1518.9	1530.7	1525.5	1541.2	1548.1	1554.1	1647.9
HTSCPC	COMMERCIAL	945.4	950.3	963.6	967.2	976.2	986.4	1069.6	1168.8	1253.8	1464.2
HTSINC	INDUSTRIAL	2404.6	2395.9	2429.8	2492.1	2527.2	2552.3	2842.6	3151.5	3530.2	4400.7
HTSTRC	TRANSPORTATION	1796.9	1736.9	1752.3	1759.3	1777.1	1755.1	1844.5	2038.7	2268.0	2698.9
HTSPDC	PRIMARY DENAND BY FUEL - TOTAL.	9081.8	9104.9	9298.6	9436.9	9560.7	9680.7	10489.2	11306.8	12223.8	14562.7
HRPPDC	RAPS	3279.3	3107.5	3137.7	3191.5	3151.7	3124.4	3275.1	**3599.0**	3850.2	4264.0
HNGPDC	NATURAL GAS	2164.9	2191.0	2348.8	2397.7	2451.9	2475.6	2705.2	**2906.9**	3145.1	3758.7
HLPPDC	LPGS	232.3	237.5	254.2	263.3	272.9	307.0	411.3	**422.5**	448.8	475.5
HCCPDC	COAL	1077.5	1120.7	1010.8	1081.4	885.6	857.3	1022.0	**1163.0**	1301.4	1757.4
HENPDC	NUCLEAR ELECTRICITY (11.654)	802.2	933.7	978.4	909.3	1165.8	1262.2	1290.2	**1301.2**	1343.4	1774.9
HEHPDC	HYDRO ELECTRICITY (3 .6)...	1053.0	1029.5	1046.9	1049.9	1068.5	1053.8	1095.9	**1170.8**	1326.5	1506.4
HOFPDC	OTHER (RENEWABLES)	368.0	382.9	418.9	440.7	461.0	496.6	584.8	**638.4**	703.4	921.0
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.8	104.7	**105.1**	105.1	104.9
	ENERGY RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	143.11	135.73	3.38.57	136.56	135.10	132.41	123.82	115.71	108.35	100.91
RCDPRC	COM. DEMAND / COM. RDP	4.07	4.09	4.08	3.99	3.92	3.87	3.78	3.69	3.56	3.32
RIDPRC	IND. DEMAND / IND. RDP	18.55	19.40	19.19	18.80	18.26	17.85	17.44	16.44	15.80	14.65
RSDPCC	SECONDARY DEMAND / POP.. . .	246.36	242.29	243.38	243.05	242.46	239.58	242.19	250.05	260.16	284.00
RSDPRC	SECONDARY DEMAND / RDP	15.95	16.08	16.06	15.74	15.46	15.09	14.42	13.74	13.24	12.26
VCRPN	CRUDE OIL SUPPLY (MCM/DAY) . .	265.	265.	264.	263.	255.	248.	278.	302.	326.	356.
VNGPN	NATURAL GAS SUPPLY (MCM)....	98987.	105372.	112494.	123594.	129198.	132538.	145468.	152163.	158418.	174460.
AECANC	C02 EMISSIONS EXC. BIOMASS (KT)	461189.	455406.	457361.	473353.	457815.	455897.	496299.	542650.	585743.	692364.

		Projections									
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
	SECONDARY DEMAND BY FUEL:										
HTSSDC	TOTAL SECONDARY DEMAND.	6654.0	6547.1	6656.0	6737.5	6811.3	7017.3	7714.1	8464.3	9235.4	10940.3
HRPSDC	RAPS	2550.4	2405.6	2432.1	2446.6	2470.8	2584.9	2958.7	3356.6	3720.9	4316.7
HNGSDC	NATURAL GAS	1789.9	1787.3	1844.7	1876.0	1897.3	1942.9	2084.3	2193.1	2331.8	2792.8
HELSDC	ELECTRICITY	1551.6	1570.7	1594.9	1608.8	1624.9	1654.7	1759.2	1907.6	2066.6	2393.2
HCCSDC	COAL	46.9	38.2	38.3	39.2	40.0	41.5	45.7	49.0	50.9	61.9
HLPSDC	LPGS	90.7	88.3	94.0	97.0	99.3	101.3	111.2	122.8	134.4	161.6
HKGSDC	COKE AND COKE OVEN GAS.	130.7	147.0	151.2	158.4	160.8	165.3	182.5	208.0	235.6	293.2
HSTSDC	STEAM	21.0	24.8	25.1	25.0	25.0	25.4	28.2	31.4	34.8	43.3
HOFSDC	OTHER	368.0	382.9	372.8	383.3	389.8	397.7	439.8	490.8	555.5	772.8
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.5	104.9	104.9	104.8
	SECONDARY DEMAND BY SECTOR:										
HTSSDC	TOTAL SECONDARY DEMAND.	6654.0	6547.1	6656.0	6737.5	6811.3	7017.3	7714.1	8464.3	9235.4	10940.3
HTSRAC	RESIDENTIAL	1506.7	1463.8	1510.4	1518.9	1530.7	1557.2	1609.8	1628.4	1631.4	1729.5
HTSCPC	COMMERCIAL	945.4	950.3	963.6	967.2	976.2	999.2	1096.8	1207.8	1292.7	1502.2
HTSINC	INDUSTRIAL	2404.6	2395.9	2429.8	2492.1	2527.2	2606.8	2905.6	3225.7	3611.4	4484.3
HTSTRC	TRANSPORTATION	1796.9	1736.9	1752.3	1759.3	1777.1	1854.1	2101.9	2402.3	2700.0	3224.3
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL.	9081.8	9104.9	9298.6	9436.9	9560.7	9894.9	3.0853.8	11790.5	12784.5	15241.5
HRPPDC	RAPS	3279.3	3107.5	3137.7	3191.5	33.51.7	3285.0	3762.9	4272.7	4666.3	5273.7
HNGPDC	NATURAL GAS	2164.9	2191.0	2348.8	2397.7	2451.9	2513.8	2705.6	2885.6	3062.4	3589.2
HLPPDC	LAGS	232.3	237.5	254.2	263.3	272.9	308.4	413.6	425.3	451.6	479.0
HCCPDC	COAL	1077.5	1120.7	1010.8	1081.4	885.6	857.2	964.3	1086.2	1225.2	1692.2
HENPDC	NUCLEAR ELECTRICITY (11.654)	802.2	933.7	978.4	909.3	1165.8	1270.2	1255.0	1252.4	1290.7	1714.9
HEHPDC	HYDRO ELECTRICITY (3.6) . . .	1053.0	1029.5	1046.9	1049.9	1068.5	1062.6	1074.2	1138.5	1293.8	1481.6
HOFPDC	OTHER (RENEWABLES)	368.0	382.9	418.9	440.7	461.0	494.0	573.9	624.7	689.6	906.0
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.5	104.9	104.9	104.8
	ENERGY RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	143.11	135.73	138.57	136.56	135.10	134.87	128.70	121.18	113.21	105.32
RCDPRC	COM. DEMAND / COM. RDP	4.07	4.09	4.08	3.99	3.92	3.90	3.86	3.81	3.66	3.40
RIDPRC	IND. DEMAND / IND. RDP	18.55	19.40	19.19	18.80	18.26	17.83	17.63	16.75	16.10	14.87
RSDPCC	SECONDARY DEMAND / POP. . .	246.36	242.29	243.38	243.05	242.46	246.54	256.00	267.68	279.18	304.26
RSDPRC	SECONDARY DEMAND / RDP. .	15.95	16.08	16.06	15.74	15.46	15.32	15.11	14.64	14.14	13.07
VCRPN	CRUDE OIL SUPPLY (MCM/DAY)	265.	265.	264.	263.	255.	247.	238.	234.	236.	221.
VNGPN	NATURAL GAS SUPPLY (MCM)	98987.	105372.	112494.	123594.	129198.	133551.	145479.	151601.	156230.	169973.
AECANC	C02 EMISSIONS EXC. BIOMASS (KT)	461189.	455406.	457361.	473353.	457815.	469646.	525472.	581751.	631354.	747711.

Appendix D Impact 3 - Higher Electricity Prices (Petajoules)   Region: Canada

		1990	1991	Projections 1992	1993	1994	1995	2000	2005	2010	2020
	SECONDARY DEMAND BY FUEL:										
HTSSDC	TOTAL SECONDARY DEMAND.........	6654.0	6547.1	6656.0	6737.5	6811.3	6799.0	7282.6	7959.0	8671.[illegible]	10215.0
HRPSDC	RPP'S.................. ..	2550 4	2405.6	2432.1	2446.6	2470.8	2492.7	2691.2	2985.1	3279.[illegible]	3820.1
HNGSDC	NATURAL GAS...............	1789 9	1787.3	1844.7	1876.0	1897.3	1896.3	2075.8	2256.2	2439.[illegible]	2825.5
HELSDC	ELECTRICITY............ ..	1551 6	1570.7	1594.9	1608.8	1624.9	1584.6	1613.8	1721.2	1847.[illegible]	2144.6
HCCSDC	COAL....................	46 9	38.2	38.3	39.2	40.0	39.9	42.8	46.0	47.[illegible]	57.7
HLPSDC	LPG'S...................	90 7	88.3	94.0	97.0	99.3	98.8	106.1	117.1	128.[illegible]	153.4
HKGSDC	COKE AND COKE OVEN G S.. ..	130 7	147.0	151.2	158.4	160.8	155.9	170.8	195.4	221.[illegible]	274.4
HSTSDC	STEAM..............	21 0	24.8	25.1	25.0	25.0	24.3	26.5	29.5	32.[illegible]	40.4
HOFSDC	OTHER.................. ..	368 0	382.9	372.8	383.3	389.8	402.4	450.7	503.2	569.[illegible]	793.6
HWDRAC	RESIDENTIAL WOOD.....	104.9	102.3	102.9	103.2	103.5	104.1	104.9	105.4	105.[illegible]	105.3
	SECONDARY DEMAND BY SECTOR:										
HTSSDC	TOTAL SECONDARY DEMAND..	6654.0	6547.1	6656.0	6737.5	6811.3	6799.0	7282.6	7959.0	8671.1	10215.0
HTSRAC	RESIDENTIAL.........	1506.7	1463.8	1510.4	1518.9	1530.7	1495.[illegible]	1521.6	1546.6	1552.8	1634.6
HTSCPC	COMMERCIAL.........	945.4	950.3	963.6	967.2	976.2	975.[illegible]	1023.9	1118.2	1195.1	1376.8
HTSINC	INDUSTRIAL.........	2404.6	2395.9	2429.8	2492.1	2527.2	2526.[illegible]	2775.4	3088.1	3457.3	4271.0
HTSTRC	TRANSPORTATION.......	1796.9	1736.9	1752.3	1759.3	1777.1	1801.[illegible]	1961.8	2206.0	2465.9	2932.7
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL.	9081.8	9104.9	9299.5	9437.8	9559.8	9632.1	10225.6	11047.3	11928.6	14086.4
HRPPDC	RPPS.........	3279.3	3107.5	3138.4	3192.1	3151.2	3171.9	3422.3	3812.7	4190.6	4738.6
HNGPDC	NATURAL GAS..	2164 9	2191 0	2348 7	2397.7	2451.8	2461.3	2691.2	2948.0	3179.3	3620.9
HLPPDC	LPGS..............	232 3	237.5	254.2	263.3	272.9	305.9	408.5	419.5	445.4	470.9
HCCPDC	COAL..............	1077.5	1120 7	1012 8	1083.4	887.4	826.7	858.5	911.6	1025.4	1299.0
HENPDC	NUCLEAR ELECTRICITY (11.654)	802.2	933 7	976 7	907.8	1164.1	1265.3	1139.7	1139.8	1139.7	1583.9
HEHPDC	HYDRO ELECTRICITY (3.6)...	1053 0	1029 5	1046 8	1049.7	1068.1	998.5	1015.0	1072.4	1138.4	1339.6
HOFPDC	OTHER (RENEWABLES)	368 0	382 9	418 9	440.7	460.9	498.4	585.5	638.0	704.5	928.4
HWDRAC	RESIDENTIAL WOOD...	104.9	102.3	102.9	103.2	103.5	104.1	104.9	105.4	105.4	105.3
	ENERGY RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD GJ)	143.11	135.73	138.57	136.56	135.10	129.36	121.58	115.08	107.77	99.48
RCDPRC	COM. DEMAND / COM. RDP......	4.07	4.09	4.08	3.99	3.92	3.81	3.60	3.52	3.38	3.11
RIDPRC	IND. DEMAND / IND. RDP......	18.55	19.40	19.19	18.80	18.26	17.46	16.93	16.06	15.44	14.20
RSDPCC	SECONDARY DEMAND / POP......	246.36	242.29	243.38	243.05	242.46	238.87	241.68	251.70	262.12	284.09
RSDPRC	SECONDARY DEMAND / RDP......	15.95	16.08	16.06	15.74	15.46	14.94	14.32	13.79	13.30	12.24
VCRPN	CRUDE OIL SUPPLY (MCM/DAY).....	265.	265.	264.	263.	255.	251.	271.	281.	281.	273.
VNGPN	NATURAL GAS SUPPLY (MCM).......	98987.	105372.	112493.	123594.	129197.	132160.	145097.	153252.	159323.	170813.
AECANC	CO2 EMISSIONS EXC. BIOMASS (KT)	461189.	455406.	457361.	473353.	457815.	456166.	497291.	546717.	591864.	697343.

		1990	1991	Projections 1992	1993	1994	1995	2000	2005	2010	2020
	SECONDARY DEMAND BY FUEL:										
HTSSDC	TOTAL SECONDARY DEMAND	6654.0	6547.1	6656.0	6737.5	6811.3	6964.6	7807.8	8834.6	10013.4	12878.2
HRPSDC	RPPS	2550.4	2405.6	2432.1	2446.6	2470.8	2515.4	2770.2	3156.8	3587.6	4531.3
HNGSDC	NATURAL GAS	1789.9	1787.3	1844.7	1876.0	1897.3	1944.6	2206.1	2470.3	2780.6	3522.5
HELSDC	ELECTRICITY	1551.6	1570.7	1594.9	1608.8	1624.9	1664.2	1867.5	2092.5	2346.7	2982.9
HCCSDC	COAL	46.9	38.2	38.3	39.2	40.0	41.4	47.7	53.6	58.4	78.6
HLPSDC	LPGS	90.7	88.3	94.0	97.0	99.3	101.2	113.9	129.0	144.8	184.3
HKGSDC	COKE AND COKE OVEN GAS	130.7	147.0	151.2	158.4	160.8	164.9	192.8	229.8	273.9	378.5
HSTSDC	STEAM	21.0	24.8	25.1	25.0	25.0	25.3	29.6	34.5	40.3	55.3
HOFSDC	OTHER	368.0	382.9	372.8	383.3	389.8	403.3	472.0	556.2	665.4	1020.1
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	104.2	108.1	111.9	115.8	124.6
	SECONDARY DEMAND BY SECTOR:										
HTSSDC	TOTAL SECONDARY DEMAND	6654.0	6547.1	6656.0	6737.5	6811.3	6964.6	7807.8	8834.6	10013.4	12878.2
HTSRAC	RESIDENTIAL	1506.7	1463.8	1510.4	1518.9	1530.7	1546.5	1596.7	1625.0	1643.8	1762.9
HTSCPC	COMMERCIAL	945.4	950.3	963.6	967.2	976.2	1002.8	1149.7	1321.7	1479.4	1877.5
HTSINC	INDUSTRIAL	2404.6	2395.9	2429.8	2492.1	2527.2	2606.6	3054.1	3564.3	4204.3	5788.7
HTSTRC	TRANSPORTATION	1796.9	1736.9	1752.3	1759.3	1777.1	1808.7	2007.4	2323.6	2685.9	3449.1
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL	9081.8	9104.9	9299.5	9437.8	9553.8	9842.7	11086.3	12399.4	14004.3	18221.6
HRPPDC	RPPS	3279.3	3107.5	3138.4	3192.1	3151.2	3213.1	3614.5	4094.1	4580.0	5593.9
HNGPDC	NATURAL GAS	2164.9	2191.0	2348.7	2397.7	2451.8	2516.4	2842.5	3190.4	3577.0	4360.2
HLPPDC	LPGS	232.3	237.5	254.2	263.3	272.9	308.3	416.2	431.5	462.2	502.0
HCCPDC	COAL	1077.5	1120.7	1012.8	1083.4	887.4	864.9	1124.8	1353.1	1650.7	2294.9
HENPDC	NUCLEAR ELECTRICITY (11.654)	802.2	933.7	976.7	907.8	1164.1	1265.3	1265.4	1265.4	1374.1	2465.6
HEHPDC	HYDRO ELECTRICITY (3.6)	1053.0	1029.5	1046.8	1049.7	1068.1	1071.2	1108.0	1261.9	1444.4	1725.5
HOFPDC	OTHER (RENEWABLES)	368.0	382.9	418.9	440.7	460.9	499.3	606.8	691.0	800.2	1154.9
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	104.2	108.1	111.9	115.8	124.6
	ENERGY RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD [illegible])	143.11	135.73	138.57	136.56	135.10	133.88	126.64	118.86	111.15	102.78
RCDPRC	COM. DEMAND / COM. RDP	4.07	4.09	4.08	3.99	3.92	3.88	3.82	3.74	3.58	3.30
RIDPRC	IND. DEMAND / IND. RDP	18.55	19.40	19.19	18.80	18.26	17.84	17.55	16.62	16.01	14.86
RSDPCC	SECONDARY DEMAND / POP	246.36	242.29	243.38	243.05	242.46	244.20	256.02	273.31	293.18	340.02
RSDPRC	SECONDARY DEMAND / RDP	15.95	16.08	16.06	15.74	15.46	15.15	14.47	13.72	13.10	11.92
VCRPN	CRUDE OIL SUPPLY (MCM/DAY)	265.	265.	264.	263.	255.	251.	271.	281.	281.	273.
VNGPN	NATURAL GAS SUPPLY (MCM)	98987.	105372.	112493.	123594.	129197.	133619.	149103.	159668.	169851.	190381.
AECANC	CO2 EMISSIONS EXC. BIOMASS (KT)	461189.	455406.	457583.	473566.	457931.	465592.	538793.	613671.	697359.	876925.

Appendix Impact 5- Modified Sectoral Growth Profile (Petajoules) — *Region: Canada*

				Projections							
		1990	1991	1992	1993	1994	1995	2000	2005	2010	2020
	SECONDARY DEMAND BY FUEL:										
HTSSDC	TOTAL SECONDARY DEMAND.	6654.0	6547.1	6620.5	6652.2	6696.8	6768.0	7289.4	7827.5	8378.7	9526.3
HRPSDC	RPPS	2550.4	2405.6	2427.9	2433.2	2449.8	2473.7	2644.7	2891.1	3139.4	3579.3
HNGSDC	NATUl?AL GAS	1789.9	1787.3	1832.4	1847.6	1859.3	1880.2	2041.3	2158.7	2279.9	2541.4
HELSDC	ELECTRICITY	1551.6	1570.7	1587.4	1593.5	1604.1	1623.3	1743.2	1867.6	1998.4	2264.4
HCCSDC	COAL	46.9	38.2	37.8	37.7	37.9	38.2	41.2	42.2	41.8	46.1
HLPSDC	LPGS	90.7	88.3	93.6	96.2	98.3	99.3	108.4	119.2	130.4	154.9
HKGSDC	COKE AND COKE OVEN GAS.	130.7	147.0	145.4	150.1	152.6	155.9	175.9	186.1	195.9	219.1
HSTSDC	STEAM	21.0	24.8	24.6	23.9	23.4	23.1	25.3	26.5	28.1	31.9
HOFSDC	OTHER	368.0	382.9	368.6	367.0	367.9	370.5	404.8	431.2	459.9	584.4
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.6	105.0	104.9	104.8
	SECONDARY DEMAND BY SECTOR:										
HTSSDC	TOTAL SECONDARY DEMAND.	6654.0	6547.3.	6620.5	6652.2	6696.8	6768.0	7289.4	7827.5	8378.7	9526.3
HTSRAC	RESIDENTIAL	1506.7	1463.8	1510.4	1518.9	1530.7	1541.6	1576.2	1598.1	1604.8	1680.3
HTSCPC	COMMERCIAL	945.4	950.3	965.3	982.3	1003.0	1033.2	1142.5	1298.6	1437.8	1739.9
HTSINC	INDUSTRIAL	2404.6	2395.9	2393.4	2397.5	2396.2	2407.1	2634.7	2770.4	2937.5	3291.8
HTSTRC	TRANSPORTATION	1796.9	1736.9	1751.5	1753.6	1766.8	1786.1	1936.0	2160.4	2398.6	2814.4
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL.	9081.8	9104.9	9252.4	9332.1	9415.5	9610.4	10423.1	11111.3	11876.9	13547.2
HRPPDC	RPPS	3279.3	3107.5	3130.0	3169.1	3120.2	3158.6	3407.1	3748.7	4037.6	4462.2
HNGPDC	NATURAL GAS	2164.9	2191.0	2334.6	2365.7	2409.4	2444.8	2661.2	2850.5	3011.2	3301.9
HLPPDC	LAGS	232.3	237.5	253.8	262.5	271.9	306.4	410.8	421.6	447.6	472.4
HCCPDC	COAL	1077.5	1120.7	993.9	1051.8	852.8	829.3	958.3	1036.8	1153.1	1352.1
HENPDC	NUCLEAR ELECTRICITY (11.654)	802.2	933.7	976.7	907.8	1164.1	1265.3	1265.3	1265.4	1302.1	1746.1
HEHPDC	HYDRO ELECTRICITY (3.6) . . .	1053.0	1029.5	1045.8	1047.8	1054.7	1035.7	1076.2	1117.3	1225.6	1388.7
HOFPDC	OTHER (RENEWABLES)	368.0	382.9	414.7	424.3	439.0	466.6	539.6	566.0	594.7	719.2
HWDRAC	RESIDENTIAL WOOD	104.9	102.3	102.9	103.2	103.5	103.7	104.6	105.0	104.9	104.8
	ENERGY RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	143.11	135.73	138.57	136.56	135.10	133.68	126.37	119.30	111.77	102.60
RCDPRC	COM. DENAND / COM. RDP	4.07	4.09	4.07	3.98	3.92	3.88	3.82	3.78	3.66	3.38
RIDPRC	IND. DEMAND / IND. RDP	18.55	19.40	18.99	18.63	18.24	17.95	17.71	16.78	16.01	14.52
RSDPCC	SECONDARY DEMAND / POP	246.36	242.29	242.08	239.97	238.38	237.78	241.91	247.54	253.28	264.93
RSDPRC	SECONDARY DEMAND / RDP.	15.95	16.08	15.97	15.54	15.20	14.87	14.34	13.56	12.85	11.42
VCRPN	CRUDE OIL SUPPLY (MCM/DAY)	265.	265.	264.	263.	255.	251.	271.	281.	281.	273.
VNGPN	NATURAL GAS SUPPLY (MCM)	98987.	105372.	112117.	122747.	128073.	131724.	144305.	150671.	154876.	162370.
AECANC	C02 EMISSIONS EXC. BIOMASS (KT)	461189.	455406.	454465.	467220.	450133.	454009.	497104.	538260.	577947.	642881.

APPENDIX E: LIST OF ACRONYMS

AFUE	Average Fuel Utilization Efficiency
AOSTRA	Alberta Oil Sands Technology and Research Authority
BOE	Barrels of Oil Equivalent
CAFE	U.S. Corporate Average Fuel Economy
CERI	Canadian Energy Research Institute
CFC	Chlorofluorocarbon
CGA	Canadian Gas Association
CH_4	Methane
CHIP	Canadian Home Insulation Program
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide Gas
Cogen	Cogeneration
COSP	Canadian Oil Substitution Program
CPA	Canadian Petroleum Association
CPI	Consumer Price Index
DRI	Data Resources Incorporated
DSM	Demand Side Management
EMR	Energy, Mines & Resources Canada
ERCB	Energy Resources Conservation Board (Alberta)
Ethanol (E85)	Ethanol with 15% gasoline
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GJ	Gigajoules or 10^9 Joules
GSC	Geological Survey of Canada
GST	Goods and Services Tax
GW	Gigawatts
GW.h	Gigawatt Hours
HDD	Heating Degree Days
HFo	Heavy Fuel Oil
I. G.C.C.	Integrated Gasification Combined Cycle
IEA	International Energy Agency
IFSD	Inter-Fuel Substitution Demand
IPAC	Independent Producers Association of Canada
IPP	Independent Power Producer
ISTC	Industry, Science & Technology Canada
LNG	Liquefied Natural Gas
mb/d	Thousands of barrels per day
Mcf	Thousands of cubic feet
Methanol(M85)	Methanol with 15% gasoline
MMb/d	Millions of Barrels per day
MW	Megawatt
MW.h	Megawatt Hours
N.B.R.	Nottaway-Broadback-Rupert
NB	New Brunswick
NEB	National Energy Board

NGLs	Natural Gas Liquids
NO_x	Nitric Oxides
N_2O	Nitrous Oxide
NUG	Non-Utility Generation
OH	Ontario Hydro
OPEC	Organization of Petroleum Exporting Countries
PEL	Petroleum Economics Ltd.
PIRA	Petroleum Industry Research Associates Inc.
PJ	Petajoules or 10^{15} Joules
Pw	Power West Financial Ltd.
RDP	Real Domestic Product
RPPS	Refined Petroleum Products
Tcf/yr	Trillion cubic feet per year
TCPL	TransCanada Pipelines
TW.h	Terawatt Hours
US DOE	U.S. Department of Energy
Vocs	Volatile Organic Compounds
WTI	West Texas Intermediate
WCSB	Western Canada Sedimentary Basin

CANADA'S ENERGY OUTLOOK: 1992-2020
QUESTIONNAIRE

In an effort to improve our service, we would like to have your views on this publication. Please complete the following questionnaire and fax it to: Neil McIlveen at (613) 996-7837, or mail it to:

Neil McIlveen
Director
Energy and Fiscal Analysis Division
Economic and Financial Analysis Branch
Natural Resources Canada
580 Booth Street, 17th Floor
Ottawa, Ontario K1A OE4

1. Which of the following best describes your organization:

government policy agency	( )	regulatory agency	( )
energy industry	( )	environmental group	( )
teaching institution	( )	other ________________	( )

2. For your work, do you find the document

very useful	( )	somewhat useful	( )
not very useful	( )	not useful at all	( )

3. How do you use the document? (check one or more responses)

for general information	( )	for research, reference	( )
for preparation of reports	( )	for teaching	( )
for decision making	( )	other ________________	( )

4. For your purposes, is the level of discussion in the document

about right	( )	too detailed	( )
not sufficiently detailed	( )		

5. How frequently should this document be published?

every year	( )	as required to reflect	
every two years	( )	changes in underlying factors	( )

6. In the future, would you prefer receiving this document

as hard copy	( )	electronic form	( )

7. Further comments?

____

____

____

Many thanks for your assistance.

Français au verso

PERSPECTIVES **ÉNERGÉTIQUES DU CANADA:** 1992-2020
QUESTIONNAIRE

Nous aimerions avoir vos points de vue sur le present Document, pour l'amélioration de la qualité de nos services, et vous prions de répondre a ce questionnaire et de le retourner par telecopier au (613) 996-7837, ou par courrier a l'adresse ci-dessous:

Neil McIlveen
Directeur
Division de l'analyse énergétique et fiscale,
Direction de l'analyse économique et financière
Ressources Naturelles Canada
580 Rue Booth, 170 étage
Ottawa, Ontario K1A 0E4

1. **Lequel des points suivants décrit le mieux votre organisation:**

agence gouvernementale ( ) agence de réglementation ( )
industrie énergétique ( ) agence enviromementale ( )
institution d'enseignement ( ) autres ________________ ( )

2. **Comment trouvez-vous le Document, en rapport avec votre travail?**

très utile ( ) un peu utile ( )
pas très utile ( ) pas du tout utile ( )

3. **Quel usage faites-vous du Document? (une ou plusieurs réponses)**

information générale ( ) recherche, reference ( )
preparation de vos rapports ( ) enseignement ( )
prise de decisions ( ) autres ________________ ( )

4. **Selon vos besoins, les sujets sent-ils abordés de manière:**

tout a fait detainee ( ) trop detainee ( )
pas suffisamment detainee ( )

5. **Quelle fréquence devrait avoir la publication d'un eel Document?**

une fois par an ( ) selon les besoins, pour refléter
une fois tous les deux ans ( ) les changement des facteurs fondamentaux ( )

6. **Dans quelle forma aimeriez-vous recevoir le Document à l'avenir?**

Document imprimé ( ) données informatisées ( )

7. **commentaires:**

____
____
____

Merci de votre collaboration.

English on the other side

6. IMPACT ANALYSIS

The reference projection is only one of many possible views of the future. Changes in any of the underlying assumptions will lead to a different outcome for energy demand, supply and related atmospheric emissions. However, a completely alternative scenario, one in which all the major price, economic and policy assumptions are altered to reflect a different world view, is both difficult to construct and obscures rather than illuminates the impact of specific changes. Accordingly, this chapter offers five impact analyses in which the assumption concerning one major variable, or a set of closely related variables, is altered. Each change reflects a plausible alternative assumption for the particular variable. Through this approach, the reader can see more clearly the consequences of the change, relative to the reference scenario results, for Canadian energy markets. It should be noted that all impact analyses share the same policy and regulatory assumptions which underpin the reference case projection.

The impact analyses examined in this chapter include lower and higher world oil prices, higher electricity prices, higher economic growth, and a modified service and industrial sector growth profile.

Key results for each case are reviewed below and more detailed tables for each case are provided in Appendix D.

6.1 Lower World Oil Prices

World oil prices are a key determinant of energy demand and supply. To assess their impact, we assume, for this analysis, that the world oil price falls to US $16 per barrel in 1995 and remains US $5 below the reference projection thereafter (the opposite assumption is explored in Section 6.2). This trajectory yields a long term oil price near the low end of the range of expert's views (see Table 2.1.1).

Lower oil prices, over the longer term, will exert downward pressure on North American natural gas prices. The reduction will not, however, be proportional to that for oil. Assuming a proportional decline in natural gas prices would result in a significant excess demand for natural gas in the North American market. Compared to the reference case scenario, natural gas becomes a more expensive fuel relative to oil.

For simplicity, natural gas exports are assumed to increase at the same rate as in the reference case. In order to maintain natural gas market stability in North America, the reinvestment ratio for the oil and natural gas industry must increase slightly in the latter years of the period and a larger share of investment is targeted to natural gas exploration and development. It is assumed also that lower oil and natural gas prices will lead to greater efficiency and lower operating costs in the oil and gas industry. Other than Hibernia and Cohasset, the lower oil prices would entail the postponement of offshore production, new oil sands mining projects and upgraders. By 2020, bitumen production is roughly 50% below the reference case level. Overall, oil supply is 12 percent lower in 2000 and 19 percent lower in 2020 relative to the reference case (see Table 6.1.1).

In relative terms, the $5/bbl decrease amounts to about a 20% decrease in the price of crude oil but only a 1070 decrease in the price of gasoline. This is largely explained by the fact that various taxes make up about 5090 of the price of gasoline and for the most part are unaffected by changes in crude