SIMULATING EVOLUTION OF TECHNOLOGY: AN AID TO ENERGY POLICY ANALYSIS

A CASE STUDY OF STRATEGIES TO CONTROL GREENHOUSE GASES IN CANADA

by

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Abstract

Issues related to the reduction of greenhouse gases are encumbered with uncertainties for decision makers. Unfortunately, conventional analytical tools generate widely divergent forecasts of the effects of actions designed to mitigate these emissions. “Bottom-up” models show the costs of reducing emissions attained through the penetration of efficient technologies to be low or negative. In contrast, more aggregate “top-down” models show costs of reduction to be high.

The methodological approaches of the different models used to simulate energy consumption generate, in part, the divergence found in model outputs. To address this uncertainty and bring convergence, I use a technology-explicit model that simulates turnover of equipment stock as a function of detailed data on equipment costs and stock characteristics and of verified behavioural data related to equipment acquisition and retrofitting. Such detail can inform the decision maker of the effects of actions to reduce greenhouse gases due to changes in (1) technology stocks, (2) products or services, or (3) the mix of fuels used. This thesis involves two main components: (1) the development of a quantitative model to analyse energy demand and (2) the application of this tool to a policy issue, abatement of CO$_2$ emissions.

The analysis covers all of Canada by sector (8 industrial subsectors, residential commercial) and region. An electricity supply model to provide local electricity prices supplemented the quantitative model. Forecasts of growth and structural change were provided by national macroeconomic models. Seven different simulations were applied to each sector in each region including a base case run and three runs simulating emissions charges of $75/tonne, $150/tonne and $225/tonne CO$_2$. The analysis reveals that there is significant variation in the costs and quantity of emissions reduction by sector and region. Aggregated results show that Canada can meet both stabilisation targets (1990 levels of emissions by 2000) and reduction targets (20% less than 1990 by 2010), but the cost of meeting reduction targets exceeds $225/tonne. After a review of the results, I provide several reasons for concluding that the costs are overestimated and the emissions reduction underestimated. I also provide several future research options.
To: Cindy and my children, Michelle, Beth and Debbie
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1. The Nature of the Problem

1.1 The Problem

Environmental issues such as climate change and the destruction of the ozone layer have stimulated discussion on a regional, national and global scale. In Canada, provincial and federal Round Tables on the environment and the economy and the federal "Greenplan" indicates the level of concern generated by reports such as the Brundtland Commission's "Our Common Future" (Brundtland 1987) and those of the Intergovernmental Panel on Climate Change (IPCC 1996). Many of these environmental problems are associated with the production and use of energy. Brundtland described scenarios where the future of fossil fuels may be determined more by the impact of their use on the ecosystem than by their availability (Brundtland 1988, chapter 7). Indeed, R.W.Fri (1990, 1) referred to a potential “energy-environment collision”.

Energy-environment issues present a number of dilemmas to the decision maker: the problems are global but responses to these problems will show wide regional variations, their complexity creates considerable uncertainty, irreversible damages may result even if actions are taken, and the planning horizon is long with significant time lags between causes and effects. Decision makers use a number of approaches to assess responses to these issues, many of which involve quantitative analysis and the use of models.

Unfortunately, conventional analytical tools generate widely divergent forecasts of the effects of policies, regulations and programs designed to mitigate environmental externalities related to energy consumption. Some models simulate energy demand by focusing on the end uses of energy; they describe energy consumption (and consequent CO₂ emissions) in great detail. They show the costs of reducing greenhouse gas emissions attained through the penetration of efficient technologies to be low or even negative (Lovins and Lovins 1991, Mills, et al. 1991, Rubin, et al. 1992, SEI/Greenpeace 1993). In contrast, models that simulate the entire macroeconomy and incorporate little detail on energy consumption and technological change typically show
costs of reduction in emissions to be much higher than those predicted by the end-use models (Barns, et al. 1992, Manne and Richels 1990a, Manne 1992, Karadeloglou 1992, EMF 1993). The decision maker’s options are not made clear when confronted by output from these various models. Scheraga (1994, 802) suggested that discomfort with model output may be the result of applying inappropriate tools to answer the decision maker’s questions.

1.2 The Objective

I propose that the methodological approaches of the different types of models used to simulate energy consumption generate, in part, the divergence found in model outputs. Thus, research efforts are required to test new models that combine the critical features of these approaches. I use a technology-explicit model that simulates turnover of equipment stock as a function of detailed data on equipment costs and stock characteristics and of verified behavioural data related to equipment acquisition and retrofitting. Such detail will benefit the decision maker by addressing uncertainty in estimating the future response of the economy to, say, a policy on the reduction of greenhouse gases due to changes in (1) technology stocks, (2) products or services, or (3) the mix of fuels used.

This thesis involves two main components: (1) the development of a quantitative model to analyse energy demand and (2) the application of this tool to a policy issue; in this case, policies to abate CO₂ emissions, one of the greenhouse gases. I ask, “Does the modelling system do what we want it to do and can it give us useful answers that will help in decision making? Will it give policy makers a higher level of confidence in assessing specific CO₂ emissions policies relative to other models being offered?” I conclude the thesis by identifying four priorities in future research.

1.3 Background

The global warming issue looms large on the world’s environmental agenda. Scientists know that CO₂, generated through the combustion of carbon-based fuels, acts as the primary contributor to the gases said to cause climate change by acting as a thermal
blanket surrounding the earth, the “greenhouse effect”. CO$_2$ assumes this distinction because of the magnitude of its production.\textsuperscript{1}

Only recently has the scientific community agreed that there is a discernible human influence on climate (IPCC, 1996a) due, in part, to a change in concentration of CO$_2$ in the atmosphere. Actual environmental and economic impacts of these changes are poorly understood, primarily because little is known about the nature of these changes.

In spite of the unknowns, many countries initially committed to reduce CO$_2$ emissions to 1990 levels by 2000 with further reductions from that level in the years following. Most of them (including Canada) did not base this commitment on detailed economic or environmental analysis. But, because commitments have been made, analysts can investigate the possibility of meeting the proposed reduction levels and proceed with developing cost estimates of meeting (or attempting to meet) these levels.

**1.3.1 The Policy Issue: Meeting CO$_2$ Emissions Targets**

If we assume that increased CO$_2$ concentrations in the atmosphere have negative climatic effects, what mitigative options are available to society? Three possible approaches have been identified: 1) CO$_2$ storage, 2) adaptation, and 3) the reduction of CO$_2$ and other gaseous emissions known to have greenhouse warming effects. These three are not mutually exclusive; it is quite possible (and likely) that, if response is required at all, the proposed action will include some synthesis of them. Most respondent or signatory countries include some form of emissions limitation.

What options are available if one is to achieve reduction in emissions? There are a number of factors that determine the quantity of CO$_2$ emitted: the type of fossil fuels consumed, the ratio of fossil fuels to other fuels, the efficiency of energy conversion to useful work, and the demand for goods and services. The COGGER report (Robinson, et al. 1993) examines an identity derived from Kaya (1989) that describes the interaction of sectoral activity and the quantity of CO$_2$ emitted:

\begin{equation}
\text{Emissions} = \text{Productivity} \times \text{Energy Intensity} \times \text{Energy Use}
\end{equation}

\textsuperscript{1} Other greenhouse gases, such as carbon monoxide, methane and the nitrous oxides, are
Chapter 1  The Nature of the Problem

\[ CO_2 = \frac{CO_2}{FF} \times \frac{FF}{PE} \times \frac{PE}{SE} \times \frac{SE}{GDP} \times \frac{GDP}{P} \times P \]  

(1)

where \( FF \) = primary fossil fuel, \( PE \) = primary energy, \( SE \) = secondary energy, \( GDP \) = gross national product, \( P \) = population. The identity points to the strong relationship between energy and \( CO_2 \) emissions but it is not comprehensive for all \( CO_2 \) emissions because it excludes emissions generated as a result of process functions (e.g., natural gas extraction and production of certain resins and plastics, hydrogen from methane, cement, lime and ammonia). Even so, it provides clues as to how actions may alter the rate of \( CO_2 \) emissions when they stimulate change in one or all of the terms in equation 1:

- **substitution among fossil fuels** (\( \Delta CO_2 / FF \)) - Different fossil fuels generate different quantities of \( CO_2 \) per unit of energy released in the process of doing work.

- **substitution of fossil fuels by other energy forms** (\( \Delta FF / PE \)) - Wind, solar, geothermal, biomass (considered \( CO_2 \)-neutral) or hydroelectric sources provide energy without using fossil fuels and release no \( CO_2 \) per unit of energy generated.

- **change in efficiency of energy conversion** (\( \Delta PE / SE \)) - Energy must be converted from one form to another to accomplish useful work (chemical to mechanical in an automobile engine) or to provide an alternative form of energy (chemical energy to heat to electricity in a coal-fired power plant).

- **change in energy intensity of the economy** (\( \Delta SE / GDP \)) - Changes in the set of technologies or whole processes that provide goods and services affect energy consumption levels. The distinction between this term and the previous term is not always clear, because both terms include some notion of change in efficiency. As a further complication, this term also includes the effects of product or service shifts (i.e., structural shifts) in society as well as changes in the value, independent of energy, of that product or service.

not included in this analysis because their contribution to the total of emissions generated in Canada is small and data on sources by technology type are limited.
Chapter 1  The Nature of the Problem

• **change in standard of living or wealth** ($\Delta GDP / P$) - Life style changes and altered demand for material goods affect the economy’s structure.

• **change in population** ($\Delta P$)

These terms can be grouped to represent fuel mix ($CO_2 / FF$ and $FF / PE$), efficiency ($PE / SE$ and $SE / GDP$) and consumption ($GDP / P$ and $P$), which were the original components of Kaya’s identity. In this analysis, I focus on the fuel mix and efficiency components of the relationship because it is not the goal of most governments, including Canada, (Robinson, et al. 1993, 2) to reduce the standard of living or population growth.

1.3.2 The Policy Dilemma

In a country as large as Canada, regional variation must be considered in the development of a $CO_2$ emissions strategy. Both national and provincial analysts have several concerns. What will be the incremental and average costs of reducing $CO_2$ emissions through changes in fuel and efficiency in the various regions and sectors? Should we act to influence the energy market? And what sort of actions should we take? The decisions made will depend to some degree on an analysis of the incremental quantitative effect of policies relative to a strategy of doing nothing. It will also depend on the confidence the decision maker has in the reliability of the model(s) behind the analysis.

Decisions made in response to these questions will have both first-order effects, altering energy supply and energy demand, and second-order effects, where one takes into account the macroeconomic feedbacks of the actions taken. What quantitative models currently provide insight into the possible consequences of actions and how do they fail or succeed in providing confidence to the decision maker concerning the effects of those actions? I review them in the context of a simplified energy system.

1.4 An Energy System

One can think of an energy system as composed of a number of parts: economic components, public institutions, industries, commercial establishments, transportation modes, residences, power generation and transformation, nonenergy services, and more. To test the need for a technology-explicit model to analyse energy demand, I have
portrayed a simplified energy system as having three major components in figure 1.1: energy demand, energy supply and the macroeconomic environment in which they act. A comprehensive modelling system will account for the interactions of these parts; supply and demand come to equilibrium and, as such, affect the macroeconomic picture:

- macroeconomic component - models provide information on the demand for goods and services, including nonenergy components such as investment, trade, nonenergy services and the like;
- energy supply component - world market prices or specific supply models provide cost estimates of alternatives for energy supply;
- energy demand component - models provide information on sectoral demand for energy and the cost associated with the production of goods and services.

Figure 1.1: A simplified energy system of three components including linkages.

Models may be designed to simulate all three components using one or a set of aggregate equations. Some analysts recognised the need to model the supply sector separately, using an optimisation framework; such specific supply models act at the supply node and supplement aggregate equations designed to represent the other two components. It is also possible that each component can contain one or more models. Data are passed from
one model to the others as each has need, with each model receiving, in return, the information it needs to analyse the impact of any changes.

1.4.1 The Demand Component

In any discussion of energy demand, analysts face uncertainties in the system.

- What is the rate of non-price-induced change in the energy efficiency of the technologies that provide services and products (the autonomous energy efficiency index or AEEI)? What will the technologies of the future look like?

- How quickly do technology stocks turn over and how quickly do new technologies capture a share of the market (penetration rate)? How will cost and non-cost factors affect investment in new technologies?

- What effect will changes in the economic environment or efforts in research and development have on the availability and penetration rates of alternative technologies?

- What effect does change in the price of fuels have on fuel switching or on shifts from capital and labour to energy (known as the elasticity of substitution, ESUB)?

When the more aggregate models are applied at this node, they may capture behavioural phenomena related to technological change very well, but at the expense of other factors that affect technology penetration. Models which simulate end-uses of energy include great detail on technologies and their ability to change overall energy demand, but do not take into account economic and behavioural factors that affect technology penetration.

Thus, uncertainties in the modelling methods applied to the energy demand component are related to process detail and to behavioural criteria, both of which are important to the decision maker. In this thesis, I address modelling deficiencies and uncertainties in the analysis of the energy demand node, focusing on commercial and residential building stock and services (outside of transportation\(^2\)) and the production of goods by industry.

\[^2\] Aside from the uncertainties of technological changes with time in the transportation sector, lack of analysis on the behavioural uncertainties associated with change in
1.4.2 The Supply Component

The energy supply node provides the fuel prices used in energy demand analysis. World prices for fossil fuel are affected by change in demand among other things, but, if the region under analysis consumes a small percentage of that fuel (e.g., Canada or one of the provinces), change in local demand has little effect on the world supply or price. This is less true with electricity because the market is considered “local” and local supply costs are affected by changes in demand. Therefore, the supply component may contain data on fixed world prices for some fuels and models to determine energy prices for others.

Energy supply models attempt to simulate relatively few energy suppliers compared to those demanding energy services. Analysts typically use linear programming or other optimisation routines to simulate supply systems. Analysts generally agree on the applicable model types in the supply sector.

1.4.3 The Macroeconomic Component

Macroeconomic models, sometimes in conjunction with input-output models, provide scenario changes in demand for products or services. Such models serve many decision makers, nationally and internationally, because they are suited to analyses of sectoral and structural change. Output from macroeconomic models can be affected by results from supply and demand models simulated under the various scenarios of growth generated by macroeconomic models. To focus on the interaction of energy supply and demand in the system, one can consider the macroeconomic feedbacks as second-order effects (effects on demand for goods and services, changes in nonenergy sectors, employment, and others). Information carried along the links to the macroeconomic node from the demand and supply nodes includes data on AEEI, ESUB, impacts of costs of technologies on products and services and changes in the quantity of emissions.

Links between the macroeconomy and the energy nodes of the system in figure 1.1 have been difficult to simulate; efforts in this direction have achieved mixed results (Grubb, et
al. 1993, 436, Wilson and Swisher 1993, 260). If the potential importance of such links are small or can be estimated in a general fashion, explicit modelling is not warranted. But if the effects of changes in the energy nodes on the macroeconomic node are suspected to be large, these links will require further analysis and lie outside the bounds of this thesis. The effects such major changes may have on the modelling results presented in this thesis are described in chapter 6.

1.5 Simulation of Energy Demand

Planners and decision makers evaluate alternative actions in response to an issue or problem using quantitative models, cost-benefit analysis, discussions with experts, gaming approaches, historical review of similar situations, and other analytical techniques. My dissertation does not deal with the benefits or shortcomings of these types of analyses, but focuses on the development of a quantitative simulation model.

One needs not construct a formalised model to assess energy demand systems. For example, after conducting case studies of certain commercial building types, the results could be extrapolated to the entire sector based on assumptions about how commercial floorspace will change with time. However, proposing alternative hypotheses for any of the inputs to the exercise requires recalculation. So, analysts turn to more formal models for policy formulation and evaluation to scan the range of options for capturing energy efficiency or, for example, reducing CO₂ emissions. I review various modelling approaches to simulate energy demand and discuss three methodological issues:

1. the conflict between “top-down” and “bottom-up” modelling approaches to energy consumption analysis in section 1.5.1 and 1.5.2,

2. problems with model structure and data, and the procedures used to mitigate them (appropriate model design, "what if" tools, sensitivity analysis) in section 1.5.3, and

3. usefulness of the modelling framework (does the analysis tool present adequate information to the decision maker, in this case, in terms of CO₂ emissions?) in chapter 2, Methods.
1.5.1 Modelling Methods Used to Simulate Energy Demand

Energy scarcity concerns of the 1970s motivated theoretical and applied research in economics, physics and engineering on the potential for economies to substitute away from energy (especially petroleum products) while maintaining satisfactory levels of economic growth. Many tools for energy analysis were developed in response to various viewpoints regarding the impacts of fuel price changes. Analysts would ask, “How important was structural change ($\Delta SE / GDP$ in equation 1) compared to efficiency ($\Delta PE / SE$) in consumer response to the oil price shocks of the ‘70s and ‘80s?” If there was a change in the standard of living, or service and product demand, analysts would look to more macroeconomic models for answers. However, a more detailed, technology-explicit end-use model would provide a more appropriate analysis of energy efficiency. I provide a brief review of models used to simulate energy consumption and economic interactions to set the stage for the development of the interactive set of models proposed here.

One can describe the structure of models used in energy analysis on many different, independent dimensions. Four are defined below (IPCC 1995b, 284, table 8.1):

Dim. 1. Internalisation of behaviour - extent to which behavioural relationships are endogenised in the model equations or left as exogenous assumptions

Dim. 2. Detail on energy end-uses - extent of the description of the end uses of energy

Dim. 3. Detail on nonenergy sectors - extent of description of the nonenergy sector components of the economy

Dim. 4. Detail on energy supply technologies - extent of the description of energy supply technologies

When looking at the various nodes of figure 1.1, one sees that Dim. 3 deals primarily with the macroeconomic component (by definition, there is no energy demand in nonenergy sectors) and Dim. 4 with the supply node, both of which present important avenues of research. But I focus on the uncertainty in modelling the demand component of the system, primarily on behavioural realism and the importance of detail on technologies and processes in the sectors. Therefore, I review existing energy demand models using only Dim. 1 and Dim. 2 as in figure 1.2.
In figure 1.2, I use the vertical axis of the matrix to portray Dim. 1 with Dim. 2 represented on the horizontal axis. As one moves from top to bottom in Dim. 1, the models shift from exogenous to endogenous depiction of behaviour. Models on the top are more suited to simulate the effect of changes in historical patterns, a more normative, exploratory analysis, while those on the bottom are more suited to predict actual outcomes as they try to explain the critical dynamic factors of energy demand.

**Figure 1.2: Comparison on two dimensions of model types used to analyse energy demand; the internalisation of behaviour in model equations and the degree of detail of end-uses of energy.**

<table>
<thead>
<tr>
<th>End Use Detail</th>
<th>Increasing Technological Explicitness</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increasing Behaviour Realism</td>
<td></td>
</tr>
<tr>
<td>- Time Trend</td>
<td></td>
</tr>
<tr>
<td>- Simple Output Ratio Models</td>
<td>- Linear Programming Models</td>
</tr>
<tr>
<td>- Aggregate Econometric Models</td>
<td>- First Generation Technology Models</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Disaggregated, Dynamic Econometric Models</td>
</tr>
<tr>
<td></td>
<td>- Second Generation Technology Simulation Models</td>
</tr>
</tbody>
</table>

Some of these models can act in more than just the energy demand node. For example, linear programming models may simulate activity in both demand and supply nodes. However, here I compare the various models as they relate to the energy demand node and how they address uncertainty there. This is not to suggest that the model types are mutually exclusive or are competitors; in fact, they may serve complementary functions.
Model types in the left quadrants of figure 1.2 have negligible technological detail of the energy demand component of the system. As one moves from left to right in Dim. 2, the level of detail on technologies and processes increases and the models become more suited to analysing the technological potential for changes in energy efficiency.

Models on the left typically use regression or other mathematical techniques to estimate aggregate relationships between energy demand and time (time-trend models), its price (own-price elasticities), other energy forms (cross-price elasticities) or other factors such as capital and labour (elasticities of substitution). Many econometric models are thought of as "top-down" because they rely on an aggregated picture of a limited number of aggregate “goods and services” in the energy-using sectors.

Most of the model types on the right depend on detailed data on technologies or processes where the data are applied to flow models of activities found in the various sectors (production of paper, provision of living space, or commercial floor space, etc.). These models are considered "bottom-up" because they simulate activity in a sector at its most basic point, the technologies or processes, and the energy end-uses they satisfy.

Although the lines differentiating top-down and bottom-up models becomes more blurred as the various models have developed over time (IPCC 1996b, chapter 8, Krause 1996), it is helpful to review them as distinct model types and understand how they differ in their underlying philosophies and their parameters. Grubb, et al. (1993, 452) stated that:

It would be facile to suppose that the difference between “economic” [top-down] and “engineering” [bottom-up] views are confined to a few modelling parameters. They reflect very different perspectives, almost paradigms, about driving forces in the energy economy. ... the different perspectives lead to widely different assumptions concerning several factors: the relationship between energy demand and future economic growth in the absence of any abatement measures; the scope for exploiting more efficient technologies; and the scope for developing new technologies as needs (such as CO₂ reduction) require.

1.5.1.1 Top-down Method

The philosophy of the top-down approach suggests that energy consumption can be understood as a function of a few aggregate explanatory variables. These relationships are thought to remain stable enough that energy demand can be forecast with a measure of
The top-down approach typically involves the construction of aggregate production functions. The models contain algorithms that link energy consumption to composite indicators of other productive inputs, such as capital, labour and materials in the industrial sector, or final goods and services in the residential sector, and to technological representations of the energy supply sector, usually optimisation models of petroleum refining, natural gas processing and electricity generation. Within an aggregate production function (or demand function), energy may be treated as an aggregate or may be decomposed into different energy forms. Top-down methodologies seek to approach a general equilibrium framework in that a change in the cost of a factor, say labour, is assessed for its impact on all others, including energy. The approach uses sets of time-series or cross-sectional data making it possible to test statistically the model parameters. Because they are rooted in historical data, the parameters of top-down models incorporate information on how consumers and firms may respond to real changes in the costs of productive and consumptive inputs.

The shortfall of the top-down approach is that its level of aggregation limits its ability to portray the true extent of the technological options for responding to a new situation, such as a threat of climate change. Wene (1996, 810) suggests that they are liable to the black-box fallacy; that the observations of previous inputs and outputs encompass all possible responses of the energy system. New technologies, new regulations, and higher prices may push the economy into a situation where parameters estimated from historical data are doubted. For example, although AEEI may have had a bias toward using more energy in the past, this may not be the case in the future. If the future bias is likely to be different, historical data are of little help in estimating the direction and magnitude of that bias. Top-down analysts can change judgmentally the AEEI or other aggregate parameters (such as ESUB) but they can not confirm statistically the new parameters because no supporting data exist. For example, Manne and Richels (1994) obtained judgmental responses from over 20 experts on five critical parameters to variables, including AEEI and ESUB, common in aggregate models. They found the range of estimates quite broad and, after testing these ranges, concluded that ESUB and AEEI were
the second and third most important parameters after GDP in their effects on energy demand and emissions generation.

1.5.1.2 Bottom-up Method

The bottom-up approach, or end-use analysis, focuses on the costs and efficiency characteristics of the technologies that meet society's requirements for energy services. An inventory of all technological options that affect energy efficiency is made and technologies that can “compete” to produce a good or service are compared in terms of their life-cycle costs (i.e., the sum of discounted capital, operating and maintenance costs over the life of the technology). Technologies can also be compared using a cost-per-unit-of-greenhouse-gas-reduced or, for that matter, any other shared feature or combination of features. The key advantage of this approach is that, by accounting for all technologies, it is better able to show the extent of economic and technical potential for improvements in energy efficiency under changing regulatory and fiscal policies.

The disadvantage of the bottom-up approach is that it is far from an equilibrium framework in its simulations without receiving input from other models. This Wene (1996, 810) calls the reductionist fallacy; i.e., that the components of the energy demand and supply nodes in the system will be unaffected by changes in the other nodes. For example, end-use models cannot determine the impact of increased employment on demand for a product and thus cannot be applied to macroeconomic analysis. Bottom-up models also assume that no intangible (non-financial) cost differences between technologies exist; that is, decision algorithms for technology choice do not explicitly include the consumer’s behaviour in purchasing technologies. This “behaviour” is assumed to be “captured” in the time-series data that are used to develop parameters in top-down models. Finally, it is difficult to collect data on the type, age or year of availability, cost and efficiency of existing and future equipment stocks. The data for bottom-up models may be rough estimates, lacking statistical verification.

Two types of bottom-up models are commonly used in energy analysis: linear programming and end-use simulation models. Although structurally very different, analysts use both of them to show the effect of policy efforts on energy consumption.
1.5.1.3 Linear Programming

Linear programming or process optimisation models can function as technology simulation models. One such model, MARKAL (MARKet ALocation), was originally developed as an energy supply model in which linear programming methodologies determined the optimal mix of energy supply technologies (Fishbone and Abilock 1981, Berger, et al. 1992). It has been adapted to include energy-consuming sectors in many countries, including some Canadian provinces: Québec, Ontario, Alberta and Saskatchewan (Loulou and Levigne 1996, Loulou and Kanudia 1997).

In finding the optimal solution for a system, MARKAL assumes that every consumer and firm is aware of the outcome of all other decisions in the present and future. Thus, consumers would choose an energy technology to heat their homes with perfect knowledge of all future investments and costs that may affect the optimality of that decision. In this sense, the model is normative; it tells policy analysts what ought to happen if they wanted an optimal outcome in terms of societal objectives.

Unfortunately, the model would not inform policy analysts of the likely effect of specific policies, because firms and households in the real world have limited information and face intangible costs. It could be misleading to use the model to test policy instruments designed to influence consumer behaviour (e.g., using MARKAL to predict response to greenhouse gas taxes).

1.5.1.4 First Generation End-use

First generation end-use models are essentially spreadsheets which link physical product outputs or services to coefficients expressing energy consumption per unit of output or service. These coefficients are modified exogenously over the forecast period in order to reflect expert opinion on the rate of penetration of new technologies. The model simply tallies up the new level of energy demand in each future year. Any change in technology over time is only implicitly simulated by the model through exogenous or simplified assumptions concerning consumer behaviour. Running alternative scenarios can be tedious and time consuming because an entire new set of detailed assumptions must be
developed for the evolution of each energy coefficient. These models contain no endogenous behavioural algorithms.

1.5.1.5 Second Generation End-use

Second generation end-use models simulate changes in equipment stocks over time, measured in terms of annual physical output of goods or services. Such models require data on the existing stocks, preferably with information about age, so that the model can retire and replace vintages of equipment over time. Competition between technologies for market share, based primarily on life-cycle costs, determines the set of technologies that replaces retired equipment and meets product or service demand. These technologies may show different energy efficiencies or use different forms of energy, so that, as new technologies penetrate, the aggregate energy efficiency and fuel mix of the sector changes. Since minimising life-cycle cost is the overriding consideration of decision-making, the model may show energy efficiency to increase or decrease over the forecast simulation period. The direction of the results depends on the characteristics of emerging technologies, and the costs of labour, discounted capital and material inputs relative to each energy input.

Once data on equipment stock have been collected, and the model’s parameter values set, these models can test an array of alternative economic visions of the future. In this sense, such models are exploratory tools, allowing analysts to test the implications of alternative policies and of factors external to the policy process (e.g., world prices for energy or costs of generating carbon dioxide). However, if model algorithms choose technologies based only on minimising life-cycle costs, we obtain a normative result much like that of linear programming models; as such, simple second generation models offer little advantage over linear programming models. In other words, second generation models typically do not include non-economic factors that may induce technology shifts: development or availability of technologies, availability of certain energy carriers, regulations, and environmental considerations. There are few second generation models in use today because of the extensive data requirements.
1.5.2 The Top-down - Bottom-up Diversity

Recent research using the top-down approach suggests that reduction of greenhouse gases will be expensive and will have a significant negative effect on economic growth. Top-down studies of the US estimate costs of $20 to $150 per tonne of carbon to stabilise emissions and $50 - $330 per tonne to reduce emissions by 20% into the next century, with final costs totaling billions of dollars (Jorgenson and Wilcoxen 1990, Manne and Richels 1990a, Edmonds and Barns 1991, Jackson 1991, Barns, et al. 1992, Manne 1992, Karadeloglou 1992, EMF 1993, Yamji 1990, Nagata et al. 1991, Barker and Lewney 1991, Barker 1993).3 These studies tend to show little opportunity for either price-induced or autonomous technical change that would save energy.

In contrast, many bottom-up studies estimate that significant achievements in greenhouse gas reductions are possible without great cost (i.e., $0/t carbon) and, in some forecasts, even generate benefits. They show relatively small, positive or negative effects (i.e., -0.6% to 0.5% of GDP) on the rate of economic growth (Lovins and Lovins 1991, Mills, et al. 1991, Rubin, et al. 1992, SEI/Greenpeace 1993). These studies identify numerous opportunities for profitable investments that improve energy efficiency. However, these opportunities tend to be analysed in isolation from the other considerations of investment decision-making.

The diversity of forecasts from these models has received considerable review (Grubb, et al. 1993, Wilson and Swisher 1993, Scheraga 1994, IPCC 1996b) and analysts have pointed to at least six factors that could explain the divergence.

1. The present state of technology efficiency, the technology “baseline” - Top down models tend to see the existing stocks lying on or close to optimal levels while bottom-up models tend to see the set of technologies as sub-optimal. Indeed, top-down models that see technologies as sub-optimal illustrate negative costs (Bradley, et al. 1991, chapter 7, Edmonds, et al. 1992). On the other hand, Morris et al. (1990)

3 For a more complete listing and detailed analysis of both these and bottom-up models, see IPCC (1995b), chapter 9.
used a wholly-engineering model and obtained positive costs for any reduction beyond those captured in the existing set of technologies.

2. Variation in time frame - Short time frames of 10 to 20 years to reach stabilisation or reduction targets are much more costly than longer time frames of 100 years (up to 3% of GDP greater for 20% to 30% reductions in emissions, Grubb, et al. 1993).

3. Applied discount rates - Discount rates applied in most top-down analyses were typically at 5% (real) or less. Some view this as too low (Williams 1990, Grubb et al. 1993). Bottom-up models that use discount rates in their analyses (second generation models) vary from 2% to 8%.

4. Estimations of and symmetric responses to ESUB - First, in many econometric models, ESUB is often estimated and is considered low by some analysts (Williams 1990, Grubb, et al. 1993). Second, it is typically held constant over time and under all conditions. Third, if fuel prices shift upward and then back, the models assume a symmetric response in energy intensity (i.e., intensity declines and rises again). Not so, say the bottom-up analysts, because once you have introduced an improved technology, the system does not revert to the old one (Scheraga 1994).

5. Definition of AEEI - Isolating the autonomous nature of AEEI from other factors that cause change in technology efficiencies is difficult. Schipper et al. (1993) described four such factors: structural changes (SEEI), lifestyle and personal income changes (LEEI), price-driven impacts (PrEEI) and policy-driven impacts (PoEEI).

6. Estimations of AEEI - Manne and Richels (1990) suggested upper and lower boundaries of 0% and 1% AEEI per year and discovered that, using 1% AEEI, energy consumption was one fifth of that under 0% AEEI by 2100. Williams’ (1990, 38) critique suggested that the lower bound was unrealistic and the upper bound too low. These factors received significant criticism from others as well (Grubb, et al. 1993, Wilson and Swisher 1993). Dean and Hoeller (1992) stated that “unfortunately there is relatively little backing in the economic literature for specific values of the AEEI ... the inability to tie [it] down to a much narrower range ... is a severe handicap, an uncertainty which needs to be recognised”.

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In reference to top-down / bottom-up uncertainty issues, Grubb et al. (1993, 435) stated:

Consequently, we can conclude with some confidence that, neglecting externalities:
1. top-down modelling studies tend to underestimate the potential for low-cost efficiency improvement (and overestimate abatement costs) because they ignore a whole category of gains that could be tapped by nonprice policy changes; whereas
2. bottom-up end-use modelling studies overestimate the potential (and underestimate abatement costs) because they neglect various “hidden” costs and constraints that limit the uptake of apparently cost-effective technologies."

This dichotomy between top-down and bottom-up approaches is especially important in the current policy-oriented research on the cost of investments in energy efficiency and consequent reductions in emissions because there is no consensus on these costs. Judicious application of algorithms that reflect consumer behaviour in purchasing technologies in an end-use modelling matrix would provide an avenue for analysts to mitigate the modelling deficiencies associated with:

- the degree of technological change in top-down models (e.g., AEEI, ESUB) and
- the impacts of real-world investment behaviour on changes in technology over time in bottom-up models.

This thesis addresses these modelling deficiencies by developing the Intra-Sectoral Technology Use Model (ISTUM) as a tool that bridges the methodological gap by addressing the major limitations of both top-down and bottom-up approaches. ISTUM contains lists and characteristics of technologies available for use that include the quantity of existing stocks required to provide the services and products demanded. It makes no assumptions about time frames and targets because it seeks to simply estimate the impact on the reduction of emissions under certain policies. It requires discount rates as an exogenous input, tested under sensitivity analysis. And, finally, crucial top-down parameters, AEEI and ESUB, can be extracted from the results of its simulations. Details are provided in chapter 2, section 2.2.
1.6 **Uncertainties, Data and the Modelling Framework**

For policy analysts, models must portray the existing conditions of the energy system and the critical dynamic relationships that permit simulation of how that system might change over time. In this thesis, I develop and test a tool to address uncertainties in the existing energy demand node at two levels (Morgan and Henrion 1990, 39, van Asselt 1996):

- uncertainties in model structure - uncertainties in sectoral function and structure. What must the model(s) do to reflect the system? How will the model(s) be applied to analyse the system? What level of disaggregation is required to appropriately assess the system?

- uncertainties in quantities - uncertainties in data on technologies and other exogenous inputs. How does one assess the inputs to the modelling framework and the impacts of variation in these input data on the model’s outputs?

Uncertainties related to the model’s algorithms, size, and level of disaggregation can be considered general modelling uncertainties and are of a different nature than uncertainties about data on, say, fuel prices or technology costs. Experienced analysts argue that uncertainty about the structure of the model can be more important than quantitative uncertainties because it is more likely to have an effect on the results (Morgan and Henrion 1990, 67). Thus, analysts have developed and used alternative modelling regimes to reflect different components of the overall energy system introduced earlier.

### 1.6.1 Addressing Uncertainties in Modelling Energy Demand

What uncertainties must be addressed by the modelling tool? How can the model address them? How can the uncertainty be assessed? Given the objective as described in section 1.2, this thesis focuses primarily on the development and assessment of the modelling tool and provides direction in how such uncertainties may be assessed.

#### 1.6.1.1 Technology Attributes Change Over Time

Technology attributes will be different in the future than in the past (Williams 1990). The literature points to the significant uncertainties surrounding the estimation of critical parameters of top-down models that reflect changes in technologies such as AEEI and
ESUB. Speaking about these parameters, Manne and Richels (1994, 54) stated that, “Until key uncertainties [regarding these parameters] can be reduced, we must be content to deal with broad ranges”, ranges much broader than earlier IPCC studies suggested. In an earlier work, they recognised the shortcoming and pointed out there was a need for greater detail on the end-uses of energy (Manne and Richels 1990).

The modelling method used in this study explicitly keeps track of technologies and their attributes by simulating technology acquisition. Aggregate models, based on aggregate data, are limited to prices and outputs as explanatory factors. This means that if structural change and technological change are expected to be important in the future and to diverge from past trends, then statistical analysis of the historic data will not be able to detect this. The primary constraint to a disaggregated energy analysis has been the availability of data, at the appropriate level, within an industry or sector. In spite of this constraint, end-use analysis and modelling (very data intensive) have made significant inroads in each sector, particularly in collecting data on appliances used in the residential sector and, more recently in technology services in the industrial sector.

It is difficult to estimate what future technologies will be like or how technological research and development will respond to changes in capital costs, fuel prices or policies and policy expectations. Top-down modellers have historically used poorly-defined, efficient “backstop” technologies and new non-carbon-based alternative fuels to prevent their models from exceeding certain bounds (Manne and Richels 1994). Bottom-up modellers speculate on the efficiencies and costs of future technologies (Williams 1990). In any case, the inclusion of any novel processes and technologies must be governed by careful review and an understanding of theoretical minima for any particular process. It is possible that a range of “new technologies”, complete with estimated costs and efficiencies be entered into the database and tested through repeated simulation under ranges of their cost and efficiency criteria, a “Monte Carlo” analysis to provide some insight into the effects of changes in these estimates.
1.6.1.2 Disaggregation Matter.

Technology attributes vary from region to region and between sectors because environmental and economic conditions vary. The problem becomes compounded in the industrial sector because the technical heterogeneity in the industrial sector far exceeds that of the residential and commercial sectors. Twenty years ago, Halvorsen (1977) showed that aggregate production functions had a problem in defining parameters if they aggregated all industrial sectors. Griffin (1979, 1981), Maddala (1981), and Jenne and Cattell (1983) demonstrate that industrial heterogeneity should be considered in industrial analysis. Thus, in this thesis, not only is there regional and sectoral disaggregation but the industrial sector is analysed with a far greater degree of disaggregation than either the residential or commercial sectors.

1.6.1.3 Costs Matter

Firms and individuals respond to price (cost) of technologies, although other technology attributes are also important. Models must include cost, especially if one or more policies to be tested will affect technology cost. Some models do not explicitly incorporate costs because, for example, they focus on scenarios of technology penetration. Such models are useful until the analyst wants to explore scenarios of financial policies that affect operating and capital costs.

Therefore, the method used in this study is driven by an assumption of cost minimisation behaviour which occurs endogenously in the model (and may be mitigated by several other factors, see section 1.6.1.6). The impact of such changes can be evaluated using sensitivity analysis and, given a range of possible technology costs in key technologies, through Monte Carlo simulations.

1.6.1.4 Timing of Costs are Especially Important

Firms and individuals make purchase decisions based on costs of capital and investment as well as operation and maintenance. The literature provides estimates of these costs based on discount rates applied to the purchase decision (DeCanio 1993, Train 1985, Lohani and Azini 1992, see table 2.4, chapter 2). Models must take into account discount
rates with costs reflecting actor-specific (industrial, residential, commercial) and action-specific (retrofit, and discretionary or non-discretionary new investment) criteria.

If managers and decision makers attempt to minimise costs based on discount rates, the model must contain algorithms reflecting this behaviour. In terms of the development of the model, this includes:

- how equipment stock is chosen:
  - life-cycle cost calculations,
  - discount rates and the importance of first or up-front costs,
  - simulation of purchasing behaviour, variation from economic efficiency;
- how equipment stock is retrofitted.

Peer-reviewed literature (see table 2.4, chapter 2) gives a range of values for discount rates. While in this analysis a fixed discount rate typical of that sector was applied in all simulations, uncertainty associated with this range can be tested through the use of sensitivity analysis (see chapter 4, section 4.6) and, more comprehensively, through the application of Monte Carlo simulations to develop a probability distribution around the mean of the outcome.

1.6.1.5 Costs of a Technology are not Represented by a Single Value.

Technology costs are best characterised with a probability distribution rather than as a single value. Not only is information on costs imperfect, resulting in differences in perceived costs, but even real costs for an installed technology differ due to shipping, installation, company purchasing criteria and other factors can vary by sector and region (A.D. Little 1984, McFadden and Fuss 1978).

This feature of technology costs can be modelled by estimating probability functions that describe the relationship between the single-point technology cost and the market share that that technology receives. Analysts have typically used a logistic curve to define this relationship as defined in chapter 2, section 2.2.2.
The shape of this logistic curve is uncertain. More empirical research on particularly key technologies may be helpful in defining an appropriate curve, but the curves may be of little benefit if it is to be applied to new processes or technologies for which no historical precedent exists. Insights from managers and decision makers may help define initially the plausible range of values of the curve’s parameters. Utilising sensitivity analyses or Monte Carlo simulations would provide some indication of the effects of changes to this parameter on technology penetration and market shares.

1.6.1.6 Non-cost Factors can be Important.

Tangible costs are only part of the assessment firms and individuals use to determine which technology to acquire. Other, non-cost factors affect purchasing behaviour; intangible benefits or costs, consumer surplus and local restrictions on fuel or technology viability shift technologies away from strictly financial criteria in determining their market share.

The application of a set of “hard” controls of technology penetration including fixed maximum and minimum market share, fixed penetration rates, established years of technology availability or unavailability, regulatory constraints and standards can easily account for physical constraints on fuel availability and technology viability. However, evidence of other, less tangible conditions depend primarily on responses from experienced personnel and expert opinion. Future empirical research will shed more light on biases in technology choice. At the present, uncertainties can be addressed through the application of a number of simulations using values drawn from a defined range of such biases (Monte Carlo simulation).

1.6.1.7 General equilibrium

Changes in technologies and shifts in cost and non-cost criteria applied to the energy demand node affect both supply and macroeconomic nodes, which, in turn, affect the demand node. These interactive effects have been tested in some model sets, with inconclusive results (Grubb, et al. 1993, Wilson and Swisher 1993).

The modelling tool must function to address these uncertainties within the demand node. Models in each node of the energy system must act interactively through feedback loops
or by iteration. New sets of data on components of the energy system may be required. In this section, the first goal is to characterise uncertainty in ways that provide policy analysts with an effective appreciation of its significance. Second, an understanding of the data and its availability allows one to develop the necessary components of the modelling framework.

1.6.2 The Model

This thesis is linked to the question of whether standard methods of model testing adequately address uncertainty in the applied models for simulating the effect of policies, or whether alternative means of addressing this uncertainty are required. In particular, I postulate here that statistically validated parameters linking energy consumption to aggregate price and output indicators are likely to generate biased forecasts that don’t help the decision maker to assess the uncertainty for estimating the future response of the economy to a specific greenhouse gas reduction policy, namely a charge for emitting CO$_2$, due to:

1. change in technologies - The technologies available for reducing CO$_2$ emissions were not the perceived alternatives facing consumers during historic periods, but will be in the future because of greater public awareness and specific government information and support policies. For example, compact fluorescent light bulbs are five times more efficient than the common incandescent ones they were designed to replace, but were not commonly available until 10 to 15 years ago.

2. change in sector structure - Trends in structural adjustments in an industry or sector could diverge significantly from historic patterns because of changing public preferences and government policies or autonomous structural shifts occurring in advanced industrial economies. For example, the shift from chlorine-based bleaching agents to ozone or peroxide alternatives in the paper industry has changed the structure of the inorganic chemicals industry. If we assume that various industries and sectors show different values for AEEI and ESUB, any shift in structure would change aggregate AEEI and ESUB values even if there were no changes in technology stocks. A disaggregated analysis would permit an evaluation of such changes.
3. **change in price elasticities** - Parameters on price elasticity estimated from historic data are unlikely to portray the full extent of the long-run response to changes in price because, over time, various unspecified variables confound the ability of statistical analysis to detect the full contribution of price changes to consumption changes. For example, autonomous technology improvements often reduce the amount of energy required to generate a product without any change in price of the fuels used to provide that energy.

These factors help to explain the motive for the approach used in this study, the application of behavioural criteria in a detailed end-use analysis of each sector. The top-down versus bottom-up modelling debate is central here; it is a debate about model validity, an issue concerning the ability of the modelling routine to address uncertainty.

On the one side are top-down modellers who believe that one has to rely on the standard approaches to model evaluation described above. They focus on the application of historical data, aggregate or detailed, for determining parameter values and for assessing model validity. On the other side are bottom-up modellers who believe that top-down models are misleading for the three reasons listed above. They are sure that one is better off, for the purposes of anticipating the future effects and costs of CO₂ reduction policies, by constructing a detailed model of technologies, to analyse on a technology-by-technology basis the life-cycle costs of each technology, and then to calculate the costs and benefits of adopting such technologies.

Bottom-up models do not attempt to explain or describe the past. Yet they are presented as a more accurate means of predicting or simulating the future response to a particular policy (UNEP 1991). To top-down modellers, such models show deficiencies in modelling behavioural realism and are likely to be biased because they underestimate the importance of the many factors that are real costs to consumers. Top-down modellers argue that uncertainty about the importance of these other factors can only be properly addressed by empirical analysis based on real consumer behaviour, even though such analysis might only be possible at an aggregate level because of data constraints. However, bottom-up modellers counter that the very technologies on which these data were based will be less important or unavailable to future decision makers.
In this study, I address directly these modelling deficiencies, primarily by acknowledging and incorporating in the study methodology the strongest arguments from both sides. Thus, my method encompasses two basic elements:

1. It addresses the uncertainty about how the system may differ in the future relative to the past by explicitly including technology-specific information and relying on this for simulating changes in technologies over time. For most top-down models, the technological structure can only be implied from the parameters of the model. This study is bottom-up; it acknowledges the critical importance of including detailed technology-specific information for the model simulation to permit analysts to focus on this significant source of uncertainty.

2. It addresses the uncertainty about how firms and households make decisions related to the energy consumption characteristics of technologies. It does so by including explicitly a decision algorithm where decision-making parameters are based on evidence collected from the programs and policies of North American utilities over the last 15 years. For most bottom-up models, life-cycle cost analysis is deemed to be sufficient to demonstrate the costs to society of various energy-efficient technologies. Yet empirical behavioural research continually shows this to be inadequate. In order to address this uncertainty, this study includes parameter values derived from numerous micro-level studies by energy utilities (Jaccard, et al. 1992a, 1992b, 1993).

In summary, top-down modellers may acknowledge the shortcomings of historically-based estimates of AEEI and ESUB and therefore adjust these parameters based on an aggregate sense of what might be possible, but not based on detailed accounting for and simulation of all technologies available and realistic technology acquisition and retrofit behaviour. Bottom-up modellers may change penetration rates of technologies, but again, this should not be done in an ad hoc manner. I propose to apply behavioural parameters to each technology competition to realistically simulate what will happen based on available detailed research into consumers’ technology acquisition behaviour. Thus, this study intends to address deficiencies in the modelling tool through methodological strategies which involve a combination of top-down and bottom-up methods that address the greatest sources of system uncertainty of each approach.
1.7 **Outline**

The methodological approach to an analysis of the Canadian system forms the core portion of chapter 2. In chapter 3, I describe the Canadian system, energy distribution in that system and assumptions related to the sectors that compose that system, and I review the results of the simulations (chapters 4 and 5) leading to conclusions and recommendations (chapter 6). I have appended to the thesis specific simulation details and results for the sectors and regions, the latest version of ISTUM’s manual and a description of the other models used.

1.8 **Chapter Bibliography**


Chapter 1  The Nature of the Problem


2. Methods

The approach proposed in chapter 1 suggests that one should apply different models to simulate different components of the energy system (figure 1.1). In my analysis, I take a magnifying glass to the energy demand component of this system. I have shown that forecasts generated by the various models historically applied to that component have generated diverse and incongruous results. I have proposed that the application of a model that can simulate detailed processes under defined behavioural parameters will help to increase the decision maker’s confidence in model forecasts by explicitly addressing uncertainty in an analysis of energy demand, particularly in response to specific policies designed to influence decisions on technology acquisition. Completing the analysis for the Canadian energy system will require nine steps.

1. Establish a macroeconomic scenario of growth and structural change.

2. Establish regional energy prices subject to international markets for fossil fuels.

3. Relative to assumptions on energy cost, construct a supply model to provide regional cost and price estimates for electricity under different supply alternatives.

4. Build demand models:
   - Commercial - A relatively uniform set of technologies that shows energy demands specific to the ultimate use of the floor space in the commercial sector.
   - Residential - A relatively uniform set of technologies and building types that vary in energy demand for a particular climatic zone and age archetype.
   - Industrial - A great variety of end-use technologies, specific to the production of certain commodities, requires significant levels of disaggregation.

5. Simulate demand models using behavioural parameters from peer-reviewed research to determine technology turnover under the defined growth scenario (from 1) and the set of energy prices (from 2 and 3):
   - Test the model’s key input values and parameters (sensitivity analysis).
• Project energy demand under specified conditions (e.g., no-change, natural, technical and economic runs).

• Simulate various “emissions charge” policies designed to influence decisions on technology acquisition.

6. Iterate between models in the system to satisfy system-wide equilibrium conditions.

7. Aggregate regional and sectoral analysis for Canada to determine the economic and physical (i.e., energy consumption and emissions reduction) impacts of policies that impose a charge on CO$_2$ emissions.

8. Because the focus here is on an analysis of the demand node, critique the demand model and its sub-models using criteria from Morgan and Henrion (1990, chapter 3):

   • effectiveness and appropriateness - Is there a good fit between the model’s structure and function and the policy goals?

   • treatment of uncertainty - Does the model enlighten the decision maker and enable cohesive, cognizant policy development by taking into account uncertainties in its analysis of the system?

   • user-friendliness - Is the model clear and explicit or a “black box”, easy to use or cumbersome, rigid or flexible?

9. Compare and contrast outputs of the model simulations with those generated by the other models: emissions reduction including average and marginal costs of such reduction and a review and comparison of specific parameters such as AEEI in the various analyses. How might this affect the decision maker’s level of confidence in the results of the analysis as a result of overcoming the most poignant criticisms of previous approaches:

   • changes in the end-uses of energy in response to an action over a twenty-year time frame (considered too short a time for some analysts, too long for many decision makers);
• incorporation of real constraints on technologies and realistic behaviour
  (diversity of perceived costs, importance of initial capital costs).

When one intensifies the focus on one portion of the energy system, modelling uncertainties, otherwise hidden under a more aggregated format, appear. In ISTUM, I can distinguish these uncertainties as exogenous or endogenous. Exogenous uncertainties are dealt with via the scenario forecast and include those related to energy prices, growth rates in industrial or sectoral activity and outputs, and structural change. Information on how these factors change is obtained from the other models that provide feedback to ISTUM. Endogenous uncertainties are outlined in table 2.1 and relate to either the model’s representation of current reality (technico-economic uncertainties) or to dynamic factors (behavioural uncertainties). Because sufficient published data to address these uncertainties are lacking, I developed a method to assess the technological and behavioural portrayal of the industrial sector and utilized similar approaches used in an analysis of the commercial and residential sector (Bailie 1994, Strickland 1996). I describe this method in section 2.3 below.

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<tr>
<th>Table 2.1: Listing of Endogenous Modelling Uncertainties</th>
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<tr>
<td><strong>Technico-economic Uncertainty</strong></td>
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<tr>
<td>1. Structure of current major processes</td>
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<tr>
<td>2. Market shares of current technologies</td>
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<tr>
<td>3. Energy efficiencies and fuel shares of current technologies</td>
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<td>4. Technology costs (capital and operating, for future competition)</td>
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<td>5. Technology energy efficiencies (for future competition)</td>
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2.1. Information from the Other Components of the Energy System

In chapter 1, I defined a simplified energy system as having three interlinked components: the macroeconomy, the supply of energy and the demand for energy. In figure 2.1, I have further defined how the energy demand component depends on output from the other two:
Figure 2.1: The simplified energy system showing data flows between model nodes and the source of data on energy consumption, CO₂ emissions and costs.
Macroeconomic models provide information on the demand for goods and services (step 1 above). While output from such models can be affected by the results from the supply and demand models run under these scenarios, I have assumed the consequences of these macroeconomic feedbacks as negligible because energy demand is generally rather inelastic and because it is usually a small part of household budgets and firm input costs (Geller and Elliot 1994). This assumption becomes more tenuous under high CO$_2$ charge runs, especially in energy-intensive industry. However, because of my focus on the energy demand node, I have limited my analysis to one growth and structural change scenario as generated by a set of models used in Natural Resources Canada’s (NRCan) publication, Canada’s Energy Outlook, 1994 Update (NRCan 1994a). This scenario is applied to all iterations of the energy supply and demand models.

Energy supply models provide cost estimates of energy supply alternatives for steps 2 and 3 above. I use world prices for fossil fuels translated by the InterFuel Substitution Demand (IFSD) model into prices for each Canadian region. Fuel price modifications are based on regional differences in production or processing costs, taxes, transportation costs, and other factors specific to each region. I assume world fossil fuel prices are not affected by change in demand because Canada is considered a “price-taker” (its demand is too small to influence world supply and world price). Regional electricity generation is affected by change in demand and therefore I have incorporated a simple optimisation model (the Electricity System Simulation Model, ESSM) to generate new electricity prices when regional demand changes.

Energy demand models provide information on sectoral demand for energy and the cost associated with the production of goods and services. Data on electricity demand are fed to ESSM so that new prices for electricity can be generated under changes in demand.

Figure 2.1 illustrates the relationship between system components in this analysis:

- a uni-directional flow of data from the macroeconomic models describing product and service demand;
• a distribution of this demand to the various components (sectors) of the energy demand node as they are represented in ISTUM;

• a set of energy prices by sector and by region delivered to the energy demand node;

• a summation of electricity demand from all the sectors in the energy demand node as feedback to the supply node; and

• an accumulation of pertinent data on costs, energy consumption and CO$_2$ emissions for analysis.

2.2. An Analysis Tool for Energy Demand, ISTUM

ISTUM’s precursors, the Industrial Sector Technology Use Model and ISTUM-2 (US DoE 1983), were developed by the US Dept. of Energy in the early 1980s to simulate the end-use of energy in the industrial sector. The original version of the model, developed for the large mainframe computers of the ‘70s and ‘80s, proved unwieldy and efforts were begun to transform the model into a version designed for personal computers. While the transformation of the model’s technology-choice algorithms and user-interface were completed prior to the start of this analysis, I developed and tested a number of other cost and non-cost algorithms which replaced or upgraded the original functions. I also developed the user-interface and data handling activities by improving the link between the model and spreadsheet software.

By far the most important component of and the largest contribution to the model’s development was the construction of the various sub-models for each of 8 industrial sectors as well as the commercial and residential sectors for each region of Canada. This work needed to be done because, in the transformation process, the ability to simulate different industries was lost and the original model had never been applied to Canada.

In the original version of the model, the major end-uses include process heat, motive force, space heat and lighting. These end-uses were more clearly defined in the databases designed for the personal computer version. In expanding the model to the residential sector, the household instead of an industrial product forms the basic unit of energy consumption. ISTUM provides each residence with the necessary generic services: hot
water, refrigeration, and other appliances. In the commercial sector, ISTUM provides units of specific floor space (e.g., office, retail, hotel, restaurant, hospital, etc.), complete with heating, ventilation, air conditioning (HVAC), hot water and other requirements.

These end-uses of energy can be referred to as energy services. Energy services may be process-specific. For example, in industry, electrolysis of alumina occurs only in the aluminum industry while digesting wood fibre into pulp is specific to the pulp and paper industry. Energy services may also be generic; producing steam by a boiler is common to most industries and many commercial establishments, even if only for space heat. All energy services are provided by equipment systems recognised as “technologies” by ISTUM.

2.2.1. ISTUM Structure, Energy Flow Models

Analysis of energy consumption in the production of a good or service requires an understanding of the activities that consume energy in a sector. First I develop a process flow model of a sector, the sequence of activities required to generate the product or service. Published engineering information, site visits and the incorporation of comments from industry experts give credibility to industry process flow models. And, for example, HVAC specialists provided insights into the interaction of the HVAC units used in most commercial structures. Chapter 3 contains sector-specific details.

Even a cursory review of process flow models reveals that the industrial sector is more technologically heterogeneous than the commercial and residential sectors. Commercial HVAC systems are fairly standard among commercial buildings, even though demands on the system vary (warehouses have different air control requirements than office buildings). Residential structures show relatively consistent demands on space heating technologies, even though the technologies vary in size and form. Both commercial and household appliances display uniformity in energy demand and range of efficiencies.

End-use modellers have long struggled with high data requirements and data scarcity in their attempts to simulate the industrial sector. If the information exists, it is seldom in some convenient, single-source location. But analysts who did not disaggregate industry into its sub-sectors encountered problems: wide variation existed in how sub-sectors
responded to changes in energy prices (Halvorsen 1977), structural shifts in production played an important role in the level of energy consumption (Maddala and Roberts 1981, Jenne and Cattell 1983), and good energy analysis required some disaggregation of energy types (i.e., better an analysis with variables for each fuel than a single variable for all energy, Griffin 1979).

Such research points to the need to disaggregate the industrial sector. Therefore, to address uncertainty caused by aggregation, the heterogeneity of the industrial sector requires separate process flow models and unique representations of the various industrial branches. In this analysis, I focus more on the disaggregation and detail of the industrial sector than the other sectors. Industry disaggregation is even more important when we consider that, in Canada, the sector also accounts for nearly 50% of all energy used.

Which industrial branch should be disaggregated from the others? A review of the degree to which various process technologies are unique to an industrial branch and the role that branch plays in the industry picture of energy consumption helped define the level of disaggregation required (Nyboer 1989, Fogwill 1991). Chapter 2 of the ISTUM Manual, Vol. I (Jaccard and Nyboer 1994, see appendix A) provides criteria for the disaggregation and development of sub-models for use in ISTUM. The disaggregated industry should:

- generate clearly defined and measurable products, consistent with the categories found in the Standard Industrial Classification system used internationally;
- show significant levels of energy consumption, usually 5% or more of total industrial consumption in a region;
- have data available for calibration.

Thus, establishing the degree of disaggregation requires a good understanding of the sector and knowledge of where energy is important to the activities of each branch.

Analysis of the process flow model will indicate where and how energy is applied to the process. From a review of the process flows and available data on these flows, one can develop an energy flow model, the key to ISTUM’s simulation. Figure 2.2 depicts a typical energy flow model, one designed for the aluminum industry. In this flow model,
we see three routines, one in which the generation of aluminum is simulated, one where motors compete to provide the machine drive required to produce aluminum and one in which steam requirements to generate the aluminum are met.

During model simulations, ISTUM begins at the first node and seeks to provide technologies to meet all services required in the primary production of aluminum. In this
Chapter 2  Method

study, aluminum demand for future years is obtained from NRCan’s CEO report, but one can also determine future production by multiplying demand of the base year by an index for industrial growth or from some other forecast.

When the “aluminum” routine is complete, ISTUM sums the demand for machine drive required to produce the aluminum and delivers this information to the Machine Drive output routine. When this routine is complete, ISTUM determines the total demand for steam from both the aluminum and the machine drive components and simulates the Steam output routine to generate it.

Thus, the model’s structure requires a disaggregation of each sector hierarchically into nodes at three levels. At the top of the hierarchy are primary nodes. In figure 2.2, we see that three such nodes exist in the demand for aluminum and the demand for the two auxiliary services, machine drive and steam. The first of these is specific to the aluminum industry, while the latter two represent generic services. Any number of generic services may be associated with the sector-specific component of the energy flow model. In the residential sector, for example, the provision of “hot water” is the only generic service to the “specific” technologies known as residential archetypes (types and vintages of housing stock) while the pulp and paper flow model requires eight such generic services.

The nodes at the second level of the structural hierarchy are called intermediate nodes. They translate demands at the primary nodes into demands for intermediate products or energy services through engineering ratios (the linking lines). For example, for each tonne of finished aluminum, 1.01 tonnes of molten aluminum are required, a relationship denoted by the line linking the primary node Aluminum and the intermediate node Molten Aluminum and defined in ISTUM’s databases.

The demand for products or services at the intermediate node is satisfied by specific types of equipment at the competition nodes, the lowest level in the hierarchy. A number of existing technologies provide the service of generating molten aluminum. These technologies are listed in the Electrolysis competition nodes attached to the Molten Aluminum node and may include developing technologies not available in the base-year.
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ISTUM keeps track of the sequence of activities and the model functions applied to the various nodes through the number associated with each node. Competition nodes receive a second number (in parentheses in the flow model) so that ISTUM can associate specific technologies with a competition node. For example, when ISTUM looks at node 3 (Electrolysis), the program calls for a function to execute a technology competition. ISTUM then seeks out and competes all technologies associated with competition node 1, the second number associated with this node.

2.2.2. Technology Evolution Rather Than Energy-Demand

ISTUM functions primarily as a model that simulates the change in technologies over time. The model accounts for non-energy operating and maintenance costs and capital costs of equipment. But, more importantly, the explicit simulation of equipment choices is based on reproducing, as accurately as possible, the process of decision-making applied to equipment acquisition. ISTUM tries to capture the behavioural responses of firms and households as these relate to decisions about technology choices.

Through utility surveys and communication with sector experts, I could estimate the functional quantities of existing stocks of technologies. This information serves as the base-year input to ISTUM. Then, during a simulation, ISTUM’s algorithms determine the shares of existing and new technologies in some future period based on four factors:

- retirement of existing stock because of age;
- retrofitting of existing stock to improve productivity, increase energy efficiency or improve reliability;
- growth or decline in demand for products or services; and
- acquisitions of new stocks to meet the excess of demand over remaining stocks.

Because the model’s databases hold crucial information on the characteristics of energy consumption of each technology type, ISTUM can estimate total energy consumption in any future period. In fact, the aggregate of any characteristic of the set of technologies (e.g., CO$_2$ or other emissions, electricity consumption, costs) can be determined.
The critical dynamic uncertainty of models that simulate technology change in the long run is technology acquisition behaviour (see table 2.1). Uncertainty about technology retirement is not large because, although retirement rates can fluctuate dramatically with the short-term business cycle, they average out over longer time periods, generally approximating the expected lifespan of different types of equipment. Likewise, periods of accelerated retrofit of existing capital stocks are not critical to the accurate portrayal of long run stock evolution (except for very long-lived stocks like buildings and infrastructure, and here I have explicitly taken this into account). Finally, the utilisation rate of equipment will also vary with the short-term business cycle, but will average out over the long run and good historical data are available for annual and average capital stock utilisation rates. I deal with the issues of retirement, retrofit and capacity utilisation in section 2.2.2.1 below.

Unfortunately, data on technology acquisition behaviour of firms and households are limited. Yet addressing uncertainty in this area is critical to the model or, for that matter, any endeavor to forecast the effect of specific fiscal and regulatory policies on technology change over time. I deal with this problem in section 2.2.2.2.

Figure 2.3 provides the basic flow chart of ISTUM’s simulation procedure. In each simulation year, ISTUM models an industry’s or sector’s process-specific component and then its generic component(s). The analyst can choose the timing and frequency of simulation, up to one simulation for each year of the time horizon (at present, a maximum of 20 years) or choose ISTUM’s default years, every fifth year for 20 years.

ISTUM determines and records changes and trends in technology mix and thus, energy consumption, by modelling energy services relative to change in demand for the products
Figure 2.3: Flow diagram of procedures in ISTUM. In the default 20 year simulation, the cycle is repeated four times, once every fifth year.

- **Exogenous Data Inputs**
  - Evolution of Product Demand
  - Existing functional stock
  - Retirement and Retrofit Conditions
  - Fuel prices, annualized costs

- **Process-Specific Component**
  - Allocate demand to intermediate and competition nodes
  - Determine the amount of retiring stock
  - Determine the degree of retrofitting in remaining stock

- **Generic Components**
  - Allocate service demand to appropriate primary nodes
  - Fuel prices, annualized costs
  - Evolution of Product Demand
  - Exogenous Data Inputs

- **Decision Points**
  - Do we have enough stock to meet the demand?
  - Are all generic services met?

- **Actions**
  - Compete technologies to provide sufficient capacity
  - Retire any surplus stock
  - Send demand for services to generic sub-models
  - Generate fuel, stock, and costs reports

- **Records**
  - Record energy consumption, stock, and annualized cost data

- **End**
generated by a given industry or the services required in a given sector (commercial floor space, residences, etc.). A simple linear equation can be used to represent such distribution of growth:

\[ PS_{n,s} = \frac{PS_n}{A} \times A_s \]  

(2)

where:

- \( PS_{n,s} \): product or service provided by technologies at competition node \( n \) in scenario \( s \)
- \( PS_n / A \): demand for that product or service per unit of sector or industry demand \( A \)
- \( A \): a single unit of sector or industry output
- \( A_s \): total demand for sector product or service in scenario \( s \)

For example, if the production of aluminum (or \( A_s \) in the above equation) from Québec is forecast to grow at an annual rate of two percent, this exogenous information is fed into the model which allocates a similar growth rate in various intermediate products and energy services: molten aluminum, space heating and lighting (each examples of \( PS_{n,s} \), a product or service). \( PS_n / A = 1.01 \) for the relationship between node 1 and node 3 in figure 2.2; for each tonne of product required, 1.01 tonnes must be smelted. If growth is set at 2% / year for node 1, it will be carried through to node 3 in the same proportion.

### 2.2.2.1. Retirement and Retrofit

ISTUM changes the quantity of existing stocks of each technology in each simulation year through retirements and retrofits. Stock in the base year is assumed to have a uniform age distribution because data on the age distribution of equipment stocks are spotty or unavailable. If an industry in a region is older than the life of its typical technology and production has seen some growth in the past, it is likely that some of its equipment stocks are nearing retirement, some are half way through their expected life and some are newly installed. These stocks can then be retired on a straight-line basis which, over the long run, can be directly related to its life expectancy. For stocks introduced after the base year, the retirement function reflects the standard logistic decay pattern found in most age profile surveys of industrial equipment. If data on the age distribution of equipment exist,
this function can be applied to that stock. Figure 2.4 depicts decay patterns for stock whose technological life is 20 years.

Figure 2.4: Decay patterns on the retirement of new and existing (base) equipment stock where average technology life is 20 years.

The degree of retrofitting is determined in a probabilistic fashion where certain constraints can be imposed by the analyst to set up a number of cost competitions between the parent or lead technology and associated retrofit options.¹

Based on retirement, retrofit, and growth factors, the model calculates whether surplus stock exits or whether new stock is required for a given year of the model run. If surplus stock exists, the model simply retires these additional units of the base stock from energy and emissions calculations, allocating them among competing technologies in proportion to their existing shares. If new stock is required the model allocates the incremental new stock among competing technologies.

¹ The life cycle cost of the lead technology and each retrofit option is distributed using a Weibull distribution, described in appendix G, where the variance is defined by the analyst. ISTUM draws random samples from the cost distributions in pairs or sets if more than one retrofit option exists and counts the “winners” (the least cost option in that set) to determine the degree of retrofit and market share of the option(s).
If end use models were designed to simulate annual changes in equipment stock, the analyst must have data on production cycles and the sum of stock prematurely retired (or “mothballed”) and include some factor on the utilisation of equipment capacity, at least in the initial years of the simulation. But ISTUM is intended for an analysis of change in equipment stock over the long run, 20 years, with the model generating snapshot pictures of the industry every fifth year. Analysts of long run macroeconomic developments seldom generate forecasts of industry growth that include production cycles in the future, preferring rather to show trends over the long term, often in terms of percent annual growth in five to ten year blocks. Therefore, in-depth analysis or inclusion of capacity utilisation cycles in the long term is not crucial to the analysis. For this same reason, and because retirement of old stock typically exceeds the rate of production decline in an industry, excess stock in any simulation year can be “retired” without having the model keep track of their possible return to activity were the demand to increase in any subsequent year.

2.2.2.2. Competition of Technologies

One method for representing technology acquisition behaviour is to conduct a simple cost-benefit analysis with available cost data. Capital, energy, operating, and material costs can be incorporated in an analysis with the lowest-cost technology capturing 100% of the market in each time step. The analysts may or may not apply discount rates to determine these costs. Optimisation models take this approach; simple spreadsheet-based bottom-up models and linear programming models are often governed by exogenously-determined constraints.

ISTUM can mimic such strict cost-benefit representations of technology acquisition behaviour, although not with the global optimising properties of a linear programming model. It too uses the cost of competing technologies as the primary factor in the purchase decision. But it uses behavioural parameters to alter the engineering cost of technologies to reflect other factors consistently shown by researchers to influence consumers’ decisions.

Life-cycle costs of a technology
One behavioural parameter, the discount rate, permits the combination of both the initial or capital costs and annual operating, maintenance and energy costs into a life-cycle cost (LCC) for each technology. The annual expenditure to own and operate that technology can then be determined and used during competition between similar technologies to provide the desired service or product. The discount rate reflects consumers' willingness to spend more money today in order to save money in the future. Life-cycle cost calculations use the discount rate to determine a value for the annual cost of purchasing and operating the technology. The cost of any particular technology in any year $i$ would be:

$$ LCC_i = \left( CC \times \frac{r}{1-(1+r)^{-n}} \right) + O_i + M_i + \sum E_{ij} $$

where:

- $LCC_i$ = annualised life cycle cost in year $t$
- $CC$ = capital cost
- $r$ = discount rate
- $n$ = technology life span
- $O_i$ = operation costs in year $t$
- $M_i$ = maintenance costs in year $t$
- $E_{ij}$ = cost of energy form $j$ in year $t$

Specific values for the discount rate, $r$, are found in the discussion of industrial, commercial and residential sectors in this chapter (section 2.3.4) and are obtained from numerous peer-reviewed studies and reports where the authors have reviewed social, private, *ex ante* and *ex post (de facto)* discount rates in the various sectors:

- **social discount rates** - the “public” discount rate, used to analyse public investments or projects of crown corporations. For example, the rate used by BC Hydro in project analysis is between 6% (1988) and 8% (1992), by Ontario Hydro 7%, New Brunswick Power 7%; I have used 7%.

- **private discount rates** - the implicit rates used by firms and households when acquiring energy-using equipment;
• *ex ante* rates - the criterion by which private projects are deemed acceptable, typically between 10% and 15%;

• *ex post* rates - the actual or “*de facto*” discount rate after a project is completed and the rate of return calculated, often much higher than *ex ante* rates. They reflect payback periods of 2 years (≈50%) or 3 years (≈30%).

Research has shown that strict cost-benefit portrayals of technology acquisition behaviour give a biased representation of real-world behaviour if they fail to account for the high time preference (discount rate) of firms and households relative to the social rate applied by governments and utilities (high time preferences result from the perception that newer, often more efficient technologies are riskier and that firms and households are capital-constrained and thus prefer less expensive, often less efficient, technologies). These studies, described in section 2.3.4, have used market surveys to compare differences in capital and operating costs of competing technologies with their relative market shares and have developed ranges of “revealed” discount rate values for firms and residences.

**Variability in the Life Cycle Cost of Technologies**

Market surveys and information from purchasing managers have shown that firms and households do not all have the same information about costs and may even face different costs depending on location and unique factors affecting distribution and installation costs at different sites. In reality, a single technology never captures all the new stock purchases, even if its $LCC$ is lower than other competing technologies, because each consumer applies a unique set of criteria to the purchase decision. Analysts typically use logistic curves such as those in figure 2.5 to represent this market behaviour (Train 1985). Where the life cycle cost (LCC) of Tech A is the same as that of Tech B ($LCC_A = LCC_B$) at LCC*, the market shares of the two technologies are equal. The slope of the curve provides some indication of the degree to which a more expensive technology would still capture some market share. As the slope approaches infinity, the proportion of the market shares allotted to the cheaper technology approaches 100%. As the slope approaches 0, the proportion of the market share allotted to the cheaper technology equals
that allotted to the more expensive technology, no matter the price difference between technologies.

**Figure 2.5:** Market share function as demonstrated in a typical logistic curve for two technologies, A and B. At LCC*, the LCC of Tech A equals that of Tech B and the market shares are equal, no matter the slope of the curve.

At first glance, one need only determine the slope of the line to approximate market shares of any two or more competing technologies. But two problems arise that make this determination difficult: lack of historic, equipment-specific data on the life cycle costs and market shares of competing technologies and, were such data available, the relevance of such historic data to new technologies. One can assess the range of values the slope may have through surveying firm and plant managers.

Historically, analysts have used the common formulation of a logistic curve in a probabilistic technology choice model which expresses the probability of selecting a technology A (here in a two-technology world) as:
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\[ P_A = \frac{1}{1 + e^{-(\alpha + \beta X)}} \]  \hspace{1cm} (4)

where:

\[ P_A = \text{probability of selecting Tech A} \]
\[ X = \text{the ratio of annualized life cycle cost of Tech A to Tech B} \]

For estimation, the formula can be converted to the logarithmic form in which the dependent variable is the log of the ratio of the probability of selecting A to the probability of not selecting A, referred to as “logit”:

\[ \ln\left( \frac{P_A}{1-P_A} \right) = \alpha + \beta X \]  \hspace{1cm} (5)

In using this logit formulation, one runs into the familiar constraints when trying to estimate parameters through regression: a large number of variables as one increases the number of competing technologies (\( \gamma Y \) or \( \delta Z \) for the next two technologies), no historical data, and no ability to estimate parameters for new technologies (application of parameters relevant to past technologies may be irrelevant to the new technology).

In ISTUM, the analyst can set the cost-variance parameter, to determine the slope of the logistic curve with an inverse power function. I determined the slope of this function based on judgment reflecting discussions with industry or sector representatives (telephone surveys), sectoral review and anecdotal market survey data such as that used in the original ISTUM database (A.D. Little 1980, 1984).

**Inverse Power Function**

The inverse power function has the following specification for determining the market share of a technology:

\[ \text{In} \text{NRCan, recognizing the need for such data, established 5 database centres on industrial, commercial, residencial, transportation and agricultural sectors. The centres analyse existing data, collect data and develop surveys to enable future estimation of parameters such as those required here. The Canadian Industry Energy End-use Data and Analysis} \]

\(^2\) NRCan, recognizing the need for such data, established 5 database centres on industrial, commercial, residencial, transportation and agricultural sectors. The centres analyse existing data, collect data and develop surveys to enable future estimation of parameters such as those required here. The Canadian Industry Energy End-use Data and Analysis
\[ MS_k = \frac{LCC_k^{-n}}{\sum_{k=1}^{\nu} LCC_k^{-n}} \]  

where:

- \( MS_k \) = market share of technology \( k \),
- \( LCC_k \) = annual life cycle cost of technology \( k \),
- \( n \) = cost variance (power function) parameter,
- \( \nu \) = total number of technologies in a competition node.

Lowering the variance of costs associated with a technology (i.e., increasing the magnitude of the power factor, \( n \)) steepens the slope of the logistic curve, as shown in figure 2.6. In other words, the more narrowly defined the cost of a technology becomes, the less likely it will overlap the costs of a competitive technology. The steeper the curve, the greater the share of the market the less-expensive technology assumes.

Figure 2.6 also provides the analyst with direction concerning the effect of changing the value of the inverse power parameter. The dotted line indicates the point at which Tech A is 15\% cheaper than Tech B. A value of 8 to 10 would reflect a situation where, at 15\% difference in price, about 80\% of new stock would be allocated to the cheaper technology, in this case, A. After posing this information to industry and sector analysts and experts, supplemented by market reports, I used a parameter value of 10 in competition functions.

**Other Parameters that Affect Market Shares**

ISTUM includes several options that allow the analyst to introduce other factors that affect purchase decisions. Many of these factors are non-cost controls on technology

Centre (CIEEDAC 1994) and its commercial (CCEEDAC, [ARC 1997]) and agricultural (CAEEDAC 1995) affiliates have participated in research design focused on this issue.
Figure 2.6: Market shares of a Technology A compared to a Technology B under different variance parameters of the inverse power function. The vertical broken line indicates where Tech A is 15% cheaper than Tech B. Derived from table 1.2, p 17, Jaccard and Nyboer 1994

purchases that often physically preclude penetration of technologies (e.g., the technology is not yet on the market but will be in some future year or the fuel distribution system is limited and prevents technologies using that fuel from penetrating, etc.).

- Minimum and maximum market shares can be set to constrain or force market penetration of any technology. These parameters simulate conditions such as limited availability of a technology or fuel or a regulation on new motor, lighting or other technology standards. The maximum and minimum shares can change over time to represent the gradual relaxation of constraints and subsequent penetration of new, innovative technologies or, say, the extension of a natural gas distribution system.

- The modeller can set parameters for year to represent market availability or competitiveness of a new technology, or to simulate, for example, regulations that prevent the purchase of outdated or inadequate equipment or building shell types.
• The life-cycle cost calculations can easily incorporate capital grants or the impacts of policies on emissions charges.

• If the modeller has cost estimates for intangible factors, such as preference for a certain type of technology or type of fuel (e.g., natural gas is often preferred over coal, even if coal is cheaper), the values can be included as a “non-cost” parameter. Because ISTUM does not track the flow of materials through technologies (at least, not at present; such data could be entered into ISTUM’s databases), this parameter can also be used to estimate benefits due to improved materials flow such as the reduced use of process water or of specialized catalysts.

The parameter has the effect of shifting the logistic curve such that, when the life cycle cost (LCC) of Tech A is the same as that of Tech B \(\text{LCC}_A = \text{LCC}_B\) at \(\text{LCC}^*\), the market shares of the two technologies are not equal. For example, in figure 2.7 at the point \(\text{LCC}'\), the market shares are equal. This implies an intangible value associated with Tech B where Tech B would be preferred even when Tech A is cheaper. The monetary equivalent of this intangible value can be estimated by \(\text{LCC}^* - \text{LCC}'\).

Although I made little use of this parameter, its value has been estimated for certain competition nodes in industries where data do exist. When the parameter has been applied to simulate preferences for specific fuels, information on its magnitude was obtained through telephone surveys with sector representatives.

2.2.2.3. Output

After the stock of technologies has been determined in a sector under a set of economic and market conditions, the energy consumption and emissions release for that sector can be calculated, based on the energy and emissions data for each type of technology. Other data are also available; ISTUM produces a set of reports on the mix of the stocks of technologies in each simulation year, the costs of operating those stocks, which stocks received new market share, and the degree of retrofit in these stocks.
Figure 2.7: Market share function of figure 2.5 is shifted to the left, favouring the purchase of Tech B. At LCC' the market shares are the same even though the annual cost of operating Tech A is less than that of Tech B. The difference between LCC* and LCC' is a monetary estimate of the intangible value that caused the shift.

2.3. An Integrated Energy Analysis Tool; Supporting Data and Models

In order to simulate potential change in technology stocks over time, ISTUM needs three types of information inputs. As a detailed end-use model, ISTUM requires data that describe technology characteristics (fuel requirements, technology life, capital costs, etc.). Second, ISTUM needs inputs on future demand for products and services and changes in sectoral structure. Finally, these data are couched in an economic matrix consisting of price and availability of fuels, and other economic or technical constraints. For example, quantities of wood waste (hog fuel) may be limited and thus wood-waste-fired technologies must be constrained to a value less than or equal to this limit.
Few historical databases exist for most of the technology or economic input data used in ISTUM. Consequently, one cannot run typical statistical tests on the model’s technology or economic variables. Sensitivity analysis and expert review serve as the primary tools in assessing the input data to address uncertainties about existing stock, technology costs and market structure. This quantitative uncertainty can be categorised in two ways:

- uncertainty in technology-specific data and how the technologies are chosen in competitions, and

- uncertainty in outputs from other models, such as fuel prices, that serve as the inputs to ISTUM.

### 2.3.1. Technology Database and the Data

It is one thing to argue and demonstrate that implicit aggregate representations of technology and technological evolution are unsatisfactory and another to demonstrate that one can obtain and assemble enough disaggregated information such that one can address the uncertainty at a less than exorbitant cost. For this study, the needs are quite specific:

- detailed information on the technologies that comprise existing building and equipment stocks, and

- information on the way in which the equipment stock changes with time.

ISTUM’s *technology database* includes levels of existing stock in terms of physical characteristics such as energy, emissions and costs. To adequately reflect potential changes in energy consumption, ISTUM’s technology databases must be constantly updated with any new or developing technologies that could affect energy consumption. Changes in process or new methods for providing the same product or service require constant review and, given the intent of the modelling exercise, must be included in ISTUM’s sub-models and the data set. Chapter 3 provides greater detail on technological information available in ISTUM’s database. Lists of technologies and their characteristics can be found in appendix A (ISTUM manual, Volume II).

Data on technology stock and characteristics have come from a myriad of sources: existing databases completed for other studies, utilities, consultants in the field and
experts in the sector. Primary technology data for the version of ISTUM used in this study were obtained for the early versions of ISTUM, developed by the US Dept. of Energy (DoE 1983). The analysis required for a review of conservation potential for BC Hydro provided baseline data on motor systems and information related to electricity consumption in all sectors (Jaccard, et al. 1992a, 1993). Earlier and subsequent reviews of the commercial and residential sectors increased the level of detail available to ISTUM (Bailie 1994, Strickland 1996). An analysis done under contract with NRCan and the Canadian Industry Program for Energy Conservation (CIPEC) required detailed review of the various industrial sectors (Nyboer 1996a). I obtained data on the existing groups of technologies, a group being defined by its ability to provide an product or service:

- existing equipment stocks;
  - efficiency of the equipment - average efficiency, efficiency loss due to impacts of behaviour (quality of maintenance, proper installation),
  - capital and operation costs, technology life, technology availability,
  - total stock of functional equipment,
- new equipment;
  - nameplate efficiency of the equipment,
  - capital and operation costs, technology life, technology availability.

2.3.1.1. Industrial Sector

End-use models require data on the characteristics and quantities of functioning stock in the base-year review of each specific industry. Primary data in ISTUM’s technology database were augmented by other databases such as the study completed at Drexel University (Brown 1985) and known as the Drexel database. In order to reflect the Canadian system, further details were sought from Lockwood-Post’s Directory of Pulp, Paper and Allied Trades, more recent databases held by utilities, information received through contracted work such as that executed for BC Hydro’s Conservation Potential Review and inputs from energy and engineering consulting firms such as Marbek Resource Consultants, Temanex and Willis Energy Services.
Although databases that describe technology characteristics are increasing, few databases define active stocks of technologies for any particular year. No such data exist for Canada. Through analyses such as the Conservation Potential Review, interaction with utility and industry engineers provided refinements and technology-specific information to reduce uncertainty related to Canadian technology data. In spite of such detailed input, there are no systematic data to confirm estimations on both equipment stock or technology characteristics. I developed a method using two components to ameliorate the problem: calibration to known energy consumption figures coupled with estimates of end-use allocation and detailed review and assessment by experienced industry personnel.

**Calibration to Energy Data**

Statistics Canada publishes two sets of data on energy consumption in industry in Canada, the Quarterly Report on Energy Supply and Demand and the Annual Survey of Manufacturers. Neither data set is comprehensive nor directly applicable to the calibration required for estimating end-uses of energy consumed in Canada’s industrial sector but, in combination, sufficient data exist to disaggregate, by region and fuel, the energy consumed in the various industrial sub-sectors. When the data are supplemented by the detailed process flow models, by engineering estimates of energy consumption required by specific technologies and by estimates of end use allocation from various reports from utilities and data agencies (e.g., Gardner 1990, US DoE 1991), one can allocate, with some confidence, the energy consumed in an industry to specific end-uses.

**Detailed Review and Assessment**

Given the level of complexity and the unique characteristics of each industry in specific provinces, recent review and analysis completed for NRCan by the Energy Research Group (ERG) of the School of Resource and Environmental Management at SFU provided further detail on the characteristics and distribution of equipment stock (Nyboer 1996a). After reading the arguments in Halvorsen (1977), Jenne and Cattell (1983), Griffen (1979) and others, energy analysts at NRCan and I became convinced that a detailed simulation model of technology change is desirable. Review of earlier work using ISTUM (Margolick, et al. 1991, Jaccard, et al. 1992c, 1992d, 1993), and the desire
of various task forces representing specific Canadian industries to meet targets for efficiency improvements, prompted NRCan decision makers and policy advisors to commission the ERG to undertake a detailed analysis of six major industries. The resultant two-year study was composed of three phases, included the cooperation and feedback of numerous industrial experts, and modelled six major energy-consuming industries over all of Canada. The study was designed to meet three objectives:

1. to generate national energy end-use / technology frameworks for energy-intensive industries;

2. to develop energy efficiency improvement estimates for each industry based on specific sets of economic and technological assumptions;

3. to provide industry Task Force Working Groups, as established by CIPEC and composed of industry and government specialists in each industry, with the opportunity to evaluate and correct input data on technology characteristics and existing stock as well as industry structure and function as represented in the model.

In Phase I existing process and energy flow models reflecting end-use consumption of energy were reviewed and refined for each industry in each region of Canada. Industry experts who were part of or selected by the task forces provided comment and critique on:

- the formal definition (SIC classes) of the industries to be analysed in the project
- a detailed profile of the industry (energy consumption, employment and more)
- an in-depth process flow model
- the parallel “energy flow model” that related energy consumption to the process equipment (end-use) involved at each step of the production cycle. This involved direct meetings with these specialists in Ottawa (chemicals, fertilizers), Toronto (cement, mining, petroleum refining), Hamilton (iron and steel), Montreal (pulp and paper, aluminum), Calgary (petroleum refining) and Vancouver (cement, lime, metal smelting, mining, petroleum refining, wood products, natural gas technologies).

Phase II involved the simulation of end-use energy consumption within the different industries over a twenty year period (1990 to 2010) at growth rates used in NRCan’s
publication, *Canada’s Energy Outlook* (CEO) (NRCan 1994a). At the conclusion of Phase II, and in preparation for Phase III, these same industry experts from the task forces received an analysis of the results of the various simulations including discount rates applied, the slope of the logistic curve representing behavioural response outside of discount rates, details on equipment stocks, the penetration of energy efficiency improvement measures and what the adoption of new energy efficiency measures imply for the industry. They responded by providing critique and corrections that reduced uncertainty surrounding these behavioural responses, technology characteristics, base year (1990) energy consumption, installed technologies, energy prices, output forecasts and any constraints on the penetration of technologies.

Phase III presented an opportunity for the task force participants to have additional scenarios run with assumptions that differed from those used in Phase II. The assumptions dealt primarily with estimates of future growth and the potential for cogenerated electricity. This allowed the task forces to develop their own views on industry change and what could be achieved in terms of energy savings. It also provided an avenue for sensitivity analysis and an analysis of the impact of alternative industry growth rates. In return, it provided a set of industry sub-models that had undergone actual “in-the-field” scrutiny for a number of different simulations under two growth scenarios. In the face of poor quality (or, in some cases, no specific) data on industry energy end-use, these iterations with experienced specialists provided both the analysts and the decision makers with a way to address uncertainties in the sector.

### 2.3.1.2. Commercial Sector

The definition of the commercial sector varies widely between utilities and government agencies. It can include all types of commercial buildings as well as light industrial and multi-tenant residential buildings. For this analysis, light industrial is included in the industrial sector and multi-tenant buildings with the residential sector. The commercial sector includes the following building types:

- warehouses and wholesale outlets,
- hotels and motels,
• taverns and restaurants,
• schools and universities,
• small office buildings and non-food retail outlets,
• hospitals and nursing homes,
• large office buildings and food retail outlets,
• miscellaneous buildings (not including residential or light industrial).

Quantity of commercial floor space for each of the sub-sectors listed above serves as the driving variable in the Commercial model. The main source of base-year data on floor space for ISTUM was a 1993 report prepared for NRCan (then known as Energy, Mines and Resources Canada [EMR 1993]). Data on total floor space in the commercial sector are not problematic but significant uncertainty exists concerning the distribution of such floor space between building types. Total commercial floor space data are gathered by several different organisations, notably the federal government and the Building Owners and Managers Association, where each agency may have differing definitions of floor space type.

Data on costs of end-use technologies came from two primary sources: Marbek’s review of the New Brunswick (1992) and BC (1993) commercial sector and a costing project done by the Dominion Company of Vancouver, BC. This information, coupled with a detailed “bottom up” review of construction and installation costs (Strickland 1996) provided reasonable estimates of technology costs. Data on regional cost variation were unavailable. However, given the relative consistency of competing technologies, the impact on ISTUM’s estimation of technology evolution is minimal.

Regional data on stocks and energy consumption came from a number of sources, primarily Statistics Canada’s energy consumption reports (Statistics Canada, 1990) and the forecasting departments of regional utilities: BC Hydro (1992), TransAlta Utilities, Manitoba Hydro (1994), Ontario Hydro (1993), Hydro Québec (1993). These were supplemented by data from analyses described above and others (Torrie Smith Associates 1992).
Many electric and gas utilities, in an effort to better understand their market, have initiated metering programs designed to analyse energy consumption patterns in their service area. As these data collection programs become more common, analysts will be better able to address the uncertainties in commercial sector.

2.3.1.3. Residential Sector

Two reports (Marbek 1991, 1993) provided the majority of the data on the residential sector. The report on the Conservation Potential Review (CPR), prepared for BC Hydro by three consultant firms, contained detailed cost and energy consumption data for most appliance options in each end-use (refrigerators, freezers, ranges, clothes washers, dryers, dishwashers, lights, fans, and water heaters). These data were used for appliance competition for all regions. The report also divided BC’s housing stock into thermal archetypes and included energy consumption, building costs, and retrofit costs for each archetype. The report itself described a variety of data sources, notably BC Hydro's Residential Energy Use Survey (1988 and 1991), Competitek technical reports obtained from the Rocky Mountain Institute, BC Hydro customer accounts, and surveys completed by energy auditors of the Power Smart Home Improvement program.

The surveys and data in the CPR report relate primarily to electricity use and do not provide sufficient information on other fuels or the insulation levels of houses using these fuels. The missing energy data could be derived from an EMR report (Marbek 1991). This report covered all regions of Canada, all sectors, and all energy sources. It provided information on appliance penetration and building shell types (known as archetypes) for Ontario and Quebec. In addition, furnace data for all provinces came from this report. An analysis of the technological structure and framework for modelling this sector in four major provinces in Canada can be found in Bailie (1994).

2.3.1.4. Transportation Sector

At first glance, the transportation sector is similar to the other sectors. Its characteristics include: (1) estimates of service demands in passenger- or tonne-kilometers; (2) use of specific, definable technologies in road, rail, air and marine transport; and (3) costs for capital, operations and maintenance.
However, attempts at modelling technology evolution in this sector based on ISTUM’s cost methodologies proved unacceptable. Although ISTUM’s transportation database could be calibrated to match energy demand for a given year, simulations of historic periods resulted in far greater penetrations of automobiles using alternative fuels and movement to higher occupancy vehicles and public transit than historical evidence indicated. In order for ISTUM to more closely mimic actual technology stocks, more and more of the endogenous activity in ISTUM needed to be determined exogenously. Cost-based criteria for technology selection that function well in others sectors could not account for technology penetration in this sector. In other words, least-cost economic criteria could not explain documented technology evolution.

This preliminary research and review of other modelling efforts suggested that the transportation sector may be best simulated using runs where technology change is developed through expert opinion. Thus, I decided to omit the transportation sector from the analysis because such analysis did not advance my objective. Although demand for transportation services is found scattered throughout the other sectors, Statistics Canada isolates energy consumed in transportation from the other sectors in the QRESD and thus permits each sector to be simulated in isolation. For example, although industry uses transportation modes to move goods from factory to market, this energy is not included in any analysis of the industry. In the few cases where transportation is involved in the production of a good (e.g., moving ore from the mine site to the mill to be concentrated), ISTUM includes the transportation element.

2.3.2. Macroeconomic Inputs

Sector structure and growth in services or products forms a second data set required by ISTUM. In 1993, NRCAN published their view of energy consumption in Canada up to 2020. It contained information on expected growth in the various sectors of the Canadian economy, and provided detailed sector structure and structure changes suitable for analysis in ISTUM. The publication, entitled Canada’s Energy Outlook, 1992-2020,

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3 Data on vehicle registration provide a source of technology-specific information not found in other sectors, permitting some comparison of model output with observed data.
(CEO) received critique and proposed amendments from industry, utilities, the ERG and other interested parties. As a result of this feedback, NRCan published an update of the report, *Canada’s Energy Outlook, 1992-2020, 1994 Update*, which became the source for the growth and price assumptions used here (NRCan 1994a). Not only did this provide a convenient starting point for this analysis but it included multi-sectoral review which addressed the uncertainty of many of the exogenous inputs to ISTUM. Table 2.2 provides an aggregate picture of expected growth in each sector. ISTUM needs more specific, disaggregated data than this table provides; these were available through NRCan’s supplementary report, *Canada’s Energy Outlook: 1992-2020, Update 1994: Detailed National and Provincial Tables* (NRCan 1994b) and are provided in appendix B.

### Table 2.2: Sectoral Growth in 1990-2010 in Real Domestic Product (except for population). Average Annual Growth Rates in %.

<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>Total Industrial</td>
<td>-1.6</td>
<td>4.6</td>
<td>4.1</td>
<td>2.4</td>
</tr>
<tr>
<td>Pulp &amp; Paper</td>
<td>-1.1</td>
<td>2.1</td>
<td>2.2</td>
<td>2.3</td>
</tr>
<tr>
<td>Iron &amp; Steel</td>
<td>-0.7</td>
<td>3.3</td>
<td>2.7</td>
<td>1.9</td>
</tr>
<tr>
<td>Metal Smelt &amp; Refine</td>
<td>3.2</td>
<td>4.2</td>
<td>3.6</td>
<td>2.3</td>
</tr>
<tr>
<td>Chemicals</td>
<td>0.3</td>
<td>2.9</td>
<td>2.4</td>
<td>2.8</td>
</tr>
<tr>
<td>Total Manufacturing</td>
<td>-1.9</td>
<td>5.3</td>
<td>4.7</td>
<td>2.9</td>
</tr>
<tr>
<td>Commercial</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
<td>2.1</td>
</tr>
<tr>
<td>Population Growth</td>
<td>1.3</td>
<td>1.3</td>
<td>1.3</td>
<td>0.9</td>
</tr>
<tr>
<td>Total Economy (GDP)</td>
<td>0.6</td>
<td>3.3</td>
<td>3.0</td>
<td>2.2</td>
</tr>
</tbody>
</table>

Source: CEO, 1994 Update (NRCan 1994b, 3, 4)

Changes in growth and structure will be affected by changes in energy demand. But expenditures on energy are not a dominant cost component for most industries or commercial operations. Geller and Elliott estimated that, for the US, “purchased energy is about 1.9¢ per dollar of value shipped, averaging 1.2¢ for electricity and 0.7¢ for fuels ...” (Geller and Elliott 1994, 3). More energy-intensive industries like pulp and paper and primary metals, expenditures exceed 4¢ per dollar. In very energy-intensive industries, primarily those using a lot of electricity (e.g., aluminum smelting, chlorine and alkali production), costs could exceed 20¢ per dollar of value shipped. In Canada, only a few energy-intensive industries will see shifts in their product demands due to increased fuel or electricity costs. Also, industries dependent on large quantities of electricity tend to be
in regions where hydroelectricity is abundant and are thus not subject to costs associated with CO\textsubscript{2} emissions. To complete this analysis, I use a fixed scenario of growth because:

• the focus is on the energy demand component and the development of a proper assessment tool for that node rather than an assessment of the link between the energy demand node and the macroeconomic model;

• changes in energy prices were assumed to have minimal effects (Geller and Elliott 1994) and;

• I did not have ready access to the econometric models used in NRCan’s CEO, The Informetrica Model (TIM) and Regional-Industrial Model (RIM).

I recognise that, in the higher emissions cost runs, the lack of a macroeconomic feedback loop to provide data on possible changes in structure becomes increasingly problematic. Therefore, discussion in the conclusions (chapter 6) focuses on the extent to which confidence in the results of simulations of higher emissions charges are affected.

Informetrica Ltd. (Informetrica 1993) provided forecasts of growth and structural change for the CEO for both the original and updated publications (1993 and 1994 versions). The primary model in Informetrica’s set, TIM, incorporates detail on consumer expenditure, construction investment, foreign trade, government revenue, employment, demographics and other factors. It is, in turn, tied to the RIM which simulates industrial activity based on a top-down articulation of regional economic measures based on forecasts from TIM. Details on TIM and RIM can be found in the appendix C.

**2.3.3. Inputs of Fuel and Electricity Prices to ISTUM**

In this analysis, I have distinguished electricity from other, primarily fossil fuel, energy carriers for two reasons:

1. Electricity price under the influence of a cost associated with CO\textsubscript{2} emissions can vary significantly by region.

Because Canada is considered a price taker rather than a price setter, Canada’s energy supply and demand picture has little or no impact on international supply and demand for
fossil fuels or their prices. Therefore, I need not re-estimate prices for fossil fuel through iteration between the demand models and models used to provide fossil fuel prices.

But suppliers of electricity operate in a protected regional market where local utilities choose the type of generation technologies used. Choices of generation technologies altered under the effects of a CO\textsubscript{2} emissions charge and a change in regional demand affect the price. To capture adequately this market effect requires iteration between the demand models and electricity supply models until some equilibrium is established.

2. CO\textsubscript{2} emissions per unit energy vary for electricity in each region and under different charge rates for CO\textsubscript{2} emissions.

The rate of release of emissions from any one unit of combusted fossil fuel remains unaltered even under the influence of a charge on carbon emissions. But the choice of technologies used to generate electricity can affect significantly the quantity of CO\textsubscript{2} emissions per kwh. Thus, under alternative emissions-charge policies, the cost of electricity and the quantity of CO\textsubscript{2} released can change dramatically. Consequently, data on the final demand for electricity after a set of simulations in a region must be fed to the supply model to determine the new price and the new level of CO\textsubscript{2} emissions.

Table 2.3 provides data on fuel prices as used in the CEO, 1994 Update. Appendix D contains tables of specific regional fuel and electricity prices used in the analysis. Fossil fuel prices reflect regional conditions and cost of energy as seen by the purchaser at the meter as generated by the InterFuel Substitution Demand (IFSD) model. Electricity prices were updated through the use the Electricity System Simulation Model (ESSM).

<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>Crude Oil</td>
<td>20.00</td>
<td>20.00</td>
<td>20.00</td>
<td>22.00</td>
<td>22.00</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>-</td>
<td>1.75</td>
<td>2.00</td>
<td>-</td>
<td>2.45</td>
</tr>
</tbody>
</table>

Source: CEO, 1994 Update (NRCan, 1994a, 1994b)
2.3.3.1. IFSD Model and Fuel Prices

The Energy Policy Branch of NRCan uses an integrated modelling framework that consists of the InterFuel Substitution Demand (IFSD) model, and two macroeconomic models that estimate utility generation of electricity (UGENEX) and oil and gas supply (OGS). IFSD adopts a “top-down” approach to estimate regional energy prices as well as demand by region and sector. It receives input from UGENEX and OGS models and contains a number of feedback algorithms to determine its estimations of future regional energy prices, total demand and supply. Appendix E holds a description of IFSD, UGENEX and OGS. None of these models are in house.

Even though IFSD generates data on future energy demand by fuel type and region, it acts here at the Energy Supply node in figure 2.1 to provide regional fuel prices based on world prices as modified by local system costs defined earlier. IFSD analysts enter initial growth and structural forecasts from TIM and RIM and world fuel prices set in international oil and natural gas markets as exogenous inputs.

2.3.3.2. ESSM and Electricity Prices

The Electricity System Simulation Model (ESSM) simulates an electricity supply system under various policy and technology scenarios to determine a least-cost mix of technologies to expand capacity and operation schedules to generate electricity. Because it carries cost and emissions coefficients for each supply technology, ESSM can estimate costs of electricity production and CO₂ emissions under each scenario. These simulations are accomplished in a spreadsheet operation controlled by macros. ESSM utilises an optimisation routine included with the EXCEL™ spreadsheet software. Figure 2.8 is a simplified flow model of the process used in ESSM to determine costs, emissions output and fuel consumption under the various scenarios and to provide new electricity prices for ISTUM’s simulations.

ESSM requires projections of both capacity and energy demands to drive the model. Demand for capacity (in megawatts, MW) is estimated based on actual electricity demand, which it receives from ISTUM. Once capacity requirements have been met, ESSM allocates generation of electricity to the set of technologies based on cost...
optimisation and other conditions (e.g., Has the utility committed to certain supply options? Are there regulations and policies that affect the choice of technologies? Are there constraints on certain supply options?). After completing this analysis, it calculates average and marginal generation costs, quantity of fuel required to operate generating technologies and CO\(_2\) emissions.

ESSM calculates the average generation cost of any electric utility system using:

\[
C_t = \left[ \left( C_{Ht} + C_{CAPt} + C_{OMt} + C_{Ft} + C_{CHA} + C_{OTHt} \right) / E_t \right] \times 100
\]

(7)

where, for year \( t \) (all costs except \( C_t \) in $millions),

- \( C_t \) = system average generation cost (cents/kwh)
- \( C_{Ht} \) = historical costs of the existing system allocated to the year \( t \)
- \( C_{CAPt} \) = annualised capital costs for new capacity
- \( C_{OMt} \) = operation and maintenance costs for existing and new stocks
- \( C_{Ft} \) = fuel cost for existing and new technologies
- \( C_{CHA} \) = total carbon emissions charges due to electricity generation
- \( C_{OTHt} \) = costs of electricity from non-utility generators or other utilities
- \( E_t \) = total GWh required in the utility’s service region

Under the assumption that the relative prices of electricity between the sectors remains the same over the simulation period (i.e., there was no price discrimination, or at least no change in price discrimination between sectors as a result of changes in electricity demand from the demand models), I converted average costs of electricity production generated by ESSM into electricity prices in each sector (residential, commercial and industrial consumers see different electricity prices based on rate classes, distribution costs and utility policies).
Figure 2.8: Flow diagram of procedures in ESSM as they occur at the Energy Supply node in figure 2.1. Electricity demand, received from the demand models, can be used to determine capacity demand. New prices for electricity are used by demand models.

Because my analysis requires the tracking of CO$_2$ emissions, those from electricity generation must also be included. The CO$_2$ emissions from generation technologies fired by fossil fuels are calculated in ESSM using:

$$CO_{2t} = \sum f \sum k \left( \frac{CO_{2f}}{GJ_f} \right) \left( \frac{GJ_f}{GWh_k} \right) \frac{GWh_k}{GWh_t} \times GWh_t$$

(8)

Adapted from Liu 1995
where

\[
\frac{CO_{2f}}{GJ_f} = \text{the carbon dioxide released from a fuel, } f,
\]

\[
\frac{GJ_f}{GWh_k} = \text{the heat factor (efficiency) of a generating technology, } k,
\]

\[
\frac{GWh_k}{GWh_t} = \text{the contribution of technology } k \text{ to total electricity production in year } t,
\]

\[
GWh_t = \text{gigawatt hours of electricity required in year } t.
\]

Like end-use demand models, ESSM requires specific information on each generation system under analysis. Systems are typically defined by provincial boundaries, but can be redefined such that they include only the regions serviced by one utility. The required information includes: existing capacities, their operating, maintenance and fuel costs, retirement schedules, peaking capacity, and technical information regarding conversion rates and emissions. Costs of fuels, discount rates and rates of return on old investments set the economic parameters in ESSM. Costs of fossil fuels are the same as those faced by the industrial sector, unless local fuels (i.e., coal) are available. For public utilities, the discount rate use was 7% while for private utilities, a 15% rate of return was permitted. Appendix F contains a more detailed description of ESSM.

ISTUM sub-models for a region were run and the electricity demand for all sectors evaluated. If aggregate demand was significantly below or exceeded the NRCan forecast for electricity demand in that region, ESSM was simulated to determine the costs of electricity at that higher demand. If the slope of the cost line generated by ESSM in the appropriate range was flat, no further iteration was required as no change in the cost of electricity would be anticipated. If the slope of electricity prices was steep, iterations continued until convergence was achieved.

### 2.3.3.3. Uncertainty in Fuel Prices

As an exogenous input, I ask, “What effect does uncertainty in future fuel prices have on technology choice and energy consumption over time?” We can test through sensitivity
analysis; a straightforward task in ISTUM. Sensitivity analyses indicate that the effect of a change in fuel price on technology choice and energy consumption depends on:

- chosen discount rate - Changes in the cost of fuels have diminishing effects as discount rate increases because initial capital costs (also known as first costs or up-front costs) become increasingly dominant in the equipment acquisition decision.

- sectoral importance - Unless fuel consumption per unit production is very high, typical ranges in variation in all fuel prices (± 20%) shows little impact in general efficiency improvement at de facto discount rates. This is because, in terms of total costs of production, energy costs are small; most US industries spend less than 2¢ per dollar on energy while labour costs are 9.5¢ and material costs are 51¢ (Geller and Elliot 1994). Decisions related to costs savings are focused on the cost of labour and materials.

Analysis for a local natural gas utility indicated that, at the perceived discount rates, fuel price changes of ± 20% altered consumption by 3% to 4% (Nyboer et al. 1996b). Certain industries, such as aluminum smelting and cement manufacture, require large quantities of process energy, in excess of 20% of total production costs. These industries are more sensitive to fuel price changes, but such industries are the exception (see chapter 4, section 4.6.1 for a review of sensitivity analysis on prices).

2.3.4. Discount Rates

Discount rates varied for the different sectors and even between sector branches. The literature shows that discount rates typical of residential and commercial consumers consistently match or exceed industrial discount rates. The impact of first costs and available capital to purchase technologies plays a much more important role than does annual operating and maintenance costs. Table 2.4 provides the range of discount rates obtained from various sources from which the rates used in this analysis were drawn.

<table>
<thead>
<tr>
<th>Sector or service</th>
<th>Range (%)</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
<td></td>
<td></td>
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</tbody>
</table>
Using sensitivity analysis, I tested the effect of a change of ±5% and ±10% added to the discount rate (e.g., 25%, 30%, 35%, 40%, 45%) on technology stock and energy consumption. The results showed that such changes in the rates have minimal impact on energy consumption (±1%, see chapter 4, section 4.6.2).

2.3.4.1. Industry Discount Rates

In industry, investments on energy efficiency are often discretionary; that is, the decision maker can choose whether or not to make the investment (e.g., replacing operating electric motors with ones of greater efficiency). Surveys of industrial investment behaviour suggest that such investments must surpass stringent investment criteria before implementation (Ross 1984; Sassone and Martucci 1985; Giffels 1984). The discount rate applied to discretionary investments is typically much higher than that applied to non-discretionary investments. A two-year payback (equivalent to a 50% discount rate) for
low capital expense items reflected published literature, and corresponded to responses from experts in the industry familiar with stock-purchasing routines. Return on capital of more expensive items typically reflected discount rates of about 30%.

A study seeking to simulate industry behaviour must be concerned with *de facto* industry discount rates, not those used in evaluating investment options. A firm may use a 15% discount rate to evaluate investment options. But if, because of a capital constraint, uncertainty in returns on the investment (Hassett and Metcalf 1993), or other internal barriers (DeCanio 1993), it only invests in the options showing the best return, the firm is really using a much higher discount rate of 30%, 50% or perhaps even 80%. Also, if the firm neglects to evaluate certain investment options, such as more efficient auxiliary equipment, it is almost impossible for a simulation model driven by life-cycle costs to replicate investment behaviour. In such situations, investment in efficient equipment is more likely a function of other factors, such as market acceptability, market information and perceived risk, rather than of life-cycle cost. Where such information on behaviour in purchasing technologies was available, exogenous constraints were used in the model.

After considering both the discretionary and the de facto discount rates and the evidence that managers expect paybacks of 2 to 3 years (Sassone and Martucci 1985, Giffels 1984, Hassett and Metcalf 1993, DeCanio 1993, Geller, et al. 1994), the rates used in this study in the industrial sector were (exceptions for particular industries are noted in chapter 3):

- process technologies (considered non-discretionary) 30%
- auxiliary technologies (considered discretionary) 50%
- all other end uses (considered discretionary) 50%
- retrofits (considered discretionary) 50%

---

4 Some of these factors, like risk, may already be included in the *de facto* discount rate.
2.3.4.2. Residential Discount Rates

In the residential sector, several studies in different regions and end-uses report a wide variety of discount rates (Hausman 1979, Ruderman 1987, Hartman and Doane 1986, and many others, summarised in Train 1985) which are encompassed by the ranges displayed in table 2.4. Factors such as income, consumer's information, the relative importance of energy bills, building codes and appliance efficiency standards influence implicit discount rates and may explain these differences (Corum and Gibson 1991). Values applied in this study were based on the most recently developed range from Hartman and Doane (1986), defined in table 2.4:

- space heating 50%
- space heat, retrofit 80%
- refrigeration 80%
- all other end uses 50%

2.3.4.3. Commercial Discount Rates

In a review of consumer discount rates, Lohani and Azini (1992) provides information concerning discount rates used for technologies in the commercial sector. As in industry, it is considered common practice within the commercial building sector to invest in energy efficiency measures that have a simple payback period of between two and three years. This implies a discount rate of between 30% and 50% (Strickland 1996). Based on this information and the ranges presented in table 2.4, the rates used in this study are:

- most shell and HVAC categories 40%
- hospitals and school HVAC 30%
- cogeneration technologies 35%

Hospital and school sectors shell / HVAC technologies are discounted at a rate of 30%, instead of 40%, consistent with evidence of their longer planning / cost horizons and the fact that they are owned publicly. Cogeneration technologies are discounted at a rate of
35% because investors in cogeneration are generally seen to have a longer planning / finance horizon than other investors.

2.3.4.4. Socio-Economic Discount Rates

All investments receive at least a 7% rate of return in an estimation of the socio-economic potential. This social discount rate matches the rate used by crown corporations like public electricity utilities, and is used here for that reason. This assumes that consumers could somehow be induced to make all energy-related investments that showed a positive return at a 7% discount rate. Such a rate would be applied across the board and no distinction would be made between discretionary and non-discretionary investments.

2.4. The Analysis

To understand the consequences of a set of policies on energy efficiency and changes in CO₂ emissions, I developed the following framework:

- the establishment of “technical change extremes”, that is;
  - a case where no change in technology stock mix occurs over the simulation period (no autonomous technological change permitted) and;
  - a case where all new stock would be the most efficient available at that time (i.e., maximum technological improvement after allowing old stock to retire naturally);
- an understanding of possible outcomes in the absence of new policies from the point of view of;
  - the regulator or policy maker (the public point of view) and
  - the regulated (the private point of view);
- the application of a range in the “degree” or “strength” of the policy or regulation.

To maintain clarity, two terms, scenario and run, require definition. A scenario is a way of conceptualising what the sector's future might be. The information reflects growth and structural changes. As described previously, this analysis uses growth rates and structural
changes found in the *CEO 1994 Update* report, a single growth rate applied under all economic conditions (NRCan 1994b).

An analyst can set up a simulation involving a particular scenario in a region under various economic parameters. Changed fuel prices, discount rates, government incentives, taxes, application of a cost to emitting CO$_2$, and constraints in market shares of a technology can be applied to a specific scenario to determine the consequences of those economic conditions on a particular industry or sector. A simulation where one (or a combination) of these parameters is changed can be considered a run.

### 2.4.1. Runs Defined

Table 2.5 summarises the seven runs proposed for each industrial sub-sector and the commercial and residential sectors. Four of the simulations described below provide information on the range of possible outcomes to which I compare the results of a set of policy runs. The frozen run provides an “unchanged state” alternative; a simulation where technology mix remains as it was in the base year, 1990. It offers a basis from which the degree of change in AEEI, energy efficiency, costs, or CO$_2$ emissions in any other run can be determined. On the other hand, the technical run depicts a situation where the most efficient technologies assume all new market shares and provides a maximum efficiency picture of that industry or sector and a reasonable reflection of what is attainable.

A natural run reflects the mix of technologies that would have occurred if *no* new policies or other influences were invoked and where firms and households act in a manner consistent with historical indicators; the *status quo*. Often called the business-as-usual\(^5\) or *private* response, this is a forecast of where society could be in the future under steady state criteria. It is no more likely to be *correct* than any other forecast of the future because we do not know what new influences will emerge that were not taken into account in the parameters. None-the-less, if decision makers propose no new actions and if no new influences appear, one could argue that this is *most likely to occur* given our

\(^5\) Some industrial analysts dislike the term “business-as-usual” because it suggests a “no change from the present” philosophy. These analysts would insist that business-as-usual is very dynamic. For this reason, I use the term “natural”.
knowledge of the system. It also provides a convenient measuring stick against which one can compare runs simulating a particular policy. Under conditions where one holds constant all costs and sectoral structure, the difference between this run and the frozen run provides the analyst with the autonomous rate of technology change or the AEEI.

Table 2.5: Brief Comparison of Runs Under One Scenario

<table>
<thead>
<tr>
<th>Title</th>
<th>Perspective</th>
<th>Conditions</th>
<th>Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frozen (1 run)</td>
<td>unchanged state</td>
<td>technology mix held constant, stocks grow to meet demands</td>
<td>determine autonomous change</td>
</tr>
<tr>
<td>Natural (1 run)</td>
<td>steady state, private view</td>
<td>no new policies, <em>de facto</em> discount rate, <em>status quo</em></td>
<td>point of comparison</td>
</tr>
<tr>
<td>Economic (1 run)</td>
<td>economic efficiency, public view</td>
<td>no new policies, social discount rate (7%)</td>
<td>estimation of &quot;societal best&quot;</td>
</tr>
<tr>
<td>Technical (1 run)</td>
<td>maximum energy efficiency</td>
<td>only the most energy efficient technologies penetrate market</td>
<td>determine level of efficiency attainable</td>
</tr>
<tr>
<td>Policy runs (3 runs)</td>
<td>test effect of policy implementation</td>
<td>impose policy under &quot;natural&quot; conditions</td>
<td>quantify impacts of policies</td>
</tr>
</tbody>
</table>

The economic run simulates a situation where consumers follow what is viewed as "public", economically efficient criteria. The comparison of the public and private view provides some indication of the general economic viability of any procedure and the possibility of reaching this "societal best" situation.

The remaining three simulations reflect the imposition of CO₂ emissions charges. The outputs of these simulations, when compared to the natural (what would have happened anyway), the economic (what is the social economic optimum) or the technical (what is the best we can do), provide the decision maker with information on which to base the actual policy tools.

2.4.1.1. Frozen Run

The frozen efficiency run differs slightly in different sectors. In residential and commercial sectors, the frozen run simulates the situation where additions and replacements of appliance and building stock over the forecast period (1990-2010) are held at their *marginal energy intensity* (energy consumption per unit) in 1990. For example, houses built in 2000 or 2010 will have the same level of insulation and
efficiency as houses built in 1990. Thus, as older, pre-1990 homes are retired, the average energy intensity of the remaining housing stock improves because replacement and additional residences are on par with 1990-calibre houses.

In some commercial sub-sectors and all industrial sub-sectors, the frozen run simulates the situation where all capacity additions and replacements over the forecast period are maintained at the 1990 average energy intensity. For example, the energy consumed per tonne of kraft pulp remains constant at its 1990 average. Marginal intensity is not applied because technologies used in industry are often made to specification, unlike household appliances and building stock which are controlled by standards and regulations. In other words, there is no “1990 model” of a kraft pulp batch digester or Hall-Herault aluminum electrolytic cell.

Change in the relative shares of products within a given sector can change energy intensity in that sector over time. Thus, in the frozen efficiency run, change in energy demand can be due to (1) change in average intensity because marginal intensity is “frozen”, (2) changes in total output or service demand, (3) changes in mix of output products, and (4) changes in major processes (e.g., a shift from chemical to recycled pulp). The technology choice algorithm is unaffected by discount rate and other purchasing behavioral parameters.

2.4.1.2. Natural Run

The natural change run simulates change in technology stocks over time, and consequent energy consumption, if technology purchasers maintain current investment behaviour when responding to projections of future demand and energy prices. The technology stock selected in this run depends on assumptions regarding the availability and cost of emerging technological options, future equipment turnover rates, and capital investment behaviour unaffected by new policies, programs, or regulations.

To simulate effectively actual behaviour, some technologies have specific constraints. In industrial branches, efficient auxiliary technologies (fans, pumps, compressors, conveyors, and process drive) were constrained to 30% of the new market shares to mimic historical trends in these units. This constraint simulates initial risk aversion to these
newer technologies and also reflects constraints on their full applicability. Similarly, efficient motors may not capture more than 60% of the new market. The less-binding constraint on motors reflects the results of demand-side management programs from various utilities aimed at promoting high-efficiency motors. In BC Hydro's recent Conservation Potential Review, Phase II, companies reported sales of efficient models at 60% of total stock sold (SRC 1994).

2.4.1.3. Economic Run

In the economic run, the end-use technology with the lowest life-cycle cost, evaluated at a 7% discount rate, will capture 100% of the new market (i.e., the variance parameter is inoperative); no other behavioural parameters are applied in this run. Natural retirement rates determine equipment turnover. The only constraints on technologies are ones related to physical or technological characteristics.

2.4.1.4. Technical Run

In the technical run, the technology in each end-use with the lowest energy consumption will capture 100% of the new market. Otherwise, the same conditions apply as found in the economic run.

2.4.1.5. Runs Using Different Emissions Charges

A set of CO\textsubscript{2} emissions simulations where the emissions producer faces a charge on CO\textsubscript{2} emissions of $75, $150 and $225 per tonne constitutes the focus of the analysis (equivalent to $275, $550 and $825 per tonne of carbon). These values were determined through earlier analyses using ISTUM (see primarily Nyboer 1996a, Roberts et al. 1996) and a review of ranges applied in other analyses using other models (IPCC 1995). All other economic conditions mimic those of the natural run described above.

A comparison of runs using different emissions charges (henceforth referred to as “cost runs”) with the natural run provides analysts and decision makers with some idea of the impact of policies involving emissions charges on the real world. Results of the frozen run can be compared to those generated by top-down models where autonomous technological change is poorly represented (AEEI = 0). On the other hand, the technical
and perhaps even the economic run better reflect typical bottom-up analyses of the system. The analyst and decision maker will be in a position to critique various model-generated outcomes and have information that permits a better analysis of policy or regulatory alternatives.

2.4.2. Iteration

I have described an iterative process between ISTUM and ESSM. However, because the cost of electricity has no effect on technology selection in the frozen run (technology mix is predetermined) or the technical run (technology mix is based solely on energy efficiency, not on price), no iterations were required for these runs. If electricity demand from the natural run for any region differed significantly from the forecast of the various utilities modelled in ESSM, and if electricity price varied significantly over the range of production for any region, ESSM evaluated a new cost of electricity as an input to ISTUM. The same procedure was applied to the socio-economic and cost runs.

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3. Sector Structure and Assumptions

In this study, I analysed seven Canadian regions: British Columbia (BC), Alberta (AB), Saskatchewan (SK), Manitoba (MB), Ontario (ON), Québec (PQ) and the Atlantic (AT) provinces, an aggregate of Nova Scotia, New Brunswick, Newfoundland, and Prince Edward Island. The territories consume little energy and no disaggregated data for the sectors are available; they were excluded from the analysis. Because Saskatchewan and Manitoba lacked sector-specific data or had a low number of firms or plants representing the various industries, the benefits of a disaggregated analysis of their industrial sector were minimal; in these regions, I aggregated all industry into “other manufacturing”.

3.1 Time Horizon and Time Steps

This analysis covers the years 1990 to 2010. The 1990 base year corresponds to that chosen for evaluation in most of the world-wide research on CO$_2$ emissions analysis. Goals for stabilisation and reduction of emissions established by various conventions and protocols utilise target dates such as 2000 and 2010. Calculations are done every 5 years.

3.2 The Canadian System

Disaggregation of the Canadian energy system requires a review of the disbursement of energy consumption by sector and region, related sources of CO$_2$, and finally, a review of differences in fuel use and availability between regions. The following tables and graphs depict levels of energy consumption and consequent CO$_2$ emissions by sector and region in Canada in 1990. Appendix B details specific regions.

3.2.1 Energy Consumption in the Canadian System

Table 3.1 displays the level of total energy consumption in petajoules (PJ) in the various regions of Canada. These data are obtained from the Statistics Canada (STC) Quarterly Report on Energy Supply and Demand (QRESD), Catalogue 57-003 for 1990. Ontario utilises one third of all energy consumed in Canada. Alberta and Québec are next with 20% and 19% respectively. The bulk of Alberta’s consumption can be attributed to the
extraction and production of energy carriers such as natural gas and refined petroleum products. For this reason, it also accounts for a much larger share of Canada’s CO$_2$ emissions than Québec even though total energy consumption is similar.

**Table 3.1: Energy Consumption by Sector and Region (PJ in 1990)**

<table>
<thead>
<tr>
<th>Sector</th>
<th>BC</th>
<th>AB</th>
<th>SK</th>
<th>MA</th>
<th>ON</th>
<th>PQ</th>
<th>AT</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
<td>447.5</td>
<td>1,045.0</td>
<td>209.5</td>
<td>60.0</td>
<td>1,162.3</td>
<td>728.7</td>
<td>335.2</td>
<td>3,996.6</td>
</tr>
<tr>
<td>Transport</td>
<td>246.2</td>
<td>245.7</td>
<td>89.2</td>
<td>81.4</td>
<td>631.6</td>
<td>362.8</td>
<td>158.6</td>
<td>1,821.3</td>
</tr>
<tr>
<td>Agriculture</td>
<td>10.1</td>
<td>53.3</td>
<td>50.6</td>
<td>20.5</td>
<td>44.0</td>
<td>19.8</td>
<td>6.4</td>
<td>204.7</td>
</tr>
<tr>
<td>Residential</td>
<td>120.4</td>
<td>148.0</td>
<td>49.3</td>
<td>50.0</td>
<td>470.2</td>
<td>262.2</td>
<td>93.9</td>
<td>1,197.1</td>
</tr>
<tr>
<td>Commercial</td>
<td>117.7</td>
<td>168.1</td>
<td>42.3</td>
<td>49.6</td>
<td>361.1</td>
<td>220.1</td>
<td>85.5</td>
<td>1,054.5</td>
</tr>
<tr>
<td>Total</td>
<td>941.8</td>
<td>1,660.0</td>
<td>440.8</td>
<td>261.5</td>
<td>2,669.1</td>
<td>1,593.6</td>
<td>679.7</td>
<td>8,274.2</td>
</tr>
</tbody>
</table>

Source: STC QRES

Table 3.2 provides a perspective on the relative importance of each sector in terms of energy consumption; this determines the degree to which ISTUM’s sub-models are disaggregated. In all provinces, the industrial sector accounts for the greatest fraction of total energy consumption; I define this sector to include energy consumed to generate electricity. Agricultural activity consumes 2.5% of total energy in Canada, primarily as transportation fuels in the prairie provinces. Agriculture was not included in the analysis.

**Table 3.2: Relative Shares of Energy Consumption by Sector and Region (%)**

<table>
<thead>
<tr>
<th>Sector</th>
<th>BC</th>
<th>AB</th>
<th>SK</th>
<th>MA</th>
<th>ON</th>
<th>PQ</th>
<th>AT</th>
<th>Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
<td>47.5</td>
<td>63.0</td>
<td>47.5</td>
<td>22.9</td>
<td>43.5</td>
<td>45.7</td>
<td>49.3</td>
<td>48.3</td>
</tr>
<tr>
<td>Transport</td>
<td>26.1</td>
<td>14.8</td>
<td>20.2</td>
<td>31.1</td>
<td>23.7</td>
<td>22.8</td>
<td>23.3</td>
<td>22.0</td>
</tr>
<tr>
<td>Agriculture</td>
<td>1.1</td>
<td>3.2</td>
<td>11.5</td>
<td>7.8</td>
<td>1.6</td>
<td>1.2</td>
<td>0.9</td>
<td>2.5</td>
</tr>
<tr>
<td>Residential</td>
<td>12.8</td>
<td>8.9</td>
<td>11.2</td>
<td>19.1</td>
<td>17.6</td>
<td>16.5</td>
<td>13.8</td>
<td>14.5</td>
</tr>
<tr>
<td>Commercial</td>
<td>12.5</td>
<td>10.1</td>
<td>9.6</td>
<td>19.0</td>
<td>13.5</td>
<td>13.8</td>
<td>12.6</td>
<td>12.7</td>
</tr>
<tr>
<td>Canada</td>
<td>11.4</td>
<td>20.1</td>
<td>5.3</td>
<td>3.2</td>
<td>32.3</td>
<td>19.3</td>
<td>8.2</td>
<td>100.0</td>
</tr>
</tbody>
</table>

In Canada, industry consumes about 48% of all energy. Energy required to convert energy into an alternative form (producer consumption of its own fuels, petroleum refining and electricity generation) accounts for 41% of total industrial consumption (table 3.3), about 19% of energy consumption in Canada. All manufacturing sub-sectors not listed in table 3.3 (food and beverage industries, textiles, plastics and many others; the
Chapter 3  Sector Structure and Assumptions

sum of all other industry sub-sectors) consume about 14% of all industrial energy while pulp and paper, the largest single industrial consumer, accounts for over 20%.

Table 3.3: Energy Consumption by Industrial Sub-sector (in terajoules [TJ] in 1990)

<table>
<thead>
<tr>
<th>Industry</th>
<th>QRESD</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Generation*</td>
<td>737,800</td>
<td>18.5</td>
</tr>
<tr>
<td>Producer Consumption</td>
<td>775,742</td>
<td>19.4</td>
</tr>
<tr>
<td>Mining</td>
<td>261,651</td>
<td>6.5</td>
</tr>
<tr>
<td>Pulp and Paper</td>
<td>815,352</td>
<td>20.4</td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>219,305</td>
<td>5.5</td>
</tr>
<tr>
<td>Smelting and Refining</td>
<td>182,973</td>
<td>4.6</td>
</tr>
<tr>
<td>Cement</td>
<td>58,134</td>
<td>1.5</td>
</tr>
<tr>
<td>Petroleum Refining</td>
<td>86,370</td>
<td>2.2</td>
</tr>
<tr>
<td>Chemicals</td>
<td>237,451</td>
<td>5.9</td>
</tr>
<tr>
<td>Other Manufacturing</td>
<td>561,656</td>
<td>14.1</td>
</tr>
<tr>
<td>Forestry</td>
<td>15,826</td>
<td>0.4</td>
</tr>
<tr>
<td>Construction</td>
<td>44,367</td>
<td>1.1</td>
</tr>
<tr>
<td>QRESD Industrial</td>
<td>3,996,623</td>
<td>100.0</td>
</tr>
</tbody>
</table>

Source: STC QRESD (57-003)
* Quantity of fuel required to generate electricity is reduced by the total electricity generated by those fuels, thus avoiding double counting.

Producer consumption includes the quantity of natural gas required to process natural gas, refinery fuel gases, coke and other petroleum products used to refine conventional and non-conventional crude oil, and the quantity of coal used to dry or otherwise prepare coal for shipment. In ISTUM, self-generated fuels consumed in the production of petroleum products are allocated to the petroleum refining sector, while the extraction sectors account for the producer consumption of natural gas and coal (not all of these latter fuels could be modelled in ISTUM because of lack of disaggregated data and technology information). For example, the petroleum refining sector actually consumed over 324 PJ in 1990; 86 PJ of purchased energy and 238 PJ of self-generated fuels.

Appendix B contains detailed regional splits and shows that some provinces are dominated by one industry. In Alberta, the natural gas processing and petroleum refining industries account for 50% of total energy consumption. In BC and the Atlantic provinces, pulp and paper industries consume roughly 46% and 32% respectively of the
industrial sector’s energy demand. In Ontario and Manitoba, other manufacturing consumes over 23% of total industrial energy.

### 3.2.2 Distribution of CO$_2$ Emissions in the System

If one takes data on the consumption of energy, the bulk of CO$_2$ emissions can be determined through the application of appropriate conversion coefficients to the physical quantities of fossil fuels consumed. Other anthropomorphic sources of CO$_2$ emissions exist in some industrial branches (release from natural gas wells, release from non-combustion chemical processes); the tally in table 3.4 includes these quantities.

#### Table 3.4: CO$_2$ Emissions by Sector and Region (’000 T in 1990)

<table>
<thead>
<tr>
<th>Sector</th>
<th>BC</th>
<th>AB</th>
<th>SK</th>
<th>MA</th>
<th>ON</th>
<th>PQ</th>
<th>AT</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial*</td>
<td>15,221</td>
<td>93,415</td>
<td>17,846</td>
<td>2,912</td>
<td>74,294</td>
<td>21,228</td>
<td>21,289</td>
<td>246,205</td>
</tr>
<tr>
<td>Transport</td>
<td>19,255</td>
<td>21,107</td>
<td>7,441</td>
<td>6,182</td>
<td>46,784</td>
<td>29,286</td>
<td>14,029</td>
<td>144,084</td>
</tr>
<tr>
<td>Agriculture</td>
<td>303</td>
<td>513</td>
<td>298</td>
<td>52</td>
<td>806</td>
<td>301</td>
<td>205</td>
<td>2,478</td>
</tr>
<tr>
<td>Residential</td>
<td>3,986</td>
<td>6,411</td>
<td>2,064</td>
<td>1,606</td>
<td>16,452</td>
<td>6,092</td>
<td>3,977</td>
<td>40,588</td>
</tr>
<tr>
<td>Commercial</td>
<td>3,242</td>
<td>5,025</td>
<td>1,045</td>
<td>1,431</td>
<td>9,012</td>
<td>4,255</td>
<td>2,034</td>
<td>26,044</td>
</tr>
<tr>
<td>Total</td>
<td>42,007</td>
<td>126,471</td>
<td>28,694</td>
<td>12,183</td>
<td>147,348</td>
<td>61,162</td>
<td>41,534</td>
<td>459,399</td>
</tr>
</tbody>
</table>


*Industrial CO$_2$ emissions include that released through power generation, producer consumption, cement and lime calcination, CO$_2$ stripped from natural gas, and non-energy CO$_2$ release.

Energy consumption and the generation of CO$_2$ emissions may not be proportionate.

Energy derived from the combustion of biomass and waste fuel (which would otherwise release its CO$_2$ during decomposition or by incineration) is assumed to be a non-net CO$_2$ contributor. Electricity may be generated from non-CO$_2$ emitting sources such as hydro or nuclear power. In table 3.5, those regions dependent on fossil-fired electricity generation have the higher proportion of the CO$_2$ emissions allotted to industry.

In Canada, industry’s share of emissions exceeds 50%. It could be argued that the allocation of electricity’s share to industry is unfair because each of the other sectors is, in part, responsible for that electricity’s generation and should bear the associated CO$_2$ emissions. But, in order to understand how CO$_2$ emissions may be controlled through policy initiatives, the analysis is best served by focusing on the point sources of the emissions and the decision makers who determine the set of stocks at these sources. In other words, because the home owner and business firm have little input to the technology
decisions that affect the level of CO$_2$ emissions generated to make electricity, I decided not to allocate the CO$_2$ associated with electricity production to the residential, commercial and various industrial branches that demonstrate electricity demand.

### Table 3.5: Relative Shares of CO$_2$ Emissions by Sector and Region (%)

<table>
<thead>
<tr>
<th>Sector</th>
<th>BC</th>
<th>AB</th>
<th>SK</th>
<th>MA</th>
<th>ON</th>
<th>PQ</th>
<th>AT</th>
<th>Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
<td>36.2</td>
<td>73.9</td>
<td>62.2</td>
<td>23.9</td>
<td>50.4</td>
<td>34.7</td>
<td>51.3</td>
<td>53.6</td>
</tr>
<tr>
<td>Transport</td>
<td>45.8</td>
<td>16.7</td>
<td>25.9</td>
<td>50.7</td>
<td>31.8</td>
<td>47.9</td>
<td>33.8</td>
<td>31.4</td>
</tr>
<tr>
<td>Agriculture</td>
<td>0.7</td>
<td>0.4</td>
<td>1.0</td>
<td>0.4</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Residential</td>
<td>9.5</td>
<td>5.1</td>
<td>7.2</td>
<td>13.2</td>
<td>11.2</td>
<td>10.0</td>
<td>9.6</td>
<td>8.8</td>
</tr>
<tr>
<td>Commercial</td>
<td>7.7</td>
<td>4.0</td>
<td>3.6</td>
<td>11.7</td>
<td>6.1</td>
<td>7.0</td>
<td>4.9</td>
<td>5.7</td>
</tr>
<tr>
<td>Canada</td>
<td>9.1</td>
<td>27.5</td>
<td>6.2</td>
<td>2.7</td>
<td>32.1</td>
<td>13.3</td>
<td>9.0</td>
<td>5.7</td>
</tr>
</tbody>
</table>

ISTUM’s models do not account for all the CO$_2$ released by industry. ISTUM tabulates CO$_2$ emissions based on the type of energy consumed by a technology or on some characteristic of a process (e.g., CO$_2$ release from calcination in cement production). But some emissions are released to the atmosphere from sources not related to the fuel consumed or the process. For example, CO$_2$ emissions from natural gas wells are a function of the set of producing wells, not technology or energy use. That is, natural gas wells contain anywhere from 1% to 30% CO$_2$ as part of their gaseous stream; this CO$_2$ is not part of the ISTUM analysis framework. Natural gas wells account for about 3% of all released CO$_2$, about 14 million tonnes. Emissions from coal mining and transmission losses from natural gas and other pipelines increase the total to 55 million tonnes CO$_2$ in 1990. Thus, when transportation’s 145 million tonnes are also excluded, ISTUM and ESSM account for approximately 253 million tonnes of the CO$_2$ generated (55%) in Canada in 1990.

### 3.2.3 Regional Differences in the Energy System Across Canada

All regions have commercial and residential sectors that can be modelled, but the distribution of industry disaggregated to its branches across Canada is far from uniform. Table 3.6 defines the set of various sub-models that exist for the industrial sector in ISTUM. Where possible, small industries, otherwise disaggregated, were included in “other manufacturing”.

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The energy accounted for in ISTUM’s sub-models exceeds 66% of total Canadian consumption. Transportation consumes nearly 22% of the Canadian total (or more than 85% of the energy not simulated in this modelling system). ESSM’s regional models of electricity generation include another 9% of the energy consumed in Canada. Thus, over 75% of all energy consumed in Canada are modelled in the system used in this analysis.¹

Table 3.6: Disaggregation of Industry Sub-sectors in ISTUM

<table>
<thead>
<tr>
<th>Industrial Sub-Sectors</th>
<th>BC</th>
<th>AB</th>
<th>SK</th>
<th>MA</th>
<th>ON</th>
<th>PQ</th>
<th>AT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical Products</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Industrial Minerals</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Metal Smelting</td>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Mining, Fossil Fuels</td>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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</tr>
<tr>
<td>Mining, Metals</td>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>Other Manufacturing</td>
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<td>✓</td>
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<td>Petroleum Refineries</td>
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<td>✓</td>
<td></td>
</tr>
<tr>
<td>Pulp &amp; Paper</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>

* All industry in Saskatchewan and Manitoba are incorporated into Other Manufacturing
** Although the AB pulp and paper model is functional, a reliable data set could not be found for calibration.

Limited access to or supply of various fuels places constraints on technology penetration. For example, the Atlantic provinces have no natural gas distribution system and, even though some significant deposits in their offshore region may soon find their way onshore, the market in the Atlantic provinces is considered too small to develop the distribution infrastructure. Other constraints are applied to wood waste and waste-derived fuels because of limited supplies of these fuels.

¹ ISTUM and ESSM actually simulate about 400 PJ less than that calculated as 75% of Canada’s total energy consumption. The difference includes about 300 PJ used in natural gas and coal processing, 16 PJ in construction, 44 PJ in forestry and 22 PJ in Alberta pulp and paper. Other industries could not be modelled in certain regions because disaggregate data were not available. Research into the different STC databases that provide energy information suggest that, even though STC QRESD values are nationally accepted as a reasonable representation of Canada’s energy supply and demand picture, inaccuracies do exist (CIEEDAC 1994a-d, 1995a, b).
Volume II of the ISTUM manual (Nyboer et al. 1996, see Appendix A) provides a complete description of each of the sub-models used. Here I include only cursory summaries of the sub-models, extracted primarily from this volume, and provide basic assumptions used in each sub-model.

### 3.3 The Industrial Sector and Assumptions

The industrial sector shows a wide variety of processes and technology types. In chapter 2, I showed that, if one is to test the hypothesis that explicit technology simulation will aid the analyst or the decision-maker, then one must explore the heterogeneity in this sector. Through detailed technological review, one can determine the importance of structural or even sub-structural change, or the degree of autonomous technological evolution that would occur even with no policies directed towards emissions reduction.

In chapter 5, I demonstrate the asymmetry of this sector in response to proposed policy changes. In this section, I provide a primer on the various industrial sub-sectors analysed and specific assumptions for each of these sub-sectors. I begin with more generally applicable assumptions on growth, structural change and certain technology constraints.

Table 2.1 in chapter 2 provided a summary of growth in industry in Canada to 2010. For each industry and sector, I show how these values translate to specific products or services in percent change over the twenty-year horizon. Appendix B contains details of regional variations in growth using physical units of production related to that industry.

In ISTUM, each industrial branch may contain a number of sub-branches, as defined at the 4 digit level Standard Industrial Classification (SIC) code in table 3.7. The SIC system is know as SIC-E, the *Standard Industrial Classification, 1980, Statistics Canada* (Cat. 12-501E). Under this system, an industry is defined as a group of establishments whose production represents a homogeneous set of goods or services or a group of establishments primarily engaged in the same or similar kind of economic activity.

<table>
<thead>
<tr>
<th>Industry Name</th>
<th>SIC-E code</th>
<th>Industry Name</th>
<th>SIC-E code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical Products</td>
<td>37</td>
<td>Industrial Minerals</td>
<td>35</td>
</tr>
<tr>
<td>Industrial Inorganic</td>
<td>3711</td>
<td>Cement</td>
<td>3521</td>
</tr>
</tbody>
</table>
A number of assumptions have been applied to the whole industrial sector.

- No variation in capacity utilisation - For each run, I assumed that capacity utilisation remains constant in the long term even though there are short term fluctuations or cycles. No reliable forecast of cycles could be found for all regions in all industries.

- No intra-sectoral structural change - Unless specifically defined in Canada’s Energy Outlook or information was directly obtained from industry representatives, the relative production of goods or services within an industrial branch remained constant.

- Cogeneration potential restricted - Certain heat-intensive industries do not utilise cogeneration technologies due to physical constraints, regulatory conditions and utility practices; thus maximum shares were set. The available share for cogeneration technologies was fixed at 50% of the potential; exceptions are noted in the text.

- Each industry is responsible only for the CO\textsubscript{2} released within its plant gates or property boundaries - Utilities are responsible for CO\textsubscript{2} released in the production of electricity because only they have control over the set of technologies used to generate
electricity. The industry does see the change in cost of electricity as the utility passes on savings or the impacts of any policy imposing emissions charges to the industry.

The industries comprising the aggregate sector called “other manufacturing” are defined in table 3.16. A brief description of the processes and primary assumptions made for each of the industrial sub-sectors defined in table 3.7 (in bold print) are provided below.

### 3.3.1 Chemical Products

This industrial branch includes firms engaged in the manufacture of petrochemicals, inorganic chemicals, specialty chemicals, fertilizer and fine chemicals. Thousands of different chemical products are produced in the industry. Only those products which are manufactured in bulk and are energy-intensive are represented in the model.

**Chlor-alkali**

Chlorine and caustic soda (sodium hydroxide) are co-produced in a ratio of 1:1.2 as part of a process known as chlor-alkali production. They are produced in electrolytic cells. Decreased demand for chlorine experienced in recent years, coupled with growth in demand for caustic soda has increased the use of caustic-manufacturing technologies that are independent of chlorine. These alternative technologies are represented in ISTUM.

**Sodium Chlorate**

An electrolytic process similar to that used in chlor-alkali cells can produce sodium chlorate. Caustic soda and chlorine, produced during the process, are mixed with each other to produce sodium hypochlorite which is subsequently oxidised to sodium chlorate.

**Hydrogen Peroxide**

The bulk of hydrogen peroxide production occurs using an organic process. A catalyst of nickel or palladium hydrogenates quinone to hydroquinone (Anthraquinone). Subsequent to oxidisation, hydroquinone produces hydrogen peroxide and regenerated quinone. The hydrogen peroxide is extracted and concentrated while quinone is recycled. A second organic, alcohol-based process generates hydrogen peroxide by oxidation of liquid isopropyl alcohol at moderate temperature.
**Methanol**

Methanol production requires two steps in a device known as a reformer. First, natural gas, fed over a nickel catalyst with steam, generates a synthesis gas of methanol, hydrogen and carbon monoxide (CO). Hydrogen and CO, when compressed to 5000 kPa at 260°C, “synthesises” methanol in the presence of a copper-based catalyst.

Any surplus hydrogen is combined with carbon dioxide to produce more methanol or it can be sent to other processes (e.g., production of ammonia, combustion in boilers, generation of electricity in fuel cells). Finally, distillation removes water and other impurities from the product.

**Ammonia and other Nitrogen Products**

In the production of ammonia, natural gas or some similar hydrocarbon acts as a hydrogen source rather than an energy source. In some cases, ammonia is produced in conjunction with methanol.

Although some heat is needed during the process to raise the temperature of the mixed feed gas (primarily methane and steam), the major energy demand is the electricity required to drive compressors. The ammonia process is exothermic and produces large amounts of steam. If ammonia is produced alone, the steam generated by the process may be used to drive the compressors.

**Ethylene**

Ethylene is produced by steam cracking (or pyrolysis) of natural gas feeds (ethane or propane) or larger hydrocarbon feeds like naphthas, gas oils and natural gas liquid. The cracking process involves injecting the feed along with steam into tubular reactor coils at high temperature and pressure. The resulting product is cooled, compressed, liquefied and fractionally distilled to produce, among other products, ethylene. Ethylene serves as the primary feedstock to a number of polymers in the manufacture of resins and plastics.

**Polymerisation**

Polymerisation is the process by which many of the primary and intermediate petrochemicals are converted into synthetic resins, plastics, and fibers. In this process
monomers (e.g., ethylene or propylene) react in the presence of a catalyst, with or without heat, to produce a long chain compound or polymer.

### 3.3.1.1 Structure of the Chemical Products Industry

The intermediate nodes in the energy flow model for Chemical Products represent chemical processes that generate the products listed above. Some of these intermediate nodes may have only one attached competition node; that is, only one set of competing technologies. Although there may be many important sub-processes in the production of a chemical commodity, either no alternative technological options exist or the intensity of those sub-processes are minor compared to the primary process.

### 3.3.1.2 Assumptions in the Chemical Products Industry

Technology stocks for the base-year and growth forecasts for the industry were difficult to obtain. The *CEO, 1994 Update* provided an expected growth to 2010 in the industry as a whole but not for specific chemical products. Assumptions had to be made concerning changes in demand of some chemicals that would compensate for the decline in chlorine production (a shift from chlorine as a bleaching agent in pulp and paper manufacturing). The problem reflects the degree of aggregation in the data on industry production. Review with industry experts and representatives of the Canadian Chemical Producers’ Association (CCPA) provided sufficient information to determine structural change in the industry and the expected sub-sector growth rates in the *CEO, 1994 Update* (table 3.8).

A number of processes in the chemical products sector are exothermic. This heat is often captured and converted to steam; I have assumed that all heat and steam generated was consumed in the industry rather than sold.

### Table 3.8: Anticipated Change in Chemical Production to 2010 (%)

<table>
<thead>
<tr>
<th>Chemical</th>
<th>BC</th>
<th>AB</th>
<th>ON</th>
<th>PQ</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chlorine</td>
<td>-46</td>
<td>-46</td>
<td>-46</td>
<td>-46</td>
</tr>
<tr>
<td>Caustic soda</td>
<td>57</td>
<td>57</td>
<td>57</td>
<td>57</td>
</tr>
<tr>
<td>Sodium Chlorate¹</td>
<td>39</td>
<td>32</td>
<td>1</td>
<td>30</td>
</tr>
<tr>
<td>Hydrogen Peroxide¹</td>
<td>40</td>
<td>48</td>
<td>8.3²</td>
<td>9²</td>
</tr>
<tr>
<td>Ammonia / Methanol</td>
<td>57</td>
<td>57</td>
<td>57</td>
<td>n/a</td>
</tr>
<tr>
<td>Ethylene / Propylene</td>
<td>n/a</td>
<td>57</td>
<td>57</td>
<td>57</td>
</tr>
</tbody>
</table>
Electrolytic cells often generate combustible gases at an electrode, primarily hydrogen. These gases were considered substitutes for purchased fuel, usually natural gas, and consumed first in all model simulations.

### 3.3.2 Industrial Minerals

The industrial minerals industry includes establishments engaged in the manufacture of cement and lime. Both products require significant quantities of energy to drive carbon dioxide from limestone in a kiln, a process known as calcination.

#### 3.3.2.1 Structure of the Industrial Minerals Industry

In the production of cement, limestone and clay or shale are mixed with additives such as sand, bauxite and iron slag to undergo three steps: (1) preliminary preparation involving crushing, grinding and blending, (2) kiln firing or calcining, and (3) finish grinding to cement powder. The product generated in kilns is known as clinker, hard nodules of unground cement.

The cement portion of the energy flow model includes three competition nodes which represent different clinker production methods: the wet process, the dry process and the fluidised bed process. At these nodes, different types of kilns and attachments compete to determine the demand for heat. ISTUM applies this demand to a second primary node, Heating, where burners compete to determine fuel mix and burner efficiency.

The finish grinding process converts the clinker to the final product, cement. At the grinding node, several different types of mills compete to grind the clinker to a powder and mix it with gypsum to produce the finished product, Portland cement. This node is separated from the kiln competitions because not all calcined material is ground; some is exported as clinker.
The lime manufacturing process also involves three basic steps: raw materials preparation, calcination, and final product preparation. Analogous to cement production, the primary activity in the production of lime involves calcining crushed limestone in a kiln. In contrast to cement production, lime production does not require extensive grinding.

Lime production is modelled by competing several different types of kilns along with associated grinding and final preparation activities. Thus, energy consumption associated with feedstock preparation and packaging are included with the estimates of energy consumption for the kilns.

3.3.2.2 Assumptions in the Industrial Minerals Industry

Growth in the cement and lime industries are closely related to growth in the construction industry. NRCan, in its CEO, 1994 Update, estimates growth in total construction to be about 2.5% per year to 2010. Compounded, this results in a growth of about 60% over the twenty year period, as shown in table 3.9.

<table>
<thead>
<tr>
<th>Product</th>
<th>Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cement</td>
<td>60</td>
</tr>
<tr>
<td>Lime</td>
<td>60</td>
</tr>
</tbody>
</table>

Source: NRCan (CEO, 1994 Update)

Based on insights gained through communication with cement industry representatives, I assumed that existing wet kiln processes (in BC, Ontario, and Québec) would be phased out gradually over the twenty year simulation period.

Bottom-cycle cogeneration (a process where waste heat from one end of a kiln drives electrical generators), was incorporated into ISTUM’s database as an “add-on” to the more inefficient wet kiln operations. I also considered top-cycle cogeneration, a technology where fuel designated for combustion in a kiln is used to make electricity first with the waste heat from the generator passing on to calcine the kiln feed. However, discussions with consultants indicated that such devices would not penetrate the cement
industry because no efficiency improvement is available through the incorporation of top-cycle cogeneration.

Any fuel of suitable heat content can be used to calcine cement, including waste derived fuel (WDF) or hazardous waste fuel (HWF). Technologies consuming WDF or HWF are considered less efficient than fossil-fired alternatives because of inherent contaminants, impurities and moisture contents of these fuels. Due to political and social opposition to combustion of HWF in or near residential areas, HWF-fueled technologies were not permitted to penetrate in model simulations.

In initial modeling runs, I assumed that WDF would be available to producers at no cost. Results indicated a shift toward less efficient technological stock; firms would have no incentive to incur the additional capital cost of more efficient equipment when fuel costs are 0. Industry representatives would not accept this trend, claiming that the limited and inconsistent supply of WDF would preempt its inclusion in the economic assessment of technology purchase. These assessments would instead be based on anticipated future costs of primary fuels: oil, coal, natural gas. However, the chosen technologies would include features permitting substitution of WDF as a supplementary or alternative fuel.

In order to simulate decision-making behavior in the industry, it was necessary to attribute some cost to WDF. For modelling purposes, a price equal to 50% of the next cheapest fuel alternative was adopted as a proxy for a market price of WDF. This fuel is typically natural gas in western Canada and coal in eastern Canada. Indexing the price of WDF to a “next best” fuel allows firms to recognise the potential fuel cost savings available with WDF in their analyses without creating a bias towards inefficient equipment.

In addition, I applied a market share constraint to reflect the limited availability of WDF. This constraint limited the penetration of technologies using waste-derived fuel to approximately 25% of the total fuel consumed (CPCA 1989).

### 3.3.3 Metal Smelting

Iron and steel production dominates the metal smelting industry. Because of the unique characteristics of steel production, two models represent the metal smelting sub-sector: iron and steel production and other metal smelting.
3.3.3.1 Structure of the Iron and Steel Smelting Industry

The iron and steel industry has been structured to include end-use energy consumption of primary steel industries, the steel pipe and tube industry and iron foundries. Although a large number of products are generated in this industry, all products must go through basic iron and steel smelting and refining processes. These processes are grouped into five steps:

1. raw materials preparation
2. reduced (pig) iron production
3. steel production
4. semi-finished products (slabs, billets and blooms)
5. finished products.

Not all processes occur at the mill site. For example, most ore preparation (concentrating and agglomeration) occurs at the mine site while production of highly specialised finished products occurs at smaller manufacturing plants. Since the focus will be restricted to the primary energy users, the integrated and mini mills, I have excluded these smaller, off-site portions of the process from the analysis. Furthermore, because the process of casting semi-finished products and the final finishing processes (hot rolling and reheating) are closely related, the energy flow model clusters the semi-finished and finished product stages into one.

Two basic processes can generate steel. In the first process, coke, a coal derivative, reduces iron oxides in ore to pig iron in a blast furnace. Basic oxygen furnaces (BOFs) refine this liquid iron along with some scrap iron by injecting oxygen, which is itself an energy-intense product. Firms using this process are known as integrated mills because they produce finished or semi-finished steel products from iron ores. In the second process, electric arc furnaces (EAFs) recycle 100% scrap metal. This process occurs in operations known as mini mills. In both cases, the molten steel is cast, inspected, semi-finished and sometimes reheated and finished. Each of a wide variety of finished products requires varying inputs of heat and mechanical energy in its manufacture.
Rapid modernisation of the steel industry focuses on technologies that concentrate on energy-saving measures and reuse of waste heat. Direct reduced iron (DRI) and direct smelted iron processes, presently in pilot scale plants, may make the coke-dominated process redundant. Other processes such as direct rolling and thin slab and thin strip casting will eliminate reheating processes.

ISTUM’s energy flow model for iron and steel permits some simulation of the processes used to make finished products, with only the most common processes included: production of slabs and sheets, billets (bars, rods) and blooms (large structural steel shapes) and processes such as annealing and galvanisation.

### 3.3.3.2 Assumptions in the Iron and Steel Industry

Product structural in the Canadian iron and steel industry will not change much over the simulation period. Value added products (finished steel) grow marginally more than raw steel products. The degree of change can be seen in table 3.10.

Representatives of the iron and steel industry foresee two general movements in steel production; (1) a shift from integrated-mill process to mini-mill processes in raw steel production, and (2) in integrated mills, a shift from the blast/BOF process to the DRI/BOF process. To account for these trends, I assumed the share of integrated-mills in Ontario’s raw steel production to decrease from 65.5% in 1990 to 45% by 2010. Further, in the integrated-mill process, the share of blast furnace/BOF steel output declines gradually from 100% in 1990 to 40% in 2010 through the penetration of DRI in combination with EAFs. This means that the quantity of coke-based reduction diminishes through natural retirement and that new capacity will be primarily DRI / EAF processes.

In Québec, about 400,000 tonnes of metal produced at the QIT-Fer et Titane plant is smelted in the Q-BOP process (a type of BOF steel-making process) to liquid steel.
subsequent to the titanium oxide process, the primary product of QIT-Fer et Titane. This output is generally reported as raw steel from an integrated mill (CANMET 1993). This unique operation is not likely to be duplicated in any future expansion; I have assumed this integrated steel output remains constant over the twenty year simulation period. This implies that the integrated mill’s share of total Québec steel output declines over time due to the overall increase of total raw steel production. I could find no estimation of the energy consumed in the production of this product - STC allots the energy consumed in the plant to the production of titanium oxide; the steel is, in essence, a by-product.

In 1990, cogeneration technologies produced about 3% of the steam required in the production of iron and steel. Because steam demand is low, I fixed the shares of steam production due to cogeneration increase to only 25% of the total by 2010 (recall that, in most major industries, shares expand to 50%).

In integrated mills, a process known as destructive distillation converts metallurgical coal into coke, coke oven gas, light gas oils, naphtha, ammonia, and a series of other coal by-products. The valuable by-products, stripped from the coke oven gas, enter the market as commodities. The coke acts as the reducing agent (i.e., strips oxygen from iron in iron oxide) in a blast furnace. Coke oven gas, with a calorific heat content lower than that of natural gas, fires a number of different operations throughout the steel mill. In ISTUM, I have assumed that coke oven gas replaces natural gas in any gas-fired operation. Although some natural gas-dedicated units exist in the typical steel mill, this assumption only says that all coke oven gas generated must be consumed in the mill before natural gas is purchased. Coke oven gas may be flared on occasion. However, compared to the total energy consumption of the mill, this loss is insignificant and plant managers avoid such situations. ISTUM keeps track of coke oven gas in terms of its calorific content, not volume of production.

3.3.3.3 Structure of and Assumptions in Other Metal Smelting Industries

All remaining metal smelting can be captured in one model framework. The steps in the production of these metals are similar although energy requirements at these steps vary
from one metal to another. Thus, the portions of the energy flow model for smelting nickel, copper, lead, zinc, magnesium and titanium resemble each other.

Only aluminum’s energy flow model is somewhat unique; concentrates (alumina) are shipped in from overseas to be purified into metal using Hall-Heroult technologies, an energy-intense electrolytic cell. Although Canada has no aluminum ore body of sufficient concentration to warrant extraction, readily available, inexpensive electrical energy attracts companies that extract the metal from alumina. Aluminum is produced in BC and Québec with the bulk of production in Québec. Both provinces have a large and inexpensive supply of hydroelectricity as well as ocean ports to import alumina.

**Aluminum**

Alumina (AlO$_3$) is added to an electrolytic cell where molten alumina in a bath of cryolite (sodium aluminum fluoride) at 980°C receives low voltage, high amperage electrical input. Aluminum collects at the bottom of each cell and is tapped off in its molten form as ingots. The liberated oxygen combines with the carbon anode to release CO$_2$ and CO. Thus, anodes require replacement once every 14 to 18 days.

Carbon anodes are produced on site. Solid pitch, a petroleum derivative, is crushed, liquefied, and mixed with graded coke at high temperature. The proportions of coke to pitch determine which of the three types of anode paste will be produced. The anode is then prebaked or simply placed in the cell and "baked" while operating (Soderberg process). In the overall process, 1.9 tonnes of alumina and approximately 0.5 tonnes of carbon produce 1 tonne of primary aluminum and 1.4 tonnes of CO$_2$ and CO.

Theoretically, only 5.64 kwh/kg are required to separate aluminum and oxygen in electrolytic cells, but old plants use as much as 17.6 kwh/kg. Newer plants use 14.3 kwh/kg and a more modern Alcoa version of the process is said to use only 11 kwh/kg. Maximum technical efficiency may hover around 8.8 kwh/kg (Chiogioji 1979). Recycled aluminum requires only 5% of the energy of original production. Increased recycling will have a significant effect on the production of virgin metal.

*Stable* anodes and cathodes are pre-commercial technologies that would completely eliminate carbon-based anodes from electrolytic cells, as well as improve electrical
efficiency by about 25% in a pre-bake plant, slightly less in a Soderberg plant. Stable anodes are ceramic/metal (cermet) electrical conductors which deteriorate very slowly (5 years of life rather than two weeks). Because they contain no carbon, no CO$_2$ is released. Energy needed for the manufacture of stable anodes would be far less than for carbon anodes, since they last about 130 times longer than carbon anodes.

Information received from the Office of Industrial Programs of the US DoE suggests that stable anodes and cathodes should be commercially available within 10 years (by 2000) and that retrofit to either Soderberg or prebake plants would not be a technical problem. See Pritchett (1987), Galambas (1988) and King (1989).

Assumptions in the Aluminum Smelting Industry

Growth in the aluminum industry in BC and PQ are displayed in Table 3.11. BC has only one aluminum smelter and, though talks of expansion are ongoing, no definite plans have been proposed before 2010. Recycled aluminum increases by nearly 50% by 2010 but the quantities are too small to have an impact on overall growth in this sector for either PQ or Canada in general.

Table 3.11: Change in Aluminum Production in Canada to 2010 (%)

<table>
<thead>
<tr>
<th>Product</th>
<th>BC</th>
<th>PQ</th>
<th>Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aluminum</td>
<td>0</td>
<td>69</td>
<td>58</td>
</tr>
<tr>
<td>Recycled Aluminum</td>
<td>0</td>
<td>49</td>
<td>49</td>
</tr>
<tr>
<td>Total Aluminum</td>
<td>0</td>
<td>69</td>
<td>58</td>
</tr>
</tbody>
</table>

Source: NRCan, (CEO, 1994 Update)

Most of Canada’s aluminum production facilities generate their own power and are not subject to prices for electricity seen by the remainder of industry. However, because the power generated could be sold to the grid, its opportunity costs match the costs of power on the grid and technology alternatives are competed under these price criteria.

The cermet process will not enter the market until 2000 in either BC or Québec.

Copper, Nickel, Titanium, Magnesium, Lead and Zinc

Often, one facility will smelt a number of metals because the concentrated ore contains a mixture of metals. For example, lead and zinc concentrates from southern BC include
cadmium, silver, gold, bismuth, antimony, indium, germanium, tin, copper, mercury, and arsenic. None of the processes to smelt these trace metals were considered for incorporation in ISTUM because the focus is on energy consumption in the production of refined metals, not product generation. Energy needed to complete the processing of the minor metals are small; these metals are considered by-products of the primary process.

Concentration of ores shipped to smelters occurs at the mine site; energy demands of these processes are incorporated in the ISTUM’s mining sub-model. Each type of concentrate is smelted and refined using different energy services. But the basic process of pyrometallurgy (using heat to purify metals) remains similar between them; most metals undergo 5 steps:

1. roasting / calcining  
2. smelting  
3. converting  
4. refining  
5. casting

Roasting and calcining processes drive off volatile substances using heat, increasing the concentration of the desired product. For example, roasting zinc concentrate, containing about 50% zinc as a sulphide, removes sulphur. The zinc combines with oxygen to make zinc oxide or calcine. Roasting releases large quantities of sulphur dioxide, a suffocating, poisonous gas, trapped and used to produce fertilizers and sulphuric acid.

The calcined material then undergoes a smelting process where heat from the combustion of sulphur or other sulphides (in the ore), fossil fuels or electricity melts the mass. The material separates into matte (desired metal) and slag (“waste” material) which may contain up to 15% of the desired metal and often re-enters the process up stream.

Matte converting involves the injection of air or oxygen to remove impurities, including residual sulphur. At this point, the metal is about 98% pure. Molten metal, poured into large flat sheets, cools off to become anodes for an electrofining cell. Although process specifics vary, electrolytic cell activity involves corrosion of the anode and deposition on the cathode. Metals attain a purity of 99.99+%.

After a specified period of time (1-4 days), the cathodes and the anode remnants are extracted from the cell. The contaminants remaining on the anodes are stripped off and
discarded or undergo further processing to capture trace metals. The remaining anode core is recast into new anodes. Sheets of pure metal are stripped from the cathodes, melted in electric or fossil-fueled furnaces and cast into slabs in preparation for shipment.

Technologies known as continuous reactors combine roasting, smelting and converting processes in one operation. Capture of energy released from combustion of sulphur during roasting, lower capital costs, reduced materials handling, economic \( \text{SO}_2 \) recovery and the ability to apply on-line computer controls to the entire operation make continuous reactors appealing. But, in many cases, technical problems have not yet been overcome.

Hydrometallurgy provides an alternative method to pyrometallurgy in the extraction and refining of metals. Metals can be extracted from ores using aqueous solutions; water-based mixtures of special reagents leach out metals from even low-grade ores, slags or mine wastes. The dissolved metals can then be extracted by precipitation or through electrowinning (like electrolysis, except that the metal is already in solution and doesn’t need to be dissolved from the anode). Hydrometallurgy, still in development stages due to the complexity of the solutions, can only be applied to some metals from ores of specific types (e.g., copper from ores containing copper oxides).

**Assumptions in Other Metal Smelting Industries**

Not all regions show the same mix or set of metals smelted. Table 3.12 displays only the major metals smelted in each region and their expected growth to 2010.

<table>
<thead>
<tr>
<th>Product</th>
<th>BC</th>
<th>ON</th>
<th>PQ</th>
<th>Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>Copper</td>
<td>22</td>
<td>39</td>
<td>9</td>
<td>18</td>
</tr>
<tr>
<td>Nickel</td>
<td>-</td>
<td>205</td>
<td>-</td>
<td>205</td>
</tr>
<tr>
<td>Lead</td>
<td>22</td>
<td>-</td>
<td>-</td>
<td>22</td>
</tr>
<tr>
<td>Zinc</td>
<td>22</td>
<td>57</td>
<td>71</td>
<td>52</td>
</tr>
<tr>
<td>Magnesium</td>
<td>-</td>
<td>-</td>
<td>288</td>
<td>288</td>
</tr>
<tr>
<td>Titanium</td>
<td>-</td>
<td>-</td>
<td>71</td>
<td>71</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>22</td>
<td>74</td>
<td>55</td>
<td>57</td>
</tr>
</tbody>
</table>

Source: NRCan, (CEO, 1994 Update)
Titanium and magnesium are extracted as primary metals only in Québec. In this region, no nickel and lead refining occurs. The energy flow model for all other regions is identical and contains copper, nickel, lead and zinc streams (as well as aluminum).

Shifts between continuous smelting and conventional smelting and shifts between hydrometallurgy and pyrometallurgy are exogenously defined, even though there are competitive aspects to their penetration into the market. At present, shifts in processes are determined by ore and concentrate type more than through competitive criteria.

Data related to smelting of other, more rare metals are poor. Energy is expended on material throughput, but data on the processes used are limited to quantities of output (i.e., no data on actual processes). The relationship between throughput and output can change, but are assumed to be constant over the simulated time period for all metal smelting operations simulated.

3.3.4 Mining

This industry includes establishments that operating mines to extract and concentrate metallic ores. It also includes establishments that mine coal by underground or surface methods, in addition to those establishments engaged in the exploration for and production of conventional and non-conventional (oil sands) crude oil and natural gas. Some metal mines have been excluded from this analysis either because they are considered too small for inclusion or because there are insufficient end-use data available.

3.3.4.1 Structure of the Mining Industry

Except for oil and natural gas extraction, the mining process generally includes seven generic steps:

1. extraction
2. transport
3. crushing
4. grinding
5. cleaning / washing
6. mineral separation
7. tailings disposal

Metal and coal mines are typically categorised as either open-pit or underground. While the general production processes in both categories are similar, specific aspects of the
mining technologies differ. For example, underground mining must be concerned with air quality control in the mine shaft (cooling, heating, ventilation). Per tonne of ore, an underground mine is more electricity-intensive than an open-pit mine.

In the mining industry, three services dominate: the transport of raw material (ore, coal, gas, crude) from the extraction site to a materials-preparation plant or mill, reduction of size of mineral bearing particles, and the separation and preparation of the raw materials for shipment and further processing. For example, copper ore is moved from the mine site to a mill to be crushed and concentrated in preparation for shipment. Coal is moved from the mine to be washed and dried prior to loading on trains.

The energy flow model separates the basic mining and extraction processes: metal underground and metal open-pit mining, coal mining, oil extraction, natural gas extraction. Numerous end-products, typically unrelated one to another, are summed to cumulative mining output through engineering ratios. Scenario data input to the model indicate the splits between coal, metal ores, crude oil extraction and natural gas extraction. Other ratios dictate the quantity of material crushed, washed, concentrated, upgraded and prepared for shipping.

Crude oil and natural gas often occurs in-situ at a high pressure. This pressure is usually sufficient to transport the gas to a processing facility and the crude oil to a refinery or shipping storage facility. Therefore, the extracting process requires little or no energy. However, the energy flow model includes energy required to generate final products (natural gas) or products ready for use in petroleum refineries (synthetic crude oil [SCO] from upgraded heavy oils and bitumen).

Disaggregation in ISTUM occurs only where it is required to explain differences in end-use energy demand. For example, even though underground metal, open-pit metal and coal mines have similar process steps, they are separated in ISTUM’s sub-model because energy consumption at these steps is different for these mine types.

3.3.4.2 Assumptions in the Mining Industry

Table 3.13 shows that growth in the mining industry, as defined here, is not uniform. Most of the growth in Alberta is in non-conventional crudes (oil sands) while in BC, it is
in the conventional crudes. In Ontario, crude oil production declines as existing wells are
drawn down and no new sources are being found.

<table>
<thead>
<tr>
<th>Product</th>
<th>BC</th>
<th>AB</th>
<th>ON</th>
<th>PQ</th>
<th>AT</th>
<th>Canada</th>
</tr>
</thead>
<tbody>
<tr>
<td>Refinable Crude Oil</td>
<td>39</td>
<td>24</td>
<td>-2</td>
<td>n/a</td>
<td>n/a</td>
<td>25</td>
</tr>
<tr>
<td>Metal, Coal, and Natural Gas</td>
<td>50</td>
<td>57</td>
<td>16</td>
<td>50</td>
<td>160</td>
<td>50</td>
</tr>
</tbody>
</table>

n/a - not applicable
Source: NRCan (CEO, 1994 Update)

Material throughput determines the quantity of energy required but only data related to
total output are generally available. Difficulties were encountered in determining both
current average ore concentrations and future changes to these concentrations. Current
concentrations were estimated based on calibration of energy consumption for 1990 and
assumed to remain constant over the forecast period.

Rock hardness affects the quantity of energy required to concentrate the ore. Not only can
hardness change within a seam but overall hardness of ores in the industry can also vary
as new mines open and others close. No information on the level or changing degree of
hardness over time could be obtained. Therefore, as with ore concentration, hardness was
estimated through calibration and maintained as constant over time.

Estimates of the change in the mix of petroleum crudes (light / medium crude and heavy
crude oil) could not be obtained. In the analysis, the 1990 mix remained constant
throughout the simulation time period. The mix of crude oil to SCO production from
bitumen was also kept constant.

Both oil and natural gas wells may contain CO$_2$ as part of the product stream. Natural gas
from the well head may contain as much as 30% CO$_2$. Although some data exist related
to the quantity vented to the atmosphere, no reliable source of future releases were
available. Since such release is not technology dependent, this CO$_2$ was not included in
the analysis.
3.3.5 Petroleum Refining

This sector includes establishments primarily engaged in manufacturing petroleum products. For modelling purposes, the industry has been limited to the Refined Petroleum Products Industry (except lubricating oil and grease).

This branch of the industrial sector plays a role in both energy demand, since it consumes energy, and energy supply, where a portion of the price of energy is determined by the production costs at the refinery.

3.3.5.1 Structure of the Petroleum Refining Industry

The refining of crude oil is both complex and energy-intensive. Type and quality of crude and processing requirements to generate the end products determine the refinery’s complexity and have significant impact on energy consumption in the plant. Crude is refined into a number of products: ethane, propane, butane, motor gasoline, naphthas, jet fuel, petrochemical feedstocks, distillate fuel oil, diesel fuel, residual fuel oils, lubricants, coke and asphalt. All crude includes these products in varying concentrations. However, it is possible to increase output per unit crude of more desirable products by using various reformulation and cracking processes.

Petroleum refining consists of a sequence of chemical and physical re-arrangements of hydrocarbon molecules. The process steps and degree of refining required depend on the quality of crude oil input and required product yield. The major process steps include:

1. atmospheric distillation
2. vacuum distillation
3. cracking
4. desulphurisation
5. alkylation
6. isomerisation
7. reforming
8. sulphur recovery
9. hydrogen production

The latter two processes should not be considered part of the actual refining process; they act as utility functions to clean out sulphurous compounds or provide hydrogen for specific in-plant operations (primarily cracking operations).
Although many different and valuable petroleum fractions are produced in a refinery, activity in the total operation can be associated with gasoline production. Using appropriate engineering ratios, the relationships established between the processes and gasoline production will determine the amount of energy demanded by each of these processes. In other words, the model represents the industry as it relates to energy consumption, rather than production of refinery products.

3.3.5.2 Assumptions in the Petroleum Refining Industry

I have assumed that gasoline will continue to be the automotive fuel-of-choice, that crude quality will remain relatively stable (except for western crude, which will become heavier and contain more sulphur), with some increased refinery activity for tomorrow's gasoline due to increased reformulation. Table 3.14 provides data on growth in the industry to 2010. I have used an alternative source for growth in the industry for Alberta. NRCan's projection is higher than the level shown in the table; however, in recognising Alberta’s unique position as its own supplier I felt that Alberta’s own projections were more appropriate.

Table 3.14: Change in Gasoline Production and Crude Oil Throughput to 2010 (%)

<table>
<thead>
<tr>
<th>Product</th>
<th>AB</th>
<th>ON</th>
<th>PQ</th>
<th>AT</th>
<th>Canada*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
<td>2.4</td>
<td>39</td>
<td>28</td>
<td>20</td>
<td>25</td>
</tr>
<tr>
<td>Crude Oil</td>
<td>32.6</td>
<td>39</td>
<td>28</td>
<td>20</td>
<td>25</td>
</tr>
</tbody>
</table>

*Aggregate for all regions but Alberta
Source: AB from Energy Resources Conservation Board (ERCB 1994), others from NRCan, (CEO, 1994 Update)

Greater demand for diesel and more refined diesel fuel specifications means that more refinery processing is required in its production. Although this affects the degree to which some of the refinery processes are used, it has no bearing on ISTUM’s simulation of the industry because, as described above, ISTUM focuses only on the degree of use of the various processes and technologies, not on the products generated.

Still gas, a refinery product generated during distillation, is usually mixed with gases generated by other refinery processes; it is also known as refinery fuel gas. No readily available estimate for the value of refinery fuel gas exists because no actual market exists.
Because its calorific content is high, it serves as a replacement for other fuels, primarily natural gas. However, increased production of the gas means that product is lost; therefore plant managers seek to reduce its generation. I considered three approaches to estimate its value: (1) avoided cost of the fuel replaced, (2) opportunity cost in potential sales to other users, and (3) loss of potential product from a purchased barrel of crude oil. Avoided costs varied depending on the fuel (or mix of fuels) that fuel gas was most likely to replace; this could change from year to year. Opportunity costs, a value related to the lost opportunity value of selling fuel gas to other users such as plastic plants, are uncertain and varied between regions depending on the end users and on shipment costs. Finally, it was not clear where total output was affected: Did production of still gas mean that less gasoline was produced? less diesel? aviation fuel? Since this could not be determined, an actual value for income lost due to product loss could not be determined.

In this study, I set value of refinery fuel gas at the price of natural gas. I denoted this as a loss to the refinery and so gave it a negative price (in ISTUM, this would mean an economic loss to the technology). I further assumed that refineries consumed all refinery fuel gas produced internally before natural gas or other fuels are consumed; some plants do share refinery fuel gas with attached petrochemical operations and, although this is important for the particular plants in question, it is insignificant in the national or regional perspective. Thus, competitions favor technologies that produce less refinery fuel gas.

I assumed that the grades of crude oil for refineries remained constant for all regions except Alberta. Economists at the Alberta Energy Resources Conservation Board, indicated that Alberta crude oil is expected to deteriorate in quality over the study period. Eventually, additional upgrading or changes in infrastructure to include more cracking, reforming and other processes will be needed to maintain the quality and quantity of gasoline produced from a barrel of oil in Alberta.

Aside from controls on the penetration of motor stock and associated auxiliary units, only hydrocracking technologies are constrained. Hydrocracking and catalytic cracking compete at the cracking competition node but catalytic cracking, because it is considered the "heart" of a modern refinery, must remain the predominant cracking technology employed (Oil and Gas Journal, July 2, 1990).
Catalytic cracking generates coke which renders the catalyst inert. Under special conditions, the coke reacts with oxygen to form carbon monoxide (CO), regenerating the catalyst. This CO refinery fuel gas can be burned with other fuel gases for process heat. Remaining petroleum coke (from distillation units) and other heavy carbon compounds (known as “bottoms”) may not be usable to the refinery. In some cases, the coke can be used to fire processes in other industries (e.g., cement or lime kilns); in other cases, it is stockpiled.

### 3.3.6 Pulp and Paper

The pulp and paper industry includes establishments primarily engaged in manufacturing pulp, paper, paperboard and building and insulation board. Although there are several other paper-related industries, only those listed in table 3.7 have been included in the model because they are large in size and their products are energy intensive.

#### 3.3.6.1 Structure of the Pulp and Paper Industry

**Pulp**

Pulping processes can be broken down into three basic types; chemical, mechanical, and recycled. The first two processes generate virgin pulp and show high energy intensity levels compared to recycled pulp. Mechanical pulping, which tends to be very electrically intensive, uses wood fiber more efficiently (90% of input leaves as fiber) than chemical pulping (40%-50% of input leaves as fiber). Recycled pulp consumes considerably less energy (about 87% less) than either of the other major processes; however, when the collection and transportation of the used paper supply is considered, the energy intensity of this product increases significantly. The products generated from each of these processes vary such that they do not generally compete on the open market.

The following production steps are common to both chemical and mechanical pulp mills which use roundwood (logs) as feedstock. Mills that use chips or recycled paper as feedstock may exclude some of these steps.
1. wood debarking   4. pulp washing
2. wood chipping    5. pulp bleaching
3. pulp making      6. pulp drying

In pulp making, the energy consumed in the digesting, refining and/or grinding stages of the chemical or mechanical pulping processes are amalgamated into a single representative technology. For chemical pulping, the representative technology is the digester; for mechanical pulping, the refiner. Requirements for direct thermal and electric energy and requirements for services provided by auxiliary systems (boilers, pumps, fans, etc.) are associated with each digester or refiner. Although the process involves several steps, ISTUM captures these steps in single nodes for chemical pulping, semi-chemical pulping, mechanical pulping and recycled pulping.

ISTUM represents pulp washing as an aggregate of several energy-consuming processes. Processes that consume less energy, such as screening and cleaning, stock preparation and slush pulp storage, are combined into a single competition node in the model.

**Paper**

Canadian mills commonly produce five paper products: tissue, newsprint, linerboard, coated and uncoated paper. These products vary in their strength, thickness, surface finish and energy consumption. The production of these paper products consumes approximately 45% of the total energy used in the pulp and paper process. The two major energy requirements are heat to dry the paper and electricity to run the numerous fans, conveyors, pumps and miscellaneous mechanical devices (agitators, presses, etc.). The following production steps are common to the production of most types of paper:

1. stock preparation  
2. sheet formation  
3. pressing  
4. drying

ISTUM’s energy flow model tries to capture energy consumption and not material flow. Accordingly, the nodes in the ISTUM energy flow model are process stages in which energy consumption can be estimated. For example, each type of paper has its own distinct energy flow node for stock preparation, paper production, and paper drying.
because each type of paper with its different thickness and moisture content requires different amounts of energy per tonne at each of these process steps.

### 3.3.6.2 Assumptions in the Pulp and Paper Industry

Table 3.15 details the expected growth and structural changes in the industry between 1990 and 2010. In this case, industry structure changes over time; recycled pulp increases dramatically (although in terms of total tonnes, it is still dwarfed by the other types of pulp) and the industry is expected to show an increase in value-added components, such as paper products, relative to its primary product, pulp.

The major assumptions associated with the pulp and paper branch revolve around the issues of cogeneration potential and the use of hog fuel, its carbon (CO$_2$) content, availability and cost.

| Table 3.15: Increase in Product Demand in Pulp and Paper by 2010 (%) |
|------------------|---|---|---|---|---|
| Product          | BC | ON | PQ | MT | Canada |
| Chemical Pulp    | 5  | 44 | 50 | 39 | 25     |
| Semi-Chemical Pulp| -100 | 44 | -87| 39 | -11    |
| Mechanical Pulp  | 129 | 44 | 28 | 39 | 54     |
| Recycled Pulp    | 186 | 44 | 253| 39 | 135    |
| Newsprint        | 43  | 58 | 57 | 71 | 57     |
| Linerboard       | 43  | 58 | 57 | 57 | 54     |
| Uncoated Paper   | 43  | 58 | 57 | 57 | 55     |
| Coated Paper     | 43  | 58 | 57 | 57 | 55     |
| Tissue Paper     | 43  | 58 | 57 | 57 | 55     |

Source: NRCan (CEO, 1994 Update)

In a study completed for Forestry Canada (Kurz, et al. 1992), the forest industry was evaluated and considered to be a net sink of CO$_2$. As such, combustion of biomass in the pulp and paper industry is considered to be CO$_2$ neutral.

Hog fuel supply is limited and thus must be controlled through the use of maximum market shares. Because of the complexities of fuel storage and handling, and because of modifications to the fire wall, burning compartment and fuel delivery system of hog fuel boilers, their capital cost is roughly four times the cost of a comparable natural gas boiler. At discount rates of 30% (roughly a three year payback), capital costs would significantly
inhibit penetration of hog fuel boilers but at social discount rates of 7%, the low cost of the hog fuel enhances its market share; it rapidly reaches hog fuel’s availability constraint. Hog fuel bears no market fuel price suitable for cross-Canada evaluation. I considered a number of approaches for deriving hog fuel prices based on estimates of opportunity cost, avoided cost of the fuel replaced and transportation cost. Opportunity costs ranged from $0.00 to -$3.75 per GJ, (a negative value related to the cost of incineration). Avoided costs varied depending on the fuel (or mix of fuel) that the hog fuel was expected to replace in a given year. Estimates of transportation costs varied with transportation distance and shipment costs. A cost of $1.00/GJ was ultimately used for modelling purposes. This cost reflected an assumed commodity price of zero, plus a weighted average transportation cost including material handling. This value was derived from a review of tipping fees charged in BC (Canadian Resourcecon Ltd. 1993.) Although cost data were available only for BC, a uniform price was assumed for all regions of Canada.

### 3.3.7 Other Manufacturing

#### 3.3.7.1 Structure of the Other Manufacturing Industries

The “Other Manufacturing” sub-model contains industries in each region for which disaggregated data exist, and which cannot be allocated to one of the industries described above. Table 3.16 displays industries typically included in other manufacturing. To limit the number of industries assessed in the model these industries were regrouped into the following seven categories.

1. Food/Beverage/Tobacco
2. Rubber/Plastic
3. Leather/Textile/Clothing
4. Wood Products
5. Furniture/Printing/Machine/Metal
6. Transportation Equipment
7. Other Manuf./Electrical & Electronics

Categories were assembled based on the similarity of energy use within that category (is it primarily motor driven? or use steam or heat in product preparation?). Since no two provinces are alike, the constituents of each category and their relative importance varies.
Table 3.16: Branches of the Industrial Sector included in Other Manufacturing

<table>
<thead>
<tr>
<th>Industry Name</th>
<th>SIC-E code</th>
<th>Industry Name</th>
<th>SIC-E code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Food</td>
<td>10</td>
<td>Wood Products</td>
<td>25</td>
</tr>
<tr>
<td>Beverage</td>
<td>11</td>
<td>Furniture &amp; Fixture</td>
<td>26</td>
</tr>
<tr>
<td>Tobacco</td>
<td>12</td>
<td>Printing and Pub.</td>
<td>28</td>
</tr>
<tr>
<td>Rubber</td>
<td>15</td>
<td>Fabricated Metal Prod.</td>
<td>29</td>
</tr>
<tr>
<td>Plastic</td>
<td>16</td>
<td>Machinery</td>
<td>31</td>
</tr>
<tr>
<td>Leather &amp; Allied</td>
<td>17</td>
<td>Transportation Equip.</td>
<td>32</td>
</tr>
<tr>
<td>Primary Textile</td>
<td>18</td>
<td>Electrical &amp; Electronics</td>
<td>33</td>
</tr>
<tr>
<td>Clothing</td>
<td>24</td>
<td>Other Manufacturing</td>
<td>39</td>
</tr>
</tbody>
</table>

3.3.7.2 Assumptions in the Other Manufacturing Industries

None of the nodes representing the industries within the other manufacturing sector have specific energy-intensive technologies or processes associated with them. In the place of these processes, all energy consumption within each industry has been aggregated into demands for generic energy end-use services such as lighting, HVAC, pumping, machine drive, etc. Any monetary value can act as the driving variable in each of these industrial groups; in this analysis, I used industrial GDP. I determined the service demanded (heat, steam, pumping, etc.) for each $million of GDP for each industry in Other Manufacturing. These became the energy coefficients for that industry. I assumed that the services required to generate the next dollar in an industry category remained the same as the previous dollar and remained constant over time. Thus, only the provision of the services saw efficiency changes as a result of technology competition. Growth in this sub-sector is presented in table 2.1 as “Total Manufacturing”.

As with other industries, production ratios between industries in this aggregate group remained the same over time. Although this is not likely to be the case, no detailed breakdown of possible shifts were available.

3.4 The Commercial Sector and Assumptions

The commercial building sector of the economy is simulated using one ISTUM sub-model. The sector includes several sub-sectors as described in chapter 2, section 2.3.1.2. Each of these sub-sectors show a heating and cooling load per m² of floorspace that remains consistent within the sub-sector but is unique between sub-sectors. That is, heat
load in schools and universities are consistent over all universities and schools but are different from the heat loads typical of hospitals and nursing homes. As in the industrial sector, capacity utilisation (occupancy, in this case) is assumed to remain constant over the long term.

The energy flow model uses “commercial building space” in m$^2$ at the primary node of the commercial sector, with lighting, HVAC/building shell, domestic hot water, plug load (miscellaneous electricity), cooking and refrigeration as energy services linked to the floor space in each sub-sector. Interactive effects (e.g., more efficient lighting means increased heat requirement in cold seasons and reduced cooling requirements in hot seasons) have not been included in this model version.

Table 3.17 shows CEO’s forecasted floor space used to drive ISTUM’s commercial sub-model. Unless specified in the CEO, sectoral splits between the different building types are assumed to remain constant over the simulation period. Demand for refrigeration, cooking, domestic hot water, and lighting end-uses per unit floor space also remain constant; only plug load is assumed to increase by 1% for the first 5 years of the forecast because of increased use of personal computers and other electric office equipment.

<table>
<thead>
<tr>
<th>Region</th>
<th>1990</th>
<th>2000</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>British Columbia</td>
<td>46.3</td>
<td>77.6</td>
<td>110.0</td>
</tr>
<tr>
<td>Alberta</td>
<td>49.7</td>
<td>76.2</td>
<td>104.6</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>13.1</td>
<td>15.0</td>
<td>16.0</td>
</tr>
<tr>
<td>Manitoba</td>
<td>16.2</td>
<td>18.0</td>
<td>20.4</td>
</tr>
<tr>
<td>Ontario</td>
<td>132.5</td>
<td>198.3</td>
<td>271.5</td>
</tr>
<tr>
<td>Québec</td>
<td>78.6</td>
<td>114.1</td>
<td>159.7</td>
</tr>
<tr>
<td>Atlantic</td>
<td>22.4</td>
<td>31.3</td>
<td>40.8</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>358.8</td>
<td>504.7</td>
<td>736.4</td>
</tr>
</tbody>
</table>

Source: NRCan (CEO, 1994 Update)

Different heating and cooling technologies exist on the market for commercial buildings. However, purchase decisions for heating and cooling equipment, and the associated fans and pumps are not independent. Therefore, in ISTUM, these technologies are treated as units, of which ISTUM’s database contains pre-determined sets or examples.
As with the heating and cooling package, ISTUM lists only the most efficient retrofit packages which would reasonably be incorporated into an existing building. The package includes options identified as economic by the *BC Hydro Conservation Potential Review 1991 Report* (Marbek 1993).

Most provinces in Canada display a relatively uniform climate within their boundaries. Thus, heating and cooling loads in each commercial sub-sector are assumed to remain constant as well. In BC, where the interior and northern regions require considerably more heating than the Lower Mainland, ISTUM’s shell / HVAC types display a weighted average heating and cooling load that remains fixed over the simulation period.

Cogeneration, practical in large facilities that have a demand for both electricity and hot water or steam, were competed to a maximum market share of between 30% and 50% of heating demand in schools, large office, hospital, hotel and miscellaneous shell/HVAC categories. These systems, designed to meet heat loads, may generate excess electricity. Generated electricity first supplies plug load and other needs with any remaining supply sold to the grid at the price of purchased electricity.

### 3.5 The Residential Sector and Assumptions

The sub-model of residential building sector simulates all the services and facilities associated with human habitats. This includes the energy requirements of single-family dwellings, row houses, town houses and apartment buildings, both new and old. ISTUM’s residential model includes a facility to analyse both energy service requirements (furnaces and alternative heat provision) and retrofit options (insulation and windows packages) for homes independently.

Table 3.18 provides information concerning growth in the sector by region. All growth and replacement of retired homes is allocated to a “new home” archetype of varying efficiencies. Because the vintage of homes is known for the regions, retirement schedules follow the “logistic curve” methodology described in chapter 2, section 2.2.2.1.

<table>
<thead>
<tr>
<th>Region</th>
<th>1990</th>
<th>2000</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Households act at the primary node of the residential sector. Different archetypes depict different house structures, annual heat loads, and insulation types. The energy flow model assumes that each house requires space heating, hot water, refrigeration and various other appliance services as well as lighting requirements. House retrofits allow the home owner to move to another, more efficient shell type with its corresponding lower demand for space heat energy.

Each technology for space heating in ISTUM combines a shell archetype and a heating system. Each archetype, defined as a set of physical measurements for floor space, window area, insulation levels, and rate of air exchange, represents a group of households. The archetype then assumes specific heat loads, costs and the degree to which they can be retrofit. For each shell archetype, ISTUM includes a choice of four to seven different heating systems: oil furnaces, natural gas furnaces (three efficiency levels), wood stoves, electric baseboard heating, and electric heat pumps.

During a simulation, each home generates demands for specific services. The demand per residence for these services is set exogenously, but ISTUM determines the technology mix to meet the service demands. Services such as clothes and dish washers demand a secondary service, the provision of hot water. After competing for the stock of hot water-using technologies, ISTUM tallies the hot water demand and competes hot water heaters to supply it.

Each of the following appliances is modeled as a separate service:

1. refrigerators    6. freezers
2. ranges           7. dryers
Chapter 3 Sector Structure and Assumptions

3. clothes washers
4. lighting
5. others
8. dish washers
9. air conditioners

3.6 Chapter Bibliography


4. Aggregate Results for Canada

Output from each region provides the basis for an all-Canada analysis. When simulations of each sector or branch were completed, the output data were reviewed for consistency, to trap errors and to determine the need for supply-model iteration (i.e., does the requirement for electricity supply in the demand sectors fall within the range of that generated in the supply sector? If not, then go through another iteration.). Then all simulations were compared to the natural run to distinguish changes between runs and determine the impacts of various policies on the natural forecast by reviewing three outcomes: energy consumption, the level of CO$_2$ emissions and the costs associated with these changes. I display the results first as an aggregation of all sectors (industrial, commercial, residential and electricity generation) and then distinguish the results of the demand sectors from the supply sector (see figure 2.1) for all Canada. Then, in chapter 5, I provide more detail for each of the provinces and finally for each of the sectors.

4.1 ESSM Assumptions

Four assumptions fixed in ESSM (Liu 1995) caused some distortion of the results under the general analysis, requiring the separation of the electricity generation sector from industrial, commercial and residential sectors:

1. All electricity-generating stock retires at a given rate and cannot be retired early. For example, if once-active coal capacity remains after a period of low demand, it will be dispatched to meet an increase in demand, even if the annualised capital and operating cost of new capacity is less than the operating cost of this old capacity.

2. No new nuclear capacity will be built.

3. No new large hydro capacity will be built.

4. Renewables cannot compete for generation share; rather, they are allocated a specific quantity of new capacity requirements exogenously. This fixed share is known as a renewable set-aside.
Also, during competition for new capacity, biomass steam and biomass gasification technologies act as the only CO\textsubscript{2}-neutral source of electricity. Biomass fuels in the supply sector include wood and wood products, agricultural products, biotic waste material from other processes (e.g., flax sheaves, chaff and bagasse) and fuels manufactured specifically from agricultural crops; the supply of biomass to generate electricity is not constrained. Biomass fuels in the pulp and paper and wood products industries include only wood waste (hog fuel) and black liquor; there are limits to this supply and, in ISTUM, technologies using them are constrained.

### 4.2 Energy Consumption

Recall that the production of goods and services remains the same for each simulation. Any changes in energy demand between runs (see figure 4.1) can be attributed either to a change in efficiency, here defined as the quantity of goods or services that can be generated per unit of energy, or to fuel switching. It should be noted that simply the act of switching fuels can invoke an efficiency change. A portion of energy released during combustion vapourises combustion by-products (e.g., water), reducing the energy available for process activities. This portion varies from fuel to fuel. Each fuel can be defined in terms of its lower heating value (LHV, excludes vapourisation heat) and higher heating value (HHV, the total heat content). Moisture or contaminants in the fuel also affect the quantity of energy that be delivered to process, reducing its “efficiency”.

The frozen run, with no change in technology type, typically displays the highest level of energy consumption. Because aggregate production over time is fairly uniform and the time interval relatively short, the graph line of the frozen run appears linear over time even though growth is at a percent rate. But energy intensity, the inverse of energy efficiency (or the energy required to generate one unit of the good or service), is not quite linear per unit of production or service because:

- scenarios show shifts in industry products - The relative shares of some products (e.g., types of pulp, types of paper, chemical production) change over time.

- the mix of average and marginal intensity - In industry, average intensity is maintained for each product stream whereas in some commercial sub-sectors and the residential
sector, the marginal intensity is held constant. This is due to differences in the construction of facilities in the sectors and the relative availability of technologies that provide support of auxiliary services. For example, as a residential consumer, one cannot purchase a 1990 model refrigerator with an efficiency similar to that of the 1970 models. But as an industrial consumer, it is quite possible that the standard motor purchased in 1990 is much like the 1970 model.

Figure 4.1: Expected energy demand in Canada to 2010, an aggregate of industrial, commercial, residential and electricity generation sectors under different economic conditions.

The technical run, the most energy efficient of all the runs, represents the other extreme, showing a low level of energy consumption. In the technical run, renewable energy supplies and other non-fossil fuel sources generate the demanded electricity, given that existing fossil-fueled, hydro or nuclear stock is permitted to finish its life. The 44% difference in energy consumption between the frozen and technical run provides some indication of the degree to which consumption can be reduced in the modelled sectors. If we assume minimal autonomous technical improvement (AEEI = 0), the “frozen” line would reflect expected consumption in top-down simulations. Given assumptions about
retirement rates, technology replacement and retrofits, the technical run could represent a bottom-up approach to such an analysis, 100% penetration of the best technologies.

One would expect that, as the cost of generating CO₂ emissions increased, energy consumption levels would decline. This is only true if there is a direct correspondence between energy consumption and CO₂ emissions (\( CO₂ / FF \) and \( FF / PE \) of equation 1, chapter 1, remain constant). But this is not always the case. For example, certain industries (primarily pulp, paper and wood products) and the electricity generation sector can use biomass, a fuel with net 0 CO₂ emissions, as an energy source. Because of the poor quality of biomass fuel and the relative inefficiency of the devices using it, average efficiency actually worsens. Thus, with increasing costs of emissions, such industries consume increasing quantities of fuel (biomass) and energy demand in each cost run exceeds that of the natural run. Most of this increased energy consumption is due to a shift in electric power generation from fossil fuels or retired hydro and nuclear to biomass gasification (see points 2, 3 and 4 under section 4.1).

Table 4.1 shows that only the socio-economic run and the technical run use less energy than the natural run. In the technical run, options such as biomass and waste fuels gain no market share because these are considered inefficient fuels consumed by inefficient technologies. The socio-economic run does permit penetration of technologies that consume these inefficient fuels but such increases in fuel consumption are overwhelmed by the penetration of other, more efficient technologies.

Figure 4.2 provides the same information as figure 4.1 but without the change in energy demand displayed by the electricity generation sector. The frozen and technical runs still delineate the upper and lower extremes in energy consumption, but the sequence of the other runs changes.
Table 4.1: Energy Demand in Canada, Including Comparison to Natural Run (Industrial, Commercial, Residential and Electricity Generation Sectors, in PJ)

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<td>(255)</td>
<td>(530)</td>
<td>(559)</td>
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Figure 4.2: Expected energy demand in Canada to 2010, an aggregate of the industrial, commercial and residential sectors under different economic conditions.

Industries like pulp and paper still have the advantage of moving to biomass fuels and, for them, energy demand increases as emissions charges go up. Constraints placed on the market share of biomass technologies in these industries prevent them from exceeding the estimated biomass supply. As a result, figure 4.2 displays the expected relationship between runs; increased emissions charges causes a more or less proportionate decline in energy consumption. In fact, the impacts of the policy with the high emissions costs
($225 / tonne CO\textsubscript{2}) approaches what could be achieved through energy efficiency improvements under the economic criteria established for the socio-economic run (recall that these criteria place a higher importance on annual operating, maintenance and fuel costs than on initial capital investment). However, as we shall see, the fuel mix and the consequent level of CO\textsubscript{2} emissions of these two runs is not at all the same.

Table 4.2 provides some insights into the differences that occur between the runs. The rate of technological improvement (change between frozen and natural runs) is nearly 14% or about 0.65% / year; useful information for the top-down modeller in need of a value for AEEI.\textsuperscript{1} The technical potential (primarily a shift to electrical devices which have high efficiencies, with that electricity supplied through renewable sources as the old generating stock retires) suggests a reduction of another 28% from the natural run. The 37% span between the frozen and technical runs provides a picture of the top-down / bottom-up range in these sectors under the assumptions and criteria for retirement described in chapter 2. This span may be underestimated for three reasons:

1. One can execute a technical run where ISTUM rebuilds the sector or industry from scratch, installing only the most efficient technologies available during that simulation period. In so doing, the technical line would drop even more but the costs to the sector would be very high; it would mean a complete stock turnover every five years.

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<td>$225</td>
<td>4,812</td>
<td>4,896</td>
<td>5,105</td>
<td>5,404</td>
<td>5,852</td>
<td>282</td>
</tr>
</tbody>
</table>
2. I have attempted to develop a complete and comprehensive database of available and upcoming technologies for which data were available. But some technologies for which data were poor or unavailable were excluded, nor do all available technologies appear in ISTUM’s database.

3. Some models use fictitious technologies that show significant improvements in energy efficiencies, believing that such technologies, although not available at present, will be developed in the future. ISTUM’s database lists no such technologies.

The economic run shows no change from the previous table because the natural run and the economic run in the supply sector are the same. Because electric utilities are either publicly owned (public economic criteria) or publicly regulated, their natural run behaviour is simulated using the social discount rate.

An emissions charge does not elicit the same degree of energy change each year (see the “Change from Natural” portion of table 4.2, graphed in figure 4.3). For each of the three cost runs, the slope of the graph line diminishes over time; that is, the rate of change in energy saved diminishes as the sectors move to more efficient technologies over time. Of course, research and development (R&D) will generate new, more efficient technologies or processes as a result of the imposition of the cost policies, but such speculative technologies are not currently in ISTUM’s database in this research project.

Figure 4.3 also points out that, as the costs of emissions increase, the impact on energy reduction per dollar of increase is not the same. In other words, doubling or tripling the emission costs do not double or triple the quantity of energy reduced; it becomes increasingly more expensive to save the next unit of energy, suggesting diminishing returns to efforts to save energy, at least according to the currently constructed model.

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1The value given here is not a true AEEI value since fuel prices were not held constant relative to capital, operating and maintenance costs. Cost changes, however, are relatively small and this may be considered a reasonable approximation of AEEI.
Figure 4.3: Reduction in energy from the natural run under the three costs-of-emissions runs for an aggregate of industrial, commercial and residential sectors in Canada.

4.3 Generation of CO₂ Emissions

Figure 4.4 graphs the CO₂ emissions generated under each simulation for all sectors and includes lines that display the two targets: 1990 stabilisation and 20% reduction (-20%) from 1990 levels. The graph indicates that stabilisation can be met at a cost level less than $75/tonne by 2000 but that no cost level modelled here can meet the second target. However, because the technical line falls below the 20% reduction target, we can assume that, at some cost, the target could actually be met; the target is technically feasible.

Remember too, that the technical run focuses on energy efficiency, not CO₂ reduction. There are inefficient technologies (e.g., biomass-fired boilers) that could further reduce CO₂ emissions from the level indicated here.

Again, the assumptions applied to the simulations of electricity generation affect the results shown here. In this case, the dispatch of electricity from sources with a lower intensity of CO₂ (i.e., the avoidance or underutilisation of existing coal capacity) in the early years allows the stabilisation target (and even the reduction target) to be met. But revival of dormant coal capacity in later years subverts actions to meet either target.
Chapter 4

Figure 4.4: CO₂ emissions in Canada, an aggregate of industrial, commercial, residential, and electricity generation sectors under different economic conditions.

These assumptions also affect the position of the technical line relative to the others. Electricity demand is much higher under the technical run than any of the others because electric technologies display high end-use efficiencies. In a technical simulation of energy supply, the existing stock of electricity generators is permitted to retire at its normal rate and be replaced by stock that uses a renewable energy supply and releases no CO₂. Because existing stock has a fairly even age distribution, stock retirement rates are linear. As a result, the slope of the technical line remains fairly constant and is negative.

The CO₂ emissions equation (equation 1, chapter 1) suggests that changes in both efficiency and the carbon intensity of fuels affect emissions levels. An improvement in energy efficiency implies an improvement in process or design (\(PE/SE\) and \(SE/GDP\) in the equation or \(PE/GDP\)). And one often considers a shift in carbon intensity of all fuels the result of fuel switching (\(CO₂/FF\) and \(FF/PE\) in equation 1 or \(CO₂/PE\)). However, simply shifting fuel types may already entail an efficiency improvement; it depends on the ratio of the HHV to the LHV of the fuel (section 4.2). As the hydrogen content of a fuel increases, the LHV / HHV ratio declines and more of the energy released on burning must be used to evaporate the water generated. For example, more of the heat released during
the combustion of coal can be applied to a process (e.g., steam generation) than the same quantity of heat released from natural gas because burning coal generates less water than burning natural gas. This has some implications regarding the emissions formula; more “efficient” fossil fuels such as coal also tend to release more CO$_2$ than the less “efficient” fuels such as natural gas. In most cases, however, the loss in energy efficiency due to fuel type is more than made up by the increased energy efficiency of the alternative technology or process. In fact, some technologies are capable of extracting the heat of vapourisation from the exhaust stream and apply it to the process.

While most industries become more energy efficient and reduce their total and per unit CO$_2$ emissions under the cost runs, others can actually become less efficient and still reduce their total and per unit CO$_2$ emissions (e.g., the pulp and paper industry). If the goal is emissions reduction, regions that have large pulp and paper industries or a significant supply of biomass available as fuel have an advantage over those that do not. Such regions may see energy intensity climb while those in regions without large biomass industries see intensity diminish.

Electricity, at point of end-use, releases no CO$_2$ and electrically driven technologies are not affected directly by any emissions charges. But the utility responsible for the production of the electricity adds the emissions charge to its electricity price. Those regions showing low CO$_2$ intensities for electricity also show strong shifts to electricity-driven alternatives and a consequent reduction in the consumption of fossil fuels in demand sectors. But, in those regions dependent primarily on fossil fuel generation, the demand sectors show increased fossil fuel consumption under cost runs; the transformation efficiency of fossil to electrical energy (between 33-40%) doubles or triples electricity prices under high cost runs, moving consumers away from electricity to fossil fuels. Thus, in these regions, the cost runs actually induce increased CO$_2$ release in demand sectors because the decline in CO$_2$ emissions due to not consuming electricity is accorded to the supply sector.

Table 4.3 provides details concerning CO$_2$ emissions. The autonomous change in CO$_2$ generation results in an 1.5% reduction from the frozen run. Given the fuel prices provided by the CEO, 1994 Update, the price of heavy fuel oil and coal declines relative
to natural gas and industries move to these more carbon-intense fuels over time. Thus, in terms of CO$_2$ emissions, efficiency improvements ($\Delta PE / GDP$) are nearly overcome by increased CO$_2$ intensity ($\Delta CO_2 / PE$). Under the assumptions made in the technical run, we could reduce by half the quantity of CO$_2$ expected in the natural run by 2010 and exceed the reduction target by 20%.

Table 4.3: CO$_2$ Emissions in Canada, Including Comparison to Natural Run (Industrial, Commercial, Residential and Electricity Generation Sectors, in millions of tonnes)

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<td>(23.7)</td>
<td>(20.9)</td>
<td>(5.7)</td>
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<td>5.2</td>
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<td>160.2</td>
<td>68.5</td>
<td>102.4</td>
<td>147.2</td>
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<td>244.2</td>
<td>265.2</td>
<td>304.9</td>
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<td>52.8</td>
<td>56.3</td>
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<tr>
<td>- 20%</td>
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<td>202.5</td>
<td>202.5</td>
<td>202.5</td>
<td>69.2</td>
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<td>115.5</td>
<td>158.6</td>
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The economic run shows only a small decline from the natural run. Recall from section 4.2 that overall energy demand was nearly the same in the $225/tonne run and the economic run but here we see that the $225/tonne run shows significantly less CO$_2$ emissions than the economic run. A review of the data indicates that, in many regions, coal is the fuel of choice for electricity generation under the economic run and, while coal technologies tend to be more efficient than their alternatives, CO$_2$ emissions are higher.

If we look at a graph displaying data from just the demand sectors (figure 4.5), we see the importance of electricity generation in reaching the stated targets. In these sectors, an emissions charge of at least a $150/tonne would be required to meet the stabilisation target and that target would not be maintained past 2000. To maintain stabilisation requires a charge of $225/tonne. Only if we maximise efficiency (the technical run) can the 20% reduction target be met. If we permitted biomass-fueled technologies to obtain a share of the market, in spite of its inefficiencies, the target could be surpassed.
Figure 4.5: CO₂ emissions in Canada, an aggregate of industrial, commercial and residential sectors under different economic conditions.

Because the natural and economic run in the energy supply sector are identical, the difference between the natural and economic runs displayed in tables 4.3 and 4.4 are dependent on just the industrial, commercial and residential sector.

As noted in the review of energy demand (figure 4.3), introducing a linear increase in emissions charges does not generate a linear decline in CO₂ emissions either; the slopes of the lines diminish over time (see the “Change from Natural” portion of table 4.3, graphed in figure 4.6). The graph in figure 4.6 also contains a line representing the stabilisation level and the line representing the reduction target of 20% below 1990 levels of emissions. Again, this supports the premise that it becomes increasingly more expensive (difficult) to reduce an additional tonne of CO₂, both over time and as emissions charges increase.
Table 4.4: CO₂ Emissions in Canada, Comparison to Natural Run (Industrial, Commercial and Residential Sectors, in millions of tonnes)

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</thead>
<tbody>
<tr>
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<td>203.4</td>
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<td>269.9</td>
<td>(1.3)</td>
<td>(4.8)</td>
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<td>(9.4)</td>
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<td>58.6</td>
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Figure 4.6: Reduction in CO₂ emissions from the natural run under three costs-of-emissions runs for an aggregate of industrial, commercial, and residential sectors in Canada.

4.4 Costs

Before assessing the costs associated with changes in energy demand or the reduction in CO₂ emissions, I review three concepts related to how cost evaluation took place in the analysis: the cost calculation and the exclusion of emissions charges from costs, marginal costs and actual costs of abatement, and private and public view of costs.
Chapter 4 Aggregate Results for Canada

- Cost calculation and emissions charges

All emissions charges, whether a tax, permit charge or other financial penalty, are assumed to be redistributed to consumers such that there is no net tax drain on society. Thus, costs are calculated based on the life-cycle costs per unit as found in the natural run:

$$TLCC_{it} = \sum_{k=1}^{v} S_{kit} \times LCC_{k(nat)t}$$

(8)

where:

- $TLCC_{it} = \text{total of all annualised (life-cycle) costs in run } i \text{ in year } t$
- $S_{kit} = \text{total stock of technology } k \text{ in run } i \text{ in year } t$
- $LCC_{k(nat)t} = \text{life cycle cost of technology } k \text{ in the natural run in year } t$
- $v = \text{all technologies for which there is a market share}$

The difference between $TLCC_{nat,t}$ and $TLCC_{it}$ provides information concerning the expenditures made in response to the conditions of run $i$ without the effect of emissions charges (including any charges on CO$_2$ emissions associated with electricity generation).

- Marginal and average costs of emissions reduction

The emissions charges imposed by a proposed policy can be considered the marginal cost of emissions reduction, the cost of the last tonne removed. That is, if the expenditure to remove the next tonne of CO$_2$ exceeded the charge imposed by the regulation (i.e., $75$, $150$, or $225$), the firm or household would pay the imposed charge. The average cost differs from this level because some emissions reduction can occur at little or no cost over what would have otherwise been spent. Thus, the average cost could equal but never exceed the marginal cost in an economically rational world. If the cost of the bulk of the alternatives for emissions reduction are near the marginal cost, average and marginal costs approach each other. If the bulk of regulation-induced costs are minimal, marginal costs far exceed average. In fact, the average cost could be positive (a monetary saving) if the imposition of an emissions charge enhances a trend already occurring in the natural run.

- Public and private view of life-cycle costs
When discussing costs and expenditures, the analyst’s viewpoint has an impact on conclusions drawn. From a public (economic run) point of view, an economic criterion such as a 30% discount rate promotes an inappropriate view of the future and the costs incurred in a natural run are much higher than they should be. From a private (natural run) viewpoint, an economic criterion such as a 7% discount rate fails to include an acceptable return for capital given risk, uncertainty, and a number of other market factors. From this point of view, the firm would lose were they to make choices similar to those under the criteria of the economic run. By comparing all runs to the natural run, we obtain the “private” or business view of life-cycle costs. From this view, all other runs should be more expensive (otherwise, in an economically rational world, it would have already been done!).

Table 4.5 contains data on the total annualised life-cycle costs as calculated using equation 8. From the private perspective, all costs except those incurred in the frozen run are more expensive than the natural run. The frozen run is less expensive than the natural because requirements of changed building codes and regulations increase the cost of construction in the residential and commercial sectors (this may not be true of all regions). Note that, as emissions charges increase, so does the cost to avoid them.

By taking the difference in costs and dividing them by the change in tonnes of CO$_2$ emissions, we can determine the average cost per tonne of emissions reduced, as in table 4.6. From this table, we see that, as emissions charges increase, more is spent to avoid the charges, and that the marginal cost far exceeds the average cost. In other words, if consumers see a charge of $225/tonne CO$_2$ emitted, the average expenditure in 2010 would be about $100/tonne.
The costs displayed in the technical run provide some indication of the degree to which
customers would need to spend to reach the CO\textsubscript{2} levels achieved by this run, given that
the technical run is concerned with energy efficiency rather than a reduction of CO\textsubscript{2}
emissions. If we assume that the marginal cost far exceeds the average cost, the charge
per tonne of CO\textsubscript{2} emissions would have to exceed $2000, with most of the costs incurred
in the early years.

The rather high costs indicated by the economic run are primarily a consequence of the
minor change in CO\textsubscript{2} emissions levels. From table 4.5, we see that from the private
perspective costs incurred in the economic run are higher than the natural run. Table 4.3
shows that the reduction in CO\textsubscript{2} emissions is quite small compared to cost runs because
the focus is economic efficiency rather than energy efficiency or emissions reduction.
Thus, any expenditure with a near 0 change in CO\textsubscript{2} emissions would result in an
extraordinarily high cost per unit CO\textsubscript{2} reduction (this provides the analyst with little
further information and this row will not be included in the following tables of this type).
Table 4.7 reviews expenditures in the various runs in the demand sectors. The patterns follow those found when the electricity supply sector was included (see table 4.5): high average cost in technical runs and increasing expenditures under the set of runs simulating emissions charges.

**Table 4.7: Annualised Costs in Canada, Including Comparison to Natural Run, for Industrial, Commercial and Residential Sectors (‘90 $billions)**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Froz</td>
<td>149.5</td>
<td>170.4</td>
<td>191.6</td>
<td>214.6</td>
<td>241.5</td>
<td>6.5</td>
</tr>
<tr>
<td>Nat</td>
<td>149.5</td>
<td>177.0</td>
<td>205.3</td>
<td>231.3</td>
<td>260.3</td>
<td>-</td>
</tr>
<tr>
<td>Econ</td>
<td>149.5</td>
<td>185.4</td>
<td>215.6</td>
<td>243.1</td>
<td>273.4</td>
<td>(8.4)</td>
</tr>
<tr>
<td>Tech</td>
<td>149.5</td>
<td>226.3</td>
<td>263.7</td>
<td>294.9</td>
<td>331.6</td>
<td>(49.4)</td>
</tr>
<tr>
<td>$75</td>
<td>149.5</td>
<td>177.7</td>
<td>206.3</td>
<td>232.5</td>
<td>261.7</td>
<td>(0.7)</td>
</tr>
<tr>
<td>$150</td>
<td>149.5</td>
<td>178.6</td>
<td>207.6</td>
<td>234.1</td>
<td>263.8</td>
<td>(1.6)</td>
</tr>
<tr>
<td>$225</td>
<td>149.5</td>
<td>179.8</td>
<td>209.4</td>
<td>236.6</td>
<td>266.6</td>
<td>(2.8)</td>
</tr>
</tbody>
</table>

When one excludes the incurred costs in the electricity generation sector from the analysis, the average cost of reducing a tonne of CO\(_2\) drops; that is, reducing a tonne of CO\(_2\) in the generation of electricity costs more, on average, than reducing a tonne of CO\(_2\) in the aggregate of the demand sectors. Table 4.6 and 4.8 hide some important regional differences, detailed in chapter 5. For example, regions dependent on electricity from fossil fuel fired generators reduce CO\(_2\) emissions by switching from electricity to fossil fuels where possible in the demand sectors. Thus, as described earlier, increasing emissions charges actually increases CO\(_2\) emissions in some of the demand sectors simulated in ISTUM.

**Table 4.8: Average Benefit (Cost) of CO\(_2\) Emissions Reduction Industrial, Commercial and Residential Sectors ($/tonne)**

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tech</td>
<td>(871)</td>
<td>(751)</td>
<td>(669)</td>
<td>(622)</td>
</tr>
<tr>
<td>$75</td>
<td>(43)</td>
<td>(39)</td>
<td>(36)</td>
<td>(39)</td>
</tr>
<tr>
<td>$150</td>
<td>(60)</td>
<td>(55)</td>
<td>(53)</td>
<td>(58)</td>
</tr>
<tr>
<td>$225</td>
<td>(81)</td>
<td>(76)</td>
<td>(73)</td>
<td>(77)</td>
</tr>
</tbody>
</table>

The change seen in the average cost of reduction, when the costs of the generation sector are excluded (compare tables 4.6 and 4.8), indicates that some sectors will spend more
than others when they seek to avoid a specific emissions charge. In fact, average costs vary considerably from sector to sector and from region to region. In some cases, average costs vary within the same sector or industry as one moves from one region to another. For example, the costs incurred to reduce emissions in the pulp and paper industry are higher in BC than they are in Ontario, primarily due to the fuel mix in the base year (i.e., Ontario firms can move from oil to natural gas at relatively low cost, while most BC operations already use natural gas and have no similar inexpensive alternative). ISTUM’s disaggregated approach enables the analyst to separate the regions and sectors; such information would be very helpful to the decision maker in a review of impacts of the policy on various sectors and sub-sectors in his / her region.

4.5 Summary of Results

Model simulations indicate that it is technically possible to meet both stabilisation and reduction targets, even without the benefit of fuel switching to biomass. To induce consumers to meet the target of a 20% reduction in CO2 emissions from the 1990 level in the sectors analysed, without imposing the efficiency constraints of the technical run, has a marginal cost of at least $150 per tonne CO2 ($550 per tonne carbon), or about $65-$75 average cost per tonne CO2 reduced (about $240 - $280 per tonne carbon). Stabilisation can be accomplished for less than a marginal cost of $75 per tonne CO2 ($275 per tonne carbon) in these sectors, or an average cost of about $45 per tonne CO2 reduced ($165 per tonne carbon).

An efficiency improvement of 14% (about 0.65% / year) can be expected due to autonomous efficiency improvements, response to fuel price change and structural shifts in the demand sectors. Even so, such an improvement amounts to only 4.5% less CO2 emitted (about 0.17% / year) than would have otherwise been generated, primarily because of a shift to more carbon-intense fuels. Under socio-economic criteria, efficiency levels in the demand sectors improve by nearly 25% over a no-change alternative and the CO2 emissions would have declined only marginally more, about 5% less than otherwise, for the same reason.
Many regions in Canada depend on electricity generated from fossil fuels. The ability to move away from this source to some non- or low-carbon-based source plays a very important role in any program to meet the targets for CO$_2$ emission levels. In my analysis, the supply-side simulations are a significant source of uncertainty (see below) and introduce a bias that I argue in chapter 5 and 6 would contribute to an underestimation of CO$_2$ reduction potential and an overestimation of the costs of reduction. Also, this analysis does not include the transportation sector, one of the largest sources (and potentially one of the cheapest points of reduction) of CO$_2$ emissions. Actions to reduce emissions in this sector could contribute a significant level of emissions reduction at lower costs than stated above.

4.6 Sensitivity Analysis

Sensitivity analyses were completed on one input and two parameters in ISTUM: fuel prices, discount rates and the variance parameter applied in the inverse power algorithm (see equation 6, chapter 2). Each of these was analysed in terms of the impact of changes in their value on levels of energy consumption in order to test the model’s response to these changes and to understand the importance of the uncertainty surrounding the input and parameters. Analysis on two industries, irons and steel and industrial minerals (cement and lime), and the residential sector are reported here. Cement and lime industries are energy-intensive and energy costs are relatively high compared to the industry average ($\approx 20\,\xi$ per $ shipped compared to $\approx 2\,\xi$ per $ shipped average) while iron and steel industries face costs of about $4\,\xi$ per $ shipped (Geller and Elliot 1994).

4.6.1 Analysis of Fuel Prices

To test the model’s responsiveness of energy consumption to changes in fuel prices, a number of analyses were completed on price changes in natural gas, coal and oil. The analyses attempted to assess the model’s response to a change in the price of one fuel while others remain constant. The values reflect both efficiency improvements and fuel switching in industry and residences in tables 4.9 and 4.10.
The cement industry has long been sensitive to changes in fuel prices and most Canadian plants are able to switch fuels rapidly. They are also capable of burning a large variety of fuels including coal coke, petroleum coke and waste-derived fuels (tires, municipal refuse, hog fuel, etc.). In Ontario, natural gas is more expensive than heavy oil or coal and captures only a small share of the market. From table 4.9, change in its consumption under small shifts in fuel price is not great, but as the natural gas price approaches that of coal and oil, the rate of change (elasticity) increases considerably. Coal prices, on the other hand, are very competitive with heavy oil, coal coke and petroleum coke. Even small shifts in price generate significant shifts in consumption, a very elastic response to price change. A review of the technology stocks points out that a change in the price of fuel encourages more fuel switching than efficiency improvements.

Table 4.10 provides results on the effects of changing the price of natural gas and then oil in a set of runs in BC’s residential sector. Response to price change here is not as dramatic as in the cement industry shown above (or, it turns out, for industry in general), because of relatively higher discount rates, the lower proportion of life-cycle costs that fuel assumes and the longevity of housing stock. In BC’s residential sector, the data suggest own-price elasticities of about -0.7 for natural gas and about -1.5 for heating oil. An analysis where the prices of all fuels were varied in the residential sector in BC generated Allan elasticities (substitution elasticity of capital expenditures and energy expenditures) of -0.8 to -1.0 when prices were varied ±10%.
### Table 4.10: The Effect of Change in Price of Natural Gas and Heating Oil on Energy Consumption in BC’s Residential Sector, 2010

<table>
<thead>
<tr>
<th>% Change in Fuel Prices</th>
<th>Energy (PJ) and % Change in Fuel Use in Residences (BC)</th>
<th>Natural Gas</th>
<th>Heating Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Energy</td>
<td>Change</td>
<td>Energy</td>
</tr>
<tr>
<td>+10%</td>
<td>63.67</td>
<td>-7.73%</td>
<td>1.70</td>
</tr>
<tr>
<td>+5%</td>
<td>66.33</td>
<td>-3.87%</td>
<td>1.84</td>
</tr>
<tr>
<td>CEO Prices</td>
<td>69.01</td>
<td></td>
<td>1.99</td>
</tr>
<tr>
<td>-5%</td>
<td>71.67</td>
<td>3.86%</td>
<td>2.16</td>
</tr>
<tr>
<td>-10%</td>
<td>74.31</td>
<td>7.69%</td>
<td>2.34</td>
</tr>
</tbody>
</table>

The sensitivity analyses point out that ISTUM shows reasonable responses to fuel price change at least over this range of ±10%. It also shows that, because response to price change is important, the analyst should review carefully the forecasted price of fuels - uncertainty concerning fuel price is significant.

#### 4.6.2 Analysis of Discount Rates

Discount rates were varied incrementally ±5% for a range of ±15% percentage points over those initially applied to the industries tested (i.e., if the natural run rate was 50%, sensitivity analysis tested rates at 35%, 40%, 45%, 55%, 60% and 65%). Table 4.11 shows that energy demand under these discount rates shows, at maximum, a ±2% change.

### Table 4.11: The Effect of Uncertainty in Discount Rate on Energy Consumption

<table>
<thead>
<tr>
<th>Discount Rate, Change from Natural Run</th>
<th>Industrial Minerals</th>
<th>Iron and Steel</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2005</td>
<td>2010</td>
</tr>
<tr>
<td>+15%</td>
<td>1.33</td>
<td>1.31</td>
</tr>
<tr>
<td>+10%</td>
<td>0.88</td>
<td>0.88</td>
</tr>
<tr>
<td>+5%</td>
<td>0.50</td>
<td>0.49</td>
</tr>
<tr>
<td>Nat. Run Rate</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>-5%</td>
<td>-0.49</td>
<td>-0.52</td>
</tr>
<tr>
<td>-10%</td>
<td>-1.10</td>
<td>-1.17</td>
</tr>
<tr>
<td>-15%</td>
<td>-1.80</td>
<td>-1.93</td>
</tr>
</tbody>
</table>

Tests beyond this range, with discount rates ±25% to 50%, have a greater effect on the levels of energy consumption and form part of the overall analysis. Thus, while the
Chapter 4 Aggregate Results for Canada

distinction between the public and private rate is important, an uncertainty of ±15% in the value applied in either the natural or economic runs is considerably less so.

4.6.3 Analysis of the Variance Parameter

Values of 6, 8, 20, and 30 were tested in a sensitivity analysis of the variance parameter (value in natural run was 10). From the graph in figure 2.6, chapter 2, a variance parameter value of “6” would suggest that, if the life-cycle costs of competing technology prices were 15% different, 72% of managers would purchase the cheaper technology, about 80% would buy the cheaper technology at a variance of 8, 93% at 20 and 95% at 30. Over the twenty year simulation period, this behavioural variation (roughly ±10%, with between 72% and 95% of managers purchasing the cheaper technology) causes less than ±2% change in energy consumption where, as the variance increases (indicated by the lower values in this inverse function), the energy levels increase because all available technologies tend to receive similar market shares. This parameter, more than the others, is affected by the composition of and information available on the set of alternative technologies and their capital, operating and maintenance costs (see table 4.12).

Table 4.12: The Effect of Uncertainty in the Variance Parameter on Energy Consumption

<table>
<thead>
<tr>
<th>Variance Parameters Tested</th>
<th>Change in Fuel Use, % in 2005, 2010</th>
<th>Industrial Minerals</th>
<th>Iron and Steel</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2005</td>
<td>2010</td>
</tr>
<tr>
<td>6</td>
<td></td>
<td>0.37</td>
<td>0.41</td>
</tr>
<tr>
<td>8</td>
<td></td>
<td>0.17</td>
<td>0.18</td>
</tr>
<tr>
<td>Base 10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20</td>
<td></td>
<td>-0.58</td>
<td>-0.72</td>
</tr>
<tr>
<td>30</td>
<td></td>
<td>-0.96</td>
<td>-1.24</td>
</tr>
</tbody>
</table>

As the parameter values applied in the tests on purchasing behaviour approach maximum economic sensitivity (low variance) or complete indifference to life-cycle cost minimisation (high variance), the changes become more dramatic, but, within this range, the impact is relatively small. These results suggest that estimations of behaviour made in the absence of enough data to run logit or other qualitative-choice models (see chapter 2) are sufficient, at least within this range, to obtain credible results.
4.6.4 Summary

The model shows sensitivity to price changes in fuels and analysts are advised to consider carefully the uncertainty surrounding forecasts of fuel price, an exogenous input to ISTUM. Within a range of ±10%, neither behavioural parameter (discount rate or variance in life-cycle costs) shows major changes in the level of energy consumption. But, at a certain level of behavioural characterisation, the model does show sensitivity to shifts in these parameters. This does not necessarily reduce our uncertainty concerning the value of the applied parameters but it does allow us to place greater confidence in research completed by energy supply utilities and academic institutions on time preference (discount rate) and market shares of technologies (variance parameter) to develop these parameter values for application in this analysis.

4.7 Remaining Issues

In addition to uncertainties listed in chapter 2, table 2.1, uncertainty affects my analysis in three other components as well: ESSM’s outputs, the technologies and their characteristics, and the transportation sector’s effect on the overall CO₂ emissions picture.

4.7.1 ESSM Results

With my focus on the demand sectors, I did not alter or further develop ESSM, the supply sector model that generated new prices for electricity under various CO₂ policies. However, after considering the regional implications (chapter 5), I recognized that the model requires some reworking to make it suitable for future analyses of this type.

Given the types of technologies listed in ESSM (e.g., the only CO₂-neutral supply technology that could compete for market shares was a biomass-fueled thermal unit) and the consequent lack of “generation flexibility” in response to changes in CO₂ emissions charges, especially in terms of existing but dormant capacity (see section 4.6 above), the model produces results that could prove unlikely or unrealistic to experts in the supply sector. For this reason, my analysis shows the supply sector disaggregated from the demand sectors in the results described above and for those described in chapter 5. In any case, the goal of this analysis involves the potential for and the benefits of iteration.
between a supply model and the set of demand models being tested here; this I have demonstrated.

4.7.2 Technology Database

It is crucial, in such a disaggregated energy analysis, that the technology detail bear strong similarity to the existing system. While significant effort went into verifying technology stock and characteristics through the data in engineering texts and through discussions and review by industry and sector experts, utility program designers, industry consultants and general practitioners, questions always remain regarding the comprehensiveness of technology detail. There are many more technologies than can be described in the model’s databases that can compete at a competition node. Thus, the goal is to represent adequately the main options available to a purchaser of technologies in an industry or sector (Roop and Kaplan, 1984). Nevertheless, it is still possible that some important technologies are overlooked or their characteristics are portrayed inaccurately.

Except for some general notion of continually-improving efficiency or process design, few data on the impacts of research and development (R&D) were available. Specific technology or process improvements are published regularly in various journals and industry brochures and, where warranted, I have included speculation on the effect of some technologies in ISTUM’s database. Although many more speculative technologies can be added, I have chosen to represent only those for which I had documentation.

A number of energy-use characteristics are dependent not on the technologies but rather on their management and maintenance or on the initial architectural or engineering design of the residence, commercial building or industrial process. This later condition (structural or process design) can be extended to include not just a specific plant, office or residence but also their interaction with other industries, floor space or residences, even across sectors. For example, the concept of industrial ecology includes the idea that energy (or materials) considered of low quality or otherwise inadequate in one industry may be useful in another; such industries could be situated next to each other in an industrial park such that waste materials or low quality heat can be utilised by the second industry or, in terms of waste heat, by residences or commercial buildings. Such
thermodynamic symbioses are not included in the model database because they could not be defined as specific technologies.

“Housekeeping” characteristics are included in the database if the human component of the action is replaced by a technical component (e.g., computer control or automatic greasing systems replace improper scheduling or maintenance routine). Even so, there remain many opportunities for efficiency improvements not presently included in the database because they are not technologies or cannot be linked to technologies. I tested an approach that lists a technology twice in the database where the second listing shows “name-plate” or engineering efficiency (rather than the average installed efficiency) coupled with higher maintenance costs implying improved maintenance practices and proper operation. But this has the effect of doubling the size of the database and the sets of competing technologies; the value gained from such an operation is minimal, especially since data to support the estimate of the improvements do not exist. Instead, one may estimate exogenously the value of improved maintenance measures (Jaccard et al. 1992a, 1992b).

**4.7.3 Impact of the Transportation Sector on the Analysis.**

All estimates of emission reductions and associated costs have been made without reference to the transportation sector. But, because this sector is one of the largest contributors to the quantity of CO$_2$ emitted, comments on total CO$_2$ reduction, technical potential and the like must be understood in terms that exclude the potentials from the transportation sector. Implications are discussed in chapter 6.

**4.8 Chapter Bibliography**


Chapter 5 Regional and Sectoral Results

Each region displays unique characteristics of energy demand because of climate, fuel supply, the industrial base and regional electricity generation, all reasons to support the level of disaggregation required in this analysis. Simulations of the various sectors by region provide evidence that these regional variations generate differences in fuel mix, CO₂ emissions and the costs of emissions reduction between provinces. Nearly 50 sub-models of ISTUM were used in the analysis, with each sub-model undergoing the 7 runs described in chapter 2. This section reports only pertinent information by region and sector; appendix B holds details.

For each region, the results on CO₂ emissions are compared to stabilisation and reduction targets for that region as if each region was responsible for meeting the targets. These targets are actually set for the whole country, and each region may contribute differently to the aggregate, but using regional targets facilitates regional analysis and provides critical information for policy analysts responsible for negotiating national and international agreements.

Table 5.1 contains a summary of marginal and average costs required to reach, if possible, the various targets in each region. If a target could not be met in emission cost runs but was met in the technical run, the marginal costs are simply described as “>225” and I include no estimate of average cost. If the targets could not be attained in any run, table cells are marked with “--”. For example, it is technically possible to attain both targets in Alberta if all sectors are included in the analysis but if we look at the demand sectors, no target could be attained in any simulation.

Table 5.2 approaches the analysis on a sector-by-sector basis. Like table 5.1, it contains a summary of marginal and average costs required to reach, if possible, the various targets in each sector or sub-sector of industrial, residential, commercial and supply sectors. Again, if a target could not be met in the simulation of the cost runs but was met in the technical run, the costs are listed as “>225” and no estimate of average cost is given with
Table 5.1: Summary of Marginal and Average Cost ($/tonne) of Various Sectors* to Attain Targets‡ by Region.

<table>
<thead>
<tr>
<th>Region</th>
<th>Demand and Supply Sectors</th>
<th>Demand Sectors</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Stabilisation</td>
<td>20% Reduction</td>
</tr>
<tr>
<td>BC</td>
<td>0  0</td>
<td>75  80</td>
</tr>
<tr>
<td>AB</td>
<td>&gt;225  -</td>
<td>&gt;225  -</td>
</tr>
<tr>
<td>SK</td>
<td>75  50</td>
<td>&gt;225  -</td>
</tr>
<tr>
<td>MB</td>
<td>75  68</td>
<td>100  75</td>
</tr>
<tr>
<td>ON</td>
<td>80  55</td>
<td>&gt;225  -</td>
</tr>
<tr>
<td>PQ</td>
<td>80  65</td>
<td>170  110</td>
</tr>
<tr>
<td>AT</td>
<td>30  20</td>
<td>75  30</td>
</tr>
<tr>
<td>CAN</td>
<td>70  40</td>
<td>&gt;225  -</td>
</tr>
</tbody>
</table>

* Supply = electricity generation sector; Demand = industrial, commercial and residential sectors.
‡ Targets are stabilisation by 2000, %20 reduction in emissions by 2010

Targets not attained marked as “—”. Note that, given the growth rates as defined in the scenario and provided by NRCan’s CEO, 1994 Update, it is not possible to attain stabilisation or reduction targets in industry in total but it is possible to reach some targets in specific industries such as pulp and paper. Industries dependent on significant quantities of heat for kilning, smelting, drying or distillation have few options for shifting.

Table 5.2: Summary of Marginal and Average Costs ($/tonne) of Various Sectors to Attain Targets.

<table>
<thead>
<tr>
<th>Sector</th>
<th>Stabilisation</th>
<th>20% Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
<td>-- --</td>
<td>-- --</td>
</tr>
<tr>
<td>Pulp and Paper</td>
<td>50  25</td>
<td>70  35</td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>150  45</td>
<td>-- --</td>
</tr>
<tr>
<td>Mining</td>
<td>-- --</td>
<td>-- --</td>
</tr>
<tr>
<td>Petroleum Refining</td>
<td>-- --</td>
<td>-- --</td>
</tr>
<tr>
<td>Industrial Minerals</td>
<td>-- --</td>
<td>-- --</td>
</tr>
<tr>
<td>Chemical Products</td>
<td>-- --</td>
<td>-- --</td>
</tr>
<tr>
<td>Metal Smelting</td>
<td>225  26</td>
<td>&gt;225</td>
</tr>
<tr>
<td>Other Manufacturing</td>
<td>&gt;225</td>
<td>&gt;225</td>
</tr>
<tr>
<td>Commercial</td>
<td>75  100</td>
<td>150  125</td>
</tr>
<tr>
<td>Residential</td>
<td>0  0</td>
<td>75  35</td>
</tr>
<tr>
<td>Electricity Generation</td>
<td>0  0</td>
<td>&gt;225</td>
</tr>
<tr>
<td>Supply</td>
<td>70  40</td>
<td>&gt;225</td>
</tr>
</tbody>
</table>
away from fossil fuels and the production of CO$_2$ if they wish to maintain exogenously-set production levels. More details are provided in section 5.8.1 and in appendix B. The supply sector results are drawn from ESSM; all others come from ISTUM.

5.1 British Columbia

British Columbia generates electricity from primarily hydraulic sources. Because of its supply of hydroelectric power and the abundance of biomass fuel, BC energy consumption explains only 9% of the CO$_2$ emissions released in Canada, a distant fourth among the provinces even though BC ranks third in terms of population.

BC sectors, including transportation, account for just over 11% of all energy consumption in Canada. The moderate coastal climate is unique in that space heat loads are lower than elsewhere in Canada, but the interior resembles conditions typical of the rest of the country. Thus, ISTUM’s sub-model for the BC residential sector displays regional disaggregation. Pulp and paper operations and supporting chemicals companies consume more than half of all industrial energy demanded, about equal to the sum of the residential and commercial sectors (at $\approx$12.5% each). Other major industries include lumber products, mining and cement production.

5.1.1 Energy

BC shows energy consumption characteristics typical of provinces where hydraulic power generates the bulk of the electricity. Because this energy source is considered CO$_2$-free, low-cost electricity under the various cost runs induces a technology shift to electricity-end-use alternatives and a consequent reduction in emissions. However, future incremental generation of electricity depends on renewables and biomass-fired generation, and not on new hydraulic sources. Thus, table 5.3 shows that energy demands increase when cost runs are compared to a natural run, indicating an increase in overall energy intensity. The technical runs shows that, if hydraulic or some alternative, non-thermal technique to generate electricity were used, total energy demand could be reduced to less than two thirds of that in the natural run. The major drop in energy consumption seen in the first simulation year (1995), except for the frozen run, arises because demand for
electricity can be met without the operation of BC Hydro’s Burrard thermal generating station. Note that the energy consumed in 1995 is the same in both table 5.3 where the electricity generation sector is included and table 5.4 where it is not; this indicates that all electricity made in BC comes from existing hydro or some other non-thermal generation source.

Table 5.3: Energy Demand in BC, Including a Comparison to the Natural Run (Industrial, Commercial, Residential and Electricity Generation Sectors, in PJ)

<table>
<thead>
<tr>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Froz</td>
<td>715</td>
<td>769</td>
<td>824</td>
<td>900</td>
<td>985</td>
<td>(138)</td>
</tr>
<tr>
<td>Nat</td>
<td>715</td>
<td>631</td>
<td>635</td>
<td>705</td>
<td>789</td>
<td>-</td>
</tr>
<tr>
<td>Econ</td>
<td>715</td>
<td>561</td>
<td>567</td>
<td>635</td>
<td>723</td>
<td>71</td>
</tr>
<tr>
<td>Tech</td>
<td>715</td>
<td>544</td>
<td>502</td>
<td>491</td>
<td>490</td>
<td>88</td>
</tr>
<tr>
<td>$75</td>
<td>715</td>
<td>643</td>
<td>672</td>
<td>745</td>
<td>829</td>
<td>(12)</td>
</tr>
<tr>
<td>$150</td>
<td>715</td>
<td>662</td>
<td>711</td>
<td>801</td>
<td>898</td>
<td>(31)</td>
</tr>
<tr>
<td>$225</td>
<td>715</td>
<td>688</td>
<td>756</td>
<td>867</td>
<td>984</td>
<td>(56)</td>
</tr>
</tbody>
</table>

Almost half of BC’s industrial energy is consumed in the production of pulp and paper. In this industry, switching to CO₂-neutral biomass also has the impact of increasing energy intensity while driving emissions levels down. A shift to biomass occurs at a relatively low cost compared to emissions charges. Even so, when the electricity supply sector is excluded, we see that a policy to impose emissions charges stimulates energy conservation and efficiency improvements. These improvements overwhelm the increase in biomass to provide a net 3% to 6% reduction in energy consumption (table 5.4).

Table 5.4: Energy Demand in BC, Including a Comparison to the Natural Run (Industrial, Commercial and Residential Sectors, in PJ)

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Froz</td>
<td>632</td>
<td>680</td>
<td>727</td>
<td>794</td>
<td>874</td>
<td>(49)</td>
</tr>
<tr>
<td>Nat</td>
<td>632</td>
<td>631</td>
<td>633</td>
<td>659</td>
<td>699</td>
<td>-</td>
</tr>
<tr>
<td>Econ</td>
<td>632</td>
<td>561</td>
<td>565</td>
<td>589</td>
<td>632</td>
<td>71</td>
</tr>
<tr>
<td>Tech</td>
<td>632</td>
<td>477</td>
<td>452</td>
<td>457</td>
<td>473</td>
<td>154</td>
</tr>
<tr>
<td>$75</td>
<td>632</td>
<td>625</td>
<td>621</td>
<td>644</td>
<td>681</td>
<td>7</td>
</tr>
<tr>
<td>$150</td>
<td>632</td>
<td>612</td>
<td>610</td>
<td>634</td>
<td>671</td>
<td>19</td>
</tr>
<tr>
<td>$225</td>
<td>632</td>
<td>607</td>
<td>604</td>
<td>628</td>
<td>666</td>
<td>24</td>
</tr>
</tbody>
</table>
5.1.2 CO₂ Emissions

There are virtually no CO₂ emissions released in electricity generation in BC; thus table 5.5 provides emissions data for the demand sectors only. ESSM simulations indicate that demand can be met through existing capacity, renewable set-asides, and biomass-fired technologies. Emissions reduction in BC occurs under cost runs primarily because of:

- an increased use of biomass as a fuel - Pulp and paper companies and wood products companies shift to hog fuel (wood waste) for process heat.

- a switch to electricity - When suitable alternatives exist, firms and households choose electrically-driven technologies instead of fossil fuel-fired ones. This response is typical of regions where CO₂-neutral generation of electricity exists.

- other fuel switching - Most residences, commercial buildings and industry depend on natural gas in BC, but those firms and households dependent on oil or coal (not a large provider of energy in BC) move toward natural gas under cost runs.

- efficiency improvements - The more efficient technologies achieve greater market share under cost runs especially in housing and commercial stock (new and retrofit), cogeneration, and auxiliary services.

- Burrard thermal generation station is not operated.

Table 5.5: CO₂ Emissions in BC, Including a Comparison to the Natural Run (Industrial, Commercial and Residential Sectors, in millions of tonnes)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Froz</td>
<td>17.3</td>
<td>18.7</td>
<td>20.4</td>
<td>22.4</td>
<td>24.7</td>
<td>(1.1)</td>
</tr>
<tr>
<td>Nat</td>
<td>17.3</td>
<td>17.6</td>
<td>17.9</td>
<td>18.2</td>
<td>19.4</td>
<td>-</td>
</tr>
<tr>
<td>Econ</td>
<td>17.3</td>
<td>16.4</td>
<td>16.1</td>
<td>17.1</td>
<td>18.9</td>
<td>1.2</td>
</tr>
<tr>
<td>Tech</td>
<td>17.3</td>
<td>11.6</td>
<td>11.0</td>
<td>10.3</td>
<td>9.9</td>
<td>6.0</td>
</tr>
<tr>
<td>$75</td>
<td>17.3</td>
<td>14.2</td>
<td>14.1</td>
<td>14.2</td>
<td>15.2</td>
<td>3.4</td>
</tr>
<tr>
<td>$150</td>
<td>17.3</td>
<td>12.9</td>
<td>12.3</td>
<td>11.8</td>
<td>12.4</td>
<td>4.7</td>
</tr>
<tr>
<td>$225</td>
<td>17.3</td>
<td>12.3</td>
<td>11.2</td>
<td>10.2</td>
<td>10.2</td>
<td>-</td>
</tr>
<tr>
<td>Stable</td>
<td>17.3</td>
<td>17.3</td>
<td>17.3</td>
<td>17.3</td>
<td>17.3</td>
<td>0.3</td>
</tr>
<tr>
<td>-20%</td>
<td>13.9</td>
<td>13.9</td>
<td>13.9</td>
<td>13.9</td>
<td>13.9</td>
<td>3.7</td>
</tr>
</tbody>
</table>

The residential sector accounts for about 30% of total reduction in emissions in the cost runs, primarily through increased efficiencies in building shells (including retrofit) and a
move to electrical space and water heating. In industry, switching fuels in boilers and heaters in “Other Manufacturing”, along with the shift to biomass in pulp and paper explains more than 50% of the emissions reduction. The commercial sector claims about 12% of the reduction seen in the $225 run.

Figure 5.1 permits a more ready comparison of runs. The graph indicates that the stabilisation target can be met in BC (in the modelled sectors) at an emissions charge somewhat less than $75/tonne and that reduction to 20% of 1990 levels can be achieved at a charge somewhere between $75 and $100/tonne. If the generation sector is included, the stabilisation target can be met with a very small cost associated with emissions. This is so because the supply model concludes that the Burrard electricity generation facility, which uses natural gas, will not be used after 1992 even in the natural run. The facility was responsible for about 1.4 million tonnes of CO₂ in 1990; its curtailment removes a significant quantity of CO₂ from the system.
The graph indicates that the $225 cost run and the technical run show just about the same level of CO\(_2\) emissions. However, the fuel mixes of the two runs are different; the technical run, by definition, depends solely on efficiency improvements to arrive at this point while the emission cost run also depends on inefficient, biomass-fired technologies (i.e., fuel substitution). This means that a greater level of CO\(_2\) reduction is available than would be suggested by the technical run because a reduction in CO\(_2\) emissions is not always correlated with efficiency improvements.

### 5.1.3 Cost

After completing the simulations for each industry and sector in a region, relevant data were entered into cost tables such as those seen in chapter 4. These costs, divided by emissions changes (table 5.5), provide the average cost of reduction, table 5.6. The table indicates that, in BC, the average cost to reduce a tonne of CO\(_2\) emitted in the commercial, residential and industrial sectors does not exceed $70/tonne under any level of emissions charge, that there are more options (or at least some more expensive options) available in the early years, and that the bulk of the options are relatively inexpensive because the average cost does not rise in proportion to the marginal cost.

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tech</td>
<td>(859)</td>
<td>(900)</td>
<td>(871)</td>
<td>(807)</td>
</tr>
<tr>
<td>$75</td>
<td>(46)</td>
<td>(41)</td>
<td>(37)</td>
<td>(33)</td>
</tr>
<tr>
<td>$150</td>
<td>(57)</td>
<td>(53)</td>
<td>(50)</td>
<td>(50)</td>
</tr>
<tr>
<td>$225</td>
<td>(70)</td>
<td>(66)</td>
<td>(65)</td>
<td>(68)</td>
</tr>
</tbody>
</table>

Table 5.7 displays the average costs when generation costs are incorporated into the analysis. Since new generation technology is biomass-fired or from a renewable source, the costs of new generation are higher than conventional fossil-fired alternatives and increase the cost of avoiding another tonne of CO\(_2\) emissions. In fact, the constraints of the supply model regarding no future hydro development prompts a significant increase in the costs such that, under the $75 / tonne charge, average costs are actually higher than
marginal costs (i.e., the utility must put in the more expensive renewable set-asides even if it would be better off paying the tax).

Table 5.7: Average Benefit (Cost) of CO₂ Emissions Reduction in BC (Industrial, Commercial, Residential and Electricity Generation Sectors in $/tonne).

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tech</td>
<td>(922)</td>
<td>(976)</td>
<td>(942)</td>
<td>(864)</td>
</tr>
<tr>
<td>$75</td>
<td>(79)</td>
<td>(83)</td>
<td>(78)</td>
<td>(72)</td>
</tr>
<tr>
<td>$150</td>
<td>(104)</td>
<td>(108)</td>
<td>(110)</td>
<td>(116)</td>
</tr>
<tr>
<td>$225</td>
<td>(131)</td>
<td>(141)</td>
<td>(147)</td>
<td>(139)</td>
</tr>
</tbody>
</table>

### 5.2 Alberta

Alberta, with its abundant resource of fossil fuel, has industry that is fossil-fuel intensive (natural gas processing, petroleum refining, petrochemical production) and utilises primarily coal-fired technologies to generate electricity. This, coupled with its cold climate, makes Alberta one of the most CO₂-intense of all the regions in Canada. Alberta consumes 20% of the energy and generates more than 27% of the CO₂ emissions in Canada (1990), second after Ontario. Yet, it is fourth in terms of population size.

#### 5.2.1 Energy

In Alberta, approximately 43% of energy consumption can be attributed to the sum of that used to generate electricity (19%, total energy net of the electricity generated) and to process fossil fuels (24%, excluding energy used to mine coal and extract crude oil). This exceeds the sum of energy used in the transportation (15%), commercial (10%) and residential (9%) and agricultural (3%) sectors. Energy consumption in mining and other manufacturing industries account for the remainder.

Just as BC is typical of provinces with hydroelectric supply, so Alberta shows characteristics typical of a fossil fuel-fired supply of electricity. Under costs runs, electricity prices rise steeply and electricity demand diminishes. The demand diminishes to the extent that no new capacity is required in Alberta under any cost run. ESSM’s rigidity in requiring dormant capacity to be utilised before new capacity is brought on
prevents fuel switching from occurring in Alberta’s supply technologies either through retirement or through retrofit. Because the efficiency of coal-fired electricity generation is only about 35%, any shift away from electricity to other fuels in the demand sectors increases overall efficiency in the aggregate. In other words, in an absolute sense, fuel switching in the demand sectors does more to improve average efficiency in Alberta than does the installation of equipment known to be more efficient than existing stock. A comparison of the “Change from Natural” portion of table 5.8 and 5.9 points this out; of the 42 to 90 PJ saved over the natural run in the various cost runs, 27 to 58 PJ (42 - 15 = 27, 90 - 32 = 58) are the result of reducing the demand for electricity.

Table 5.8: Energy Demand in Alberta, Including a Comparison to the Natural Run (Industrial, Commercial, Residential and Electricity Generation Sectors, in PJ)

<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1995</td>
<td>2000</td>
<td>2005</td>
<td>2010</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Froz</td>
<td>1,381</td>
<td>1,575</td>
<td>1,722</td>
<td>1,860</td>
<td>1,992</td>
<td>(178)</td>
</tr>
<tr>
<td>Nat</td>
<td>1,381</td>
<td>1,398</td>
<td>1,462</td>
<td>1,573</td>
<td>1,691</td>
<td>-</td>
</tr>
<tr>
<td>Econ</td>
<td>1,381</td>
<td>1,354</td>
<td>1,416</td>
<td>1,527</td>
<td>1,643</td>
<td>43</td>
</tr>
<tr>
<td>Tech</td>
<td>1,381</td>
<td>1,263</td>
<td>1,230</td>
<td>1,216</td>
<td>1,203</td>
<td>134</td>
</tr>
<tr>
<td>$75</td>
<td>1,381</td>
<td>1,355</td>
<td>1,412</td>
<td>1,524</td>
<td>1,640</td>
<td>42</td>
</tr>
<tr>
<td>$150</td>
<td>1,381</td>
<td>1,340</td>
<td>1,395</td>
<td>1,505</td>
<td>1,618</td>
<td>58</td>
</tr>
<tr>
<td>$225</td>
<td>1,381</td>
<td>1,326</td>
<td>1,380</td>
<td>1,488</td>
<td>1,601</td>
<td>72</td>
</tr>
</tbody>
</table>

When the electricity supply sector is excluded from the energy demand picture (table 5.9), we see that efficiency improvements in the demand sectors are considerably less than in BC due, in part, to the effect of emissions charges on electricity prices. Although there are other contributing factors (primarily the mix of industry, see below), the high price of electricity under cost runs drives consumers away from the more efficient electric technologies if a fossil-fuel driven option exists.

Because of their inherent energy-intensive processes, industries in Alberta have little opportunity to increase efficiency. About 75% of the decline in energy consumption in cost runs comes from the commercial and residential sectors even though industry
Table 5.9: Energy Demand in Alberta, Including a Comparison to the Natural Run (Industrial, Commercial and Residential Sectors, in PJ)

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Froz</td>
<td>939</td>
<td>1,094</td>
<td>1,204</td>
<td>1,315</td>
<td>1,424</td>
<td>(44)</td>
<td>(72)</td>
<td>(88)</td>
<td>(98)</td>
<td></td>
</tr>
<tr>
<td>Nat</td>
<td>939</td>
<td>1,050</td>
<td>1,133</td>
<td>1,227</td>
<td>1,326</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Econ</td>
<td>939</td>
<td>1,007</td>
<td>1,086</td>
<td>1,181</td>
<td>1,279</td>
<td>43</td>
<td>46</td>
<td>46</td>
<td>48</td>
<td></td>
</tr>
<tr>
<td>Tech</td>
<td>939</td>
<td>910</td>
<td>965</td>
<td>1,040</td>
<td>1,114</td>
<td>140</td>
<td>168</td>
<td>188</td>
<td>212</td>
<td></td>
</tr>
<tr>
<td>$75</td>
<td>939</td>
<td>1,036</td>
<td>1,118</td>
<td>1,212</td>
<td>1,311</td>
<td>15</td>
<td>15</td>
<td>15</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>$150</td>
<td>939</td>
<td>1,030</td>
<td>1,110</td>
<td>1,203</td>
<td>1,302</td>
<td>21</td>
<td>23</td>
<td>24</td>
<td>25</td>
<td></td>
</tr>
<tr>
<td>$225</td>
<td>939</td>
<td>1,021</td>
<td>1,101</td>
<td>1,195</td>
<td>1,294</td>
<td>30</td>
<td>32</td>
<td>32</td>
<td>32</td>
<td></td>
</tr>
</tbody>
</table>

consumes about 60% of the energy in demand sectors. In other words, the major energy-consuming industries in Alberta are already relatively efficient; increasing the cost of fuels will not cause major improvements in efficiency because fuel costs have played an important role in these industries for some time already.

5.2.2 CO₂ Emissions

A comparison of table 5.10 and 5.11 indicates that CO₂ emissions diminish primarily through a reduction in electricity demand. In the residential sector, for example, CO₂ emissions actually increase under cost runs because household consumers avoid high-priced electricity for hot water or space heating. In fact, fossil fuel shares among end-use technologies rise as the costs of emissions rise in all demand sectors. The cost per unit electricity rises much faster than the cost per unit fossil fuels under cost runs because the production of each GJ of electricity requires approximately three GJ of heat energy from coal and thus bears three times the cost burden (again, this is because ESSM does not permit premature retirement of existing coal-fired stock, preventing fuel switching which otherwise may have occurred).

Table 5.10 shows that Alberta cannot reach targets for emissions reductions except under the technical run. And this only occurs because of assumptions that the electricity supply sector will replace all retired technologies and meet all increased demand with a CO₂-free electricity supply. The data in table 5.11 indicate that, even in the technical run, reaching either a stabilisation or reduction target in the cumulative demand sectors can not be
accomplished. Further disaggregation of these data would show that reaching stabilisation and reduction targets is possible in Alberta’s commercial and residential sectors but not the industrial sector because industries’ limited options to reduce emissions. For example, energy-intensive industries like pulp and paper, petroleum refining and cement use natural gas, the least carbon-intense of the fossil fuels, as the primary supplier of heat energy. In summary, electric utilities must move to renewable resources or natural gas and industry structure must shift to less intense products if Alberta is to meet either CO$_2$ emissions target.

This analysis of the reduction potential of Alberta CO$_2$ emissions highlights the importance of initial supply assumptions and the need for interaction between end-use...
models and a general equilibrium (macroeconomic) model. CO₂ reduction potential may have been underestimated in Alberta because:

- constraints in the supply sector prevented expansion into alternative fuels such as natural gas and other non-fossil sources,
- the retarding action of high electricity prices prevents efficiency and fuel switching in the demand sectors of the system,
- the possibilities of switching industry structure have been overlooked, and
- the possible impacts of R&D on new technologies or processes in Alberta’s energy-intensive industries that would be available in later years (2000, 2005, 2010) have not been included.

The costs associated with emissions reduction in the demand sectors may be overestimated because consumers purchase expensive technologies to avoid an exaggerated cost of electricity. On the other hand, were supply assumptions changed and constraints relaxed, costs incurred in the supply sector would increase compared to current simulations where no new capacity is purchased (this wouldn’t raise the price of the electricity because the electricity would be made with fewer CO₂ charges attached; in fact, the electricity would be cheaper).

**5.2.3 Cost**

The aggregate cost picture (table 5.12) indicates that the average cost of reduction in Alberta is low compared to the marginal cost, due primarily to a shut-down of coal-fired electricity capacity in response to reduced electricity demand. In cost runs in Alberta, electricity demand never exceeds existing capacity, even in 2010. ESSM dispatches the least CO₂-intense generation sources first, and, because no new capacity is required, no new costs are incurred and CO₂ emissions are avoided. Unfortunately, ESSM prevents natural gas or new CO₂-neutral supply from entering the electricity grid and any increase in demand due to growth in “captive” electricity users (sectors that must use electricity to accomplish production or service provision) is met by existing, otherwise dormant coal capacity.
Table 5.12: Average Benefit (Cost) of CO\textsubscript{2} Emissions Reduction in Alberta (Industrial, Commercial, Residential and Electricity Generation Sectors, in $/tonne).

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tech</td>
<td>(278)</td>
<td>(240)</td>
<td>(190)</td>
<td>(174)</td>
</tr>
<tr>
<td>$75</td>
<td>(45)</td>
<td>(14)</td>
<td>(8)</td>
<td>(27)</td>
</tr>
<tr>
<td>$150</td>
<td>(48)</td>
<td>(27)</td>
<td>(23)</td>
<td>(39)</td>
</tr>
<tr>
<td>$225</td>
<td>(71)</td>
<td>(48)</td>
<td>(42)</td>
<td>(52)</td>
</tr>
</tbody>
</table>

Under cost runs, households and firms face very high electricity prices because the emissions charges are passed on to the consumer. The effect on electricity prices is magnified because the fuel used to generate the electricity is coal, the most carbon-dense of the fossil fuels. Thus, households and firms will spend far more than the marginal rate to avoid electricity. In fact, if a fossil fuel alternative exists, consumers would be better off to switch from electricity to that fuel, purchase the more expensive fossil fuel-fired technology and pay the CO\textsubscript{2} charge than to maintain their consumption of electricity. Table 5.13 shows that the average cost to the consumer to reduce a tonne of CO\textsubscript{2} emissions exceeds the marginal cost of reduction two to four times.

Table 5.13: Average Benefit (Cost) of CO\textsubscript{2} Emissions Reduction in Alberta (Industrial, Commercial and Residential Sectors, in $/tonne)

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tech</td>
<td>(424)</td>
<td>(436)</td>
<td>(424)</td>
<td>(429)</td>
</tr>
<tr>
<td>$75</td>
<td>(295)</td>
<td>(281)</td>
<td>(152)</td>
<td>(277)</td>
</tr>
<tr>
<td>$150</td>
<td>(377)</td>
<td>(323)</td>
<td>(253)</td>
<td>(343)</td>
</tr>
<tr>
<td>$225</td>
<td>(371)</td>
<td>(379)</td>
<td>(346)</td>
<td>(427)</td>
</tr>
</tbody>
</table>

As a result, the consumer, driven to purchase fossil-fired technologies under cost runs, increases consumption of fossil fuels in all sectors (except supply). Still, table 5.12 shows that, when supply and demand sectors are aggregated, the average costs are lower than the marginal costs (as expected); these values reflect the real cost of CO\textsubscript{2} reduction in the region. Consumers who do not have technology alternatives that consume fossil fuels rather than electricity, or utilise some other CO\textsubscript{2}-neutral energy supply, will face very high electricity costs if emissions charges are implemented.
5.3 Saskatchewan

Like Alberta, Saskatchewan utilities use primarily coal to generate electricity. Its electric utility and industrial sectors account for 47% of total energy demand in Saskatchewan and release 62% of its CO$_2$ emissions. Agricultural activities are responsible for over 11% of energy consumption, by far the largest of any province and about equal to residential (11.5%) and commercial (9.5%) consumption. Saskatchewan was responsible for 5.3% of Canada’s total energy demand in 1990 and accounted for 6.2% of its total release of CO$_2$ emissions in that year.

Table 5.14 provides information on the average costs of reducing a tonne of CO$_2$ in Saskatchewan. As in Alberta, consumers spend more to avoid the purchase of electricity than to avoid the purchase of fossil fuels. Thus, the average cost per tonne of emissions reduction in the demand sectors exceeds the marginal cost (table 5.15). However, because Saskatchewan’s industrial structure is very different from Alberta’s (agriculture / food products and mining), Saskatchewan could stabilise its emissions to 1990 levels if emissions charges were to reach about $75 / tonne of CO$_2$. Reduction to 80% of 1990 levels is possible if coal-fired generation of electricity is replaced by some CO$_2$-neutral source of energy. This points to the importance of the electricity supply sector in meeting stabilisation or reduction targets.

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
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<td>(459)</td>
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<td>(340)</td>
<td>(298)</td>
</tr>
<tr>
<td>$75</td>
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<td>(51)</td>
<td>(43)</td>
<td>(36)</td>
</tr>
<tr>
<td>$150</td>
<td>(89)</td>
<td>(79)</td>
<td>(72)</td>
<td>(62)</td>
</tr>
<tr>
<td>$225</td>
<td>(96)</td>
<td>(91)</td>
<td>(86)</td>
<td>(76)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
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<td>Tech</td>
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<td>(675)</td>
<td>(614)</td>
<td>(583)</td>
</tr>
<tr>
<td>$75</td>
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<td>(60)</td>
</tr>
<tr>
<td>$150</td>
<td>(205)</td>
<td>(159)</td>
<td>(130)</td>
<td>(113)</td>
</tr>
<tr>
<td>$225</td>
<td>(288)</td>
<td>(214)</td>
<td>(164)</td>
<td>(141)</td>
</tr>
</tbody>
</table>
5.4 Manitoba

Manitoba consumes about 3.2% of the nation’s total energy. Like BC, it generates almost all of its electricity from hydraulic resources. Consequently, it is responsible for only 2.7% of total CO\textsubscript{2} emissions in Canada. More than half of these emissions come from the transportation sector, which alone consumes 31% of the region’s energy. Industry consumes 23% of the energy and generates 23% of the emissions, while the residential and commercial sectors account for about 19% each but generate only 13% and 12% respectively of the CO\textsubscript{2} emissions in the province.

Manitoba exports large quantities of electricity. I assumed that any increase in future demands can be met first by this hydraulic capacity. Therefore, no new capacity would need to be built and the net cost to the consumer is essentially $0. Thus, households and firms can respond to increasing emissions charges by moving, where possible, to technology alternatives that use electricity.

Table 5.16 provides the average cost of reduction per tonne of emissions among the demand sectors. Because no emissions and no major change in electricity prices are expected, the data which include this sector are identical to those in table 5.16. Manitoba can reach the stabilisation target through the imposition of a $75 / tonne emissions charge at an average cost of $68 / tonne and could reach the 20% reduction level with a charge somewhere near $100 / tonne and an average cost of $75 / tonne.

5.5 Ontario

No other region in Canada displays the variety of energy and commodity production and the range of energy services demanded as is seen in Ontario. Ontario Hydro generates
electricity using fossil fuels (primarily coal), hydraulic power and nuclear energy. Industry includes the processing of raw materials such as iron ore to steel and wood to pulp, as well as a large manufacturing sector that produces finished steel products, plastic products, textiles, glass, automobiles, automotive parts and numerous other commodities.

Ontario accounts for 32% of Canada’s total energy demand and generates 32% of its CO₂ emissions, the largest quantities of any single region in Canada. Table 5.17 provides a breakdown of energy consumption and CO₂ generation by sector. This table indicates that industry is carbon-intensive (i.e., its contribution to emissions exceeds its relative demand for energy), primarily due to its reliance on coal to make electricity (the supply sector has been aggregated with industry), raw steel and cement. It also indicates that the commercial and, to some extent, residential sectors are quite dependent on electricity to provide heating services, shown by a relatively low energy-to-emissions ratio.

**Table 5.17: Energy Consumption and CO₂ Emissions by Sector in Ontario, 1990 in %.

<table>
<thead>
<tr>
<th>Sector</th>
<th>Energy</th>
<th>CO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industry</td>
<td>43.5</td>
<td>50.4</td>
</tr>
<tr>
<td>Transportation</td>
<td>23.7</td>
<td>31.8</td>
</tr>
<tr>
<td>Agriculture</td>
<td>1.6</td>
<td>0.5</td>
</tr>
<tr>
<td>Residential</td>
<td>17.6</td>
<td>11.2</td>
</tr>
<tr>
<td>Commercial</td>
<td>13.5</td>
<td>6.1</td>
</tr>
<tr>
<td>% of Canada</td>
<td>32.3</td>
<td>32.1</td>
</tr>
</tbody>
</table>

Source: Derived from STC QRESQ (57-003) and Environment Canada (1990)

Although some local petroleum deposits exist, most of Ontario’s fossil fuel demands are met by imports, either from abroad (crude oil), from the US (coal) or from western Canada (natural gas, crude oil, coal). Thus, except for uranium and its hydraulic sources, Ontario must depend on others for its primary energy needs.

**5.5.1 Energy**

ESSM’s built-in assumptions regarding the rejuvenation of once-dormant coal capacity and the constraint on hydraulic and nuclear generating capacity have an important effect on energy and emissions levels in Ontario’s future (see chapter 4, section 4.1, 4.7.1). In
any future simulations of this supply system, these assumed constraints must be relaxed to permit a more realistic portrayal of electricity supply.

Existing generation capacity presently exceeds demand in Ontario and is expected to do so for some years. Near the end of the simulation period, when existing capacity levels fall short of demand, the capacity of biomass for electricity generation increases and old coal capacity is used to its maximum. This increases both energy consumption levels and CO₂ emissions (see section 5.5.2 and figure 5.3 below) in the later years of all runs except the frozen run, where hydraulic and nuclear contributions to supply are permitted, and the technical run where other low-intensity supply options are invoked.

Thus, table 5.18 shows that total energy consumption in cost runs rises to levels above natural and even frozen runs because of the need to replace retired nuclear and hydraulic generation capacity with stock that requires thermal fuel such as biomass and coal (i.e., once-dormant capacity). Use of these technologies overwhelm the efficiency gains made in the demand sectors. When the data on the generation sector are excluded, we see a more typical set of results (table 5.19) and gain some appreciation for the magnitude of the energy consumed in the supply sector to provide electricity.

Table 5.18 Energy Demand in Ontario, Including Comparison to Natural Run (Industrial, Commercial, Residential and Electricity Generation Sectors, in PJ).

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Froz</td>
<td>1,828</td>
<td>2,049</td>
<td>2,312</td>
<td>2,584</td>
<td>2,888</td>
<td>(218)</td>
<td>(251)</td>
<td>(163)</td>
<td>(44)</td>
</tr>
<tr>
<td>Nat</td>
<td>1,828</td>
<td>1,831</td>
<td>2,062</td>
<td>2,421</td>
<td>2,844</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Econ</td>
<td>1,828</td>
<td>1,652</td>
<td>1,869</td>
<td>2,222</td>
<td>2,631</td>
<td>179</td>
<td>192</td>
<td>199</td>
<td>214</td>
</tr>
<tr>
<td>Tech</td>
<td>1,828</td>
<td>1,468</td>
<td>1,466</td>
<td>1,517</td>
<td>1,599</td>
<td>364</td>
<td>595</td>
<td>905</td>
<td>1,245</td>
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<td>1,834</td>
<td>2,103</td>
<td>2,503</td>
<td>2,906</td>
<td>(2)</td>
<td>(42)</td>
<td>(82)</td>
<td>(62)</td>
</tr>
<tr>
<td>$150</td>
<td>1,828</td>
<td>1,905</td>
<td>2,234</td>
<td>2,687</td>
<td>3,052</td>
<td>(74)</td>
<td>(172)</td>
<td>(266)</td>
<td>(207)</td>
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<tr>
<td>$225</td>
<td>1,828</td>
<td>1,943</td>
<td>2,339</td>
<td>2,844</td>
<td>3,194</td>
<td>(111)</td>
<td>(277)</td>
<td>(422)</td>
<td>(349)</td>
</tr>
</tbody>
</table>
### Table 5.19: Energy Demand in Ontario, Including Comparison to Natural Run (Industrial, Commercial and Residential Sectors, in PJ).

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Froz</td>
<td>1,634</td>
<td>1,855</td>
<td>2,095</td>
<td>2,351</td>
<td>2,639</td>
<td>(95)</td>
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<tr>
<td>Nat</td>
<td>1,634</td>
<td>1,760</td>
<td>1,901</td>
<td>2,075</td>
<td>2,299</td>
<td>-</td>
</tr>
<tr>
<td>Econ</td>
<td>1,634</td>
<td>1,581</td>
<td>1,709</td>
<td>1,875</td>
<td>2,085</td>
<td>179</td>
</tr>
<tr>
<td>Tech</td>
<td>1,634</td>
<td>1,312</td>
<td>1,350</td>
<td>1,439</td>
<td>1,560</td>
<td>447</td>
</tr>
<tr>
<td>$75</td>
<td>1,634</td>
<td>1,723</td>
<td>1,844</td>
<td>1,997</td>
<td>2,209</td>
<td>37</td>
</tr>
<tr>
<td>$150</td>
<td>1,634</td>
<td>1,682</td>
<td>1,782</td>
<td>1,917</td>
<td>2,121</td>
<td>77</td>
</tr>
<tr>
<td>$225</td>
<td>1,634</td>
<td>1,630</td>
<td>1,714</td>
<td>1,835</td>
<td>2,039</td>
<td>130</td>
</tr>
</tbody>
</table>

Figure 5.2 allows us to picture the data in table 5.19; the frozen line and technical line appear as upper and lower boundaries to the set of runs depicting the public and private views (natural and economic lines) and policy impacts.

**Figure 5.2: Energy demand in Ontario under different economic conditions (industrial, commercial and residential sectors, in PJ)**

Under the conditions of the run simulating $225 / tonne of emissions, total energy demand approaches that of the economic run. In other words, an added charge to the combustion of fossil fuels moves society (at least in these demand sectors) to a more efficient
position. But, as we have seen for the aggregate picture of Canada (Chapter 4, section 3.6.2), the fuel mix of these two runs varies such that the level of CO₂ emissions are actually very far apart (see both figures 5.3 and 5.4).

5.5.2 CO₂ Emissions

By forcing the electric utility to use existing generating capacity first, and by preventing the establishment of new nuclear or hydraulic capacity and the penetration of natural gas-fired stock, we obtain the unique consequence of having more CO₂ generated in the natural run (and even in a cost run) than what would have happened had the utility supply mix remained essentially as it was in the frozen run (figure 5.3). Thus, reducing the level CO₂ emissions in the generation supply sector depends not only on the alternative generation sources available but also on the retirement schedule for fossil-fired (i.e., coal-fired) generation stock, an issue requiring the upgrading of future versions of ESSM.

In both figure 5.3 and 5.4, we see that CO₂ emissions in the economic run exceed emissions levels in both the natural and frozen run; inexpensive coal and an oil prices that drops below natural gas prices induce shifts to coal- and oil-fired technologies (fuel prices were those used in NRCan’s Canada’s Energy Outlook, 1994 Update).

This shift to the more economic, and often more efficient, carbon-intense fuels highlights the need for carbon-specific policy tools rather than general, or energy-specific tools to control emissions levels. For example, in an analysis completed for the Canadian Emissions Modelling Forum (Nyboer et al. 1994), top-down and bottom-up modellers were asked to determine whether a levy on energy was more or less effective than a levy on carbon content in reducing emission levels.¹ There Nyboer et al. (1994) tested carbon-specific tax policies against energy tax policies and showed that carbon-specific tax policies were more effective in reducing emissions than were similar taxes on energy consumption. In fact, energy taxes, designed to improve efficiency in the hope of achieving emissions reduction, could actually increase CO₂ emissions in industries where

¹ Although two meetings of the Forum were held in February and June, 1994, NRCan discontinued the program thereafter. Minutes of the meetings exist but remained unpublished and otherwise unavailable.
process heat was important because energy taxes prompted a move away from biomass (a CO₂-neutral but inefficient fuel) and natural gas to heavy oil and coal.

**Figure 5.3: CO₂ emissions in Ontario under various economic scenarios.** The graph includes lines indicating the point of stabilisation at 1990 levels and a 20% reduction from 1990 levels (industrial, commercial, residential and electricity generation sectors, in millions of tonnes).

An analysis of the demand sectors, graphed in Figure 5.4, permits a view of the system without the effects of the data from the electricity generation sector. It shows that, at a marginal cost of about $150 / tonne CO₂, the stabilisation target can be met in the demand sectors and that, at a cost in excess of $225 / tonne, the reduction target can also be met. Note also that the economic run, which showed about the same energy intensity as the $225 cost run, shows no appreciable reduction in CO₂ emissions from the natural or frozen runs. Coal and oil, both of which are less expensive and a more efficient fuel than natural gas (i.e., a higher LHV / HHV ratio than natural gas), show increasing fuel shares in economic runs. This points to the importance of the CO₂ intensity factor for carbon in fuel \( (CO₂ / FF) \) in Kaya’s identity (equation 1, chapter 1).
Figure 5.4: CO₂ emissions in Ontario from the demand sectors. The graph includes lines indicating the point of stabilisation at 1990 levels and a 20% reduction from 1990 levels (industrial, commercial and residential sectors, in millions of tonnes).

5.5.3 Cost
As I have pointed out for this and other regions, expensive options are invoked in the production of electricity in cost runs in certain years due to constraints in ESSM. Consequently, the costs to reduce the level of CO₂ emissions are typically higher than when the demand sectors are reviewed at the exclusion of the supply sector. For this reason, average costs associated with emissions reduction in table 5.20 usually exceed those in table 5.21. Where the costs in table 5.20 do not exceed those in table 5.21 (e.g., in 2000), it is, on average, less expensive to reduce CO₂ emissions in the supply sector than the demand sector.
Table 5.20: Average Benefit (Cost) of CO\textsubscript{2} Emissions Reduction in Ontario (Industrial, Commercial, Residential and Electricity Generation Sectors, in $/tonne).

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tech</td>
<td>(784)</td>
<td>(650)</td>
<td>(456)</td>
<td>(351)</td>
</tr>
<tr>
<td>$75</td>
<td>(61)</td>
<td>(44)</td>
<td>(49)</td>
<td>(53)</td>
</tr>
<tr>
<td>$150</td>
<td>(83)</td>
<td>(62)</td>
<td>(69)</td>
<td>(82)</td>
</tr>
<tr>
<td>$225</td>
<td>(84)</td>
<td>(75)</td>
<td>(86)</td>
<td>(102)</td>
</tr>
</tbody>
</table>

Table 5.21: Average Benefit (Cost) of CO\textsubscript{2} Emissions Reduction in Ontario (Industrial, Commercial and Residential Sectors, in $/tonne).

<table>
<thead>
<tr>
<th>Run</th>
<th>1995</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tech</td>
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<td>(742)</td>
<td>(641)</td>
<td>(600)</td>
</tr>
<tr>
<td>$75</td>
<td>(45)</td>
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<td>(47)</td>
</tr>
<tr>
<td>$150</td>
<td>(59)</td>
<td>(61)</td>
<td>(61)</td>
<td>(67)</td>
</tr>
<tr>
<td>$225</td>
<td>(80)</td>
<td>(82)</td>
<td>(82)</td>
<td>(86)</td>
</tr>
</tbody>
</table>

I have mentioned that Ontario’s demand and supply sectors meet their energy requirements using a variety of sources: heavy and light fuel oil, natural gas, coal, electricity from hydraulic and nuclear sources, wood and a small amount of “waste-derived fuels” (in the cement industry). The variety of fuels available provides some opportunity to move away from carbon-intense fuels but it also means that a lot of existing stock will need to be replaced or retrofitted with more efficient or alternatively-fueled options. Thus, even though the opportunities to reduce CO\textsubscript{2} emissions in this region may be good (at least Ontario could meet the targets), the average costs of reduction are not, on the whole, any lower than those in other regions. To meet the stabilisation target would require an emissions charge of between $80 and $150 / tonne CO\textsubscript{2}, at an average cost of between $50 and $60 / tonne, depending on supply constraints; a 20% reduction requires marginal costs exceeding $225 / tonne.

5.6 Québec

Like BC and Manitoba, Québec depends on hydraulic energy to generate electricity. Like Manitoba, it presently exports a considerable quantity of this electricity to the US but it also imports a sizable amount from Labrador. Québec’s high dependence on hydro-electricity explains why it generates only 13% of Canada’s CO\textsubscript{2} emissions and yet
consumes 19% of its energy. This places it third in energy consumption and in emissions production even though it is second, after Ontario, in population size.

### 5.6.1 Energy and CO₂ Emissions Comparison

As in other hydroelectric provinces, when electricity demand exceeds production from existing capacity, ESSM purchases biomass-fired generation technologies. Thus, as in BC, energy consumption in this sector rises both in the later years of the simulation and as emissions charges increase. This would mean that overall energy intensity rises under the imposition of policies enforcing emissions charges. The use of electric heat for residential and even industrial applications (e.g., highly-efficient electric boilers) cause demand for electricity to rise as emissions charges increase and consumers avoid fossil fuels. Figure 5.5 shows the sharp rise in total energy demanded because of the increased demand for electricity from biomass-fired generation under both the $150 cost run some time between 2000 and 2010 and much earlier (between 1995 and 2000) in the $225 run.

**Figure 5.5: Energy demand in Québec under different economic conditions (industrial, residential, commercial and electricity generation sectors, in PJ).**
In figure 5.6, the effect of the electricity-generation sector is removed and the graph lines return to their expected relative positions; increased emissions charges stimulate increased penetration of efficient technologies and a reduction in energy intensity. Much of the efficiency improvement in the cost runs comes from shifts to electrically-powered technologies. As long as the supply sector can provide this electricity from hydraulic sources, overall energy intensity continues to decline. As soon as the supply sector begins to depend on biomass to generate its electricity, energy intensity levels increase. The rate of increase is compounded by the relative inefficiency of biomass-fired technologies to fossil fired ones (although, with newer biomass gasification technologies, this relative difference declines; it is these types of technologies that penetrate the supply system).

**Figure 5.6: Energy demand in Québec under different economic conditions (industrial, commercial and residential sectors, in PJ).**

Demand for electricity grows considerably under the cost runs. Since frozen, natural and economic runs do not exceed capacity (I have assumed that exported electricity can be used “in province” as demand rises because many of Hydro Québec’s export contracts are short to medium term), the position of the graph lines for these runs does not change when the supply sector data are extracted from the total to leave only the demand sectors.
The technical runs in both the demand and supply sectors also assume that any further increase in electricity demand can be met by “renewable supply” technologies such as wind, solar or small hydro.

Québec is one of only two regions (the other is the Atlantic region) to show that an emissions charge could actually release less CO₂ than if technical energy efficiency were maximised; the graph line of the $225 run lies below the graph line of the technical run in figure 5.7. The increase in demand for electricity derived from biomass sources and the use of biomass fuel as an alternative to fossil fuels in the pulp and paper industry lead to this result. Therefore, due to the enhanced use of biomass, Québec could actually become increasingly inefficient, raising its overall energy intensity, and still meet or beat emissions targets. Figure 5.7 shows CO₂ emissions in just the demand sector. The graph of the aggregate demand and supply sector is practically identical to the graph in figure 5.7 because the supply sector generates virtually no CO₂ emissions.

**Figure 5.7: CO₂ emissions in Québec from the demand sectors.** The graph includes lines indicating the point of stabilisation at 1990 levels and a 20% reduction from 1990 levels (industrial, commercial and residential sectors, in millions of tonnes).
Figure 5.7 points out a second feature, one unique to Québec. Even though overall energy intensity is lower in the natural run than the frozen run, as shown in figure 5.6, the level of emissions generated is not; the natural line representing CO₂ emissions lies above the frozen line in figure 5.7. In Québec in 1990, electricity provided a large portion of the energy required for process heat in industry (e.g., electric boilers and heaters) and for space heating in the residential and commercial sectors. Most of these industries and houses were built in a time when pipeline constraints meant that natural gas was not locally available. Now most of the populated regions of Québec have access to natural gas. Thus, the natural gas market is not mature in Québec; the natural run picks up on this and shows the market shares of natural gas increasing with respect to electricity.

Discussions with regional experts at Hydro Québec and in the Québec Ministère des ressources naturelles point out that there is a non-cost-based reluctance to move to natural gas from electricity (i.e., fear of explosions) and that, in ISTUM, the penetration of natural gas technologies may be exaggerated. However, no data were available to test the application of a non-cost parameter (see chapter 2, section 2.) to the individual sectors or industry and so none was applied in this case.

### 5.6.2 Cost

As in many other provinces, constraints in the generation sector result in options for emissions reduction that are more expensive than those in the various demand sectors. Thus the average cost of emissions reduction in Québec is higher under the tax runs when all sectors are considered (table 5.23) than when just the demand sectors are considered (table 5.24).

**Table 5.23: Average Benefit (Cost) of CO₂ Emissions Reduction in Québec (Industrial, Commercial, Residential and Electricity Generation Sectors, in $/tonne)**

<table>
<thead>
<tr>
<th>Run</th>
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<th>2000</th>
<th>2005</th>
<th>2010</th>
</tr>
</thead>
<tbody>
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<td>(1,008)</td>
<td>(903)</td>
<td>(793)</td>
</tr>
<tr>
<td>$75</td>
<td>(43)</td>
<td>(51)</td>
<td>(57)</td>
<td>(62)</td>
</tr>
<tr>
<td>$150</td>
<td>(90)</td>
<td>(93)</td>
<td>(99)</td>
<td>(104)</td>
</tr>
<tr>
<td>$225</td>
<td>(134)</td>
<td>(132)</td>
<td>(138)</td>
<td>(143)</td>
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</tbody>
</table>
Table 5.24: Average Benefit (Cost) of CO₂ Emissions Reduction in Québec (Industrial, Commercial and Residential Sectors, in $/tonne)

<table>
<thead>
<tr>
<th>Run</th>
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<td>$225</td>
<td>(61)</td>
<td>(54)</td>
<td>(54)</td>
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</table>

From figure 5.7 and table 5.23, stabilisation of emissions by 2000 would require an emissions charge of somewhere between $85 and $100 / tonne CO₂. The average cost to the consumer would be about $65 / tonne. If the constraints in the supply model were relaxed (i.e., new hydraulic resources were permitted), the average cost, from table 5.24, would decline to approximately $25 / tonne. To reach stabilisation would require a marginal cost of about $170 / tonne with an average expenditure of $110 and $45 / tonne depending on supply constraints.

5.7 Atlantic

The Atlantic region of Canada consumes just over 8% of the total Canadian demand and is responsible for 9% of its CO₂ emissions. In 1990, old coal- and oil-fired generating facilities provided 40% of the electricity in the region even though there was a large hydraulic generation site in Labrador, Newfoundland; Québec received (and still receives) this electricity. This old coal and oil capacity retires early in the simulation and is replaced primarily by new oil-fired technologies in the natural run.

The industrial sector and the generation of electricity consumes nearly half of the region’s energy and is responsible for just over half of its CO₂ emissions. The transportation sector consumes half of the remainder and generates 33% of the emissions. The residential and commercial sectors each consume about 12% of the total energy in the region but the residential sector generates twice the emissions (10% of total) of the commercial sector, indicating the importance of electricity in the commercial sector.

Like Québec, the Atlantic region shows less CO₂ emissions in its cost runs than in the technical run, primarily by using biomass in its wood products and electricity generation industries. Because the region has no access to natural gas, the Atlantic provinces have
fewer options in their attempts to reduce emissions than other provinces. The primary focus of consumers is to shift towards technologies using electricity generated from biomass and, for this reason alone, the region can attain stabilisation at a minimal emissions charge, much less than $75/tonne. In fact, at $75/tonne, the region can reach its reduction target.

5.7.1 Energy

Just over 77% of all industrial energy (excluding generation) is consumed by two industries: pulp and paper (51.5%) and petroleum refining (25.5%). This amounts to 38% of all energy consumed in the Atlantic provinces. The dominance of pulp and paper on the energy scene explains why it is rather inexpensive to move from a higher to lower CO₂ intensity; there are strong shifts to biomass under runs where the emissions charges increase. In the remainder of industry, the commercial sector and the residential sector, there are few choices but to move away from oil to electricity and, in the residential sector, to wood. Outside of the production of electricity generation, only industrial minerals (cement and lime production) use coal; they also use carbon-intense petroleum coke from a local refinery.

Like most of the regions in Canada, fossil-fired electricity supply is replaced by biomass-fired supply under cost runs. In the Maritimes, this shift is more dramatic than in other regions because of the rapid retirement of old coal- and oil-fired stock. Although a large hydraulic source exists in Labrador, I have assumed that this source is unavailable to the Atlantic region because of long-term contracts with Québec and its crown corporation, Hydro Québec. In figure 5.8, each cost run is successively more energy intense than the preceding one. The graph line of the technical run drops so much because of the supply-model’s constraint to use biomass as a driving fuel is relaxed and other, non-thermal capacity can provide the demanded electricity.
Figure 5.8: Energy demand in the Atlantic Canada under different economic conditions (industrial, commercial, residential and electricity generation sectors, in PJ).

Figure 5.9: Energy demand in the Atlantic Canada under different economic conditions (industrial, commercial and residential sectors, in PJ).
Although there are gains in efficiency to be made in industry, the greatest potential for energy efficiency gain is in the residential and commercial sectors as they move from wood (residential only) and oil to electricity over time. The increase in total energy consumption over the period is minimal, even though there is growth in the population of the Atlantic provinces. Figure 5.9 shows that the effect of increasing emissions charges on demand sectors is small, in terms of energy consumption, because the charges induce pulp and paper managers and residential owners to use biomass where once they used heating oil.

### 5.7.2 CO₂ Emissions

Figure 5.10 shows that there is very little change over time in the level of CO₂ emissions in the Atlantic region in the natural run because of the switch to electricity and biomass from heavy fuel oil and furnace oil. Thus, applying a low emissions charge would enable

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**Figure 5.10:** CO₂ emissions in Atlantic Canada from the demand sectors. The graph includes lines indicating the point of stabilisation at 1990 levels and a 20% reduction from 1990 levels (industrial, commercial and residential sectors, in millions of tonnes).
the region to meet its stabilisation target by 2000 and an emissions charge of $75 / tonne would allow the region to reach its 20% reduction target by 2010. Because of the potential to switch to biomass fuels, it is possible for the region to exceed even the level of reduction gained by maximising efficiency (the technical run). So we see that both the $150 and $225 / tonne runs show less CO₂ emissions than the technical run.

5.7.3 Cost

With a marginal cost of less than $40 / tonne CO₂, the average cost of reductions to reach the stabilisation target in the Atlantic region would be about $20 / tonne CO₂. Reaching the reduction target requires a marginal cost of $75 / tonne, for an average cost approaching $30 / tonne. The costs incurred in the supply sector per tonne of emissions reduction are about the same as those in the demand sectors, I have only shown the average costs in the demand sectors in table 5.25 below.

Table 5.25: Average Benefit (Cost) of CO₂ Emissions Reduction in Atlantic Canada (Industrial, Commercial and Residential Sectors, in $/tonne)

<table>
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<tr>
<td>$225</td>
<td>(37)</td>
<td>(32)</td>
<td>(28)</td>
<td>(33)</td>
</tr>
</tbody>
</table>

5.8 Sectoral Results

Analysis of ISTUM’s simulations indicate that each region shows unique characteristics related to its mix of industry, resources, fuel supply, and population. But each of the sectors and sub-sectors also show unique characteristics common to that sector / sub-sector in all regions. And these common traits, shared in that sector or sub-sector, are affected by the regional characteristics outlined above. In this section of the analysis, I review some of these sectoral characteristics.

5.9 Industrial Sector

Canada’s industrial sector is dominated by resource industries where the primary activity of the industry is to process raw material into some semi-finished product. Industries like
Chapter 5 Regional and Sectoral Results

pulp and paper, iron and steel, industrial minerals, wood products, mining, metal smelting, oil and heavy oil extraction and refining consume the bulk of the Canada’s industrial energy and provide commodities sold around the world for further processing. The most energy-intense portion of the production of most goods occurs in the early stages of its manufacture. Such industries have typically few options for energy (or CO$_2$) reduction because the processes are straightforward and energy-intensive compared to industries where many tens or hundreds of processes, each requiring only a small amount of energy, transform these semi-finished products into their final form.

It is not possible to give an adequate account of CO$_2$ and efficiency events in the industrial sector in the aggregate. However, rather than provide detail on each industry in each region, I highlight some typical results and leave the detail to appendix B.

5.9.1 Energy

Figure 5.11 shows that, because the rate of growth in industry exceeds the rate of efficiency improvements, energy consumption in industry rises continually under all simulations. Progressive emissions charges typically increase general efficiency. Because pulp and paper uses inefficient, biomass-fueled technologies and because it is the single largest energy consumer in Canada, the cost run graph lines and the natural line are more tightly grouped than they otherwise would be.

Some industries use large amounts of heat to accomplish their activities; pulp and paper processes use steam while cement and lime production depend on direct heat from combustion. Other industries are very dependent on electricity to drive large motors (metal mining operations grind ores to release metals) or to generate or purify chemicals or metals in electrolytic cells. These differences in end-uses, described in more detail below, alter the effects of emissions charges on the industry. Unless new processes are developed, industries have only two options: switching to less CO$_2$-intense fuels and
improving the efficiency of the technologies. In many cases, simply the act of switching fuels introduces efficiency change as well. If a new process is developed and it falls within the scope of a single competition node, we need only to add this process to ISTUM’s database. If the new process spans more than one node, a new flow model for that industry which includes this process must be constructed.

### 5.9.2 CO₂ Emissions

In general, industries that have a high requirement for process heat, whether steam or direct, and have an alternative non-carbon-based energy source, provide the greatest potential to reduce emissions. Three such alternatives exist: electricity from non-fossil fuel generation, biomass and waste fuels.² Otherwise, outside of changing product demand, the only options to reduce emissions are switching to less carbon-intense fuels or efficiency improvements. In figure 5.12, the $150 and $225 graph lines lie on or below

² Waste fuels are considered neutral because the carbon would have otherwise been released as CO₂, carbon monoxide or methane through incineration or decomposition.
the technical line, indicating that, for at least 1995, the benefits of fuel switching exceeds the benefits of efficiency improvements, primarily through shifts to biomass fuels.

Because Canadian industry tends to be resource-based and energy-intense, production of CO$_2$ cannot reach even stabilisation levels (figure 5.12). This is not true of all industry in all regions; pulp and paper can attain both targets, primarily due to their use of biomass, even though biomass availability is constrained. In spite of industry’s inability to reach any of the specified targets, it still contributes over 40% of the total emissions reduced in the simulations, the largest share of any sector analysed.

**Figure 5.12: CO$_2$ emissions in Canadian industry.** The graph includes lines indicating the point of stabilisation at 1990 levels and a 20% reduction from 1990 levels (millions of tonnes).

![Figure 5.12: CO$_2$ emissions in Canadian industry.](image)

In most provinces in Canada, the price for coal is either below or falls relative to the price of heavy fuel oil. In all provinces but Alberta, both coal and oil prices are below or are falling relative to prices for natural gas. In the natural run, industries dependent on heat or steam move toward oil and coal from natural gas and electricity, especially in boilers in the general manufacturing sector. This is most evident in Ontario where the shift is from less carbon-intense to more carbon-intense fossil fuels and in Québec where the shift is...
from electricity to oil and coal. Consequently, in these industries, the CO$_2$ emissions in the natural run exceed that of the frozen run where fuel mix remains constant.

### 5.9.3 Cost

In spite of its inability to reach stabilisation targets, industry has a significant potential to reduce emissions at a fairly low average cost as shown in table 5.26. The average cost to industry to reach Canada’s stabilisation target (at a marginal cost of less than $75, see chapter 4, section 4.3) would be about $30 / tonne.

**Table 5.26: Average Benefit (Cost) of CO$_2$ Emissions Reduction in Canadian Industry ($/tonne)**

<table>
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<tr>
<td>$225</td>
<td>(67)</td>
<td>(70)</td>
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</table>

### 5.9.4 Specific Industries

A major premise of this thesis is that diversity in industry requires disaggregation in any modelling exercise to understand the effects of policies, product and service demand, energy prices and other factors on energy demand, emissions and other aspects of the energy system. Once disaggregated, one can again aggregate the data, as I have done here, with a much clearer understanding of why the aggregated forecasts behave as they do. Here I provide some examples of variations in industry in the context of the reduction of CO$_2$ emissions.

Industry response to the imposition of emissions charges depends in part on the response of the electricity-supply sector to those costs. In regions where the price of electricity jumps considerably under imposed charges, an industry decision-maker will seek to avoid the purchase of electricity and show a very different reaction than if that industry were located in a region where electricity supply shows little price change in response to emissions charges. For this reason, for example, chemical producers’ average cost per tonne of emissions reduction in Alberta is roughly four times the cost of reduction in other
regions. It is not just the avoided cost of electricity; Alberta’s chemical industry is focused more on organic or petrochemical products (i.e., is structurally different) than the chemical industry in the other regions of Canada.

Even if we could neutralise the impact of different fuel and electricity prices, each industry shows unique responses to an emissions charge. I point out some of these below.

5.9.4.1 Pulp and paper

Table 5.2 shows that pulp and paper is the only industry that can attain both targets; it can do so primarily because it has the ability to switch to an alternative, CO₂-neutral fuel, biomass. Yet, even though it is the dominant energy-using industry in Canada, it is not able to make up for the inability of the other industries to meet the targets.

Under the natural run, the industry is not inclined to move to biomass because the technologies are expensive and biomass boilers usually require a supplementary fuel to ensure consistent and controlled burning. Only in BC does biomass increase its market share in the natural run, primarily because existing policy regulations prevent or curtail the disposal of wood waste in landfills or through combustion (i.e., beehive burners).

5.9.4.2 Mining

Most of the energy consumed in metal mining occurs in the crushing and grinding processes. These energy-intense processes, driven by large electric motors, present little opportunity for the reduction of CO₂ emissions, except that, as the motors and crusher / grinders become more efficient, electricity demand and its related CO₂ declines. Recall, however, that such reductions are not accredited to the industry but to the supply sector.

Shifts to more efficient motors and auxiliary units occur in the natural run because it is economically efficient to move to these technologies. Any increase in the cost of electricity has the effect of hastening this movement and actually results in a net benefit to this portion of the industry. In other words, the imposition of a cost to emissions saves the mining industry money and the cost per tonne of reduction is positive in regions where metal mining dominates the mining industry.
5.9.4.3 Industrial minerals

Products generated in the industrial minerals group, dominated by cement and lime, are very energy-intense. Because fuel costs account for 20% to 30% of the total costs of production and because any combustible fuel can be used in a cement or lime kiln, most plants in the industry can switch fuels quickly and respond rapidly to changes in fuel prices. Therefore, although the industry cannot substantially reduce consumption of energy to reduce emissions, emissions reduction is inexpensive because shifting the fuel mix is inexpensive. This is not true in Alberta because all cement plants use natural gas and no fossil fuel alternatives with a lower carbon density are available to plant managers.

5.9.4.4 Petroleum refining

In some respects, petroleum refining is like the cement industry in that its energy intensity is high and it has the option of shifting easily to different fuel types. Yet it is quite different in that it generates almost all of its own fuel supply, some of it as a by-product to the refining process (refinery fuel gases). Thus, the technology cost of switching fuels is small but, because they use their own fuels before they purchase fuel (usually natural gas, except for Atlantic region refineries), there is only a minimal decline in CO$_2$ intensity.

The demand for reformulated and improved gasoline and diesel fuel requires that refineries increase production activity because more manipulation of the product is required in the process. Therefore, in an effort to reduce emissions from automobiles and other transport modes, the refineries must expend more energy and consequently release more CO$_2$. Nevertheless, in spite of this increased activity, the industry is able to reduce its CO$_2$ intensity.

5.10 Commercial Sector

Most commercial enterprises depend on only two distinct sources of energy, electricity and natural gas or, in the eastern regions, fuel oil. Because fuel oil is typically more expensive and requires more handling than natural gas, the latter is the fuel of choice where it is available. Thus, the commercial sector has few options, except for efficiency
improvement and a shift to electricity for water and space heating, if it wishes to reduce its energy consumption and level of CO\(_2\) emissions.

**5.10.1 Energy**

The commercial sector is subject to a number of construction standards (building codes and American Society of Heating, Refrigeration and Air-conditioning Engineers [ASHRAE] standards) that affect energy consumption. These were not assumed to change over time, but their effect can be inferred from figure 5.13; the sector moves to an energy-intensity path somewhat lower than the frozen run. The technical run moves the commercial sector to its least-intense position primarily through a shift from fossil fuel to electric heating. The economic run also moves quickly to a more efficient position (due to retrofit activity) but begins to rise in the latter years because it maintains the use of fossil fuels rather than switching to electricity as occurs in the technical run.

**Figure 5.13: Energy demand in Canada’s commercial sector under different economic conditions (PJ).**
5.10.2 CO₂ Emissions

Although responsible for nearly 13% of Canada’s total energy consumption in 1990, the sector produces just under 6% of its emissions. This indicates the degree to which it is dependent on electricity for its provision of services. A review of the CO₂ emissions generated by the commercial sector (figure 5.14) shows stabilisation in the commercial sector can be attained at a marginal cost level of less than $75 / tonne and that reaching the reduction target will require a cost just in excess of $150 / tonne. It becomes evident that the economic run chooses fossil fuels over electricity in the production of space and water heat because the emissions levels, though initially low, rebound to a level above that expected in the natural run.

Figure 5.14: CO₂ emissions in Canada’s commercial sector. The graph includes lines indicating the point of stabilisation at 1990 levels and a 20% reduction from 1990 levels (millions of tonnes).
5.10.3 Cost

Table 5.27 shows that the average costs of emissions reduction are rather high for the first simulation year, dropping thereafter, and that they are very high in the lowest cost run. Two factors drive up these average costs:

- retrofits to building shells that occur in the first years of the simulation under a competition algorithm that allows for some market share of more costly retrofits, and
- the costs that consumers will pay to avoid the purchase of electricity in Alberta, Saskatchewan and Ontario. Of all the sectors, the commercial sector is the most captive to electricity (i.e., it has few technology options to move away from electricity) and costs to avoid electricity are high in those provinces.

Because costs are high and quantities of emissions reduced are low, the commercial sector can be seen as an expensive source of CO$_2$ emissions reduction.

<table>
<thead>
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5.11 Residential Sector

The residential sector is responsible for 14.5% of the energy consumed in Canada and about 9% of its CO$_2$ emissions. It shows significant possibilities for efficiency improvement and emissions reduction, primarily in the elimination and retrofit of old housing stock. Like the commercial sector, the construction of news homes is governed by a set of policies deemed to remain unaltered over time.

5.11.1 Energy

New homes show significant efficiency improvements over old homes such that, as old homes are retrofitted or retired, the net change in overall energy consumption is small.
over time. Even though the number of homes rises nearly 40% over the twenty years, energy consumption rises only 26% under the frozen run (1990 marginal efficiency is used for new homes) and only 10% under the natural run. Numerous retrofit possibilities exist in this sector; this, along with the improved efficiency of new structures and the destruction of the old, results in the decline in energy intensity in the residential sector.

In the socio-economic run, energy efficiency exceeds that of the cost runs but the fuel mix is not at all similar. This is because the cost runs trigger a move to electricity while, in the economic runs, the move is towards fossil fuels, primarily natural gas. Some regions of Canada have only recently had access to natural gas (e.g., Vancouver Island, much of Québec) and the socio-economic criteria as well as the cost runs stimulate the shift to this fuel over heating oil. In the technical run, housing stock is almost totally dependent on electricity. See figure 5.15.

**Figure 5.15: Energy demand in Canada’s residential sector under different economic conditions (P.J).**
5.11.2 CO₂ Emissions

Increased shell efficiency over time and a shift toward natural gas from heating oil to provide heating services allows this sector to meet emissions targets without the imposition of an emissions charge (figure 5.16). Socio-economic conditions hasten fuel shifting, especially from electricity to natural gas in BC and Québec. For this reason, the economic run and the natural run generate about the same amount of CO₂ even though the economic run shows a lower energy intensity. Increasing emissions charges prompts residential decision makers toward the use of electricity in the hydroelectric provinces and toward very efficient natural gas-using homes in provinces dependent on fossil-fired electricity.

As in the commercial sector, the technical run’s choice of electricity for space and water heating results in a very low (near 0) emission level by 2010, given the assumptions about the allotment of emissions to the producer. In a region where all electricity comes from non-fossil-fuel sources, this would actually be true but full life-cycle accounting would change this picture in a region dependent on fossil fuel combustion to generate electricity.

5.11.3 Cost

If the existing residential construction standards are maintained over the next 20 years, no net emissions charge need be invoked. The marginal cost of reducing emissions to meet the Canadian stabilisation target (about $70 / tonne) would induce an average expenditure of about $40 / tonne CO₂ reduced as shown in table 5.28. In the residential sector, applying a marginal cost of this magnitude would allow the residential sector to attain the 20% reduction target (see figure 5.16).

Table 5.28: Average Benefit (Cost) of CO₂ Emissions Reduction in the Canadian Residential Sector ($/tonne)

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Figure 5.16: CO\textsubscript{2} emissions in Canada’s residential sector. The graph includes lines indicating the point of stabilisation at 1990 levels and a 20% reduction from 1990 levels (millions of tonnes).

5.12 Electricity Generation Results

In regions where fossil fuel acts as the primary energy source in the production of electricity, the ability to switch from coal to natural gas or from coal and natural gas to non-fossil fuels provides one of the greatest potential sources of CO\textsubscript{2} abatement for that region. However constraints in ESSM (see chapter 4, section 4.1) prevent some of these shifts from occurring, a matter of concern in this analysis (see chapter 4, section 4.7.1). Nevertheless, the goal of the analysis included demonstrating the interactive ability of ISTUM with a supply model; this was successfully accomplished. Results from ESSM are described below.

5.12.1 Energy

In figure 5.17, we see that demand for energy drops in the first year of simulation, primarily because, with a decline in demand for electricity, regions that have non-thermal sources of energy (BC, Ontario, Atlantic) use these first. Most provinces have reported over-capacity, or at least, no need to increase capacity until the turn of the millennium.
The constraint on hydraulic and nuclear sources of electricity are not applied to the frozen simulation. Therefore, any new capacity added in the economic run (in the case of public or regulated utilities, this would be the natural run) would be associated with the renewable set-asides or some thermal source.

Figure 5.17: Energy demand in Canada’s electricity supply sector under different economic conditions (PJ).

Demand for electricity increases under most cost runs in regions where the primary sources are not thermal because, in these regions, it acts as a CO$_2$-neutral form of energy. Thus, utilities choose biomass-fired supply because they are constrained from building new hydro or nuclear supply. This choice causes energy demand in generation to rise as the imposed emissions charges rise. As a result, the demand for energy in the supply sector becomes increasingly greater as the demand for electricity grows.

The technical run assumes that all retired supply can be replaced by sustainable, non-thermal sources and thus energy demanded for generation of electricity drops in direct proportion to the rate of retirement of old generating stock. Note that in this run, there is no diminishment of electricity demanded by the consuming sectors (in fact, demand
typically increases) while in the emission cost runs, demand declines in regions where electricity is CO$_2$-intense.

### 5.12.2 CO$_2$ Emissions

Translating the energy graph of figure 5.17 into the CO$_2$ emissions graph in figure 5.18 provides some insight into the events that occur in various Canadian regions. The frozen line maintains a relatively consistent increase in emissions relative to what was generated in 1990. The natural / economic lines indicate that, due to over-capacity, thermal plants are shut down and emissions levels drop accordingly. They also show that, as increased capacity is required, fossil fuels serve as the primary choice (e.g., combined cycle gas-fired turbines, coal gasification, etc.).

**Figure 5.18: CO$_2$ emissions in Canada’s electricity supply sector.** The graph includes lines indicating the point of stabilisation at 1990 levels and a 20% reduction from 1990 levels (millions of tonnes).

The large drop in emissions in cost runs indicates that, in those regions where the cost of electricity doubles or triples under the effects of the emissions charge, the demand declines to the point where the stabilisation target can be easily met. The drop is due to
plant shut-down rather than efficiency improvements or alternatively-fueled sources (actually, in a total system perspective, the fuel switching does occur, but it occurs in the demand sectors when consumers moved away from electricity in sensitive regions). As demand increases, mothballed coal and oil capacity is brought back on line (one of the constraints in ESSM) and CO$_2$ emissions begin to rise again, although not to the level they would have had no emissions charges been allocated. In future analyses of this type, these ESSM constraints will require modification.

5.12.3 Cost

Charges for emissions vary significantly from region to region, depending on the historical mix of generating sources. Average costs in the provinces vary from no cost (in provinces where no CO$_2$ was or will be emitted and so none can be reduced) to costs exceeding the marginal costs (primarily because the model brings old stock back into service forcing consumers to buy expensive technologies to avoid the purchase of electricity).

<table>
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5.13 Chapter Bibliography


6. Conclusions and Recommendations

I have proposed and tested a modelling approach and further refined a specific modelling tool (ISTUM) designed to aid decision makers in their analysis of energy systems. No models are perfect; analysts and decision makers are well served to know of and understand the models’ imperfections. There must also be a way to offer a sound critique of the tool; in testing the veracity of the model, one should:

• compare model output to actual events or data - How well does it mimic the system?
• compare the model to other models applied to the same “portion of reality” - How does it deal with key issues and uncertainties compared to other models? How do its outputs compare with that of other models?
• assess the believability and confidence the model provides to the decision maker - Does the degree of detail and the model’s transparency provide a level of confidence and understanding for policy and decision makers that exceeds that found in the alternatives?

In the first three sections of this chapter, I analyse of the outcomes described in chapters 4 and 5 in the light of certain criteria for model assessment. I focus on three issues:

• a general evaluation of ISTUM and ESSM as modelling tools in the context of the overall modelling system (section 6.1) - Are the models appropriate for and effective in their task, efficient in their operations, able to analyse and clarify issues of uncertainty and provide information that aids the decision maker? Are they flexible in their application? Are they easy to handle in their operation and maintenance?
• an evaluation of results (section 6.2) - Compared to other models actively used in similar analyses, how have they improved or aided our understanding of the energy demand system as far as it concerns CO₂ emissions issues?
• how the decision makers may interpret and use these results in the development of policies (section 6.3) - How can abatement cost curves be developed and what do
they tell us about the application and the consequences of action plans and policies in the various regions and sectors?

To complete the analysis, section 6.4 contains caveats related to the operation primarily of ISTUM and somewhat of ESSM and the model system. Specific caveats that reflect idiosyncrasies of each sector or industrial branch in ISTUM are found in appendix B. Finally, in section 6.5, I make recommendations regarding areas needing improvement and proposals for further study and future research.

6.1 General Model Evaluation

ISTUM is versatile in that it can focus on any attribute of technologies or processes: capital, operating, maintenance and fuel costs, energy, emissions, employment (if levels of employment can be associated with a technology or process) and material flows. ESSM is capable of reflecting technological, cost and emissions changes under different demand scenarios in the electricity supply sector, in spite of built-in constraints which affected significantly outcomes in the demand models. In this thesis, I reviewed policies affecting CO$_2$ emissions but other policy issues and emissions analysis could become the focus of future studies. Here I evaluate the models under a set of criteria to assess their usefulness as tools to analyse technology- or energy-related issues primarily in the demand sectors (ISTUM) and somewhat in the electricity supply sector (ESSM) as this sector applies to the demand sector as defined in figure 2.1.

6.1.1 Effectiveness and Appropriateness

Two fundamental questions can be asked of any model: Does it do what it is supposed to do? Are the results of use to decision makers? When we consider the demand sectors in this analysis, we wish to know if the modelling tool is effective in dealing with energy and emissions issues. In section 6.2, I demonstrate that the information obtained from ISTUM / ESSM simulations not only provides the expected aggregate picture of emissions reduction when compared to published results from alternative models, but also helps the analyst to understand the response of the sectors and regions to imposed emissions costs. The focus is not on the confidence the analyst or decision maker has in
the specific modelling outcomes (few actually believe the forecasts generated by their models), but confidence in the process that produced the results especially if it promotes an understanding of the outcomes.

In a previous analysis, ISTUM was used to address an issue concerning the allocation of emissions costs, one assessed at the Canadian Emissions Modelling Forum, where modellers were asked to determine whether a levy on energy was more or less effective than a levy on carbon content in reducing emission levels (see chapter 5, section 5.5.2). Using ISTUM, we determined not only that carbon taxes more effective than energy taxes but also why and where they were more effective. In some sectors, energy taxes actually served to increase CO$_2$ emissions because the consumers moved from less efficient, less CO$_2$-intense fuels like wood waste to more efficient but more CO$_2$-intense fuels like coal and oil (e.g., in pulp and paper). Results generated by aggregate models used in the forum, although they too showed carbon taxes to be more effective, could not point out why and where and the models did not show sufficient disaggregation to confirm or reject the seemingly counterintuitive result described above.

Is there a match between the models’ purpose and the information needs of policy and decision makers? Governments are reviewing many policies intended to affect decisions about technology acquisition in both supply and demand sectors. Efficiency programs sponsored by government agencies and utilities are typically directed at specific end-uses (e.g., efficiency programs for motors and auxiliary services, “Power Smart”, “House Works”, and International Standards Organization programs such as ISO 9000 and ISO 14000). NRCan produces annually an efficiency trends document that highlights shifts in technology penetration (NRCan 1996). Thus, ISTUM / ESSM results, which highlight specific energy or emissions characteristics of the demand and electricity supply components of the system, do provide useful feedback to the decision-maker. For example, ISTUM outputs from this analysis can be used to estimate emissions reduction by sector and by region to permit tailored policy development (see section 6.3).
6.1.2 Treatment of Uncertainty

How well does ISTUM address the uncertainties decisions makers face when they view the historical output of both the more aggregate, top-down models and the more detailed bottom-up models in their analysis of the demand sectors? Does ISTUM allow the decision maker to analyse and review the uncertainties and risks involved with implementing certain policies or regulations?

ISTUM was designed to address uncertainties known to contribute to the divergence of results from both aggregate and disaggregate econometric models on one hand and first generation technology and LP models on the other (see section 1.6 of chapter 1 for details, table 6.1 for a summary). Through the application of ISTUM’s modelling techniques, the impacts of these uncertainties on energy consumption or CO$_2$ emissions can be assessed and clarified. These techniques may not be novel in and of themselves but are uniquely combined in ISTUM to overcome the problems of inadequate portrayal of activity in the demand sectors exhibited by other models. They include:

- detailed description of technology by sector, industry and region
- disaggregation of sectors and industries by region
- utilisation of cost minimising algorithms
- application of discount rates to capital expenditures
- application of probability functions that relate a technology’s cost and its market share (technology penetration)
- application of non-cost criteria to algorithms of technology choice
- ability to generate output that permits linkage to other models

Using these techniques, analysts can assess the effect of changes in parameters on policy initiatives such as those to limit CO$_2$ emissions. Through sensitivity analysis (testing of the range associated with parameters) and the application of Monte Carlo simulations (many simulations using randomly selected values from the range of the parameter being tested), one can assess the importance of each parameter on model results.
Table 6.1: Uncertainties and How Various Models Deal with Them

<table>
<thead>
<tr>
<th>Uncertainty*</th>
<th>Issue</th>
<th>Econometric Models (aggregate and disaggregate)</th>
<th>First Generation Technology Simulation and LP Models</th>
<th>ISTUM (Technology Simulation Models)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology change</td>
<td>assess changes in AEEI, ESUB</td>
<td>cursory, poor data on technology</td>
<td>lack of data on behaviour</td>
<td>detailed data on technology and behaviour</td>
</tr>
<tr>
<td>Disaggregation</td>
<td>capture variability by sector and region</td>
<td>poor parameter verification</td>
<td>high level of disaggregation</td>
<td>high level of disaggregation</td>
</tr>
<tr>
<td>Cost</td>
<td>is technology choice cost-based?</td>
<td>based on historic data, no data on tech. changes</td>
<td>limited assessment potential</td>
<td>mitigated cost minimisation algorithm</td>
</tr>
<tr>
<td>Timing of costs</td>
<td>actor- and action-specific discount</td>
<td>aggregate discount rates</td>
<td>disaggregate, if applied</td>
<td>disaggregate</td>
</tr>
<tr>
<td>Variability in costs</td>
<td>assessment of variability in technology costs by sector and region</td>
<td>poor technology disaggregation, assessed only in aggregate analysis</td>
<td>none</td>
<td>probability distribution around technology’s mean cost</td>
</tr>
<tr>
<td>Non-cost factors</td>
<td>assessment of other factors that affect purchase decisions</td>
<td>considered captured in behaviour</td>
<td>none or exogenous</td>
<td>a number of specific factors, some exogenous</td>
</tr>
<tr>
<td>General equilibrium</td>
<td>interaction of energy and other factors</td>
<td>typically shows general equilibrium</td>
<td>none, requires exogenous inputs, linkage</td>
<td>partial equilibrium, requires linkage</td>
</tr>
</tbody>
</table>

*See section 1.6, chapter 1 for details

6.1.3 Ease of Use

Model must be easy of use, as defined by at least three criteria:

1. **Data requirements and setup**: What is required to make the model operational and suitable for the analysis at hand? Does the model require a lot of data? Is it difficult to set up and calibrate? Are guidelines and instructions adequate? What sort of expertise is required for setup?

ISTUM’s sub-models are not complex, are accompanied by a manual, a described set of energy flow models and the underlying dataset for Canada. Even so, specific data requirements are large; the major time obligation involves updating or altering the sub-models for a specific region, sector or sub-sector, finding supporting data on technologies and existing stock, and understanding the behavioural parameters affecting decision making as they relate to technologies and fuel selection. At this level, the work required
to set up the model would exceed that required to develop a top-down model and be equivalent to any other bottom-up model for that same region or sector.

Like ISTUM, ESSM is not complex but analysts do require a good knowledge and representative data set of the various power utilities ESSM simulates.

National and international experience suggests that calibration data are poor (see section 6.5.1, No. 1) and requires assumptions about industry structure and technology mix. Calibration requires a good, in-depth knowledge of the sector or industry.

2. **Operation, clarity and explicitness:** Who can run the model? Are the requirements for executing a simulation defined clearly? After the simulation is complete, are the results portrayed clearly? Can the results be traced to their origin?

Once the input data have been properly calibrated and the model’s dataset updated, execution of single or multiple model runs is menu-driven and very simple. All updating procedures are defined in the manual and the associated “Quick Guide” to ISTUM. Because all outputs are formatted as simple spreadsheets that can be read into any of the commonly available packages of spreadsheet software, complexity of the analysis of the data is determined primarily by the goal of the analysis, and not by model constraints.

But the model is large and detailed and generates considerable output; it requires practice to review properly the results and understand what the output data may indicate about either the inputs (i.e., recognising errors in data input) or about the actual outcomes of the simulations. Although the manual contains a guide to typical input errors, and a procedure to recognise them, these are not a substitute for experience and repeated exposure. However, this is not assumed to be more onerous than would be expected of any other model.

ISTUM’s algorithms are simple enough to allow the modeller to trace data outputs to their origins. Simple back-of-the-envelope calculations let the analyst ascertain the reason for what may appear, at first, to be anomalies. Providing opportunity to retrace model procedures and the effects of the behavioural parameters avoids the “black box” and “reductionist” fallacy (Wene 1996, see also chapter 1, section 1.5.1).
ESSM, once set up, requires only inputs of energy demand from simulations in demand models or from some scenario of growth. A set of macros drive the model to completion.

3. Application: What is involved with applying the model to new growth or structural scenarios? How readily can the tool be used to test various policy initiatives?

ISTUM permits analysts to apply any number of scenarios or economic conditions to the calibrated data. Once the model’s dataset is complete, the analyst can assign variance parameters, use a variety of industry or sector structure and growth scenarios, and establish simulations reflecting different economic criteria (high or low fuel prices and discount rates, market share limitations, emissions charges, etc.) by setting up spreadsheets that contain the pertinent data.

ISTUM is designed to be a “what if” tool where policies, regulations or standards that focus on characteristics associated with technologies or processes can be applied quickly and can generate results promptly. This is not the case with both optimisation models or aggregate models because there are few historical data to estimate changes in parameters or define constraints under new economic and technical conditions.

ESSM contains spreadsheet cells where various parameters and inputs can be quickly altered. These include discount rates, emissions costs, technology lists and associated data, as well as future demand for electricity.

6.1.4 Summary

Table 6.2 provides a judgmental comparison of the criteria defined above applied to top-down, bottom-up and ISTUM models in their ability to analyse energy consumption in the energy demand sectors (the energy demand node of chapter 2, figure 2.1). The scale used in the table, values from 1 to 5, define the degree of success attained by that model in maximising or minimising the criterion and are based on the comments made above. The assessments are rather arbitrary, but they do provide a point of comparison.

Table 6.2: Comparison of General Attributes in Policy Development When Dealing with Demand Sector Energy and CO$_2$ Analysis

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Top-down</th>
<th>Bottom-Up</th>
<th>ISTUM</th>
</tr>
</thead>
</table>

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While these are valuable criteria by which to assess a model’s usefulness and functionality, perhaps the best evidence of its practicality and application lies in the desire of policy and decision makers to use ISTUM and its outputs in their analyses and publications. ISTUM has been used in a number of analyses and its database provided information for a number of government documents (see, for example, Margolick et al. 1991, Jaccard, et al. 1992a, 1992b, 1992c, 1992d, Nyboer et al. 1996a, 1996b, Roberts et al. 1996 for completed analyses and NRCan 1996, 1997 for government documents). There is good reason to believe that these demands for ISTUM-based analyses will continue.

There is no doubt that, when the demand sectors are reviewed in such detail, feedback loops that include supply and macroeconomic models are needed. I have demonstrated the benefits of simulating electricity supply models, used iteratively with the demand models, in terms of its impacts on the demand sectors. Although not specifically part of this analysis, there is a need for interaction with a macroeconomic model to provide reasonable estimates of change in growth and structure in the tested scenarios.

### 6.2 Evaluation of Results

Analysts often test aggregate models using a technique called “backcasting” where, once model parameters have been estimated from data from some period in history, analysts program the model to begin its simulation from some earlier point to the present and compare results to available, present-day data in order to make any necessary adjustments. Such a technique could also be applied to ISTUM. Unfortunately, there are insufficient time series data available at the level of disaggregation needed to allow backcast simulations. Instead, I compare ISTUM’s forecasts to those published by analysts using other models.

In this analysis, I chose to focus on CO₂ emissions because of the importance of the issue both in the public mind and in the literature. In chapters 4 and 5, I provided simulation
results. Here I evaluate three components of these results, comparing them to published material; each of these are discussed in more detail below.

- ISTUM can generate long-run values for parameters useful to macroeconomic modellers which are, in turn, vital to continued simulation using ISTUM.

- Costs associated with emissions reduction generated in this analysis are higher than those from bottom-up modellers and lower than those from by top-down modellers.

- There is great heterogeneity in and between the sectors that more aggregate models cannot analyse. Such knowledge, supported by the detail, allows for a careful evaluation of the impacts of policies and permits fine tuning in their implementation sectorally, regionally and temporally.

### 6.2.1 Evaluation of Parameters

ISTUM can be used to derive two parameters of value to macroeconomic modellers; the AEEI and ESUB. Although neither is required by ISTUM nor was their development considered a test of the model, one of the parameters, AEEI, can be easily derived from the work done in the modelling routine described in chapter 2 and provides a valuable point of comparison. The process involves simply determining the ratio of the difference in energy consumption between the frozen run and the natural run and the energy consumed in the natural run \((E_{froz} - E_{nat}) / E_{nat}\) when the price of fuels is held constant relative to other costs over time. Although the price was not held constant in the natural run, the calculation can provide an estimate of the value of AEEI as seen in table 6.4. In ISTUM, the AEEI values change over time (see table 6.3) and vary from region to region, depending on the degree to which industry dominates and the degree to which supply sectors can use non-thermal sources of electricity.

<table>
<thead>
<tr>
<th>Model</th>
<th>AEEI Values</th>
<th>AEEI Values Tested</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top-down</td>
<td>-</td>
<td>0 - 1.5</td>
<td>Manne and Richels (1994)</td>
</tr>
<tr>
<td></td>
<td>-</td>
<td>1.5</td>
<td>Mintzer (1987)</td>
</tr>
<tr>
<td></td>
<td>-</td>
<td>1.0</td>
<td>EMF (1993)</td>
</tr>
<tr>
<td>Bottom-up</td>
<td>1.64</td>
<td>Williams (1990)</td>
<td></td>
</tr>
<tr>
<td>Electricity use</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
I could find no actual values for AEEI in the literature; parameter values used in top-down models were not obtained from data analysis but were simply tested over a range to determine their effect on energy consumption. As reported in chapter 1, the size of this parameter has significant implications on the change in energy consumption and consequent emissions reduction. Initial estimates for this parameter as used in top-down models were low (Whalley and Wigle 1990a, 1990b, Manne and Richels 1990a, 1990b) and were tested for higher values after receiving critique (Williams 1990, Wilson and Swisher 1993). Some researchers estimated a value for AEEI from specific industries or industrial processes (see table 6.3), but these estimates only reflect the variations that exist in the demand system between sectors and indicate that values used in top-down analyses may be underestimated. ISTUM’s estimates show that the value would indeed be higher than these earlier, pessimistic values, perhaps as high as the 2% / year found by Schipper and Meyers (1992) in manufacturing sectors in OECD countries.

Table 6.3 also displays selected sectoral and regional estimates for AEEI to show the variation that exists between sectors and between regions. The variation stems from a number of possible sources: the state of the efficiency of existing stock in the base year, the potential for improvement in the available set of technologies (i.e., those listed in ISTUM’s database) and the rate of turnover or the retrofit potential of equipment stock.

AEEI values vary over time, primarily because, as the market becomes saturated with efficient alternatives, autonomous improvement declines (recall that new, more efficient,
speculative options are not included in the database). This issue is revisited in section 6.2.3 and 6.5.2.

The elasticity of substitution (ESUB) between energy and other factors to production, another parameter of importance to econometric modellers, is more difficult to obtain from the simulations completed here. The value of ESUB can be determined when certain simulation parameters are controlled or held constant, its estimation was not intended to be part of analysis. Estimation of both of these parameters, AEEI and ESUB, form the basis of future investigations using ISTUM and can serve as valuable feedback parameters to macroeconomic models.

### 6.2.2 Cost Comparisons

Both top-down and bottom-up modelling techniques have been used by analysts to determine the costs of emissions reduction in both $ / tonne and total costs as a percent of GDP. Unfortunately, analysts did not always define clearly to what their cost / tonne figures refer. Were they related to the cost per tonne of carbon or carbon dioxide ($1 / tonne CO$_2$ = $3.67 / tonne carbon)? Were the emissions costs marginal or average? Were there any dynamic features in these cost figures (i.e., average cost figures can vary from year to year). What discount rate was used in estimating these costs? Were these costs the aggregate of all sectors in the economy?

ISTUM / ESSM outputs can be presented in cost per tonne of carbon or CO$_2$, in both marginal and average costs, by sector and region or as an aggregate of all modelled sectors and regions, but defined values from the literature to which these can be compared were not readily available. Therefore, I have compared cost values as a percent of sectoral GDP in table 6.4. The table presents data from the Energy Modeling Forum (EMF 1993) where modellers were requested to simulate their models under a defined set of conditions. These conditions do not precisely match those used in this modelling analysis because the detail required in this analysis exceeded what could be provided in EMF’s scenario description, especially in terms of growth in particular sectors. However, comparison does provide some insight into the function of ISTUM relative to typical top-down models.
Table 6.4: Comparison of Costs of Emissions Reduction from Different Model Types (%GDP)

<table>
<thead>
<tr>
<th>Model type</th>
<th>Cost to stabilise</th>
<th>Cost to reduce 20%</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Top-down models</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ERM</td>
<td>0.4</td>
<td>1.1</td>
<td>Edmonds &amp; Reilly (EMF 1993)</td>
</tr>
<tr>
<td>Global 2100</td>
<td>0.7</td>
<td>1.5</td>
<td>Manne &amp; Richels (EMF 1993)</td>
</tr>
<tr>
<td>MWC</td>
<td>0.5</td>
<td>1.1</td>
<td>Mintzer (EMF 1993)</td>
</tr>
<tr>
<td><strong>Range</strong></td>
<td>0.2 - 0.7</td>
<td>0.9 - 1.7</td>
<td>EMF 1993</td>
</tr>
<tr>
<td><strong>Bottom-up models</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.0</td>
<td>0.5</td>
<td>Carlsmit (1990)</td>
<td></td>
</tr>
<tr>
<td>0.0</td>
<td>0.5</td>
<td>Chandler &amp; Kolar (1990)</td>
<td></td>
</tr>
<tr>
<td>-</td>
<td>-1.2‡</td>
<td>Mills, et al. (1991)</td>
<td></td>
</tr>
<tr>
<td>ASE</td>
<td>-</td>
<td>-0.4‡</td>
<td>Alliance to Save Energy, et al. (1991)</td>
</tr>
<tr>
<td>OTA</td>
<td>-</td>
<td>-0.2‡</td>
<td>Office of Tech. Assessment (1991)</td>
</tr>
<tr>
<td><strong>ISTUM</strong></td>
<td>0.15 - 0.2</td>
<td>&gt; 0.6 - 0.9</td>
<td></td>
</tr>
</tbody>
</table>

* Many other models and results exist but were run under different scenarios than those run for EMF. Their values are not reported here because they are difficult to compare to ISTUM results.

‡ No EMF-like unified scenarios were established to provide results in bottom-up models as in top-down models. Values marked here achieve reductions slightly greater than 20%.

§ The range shows an increase in costs as a percent of GDP over the 20-year simulation.

A number of other articles and publications exist in which analysts ran top-down models and obtained different quantities of reduction under different socio-economic scenarios. The cost to regional GNP varied from 0.1% to 10.9% for rates of reduction of CO₂ emissions between 8% and 96% from the baseline. It is difficult to provide a point of comparison between these outputs and those generated by ISTUM.

The bottom-up analyses presented in table 6.4 were not run under a similar set of socio-economic conditions. They are provided as typical examples of results generated from end-use analysis. Some of the values listed to reduce emissions by 20% actually achieve reductions in excess of 20% (e.g., the -0.4% GDP cost in the ASE model achieved a 26% reduction from the base year) but are categorised here to provide a point of comparison.

Values generated in ISTUM cover the range of costs as they change over the specific simulation periods. Costs increase over the 20-year simulation because the mix of alternatives in the early years includes a greater proportion of less expensive options which, once adopted, leave only the more expensive ones in latter years. ISTUM’s cost
values of 0.15% to 0.2% of GDP to stabilise and 0.6% to 0.9% to reduce fall somewhere in between those costs generated by the top-down models and the bottom-up models. This is as expected; ISTUM extensive database allows for technological variation and choice not available in top-down models. ISTUM’s algorithms permit the penetration of lease-cost abatement options to lower the net cost of abatement while at the same time preventing excessive shifts in technology stock typical in bottom-up models that show no behavioural effects.

6.2.3 **Can we reach the target?**

There is no doubt that the technologies exist to meet both stabilisation and reduction targets. The primary constraint is not technical know-how, nor is it the lack of energy supplies to drive such technologies. Rather, it is the balance and interplay of these technologies with the prevailing political and economic environment that will determine if the targets can be attained. ISTUM provides the decision-maker with some idea of the consequences of change in both the technical and the political / socio-economic spectrum. Its detail can point out the degree of response from different sectors and regions in Canada and can provide background for regulatory or other fiscal measures to allow Canada to meet its target(s).

Under the simulation criteria defined in chapter 2, Canada can attain the stabilisation target, primarily through reductions in the less energy-intense commercial and residential sectors. It is one thing to know that this is possible, but there is significant advantage to knowing where and how this is possible. The disaggregation in the model provides such an advantage, and serves to increases one’s confidence level regarding the issues and the impact of actions taken (see section 6.3 below for the benefits of disaggregation); the model’s detail affords three advantages to the decision maker.

1. **Understanding the demand and supply sectors:** Many opportunities for emissions reduction exist in the interaction between demand and electricity supply sectors, especially in the use of specific alternative technologies such as cogeneration in industry and certain commercial enterprises or the development of sustainable supply technologies (see Williams 1990 for examples). Because of the wide regional
variation of utility and government policies and regulations concerning non-utility generation and the transportation and distribution of electricity (known as wheeling), cogeneration potential was fixed in this analysis to control for another important source of variation. Analysts can, by relaxing this constraint, review the impacts of increased cogeneration on efficiency improvements and petroleum refining.

2. Understanding opportunities for potential emissions reduction: ISTUM provides specific details on the nature and sources of CO$_2$ reduction potential and the analyst can pinpoint or highlight such sources to develop targeted policies. For example, R&D programs can be focused on the development of new processes in CO$_2$-intense industries like iron and steel and petroleum refining.

3. Understanding regional and sectoral variations: The application of any single policy, such as a national emissions charge of, say, $75 / tonne CO$_2$, will generate different results in the different regions and sectors in Canada. Understanding these variations through disaggregated models provides both provincial and national decision makers with information unavailable from more aggregate models on why the variation exists and what can be done to allay potential conflict or promote resolution.

Based on the simulations completed in this analysis, can Canada reach the targets? It appears that Canada could stabilise but not reduce its emissions to reach the -20% target. Yet there are several conditions that lead me to suspect a bias towards both underestimating the potential reduction and overestimating the costs:

- **inadequate tax response in ESSM** - ESSM’s rigidity and underlying assumptions prevented the generation of electricity supply from non-fossil or alternative fossil-fuel sources. Consequently, not only was emissions abatement from the supply sector underestimated but the use of faulty (high) electricity prices in ISTUM for some regions prevented the penetration of some efficient technologies. Although costs in supply sector operations may thus have been underestimated, consumers in the demand sectors spent more than they had to in their attempt to avoid purchasing the expensive electricity.
• lack of “new and improved” technologies in ISTUM’s database for 2000 to 2010 -
The decline in the AEEI over time points out the need to include new technology options in future years. As energy costs climb, technology research and development will focus on the energy characteristics of production and service provision. Even though estimates of type and degree of technology change are unavailable, ISTUM can be used to speculate on the impact of the penetration of some set of theoretical technologies.

• high discount rates in ISTUM’s cost runs - When managers or consumers expect short payback periods or high rates of return on investment, costs associated with maintenance, operation and fuels are deemed less important. When these costs rise (as under the imposition of an emissions charge), discount rates can be expected to diminish. This will not only move consumers to a more energy-efficient and less CO₂-intense position, but will also reduce the perceived costs associated with emissions reduction.

• lack of an “equilibrium” feedback loop - Just as it is true that different industries and different sectors show different responses to an emissions charge, so the price and consumption of goods and services will change as well. Such structural shifts in the overall economy (society) are not captured in this analysis. Emissions charges would be expected to reduce consumption of carbon-intense goods and services at some increased cost to society. But, if the equilibrium models adequately reflect market forces, these costs would be less than the costs incurred by the producer of such goods and services were production to remain unchanged. Thus both the level of emissions and the cost to reduce emissions would diminish from those generated in this set of simulations.

• exclusion of transportation - Transportation accounts for a large portion of the energy and emissions picture where great potential for efficiency improvement and emissions reduction exist.

• exclusion of broader energy management opportunities - ISTUM is not able to mimic actions related to assessments of energy consumption on a larger, more
integrated scale such as those used in community energy management and industrial ecology.

None of these issues alter the value and functionality of ISTUM as a useful modelling tool in the evaluation of policies to reduce CO₂ emissions. It indicates, rather, a need to develop appropriate supply models, a reassessment of data inputs to ISTUM, and the development of a method to promote interaction with equilibrium models.

6.3 Regional Contributions to Emissions Reduction and Abatement Costs

6.3.1 Canada, by Region

One can infer that, if a region generates a larger proportion of total emissions than other regions, it would have a greater potential to reduce these emissions. Without detailed analysis to review this assumption, many decision makers would apply a principle of proportionality and allot quantities of emissions reduction to the various regions based on their level of contribution to total emissions. In fact, the analysis in chapter 5 uses such a principle and this approach often becomes the focal point of negotiations on the global scale where each country is asked to commit to reduction based on their relative contribution. For example, the only quantitative target in the Framework Convention on Climate Change requires parties from developed countries to aim for a 1990 stabilisation target by 2000 (IPCC 1996, 104).

But, as Banuri et al. (1996) point out, such allocations are likely to be inequitable under a number of other criteria and a more expensive option than allocations based on, say, ability-to-pay or least-cost principles. ISTUM / ESSM simulations provide data to make informed allocations of expected emissions reduction to the various regions. Table 6.5 shows, for example, that it may be less costly to expect proportionally greater reductions from regions with hydroelectric supply than those regions supplied historically by fossil-fired generation by 2010. It also indicates that regions dependent on energy-intensive

1 Hydroelectric and biomass sources are considered CO₂-free, but indications are that these assumptions may need to be revisited in the future. This would have some impact on the establishment and attainment of targets, but is beyond the scope of this thesis.
industries, such as Alberta, may not have the opportunity to reduce emissions unless significant structural shifts occurred in both its supply and industrial sectors. Atlantic Canada’s significant contribution to emissions reduction (see Sup & Dem in table 6.5) occurs because of assumptions made regarding the retirement of its existing, old oil- and coal-fired stock of electricity supply technologies.

### Table 6.5: Relative Contribution to CO₂ Emissions Targets from Each Region (%)

<table>
<thead>
<tr>
<th>Region</th>
<th>% Share of Total Canada*</th>
<th>Stabilisation</th>
<th>Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Sup. &amp; Dem. ($70/t)</td>
<td>Demand ($150/t)</td>
</tr>
<tr>
<td>BC</td>
<td>7.2</td>
<td>8.6</td>
<td>13.8</td>
</tr>
<tr>
<td>Alberta</td>
<td>33.5</td>
<td>7.1</td>
<td>1.4</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>6.7</td>
<td>1.1</td>
<td>1.2</td>
</tr>
<tr>
<td>Manitoba</td>
<td>1.9</td>
<td>1.9</td>
<td>4.6</td>
</tr>
<tr>
<td>Ontario</td>
<td>31.9</td>
<td>27.3</td>
<td>40.0</td>
</tr>
<tr>
<td>Québec</td>
<td>10.1</td>
<td>18.3</td>
<td>31.1</td>
</tr>
<tr>
<td>Atlantic</td>
<td>8.7</td>
<td>35.7</td>
<td>7.9</td>
</tr>
<tr>
<td>Canada (% of target attained)</td>
<td></td>
<td>103.5</td>
<td>100.0</td>
</tr>
</tbody>
</table>

* Includes only sectors modelled in ISTUM and ESSM, from chapter 3, table 3.4 and 3.5.

Table 6.5 can be derived from a set of abatement cost curves developed for each region or sector. An abatement cost curve represents the quantity of CO₂ emissions that can be reduced at different marginal costs at a specific point in the future. In Figure 6.1, we see two such curves, one representing the quantity of CO₂ reduced from what would have otherwise occurred in the natural run by 2000 (the target year for stabilisation) and the other the quantity reduced by 2010 (the target year for 20% reduction). The vertical lines indicate the quantity of reduction from the level of emissions generated in the natural run that are required to meet the specific emissions targets.

The following five figures provide examples of cost curves from specific regions and illustrate the regional variations that exist; the first four figures show aggregate curves for BC, Alberta, Ontario and Québec while the final figure presents an aggregate curve for all of Canada (figure 6.5). These figures were chosen because they illustrate regions where:

- no cost to emissions need be imposed to reach at least one target (BC, figure 6.1),
• no targets can be reached under any cost allocations (Alberta, figure 6.2),
• cost allocations will allow the region to attain at least one target but not both (Ontario, figure 6.3), and
• both targets can be attained if costs to emissions are imposed (Québec, figure 6.4).

An analysis of each graph will allow the decision maker to estimate the level of emissions charges to impose to attain a particular target in that region. For example, in figure 6.1, no emissions charges are required to attain stabilisation by 2000 (the stabilisation line falls to the left of the “2000” graph line) in BC. A marginal cost of approximately $80 / tonne CO$_2$ would be required to meet the 20% reduction target by 2010 in BC.

On the other hand, the abatement cost curves for Alberta in figure 6.2 graphically illustrate the reason why it appears unlikely that any target can be reached there, no matter what level of marginal costs may be applied. Although this conclusion must be tempered by the uncertainty of the assumptions made in ESSM regarding Alberta’s electricity supply, Alberta’s industrial sector, very dependent on carbon-intensive industrial activity, contributes significantly to the steepness of the curves.
Figure 6.1: CO₂ abatement cost curve for BC. Vertical lines indicate abatement needed to reach targets; horizontal lines indicate marginal cost required. For industrial, residential, commercial and electricity supply sectors (million tonnes).

Figure 6.2: CO₂ abatement cost curve for Alberta. Vertical lines indicate abatement needed to reach targets; horizontal lines indicate marginal cost required. For industrial, residential, commercial and electricity supply sectors (million tonnes).
Figure 6.3: CO$_2$ abatement cost curve for Ontario. Vertical lines indicate abatement needed to reach targets; horizontal lines indicate marginal cost required. For industrial, residential, commercial and electricity supply sectors (million tonnes).

Figure 6.4: CO$_2$ abatement cost curve for Québec. Vertical lines indicate abatement needed to reach targets; horizontal lines indicate marginal cost required. For industrial, residential, commercial and electricity supply sectors (million tonnes).
Figure 6.5: CO\textsubscript{2} abatement cost curve for Canada. Vertical lines indicate abatement needed to reach targets; horizontal lines indicate marginal cost required. For industrial, residential, commercial and electricity supply sectors (million tonnes).

The abatement cost curves provide some evidence to the analyst of the possibility of meeting specific targets that lie beyond the range of the marginal cost policy runs tested here. For example, a review of the technical runs for Ontario indicate that reaching the reduction target by 2010 would be possible, but it would require a marginal cost higher than $225 / tonne. This conjecture is supported by a simple extrapolation of the abatement cost curves seen in figure 6.3. The same estimation principle can be applied in figure 6.5 for all of Canada.

6.3.2 Canada, by Sector

As in the discussion on regional marginal and average costs and contributions to emissions reduction, equitable sectoral emissions may not coincide with the proportionality principle either. Table 6.6 shows that industry, the primary producer of CO\textsubscript{2} emissions responsible for nearly 63\% of total emissions from the demand sectors (excluding transportation) in Canada, contributes proportionally less than (only 55\%) the other sectors to meet stabilisation goals. In response to competitive market pressures and the inauguration of the Canadian Industry Program for Energy Conservation (CIPEC) in 1976, this sector has been actively reducing its energy consumption per unit and,
consequently, its rate of emissions release, for at least 10 years prior to the agreed-upon base year, 1990. If we establish emissions targets relative to emissions in 1990, the other sectors, which made no similar efficiency advances, would find it easier to meet stated targets and to contribute proportionally more to CO$_2$ emissions stabilisation or reduction than the industrial sector.

Abatement curves can be derived for each of the various sectors and sub-sectors as was done for selected regions. Like the regional abatement cost curves in figures 6.1 to 6.5, abatement cost curves representing reduction potential in the sectors and sub-sectors show considerable variation. Industry, as a whole, is unable to attain either target and would show cost curves similar to Alberta’s. Yet, upon disaggregation, we note that some industries, such as pulp and paper, can reach both targets at some level of emissions charges, like the cost curves in figure 6.4. The commercial and residential sectors could reach either target; in fact, the residential sector can reach stabilisation without the imposition of an emissions charge (see chapter 5, table 5.2).

### Table 6.6: Relative Contribution of Each Sector to CO$_2$ Production and to Meeting CO$_2$ Emissions Targets (%)

<table>
<thead>
<tr>
<th>Sectors</th>
<th>Total Canada*</th>
<th>Stabilisation</th>
<th>20% Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Sup &amp; Dem</td>
<td>Dem. only</td>
</tr>
<tr>
<td>Industry</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pulp and Paper</td>
<td>45.2</td>
<td>35.0</td>
<td>54.7</td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>6.8</td>
<td>19.4</td>
<td>25.8</td>
</tr>
<tr>
<td>Mining</td>
<td>9.3</td>
<td>0.1</td>
<td>0.2</td>
</tr>
<tr>
<td>Petroleum Refining</td>
<td>5.9</td>
<td>0.3</td>
<td>0.4</td>
</tr>
<tr>
<td>Industrial Minerals</td>
<td>4.9</td>
<td>1.4</td>
<td>3.1</td>
</tr>
<tr>
<td>Chemical Products</td>
<td>3.4</td>
<td>0.8</td>
<td>1.3</td>
</tr>
<tr>
<td>Metal Smelting</td>
<td>2.1</td>
<td>3.6</td>
<td>4.4</td>
</tr>
<tr>
<td>Other Manufacturing</td>
<td>9.0</td>
<td>7.9</td>
<td>16.9</td>
</tr>
<tr>
<td>Commercial</td>
<td>9.7</td>
<td>6.4</td>
<td>13.8</td>
</tr>
<tr>
<td>Residential</td>
<td>15.9</td>
<td>15.1</td>
<td>31.5</td>
</tr>
<tr>
<td>Generation</td>
<td>29.1</td>
<td>43.5</td>
<td>N/A</td>
</tr>
<tr>
<td>Canada (% of target attained)</td>
<td>103.5</td>
<td>100.0</td>
<td>73.4</td>
</tr>
</tbody>
</table>

* Contribution to total emissions in Canada, includes only sectors modelled in ISTUM and ESSM
6.4 Caveats

No single model can simulate all phenomena associated with a certain process in the real world. The model’s limitations must be clearly stated and accounted for in any analysis of the modelled system. I have described these limitations, expressed as model caveats and sector caveats, below.

6.4.1 ISTUM Caveats

A number of model caveats exist; these can be grouped into those related to fuels, technology definition and disaggregation, and non-technological issues.

ISTUM’s structure includes its inherent assumption of partial equilibrium; ISTUM cannot determine the effects of its simulations on fuel prices or product / service demand without the aid of other models. If, through simulation, ISTUM calls for a significant increase in a scarce fuel, ISTUM cannot determine what will happen to the price of that fuel in future years. If increased costs of production raises the price of a good or service, ISTUM has no way of determining the effect on demand for that good, shifts in structure or effects on fuel prices for the next simulation loop (although this latter is likely to be negligible because of its international nature). For this reason, future research should focus on the development of operative links between equilibrium, macroeconomic models and the simulation models, ISTUM and ESSM (see section 6.5.2 below).

6.4.1.1 Fuel-related Caveats

Aside from the inability of ISTUM to determine the impact of a change in demand on the price of fuel, three other fuel-related caveats exist. Two of these deal with fuel prices and the third with self-generated energy, especially electricity:

1. Because large commercial operations and individual plants within an industry may negotiate energy prices directly with utilities or suppliers, different industrial or commercial consumers may pay different prices for the same energy form, even within a relatively uniform sector or industrial branch. Such information is difficult to obtain (often confidential) and would greatly increase the model’s complexity.
2. ISTUM is not currently constructed to permit analysis on time-of-use pricing or block pricing. Sector-specific fuel prices are assumed to be uniform over the range of quantities purchased.

3. The ability to cogenerate electricity and process or space heat improves the efficiency of both electricity generation and provision of heat. However, maximum penetration of such technologies is exogenously set in model runs because a number of non-cost-based issues affect their penetration: utility resistance, requirements for increased diversification in a commercial or industrial environment (industries and firms must now invest in a cogeneration specialist), managerial reluctance to expand into this area. A shift to self- or cogeneration would have considerable impact on the supply sector especially in provinces like Alberta where electricity supply technologies are CO₂-intense.

6.4.1.2 Technology-Related Caveats

Improvements in energy efficiency not explicitly a function of equipment choice are ignored by the model. Generally, this analysis assumes that most energy-intensive industries are aware of opportunities for housekeeping measures that could improve energy efficiency, but this is not always the case. For example, Solomon and Associates, a consulting firm that specialises in analyses of the petroleum refining industry, claims that up to 40% of energy savings may be obtained with better managerial and maintenance routines. However, it is unclear whether, say, the installation of a computer to provide more rapid response to changes in process is considered a technological improvement or a behavioural one.

Where possible, I have included technology packages that simulate improved process design, control and automation (such as “pinch” technologies where “waste” heat from one process is suitable for use in another process in the same plant). But, as with system maintenance, these potential sources of efficiency improvements tend to be very site-specific and difficult to capture in the database.

ISTUM may underestimate the technical potential for efficiency improvement simply because, in reality, each plant, commercial building or home would be able to optimise
separately, whereas ISTUM only optimises the aggregate sub-sector. This involves an assumption of averages, and that a fair evaluation of the average will provide a fair picture of energy consumption in the sector or branch.

### 6.4.1.3 Non-technological Caveats

Although there is considerable effort in ISTUM to include a broad range of factors affecting real-world technology selection, the model is still primarily driven by cost-minimising behaviours. In some cases, the penetration of a new technology may be better explained as some asymptotic function of time rather than cost. However, this implies that the modeller will be able to obtain parameter estimates of this asymptotic curve, even if it pertains to a totally new product. Since it is impossible to know consumer tastes for new products, another approach is to state explicitly the penetration (product acceptance) rates that will be exogenously estimated to drive the model. Where such an approach is used in ISTUM, it has been stated.

### 6.4.2 Sectoral Caveats

Apart from model-related limitations and conditions, each sector contains unique characteristics that affect its sub-model’s function. These tend to become specific, are only summarised here and can be found in detail in appendix B.

The condition of partial equilibrium described in section 6.4.1 is most felt in the industrial sector because of the interdependence of industries and the variety of energy sources. Changes in the construction industry determines demand for cement and dimension lumber, production of automotive products changes demand in iron and steel smelting, which in turn, affects mining. Industry also makes use of unique sources of energy such as black liquor, biomass and refuse derived fuels.

Other sectoral caveats include:

- disaggregation of industry products and assessment of which of these products should be included in the modelling,
- assessment of value associated with unique fuels or energy sources such as waste derived fuels, hazardous waste fuels, refinery fuel gas and various biomass fuels,
• changes in grades of raw materials such as mined ores, crude oil and fibre for pulp,
• exclusion of interactive effects between technologies (e.g., high efficiency lighting systems produce less waste heat and affect cooling and heating loads and, thus, demand on associated technologies)
• changes in quality and types of products and services (e.g., residential floor space per inhabitant changes over time)

6.5 Future Applications and Research

In discussions with industrial plant managers and their executive officers, the concept that “you can’t manage what you don’t measure” surfaced consistently. While true of industrial and commercial establishments, it is also true of the energy consumption and emissions picture in Canada. Measurement, monitoring and analysis require the diligence of many modellers using a variety of models designed to simulate specific components of the system in an effort to “manage” that system. Here I review two questions related to the maintenance and improvement of the energy and emissions picture in the demand component:

1. What is required to allow for proper measurement, monitoring and management of energy and emissions and permit the future application of the modelling techniques described herein?
2. What is required to improve the analysis of the general system (future research)?

6.5.1 Future Application

ISTUM’s structure and databases allow for analysis of any technology-related issue, many of which are crucial to global, national or regional policy development. Progress is hampered by primarily data constraints in three areas, described below:

1. Calibration data are poor.
   • Energy consumption data are often improperly reported, aggregated, or hidden (to maintain confidentiality). Activity data (production and service requirements) suffer from the same problems.
• There has to be a good relationship between the energy consumed in and the activity of a sector in a region. But the energy and production data are usually collected on different surveys sent to different samples sizes and respondents under different temporal criteria (some are fiscal year surveys, while others are calendar year surveys).

In an effort to properly measure and monitor energy consumption, the Canadian Industry Energy End-use Data and Analysis Centre (CIEEDAC) and Statistics Canada are in cooperation with various industry associations to improve data collection techniques and data harmonisation. Such work is far from complete but is in progress.

2. Much of the data used in this analysis are “soft” in that they are estimated by consultants, engineers, industry specialists and other knowledgeable people. Disaggregate data on technology stock and engineering coefficients exist in various, diverse sources but a good technology-specific data set for Canada needs to be developed. CIEEDAC has developed an inventory of existing or available databases, updated annually. CIEEDAC has also reviewed the work done in other countries (primarily France and the US) and proposed a plan to proceed with the development of a more defined data set related to end-use energy consumption in industry (CIEEDAC 1994). Other data centres in Canada are focusing on their respective sectors to the same end.

Good information on future technologies and how they differ from those used today is speculative. Estimations of their characteristics can be made and the effect of their penetration into the market can be tested through sensitivity analysis and Monte Carlo techniques.

3. There are some data on the relationship between life-cycle costs of equipment and their market shares among competing technologies, particularly for residential appliance and commercial HVAC technologies. Individual companies or firms may have information related to the share of their product in the market but these are not publicly available. The development of probabilistic technology choice models (see
chapter 2, section 2.2.2.2) depend on such data. Data of this sort are not available for most building shells or for most industrial processes; CIEEDAC is involved actively with NRCan to seek to establish some protocol to define these types of data. This would include improved survey techniques which could involve interviews with firms and individuals who make technology purchase choices.

Further testing of the effect of changes in the parameter or expected ranges of the parameter can be completed through more comprehensive sensitivity analysis and Monte Carlo simulations.

6.5.2 Future Research

The primary goal of this thesis was to show the need to develop models that could be appropriately applied to one specific component of the energy system, in this case, the demand node. But this can be seen as just one step in the overall goal to improve the analysis of the whole system, not just the demand node (see figure 2.1, chapter 2). With this in mind, I wish to suggest four research opportunities that would improve this more general analysis:

1. development of a link between equilibrium or macroeconomic (top-down) models and ISTUM - Top down models provide the forecasts of growth and change in structure necessary to construct scenarios for the demand node analysis. In turn, ISTUM can provide data on crucial parameters to the macroeconomic model. Thus, a significant area of research will be to develop some macro-end use link, similar to that tested by Wene (1996) using an optimisation and a macroeconomic model.

2. determination of parameters useful in top-down analyses, AEEI and ESUB - ISTUM can generate long run values for some of the parameters required by macroeconomic analysts, including the elasticity of substitution between energy and other factors to production and the rate of autonomous energy efficiency improvement. Analysis of the AEEI would require some improvement of ISTUM’s database on technologies that might be available in the future. In fact, ISTUM can provide estimates of many of the other indices of efficiency improvements mentioned by Schipper et al. (1993)
as well as the extent and dynamics of such improvements under various policies designed to control emissions.

3. the development or improvement of an interactive supply model - Just as there are links between the macroeconomic and the simulation models, so there must be a link between a supply model and these two models. The relationship between the supply and demand models is fairly simple and involves only the exchange of specific values: electricity or energy demand to the supply model and a set of new energy prices in return.

4. an analysis of the cogeneration potential in industry and other demand sectors under a changing set of policies and regulations concerning both electricity generation (non-utility generation, privatisation) and its transportation and distribution.

Finally, in the context of a general analysis of the overall energy system, there are a number of extra-technological features that require further research because they will have great impact on technological evolution simulated in models like ISTUM. To summarise, an analysis of decision making on the capital stock required to meet service and product demand can take place on a hierarchy of levels (Jaccard 1997):

1. Urban or societal form - The most encompassing level of organisation where decisions are made about societal structure and requirements. The duration of decisions made at this level is estimated to be 75 - 250 years. Energy issues would include an analysis of community planning (urban densification, self-sufficient communities), community energy management and industrial ecology.

2. Buildings, industrial process, transit modes - Once decisions have been made about urban planning and societal structure, provision of the required products and services to meet the needs of that society follow. Such decisions affect the system for 25-100 years, roughly the expected life span of the structures constructed.

3. Equipment - The lowest level of the hierarchy where the services and products demanded requires investment in equipment stocks whose typical life duration is 5-25 years.
An analysis of levels 1 and 2 can not be adequately accomplished through standard top-down or bottom-up forecasting models. It would require an alternative approach known as “backcasting” where some desirable socio-economic future would be postulated and modellers, analysts and decision makers would determine what would be needed to get there from the present (Robinson 1992).

ISTUM’s role would not change from that presented here; it would provide information on energy and emissions under these “backcasted” scenarios.

6.6 Chapter Bibliography


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2 This backcasting should not be confused with the technique of model testing where analysts program models to begin its simulation from some historical point to the present to be able to compare model output with actual data.


