A QUANTITATIVE ANALYSIS OF SOME POLICY ALTERNATIVES AFFECTING CANADIAN NATURAL GAS AND CRUDE OIL DEMAND AND SUPPLY

by

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ABSTRACT

Only recently has the Canadian federal government become involved in the regulation of energy prices. Since 1973 the federal government has imposed an export tax on crude oil, set the wellhead price of crude oil, implemented a one-price policy for domestic crude oil, regulated the Toronto city-gate price of natural gas, and increased the export price of natural gas. The federal government has also been involved in restricting the flow of energy quantities, mostly in the export market. The lack of rigorous economic analysis of the implications of these and other policy recommendations, as contained in various reports by the Department of Energy, Mines and Resources and the National Energy Board, motivated me to build an economic policy-oriented model describing some aspects of Canadian energy demand and supply.

The demand part of the model contains a set of estimated equations that describe the demand for crude oil, natural gas, electricity and coal within each of the five major consuming regions - Atlantic, Quebec, Ontario, Prairies, and B.C. A change in any energy price through government regulation will induce interfuel substitution and alter the mix of energy fuels demanded. To forecast future energy demand, the parameters estimated from historical experience are used in conjunction with forecasts of the exogenous variables, the latter usually obtained from government sources. The resulting "base-case" forecast of energy demand is compared with the forecasts by the National Energy Board and the Department of Energy, Mines and Resources.

The supply side of the model considers only the supply of crude oil and natural gas. The output of these fuels can be affected through any policy which affects either the amount of fuel demanded by Canadians or the amount of fuel demanded in the export market. An interesting component embedded in the supply model for crude oil is the Sarnia-Montreal pipeline. The flow through the Sarnia-Montreal oil pipeline can be altered in the model to examine certain trade-off possibilities between imports and exports of crude oil. The supply model for both crude oil and natural gas contains details relating to production, exploration, development, costs, taxes, royalties, and the distribution of economic rents among producers, consumers and governments.

The complete model is used to provide results of some sensitivity experiments and some policy experiments. The sensitivity experiments involve altering the basic assumptions with regard to the growth of real gross national expenditure, the offshore oil price and the efficiency factors for oil and gas use. The policy experiments focus on three main areas: the pricing of oil and gas, the trading of oil and gas, and the eastward flow through the Sarnia-Montreal oil pipeline.

I believe that the dissertation provides three main contributions: I believe that the specification and estimation of the aggregate demand system is a useful contribution. I believe that the process of building a model which integrates the supply and demand relationships, and details the costs, rents and trade flows for both crude oil and natural gas has been successful. And I have been successful in using the integrated energy system to generate quantitative results under alternative policies.

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To an excellent adviser and a good friend: thank you, John Helliwell. I wish to thank John for suggesting my research topic, for encouraging and assisting in its long development, and for generously giving his time for discussing and arriving at ingenious solutions to my problems. I also wish to acknowledge the helpful discussions provided by my other two committee members: Ernie Berndt and Paul Bradley; and by the other members of my departmental examining committee: Anthony Scott, Terry Wales and Milton Moore. Of course, I accept the responsibility for any errors contained within the thesis. I would like to acknowledge financial support from the Canada Council and from the Dafoe Foundation. I am indebted to the Computing Centre at U.B.C. for maintaining a superb computer environment, which I used extensively.

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1. Introduction

Only recently has the Canadian federal government become involved in the regulation of energy prices. Since late 1973 the federal government has imposed an export tax on crude oil, set the wellhead price of crude oil, implemented a one-price policy for domestic crude oil, regulated the Toronto city-gate price of natural gas, and increased the export price of natural gas. The federal government has also been involved in restricting the flow of energy quantities, mostly in the export market. The Canadian government, on the recommendation of the National Energy Board, has refused since 1970 to issue any new export permits for natural gas and has agreed to a rapid phase-out of all exports of crude oil after November 1974. The Canadian government insisted that a pipeline extension from Sarnia to Montreal be built for the purpose of using western Canadian crude oil to displace some imports by mid-1976. But the lack of a rigorous economic analysis of the implications of policy recommendations contained in recent publications by the National Energy Board [34,35,36] and the Department of Energy Mines and Resources [31] has motivated me to build an economic policy-oriented model describing Canadian energy demands and

supplies.[1]

The latest report by the Department of Energy Mines and Resources [32] is more thorough than any of the previous government publications in specifying the economic implications of policy alternatives, and hence provides results which are useful for comparison. In section 2.6 the results of the base case demand forecast are compared with those of the Department of Energy Mines and Resources. The Department of Energy Mines and Resources report has only two basic scenarios: a high price and a low price experiment (although high and low activity experiments are sometimes reported). However, the demand model used in the Department of Energy Mines and Resources study is unable to predict endogenously the total impact on interfuel substitution caused by changes in relative energy prices. The report, nevertheless, recognizes that pricing options are important: "...to the degree that governments control the prices of oil and natural gas directly and exercise substantial influence on the price of electricity and coal, pricing policy can be used to facilitate the substitution of one energy source for another" [32, p.136]. I intend to experiment with a wider range of policy alternatives than was considered in the Department of Energy Mines and Resources study.

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[1] I have been responsible for most of the development work on the demand sector, the non-frontier conventional crude oil production sector and the non-frontier natural gas production sector. Within the production sectors, the taxation and royalty equations in the post-1973 period are the work of Bruce Duncan. The modelling of the frontier Mackenzie natural gas sector and the non-conventional Alberta oil sands sector has been done by others, but is compatible with the modelling environment used for my sectors.

In the introduction, a very broad outline is provided indicating what the model does and how it works. Chapters 2 to 5 contain descriptions of the main sectors. In chapter 6 I analyse the kind of policy alternatives for which the model can be used. The last chapter provides a summary of the work. The six appendices provide all of the variable names, equations, data sources and detailed descriptions of the demand model, non-frontier natural gas model, non-frontier conventional crude oil model, the base case model solution, and the policy alternatives.

Before describing, in rather general terms, the major sectors of the model, the nature of a simulation system will be explained. The following definition will be used for the process of simulation:

> Simulation is a numerical technique for conducting experiments on a digital computer, which involves certain types of mathematical and logical models that describe the behaviour of a business or economic system (or some component thereof) over extended periods of real time. [114, p.3].

A simulation process[2] is used because the model contains a large number of simultaneous equations and must be solved over an extended period of time. The simulation process makes it possible to solve complex systems over time, and to study the effects on the system's behaviour due to policy changes in the structure of the model. In an attempt to be more specific about what is meant by a simulation model the following definition is used:

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[2] The numerical technique used in the solution of the simulation process is the Gauss- Seidel iteration process, described in the Bank of Canada publication, Simulator (1972).

> A scientific model can be defined as an abstraction of some real system that can be used for the purposes of prediction and control. The purpose of a scientific model is to enable the analyst to determine how one or more changes in aspects of a modeled system may affect other aspects of the system or the system as a whole. [114, p.9-10].

Any simulation model must embody two opposing attributes - simplicity and realism. As the reader examines the simulation model in more detail, he can judge for himself whether I have struck an acceptable compromise between simplicity and realism.

In the design and operation of the model, special attention is paid to energy trade and transportation, and to the current role of domestic crude oil and natural gas prices as key elements in the federal government's energy policy. World crude oil prices are treated as being determined outside Canada, and city-gate Toronto natural gas prices and wellhead crude oil prices as being determined by some policy rule. The relevant transport costs are then added or subtracted to obtain the crude oil and natural gas prices applicable in each of Canada's five consuming regions (B.C., Prairies, Ontario, Quebec, and Atlantic). These prices are then used within a consistent set of estimated demand equations to obtain forecasts of demand for each of four primary energy sources (including coal and electricity in addition to crude oil and natural gas) within each of the five regions. More details on the demand sector are contained in chapter 2.

Given a forecast for crude oil exports, the explicit treatment of the flows through the Montreal pipeline, and the regional demands for crude oil, the model can determine the crude oil imports into eastern Canada and the amount of shut-in crude oil producing capacity in Western Canada; or, in later

years, the amount by which National Energy Board forecasts of crude oil production fall short of demand west of the Ottawa Valley line, thus requiring westbound flows through the Montreal pipeline. These crude oil flows are also affected by the amount of synthetic oil produced, as modelled in the oil sands sector. A detailed description of the non-frontier conventional crude oil sector is contained in chapter 5.

Canadian demands for natural gas are combined with exports under existing contracts to give a requirements series that is met from non-frontier and frontier sources, depending on the assumptions made in the arctic pipeline sector about the timing and extent of arctic development. If demand exceeds supply there is no automatic trade flow to make up the shortage, as there is in the case of crude oil. Thus the preparation of an integrated and consistent natural gas forecast may require altering the price policies or obtaining access to frontier supplies to avoid potential shortages. Chapter 4 contains the details about the non-frontier natural gas sector.

The model contains considerable detail in the tax and royalty arrangements that distribute, in conjunction with energy price policies, the economic rents from energy resources among producers, consumers, and governments. Past costs, revenues, and tax structures have all been considered, so that the total financial history of the conventional oil and gas industries can be assessed. This accounting over a 'full cycle' of investment is important in extractive industries where exploration and development expenditures can precede production by many years. These timing relationships are complex enough to make simulation

necessary for accurate measurements of the effects of alternative policies.

In chapter 6, I provide an analysis of some sensitivity experiments on various important exogenous variables in the demand model, and an analysis of some policy experiments. The sensitivity experiments involve altering the standard assumptions with regard to the growth in real GNE, the offshore oil price and the efficiency factors for oil and gas. The policy experiments focus on three main areas: the pricing of oil and gas, the trade of oil and gas, and the eastward flow through the Sarnia-Montreal pipeline.

The assessment of the future effects of policies, reported in chapter 6, must be regarded as tentative, for one is still forced to rely on second-hand forecasts of the likely flows of conventional crude oil and natural gas from established reserves, and on the likely quantities of new crude oil and natural gas discoveries in non-frontier regions. In addition, the estimates of the rising costs of new non-frontier crude oil and natural gas reserves are very approximate and based on historical data which may be inappropriate for the forecast period. Despite all of these shortcomings, the model does provide a valuable device for integrating the many strands of energy policy that are otherwise likely to be treated by partial and inconsistent analysis.

2. Energy Demand Model

Expected demands for primary energy fuels in Canada will play a pivotal role in assessing Canadian energy policy. For instance, forecasts of both Canadian demand for natural gas and deliverability of natural gas from the non-frontier producing regions will be important in determining the optimum date for delivering frontier sources of natural gas to Canadian markets. The primary fuels considered are crude oil, natural gas, electricity and coal. But the demand for any single fuel cannot be examined in isolation. The existence of substitute energy sources, and of substitutes for energy itself, implies that a system of inter-related demands must be examined.

The development of this chapter is separated into six sections. In section 2.1 an evaluation and summary of some previous demand studies is provided. The assumptions behind the formulation of the demand model are contained in section 2.2. The next two sections contain the details about the construction of the data, the structure of the estimation equations, and the estimation techniques. In section 2.5 the underlying forecast assumptions and forecast results are briefly described. The last section contains a comparison of my demand forecast with forecasts by the National Energy Board and Department of Energy Mines and Resources.

2.1 Summary of Some Previous Demand Studies

Most studies on the economics of the petroleum sector have focused on problems of supply. But the demand for crude oil and natural gas must also be examined. Some ad hoc studies of demand extrapolate historical trends in energy growth (National Energy Board [33,34,36]). Other studies use the assumption that the trend in the energy-GNP ratio is constant (Darmstadter [45]). It has been pointed out by Berndt [16] and Mitchell [112] that one must consider relative prices and income in order to predict the demand for energy.[3] There has been quite a lot of research analysing the demand for a certain fuel in a certain sector of the economy (Balestra [11,12], Baxter and Rees [14], Khazzoom [95,96], and Mount, Chapman and Tyrrell [113]). Recently there has been a flurry of research considering the demand for all substitutable energy products by end-use sector (Fuss, Hyndman and Waverman [60], Gorbet [63], and Hunt and Smith [87]); and also considering the demand for energy as a derived factor demand from a production function (Berndt and Wood [15], Fuss et al [60], and Humphrey and Moroney [86]).

A paper by Berndt and Wood [15], investigating the United States manufacturing industry, seemed to start the trend towards research explicitly testing for cross-substitutability between energy and non-energy inputs. The results show that energy is

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[3] I shall use the terminology 'demand for energy' to mean the demand for an aggregate of final end-use energy products. Whenever the demand for crude oil, natural gas or other raw products is being discussed I shall use the terminology 'demand for primary energy products'.

responsive to its own price, that energy is slightly substitutable with labour, and that energy is complementary with capital.

The following is a brief description of the two most comprehensive models of Canadian demand for energy. The study by Fuss, Hyndman and Waverman [60] utilizes the same method as Berndt and Wood, using data for the Canadian manufacturing industry. Their results differ quite remarkably: in Canada energy and capital are found to be substitutes rather than complements, and energy and labour are found to be much more substitutable [60, p.26, table 8]. But they have extended the Berndt-Wood approach by calculating a share matrix consistent with the production function for each energy type in the manufacturing sector. The micro-specification is weaker in the residential and commercial sector. A logit model is used in the residential sector to estimate the shares of each fuel, given the output of the sector and relative prices; a linear demand function is used in the commercial sector to estimate the total demand for energy . It would be very difficult to use their results to arrive at an aggregate consumption of primary energy products because the industrial sector is represented by only manufacturing, the commercial sector has no fuel shares estimated, and the transportation sector is absent.

Gorbet [63] generally uses a log-linear form of regression equation to establish a relationship between aggregate energy

demanded[4] and aggregate activity and price variables for the commercial, industrial and residential end-use sectors treated separately. The model then feeds the calculated total energy demand for each sector through a matrix of projected "market shares which seem consistent with anticipated developments in technology and relative prices of alternative energy sources" [63, p.15] in order to arrive at demands for specific energy products.[5] The last step in the model is to use fixed coefficients to estimate the Btus of coal, natural gas and fuel oil which are necessary to produce the projected use of electricity (net of hydro and nuclear generated electricity) summed over all end-use sectors. This model goes a long way toward deriving the demand for primary energy products from the demand for energy in the end-use sector. However, the transportation end-use sector has not yet been completed, and the market share matrix has not yet been estimated using the same prices which appear as exogenous variables in the regression equations. This inconsistency could lead to incorrect results when the model is subjected to price shocks. In the last step of the model, there is no transformation of the demand for refined products into a demand for crude oil.

These models may be unreliable to the extent that they are static, which assumes that adjustment of energy demand takes

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[4] For each of the five regions used in the analysis the total energy consumed, measured in 'input Btus', was converted to energy actually utilized, measured in 'output Btus'. The conversion was necessary because various fuels which compete in the same end-use sector have different efficiency factors.

[5] The predicted output Btus by energy product are converted back to an input Btu measure by applying the same utilization efficiency factors used before.

place within one period (year). For abrupt and large changes in relative prices, technology or tastes a dynamic model should be used. Gorbet claims that as far as adjustment lags are concerned "most people agree that the approach to equilibrium is quite protracted since the process of adjustment entails replacing existing capital appliances with more energy efficient appliances" [63, p. 10]. Another perplexing problem which must be faced is how confident one can be in using elasticity estimates derived from a period of gradually falling relative energy prices to a future period characterized by increasing relative energy prices. A major barrier to a symmetric response would be the impossibility of immediate replacement of capital stock.

2.2 The Formulation of the Demand Model

Two major criteria were used to formulate the demand model used in this study: the model must explain the interdependence of fuel demands, and the parameters of the model must be derived empirically. The first criterion is based on the assumption that market developments affecting the price of crude oil, electricity or coal can influence the level of demand for natural gas. The second criterion requires that the model be designed to make use of available data. In our case the data cover the period 1958-1973; and most of it has been obtained from Statistics Canada publications, as described in appendix 3.

It is hypothesized that electricity or crude oil products can be substituted for natural gas in most markets where natural gas is sold; and that coal and crude oil products can be used as substitutes for natural gas in the generation of thermal electricity. It is assumed that coal will not compete as a substitute in most domestic markets (except for thermal electricity generation). Only for a small part of Ontario industrial demand is this assumption about coal likely to be inappropriate.

Although it is only the wellhead demands for crude oil and natural gas which are needed for the policy analysis in the thesis, the substitutability of energy products requires a framework in which the demand for all energy products must be considered. The demand for energy is essentially a derived demand for an intermediate product: hence given the desired output, the relative prices of all factor inputs, and the degree

of substitution possibilities among inputs allowed by technology one can determine the demand for energy. A rigorous approach to the demand for energy would execute such an analysis for each of the major end-use sectors: commercial, residential, industrial and transportation. Then within each end-use sector the total demand for energy would be decomposed into the demand for the relevant energy products via a share matrix which signifies the interfuel substitutability. This level of disaggregation is attractive if the energy users are reacting to a different set of variables, different substitution possibilities, or different relative prices in different end-use sectors.

The demand model presented below is more aggregated than the ideal model discussed above. But it is hoped that the assumptions necessary to formulate the aggregate model are theoretically and empirically reasonable. Most of the assumptions are due to data limitations. It is assumed that the aggregate production function in each of the end-use sectors is weakly separable in its energy inputs: i.e., the production function for sector s,

Qs = Qs (E1,...,En,K,L,M), can be rewritten as

Qs = Qs (F(E1,...,En),K,L,M), where Qs is the output, E(E1,...,En) is an aggregate function for all the energy inputs Ei, K is the aggregate capital input, L is the aggregate labour input, and M is the intermediate input. The weak separability assumption means that the marginal rate of substitution between Ei and Ej is independent of the quantities of K and L demanded. The assumption about the weak separability of energy is also made by Fuss, Hyndman and Waverman [60] using Canadian data and

by Hudson and Jorgensen [85] using U.S. data. However, the empirical findings of Berndt and Wood [15], using aggregate U.S. manufacturing data, reject the validity of the weak separabilitiy assumption for energy at the 99% confidence level. Since there has been no evidence rejecting the weak separability assumption for energy using Canadian data, the assumption was used in order to simplify the analysis.

It is assumed that the aggregate energy production function is continuously twice differentiable and exhibits constant returns to scale, which implies that one can use the duality between cost and production to demonstrate the existence of a cost function, Cs = Cs (PE1,...,PEn,Zs), where Cs is the total energy cost, Zs is the aggregate energy input, and PEi is the price of the i'th energy fuel. It is assumed that the parameters associated with the aggregate energy cost function are the same in each of the end-use sectors, which permits the estimation of only one energy cost function. Hence the data for each energy fuel have been aggregated over all end-use sectors. Therefore the substitution possibilities which are derived from the model will be an average for the fuel. Since the data cannot be broken down any further than the major end-use sectors (residential, commercial, industrial and transportation), aggregation has already made it impossible to determine substitution between fuels demanded for the same ultimate use of energy, mainly for heat or light. The assumption that a fuel reacts similarly across sectors to the same set of exogenous prices has its main weakness in the fact that the fuel prices are assumed to be the same in all sectors. It is well known that natural gas and

electricity rates vary among different classes of users (mostly through different two-part rate schedules); and a different set of crude oil products (with their different prices and excise taxes) are used in each end-use sector. Price differences across end-use sectors may also arise due to different wholesale and retail margins. It is primarily because data are not available to derive all of the fuel prices in each of the end-use sectors in each of the five regions in Canada over time that the assumption has been made to use 'city-gate' or 'refinery-gate' primary product prices. It is hypothesized that estimating the substitution possibilities among the primary fuels using city-gate prices will approximate the average substitution of the fuel over all the end-use sectors. A disadvantage in not working backward from the end-use sectors is that the structure lacks richness: for instance, it is impossible to assess the impact of the energy policies on the demand in various end-use sectors. Since the major aim of the dissertation is to examine the Canadian government policies as they affect the price and quantity of oil and natural gas in crude form, I am content with estimating directly the demand for crude products.

2.3 Structure of the Estimation Equations and Data

For estimation purposes the functional form of the energy cost function is chosen to be the translog. The translog function has been discussed by Christensen et al [41] and utilized empirically for energy studies by Atkinson and Halvorsen [10], Berndt and Wood [15], Fuss et al [60], Hudson and Jorgensen [85], and Humphrey and Moroney [86]. The advantage of the translog function over the traditional double logarithm demand equation is that the elasticity of substitution among commodities is not constant and equal to unity. The disadvantage of using this functional form is that it is very difficult to formulate a stock adjustment model.

The translog is one of several general formulations which place no restrictions on the Allen partial elasticities of substitution, and can be interpreted as a second order approximation to any arbitrary twice-differentiable cost function. The assumption of cost minimizing behaviour, with input prices and output taken as given, and of certain regularity conditions on the cost function (non-negative, linear homogenous in prices, and concave) implies input demand equations with the dependent variable being the cost share: i.e. $Si = PEi*Ei/C = ai + sum(j=1,n)\ bij*lnPEj$, $i=1,...,n$. The system of share equations is constrained by certain parameter restrictions (which are not all independent): linear homogeneity in prices implies that $sum(j=1,n)\ bij = 0$; symmetry implies that $bij = bji$ $(i,j=1,...,n)$; and the unity of the cost share summation implies that $sum(i=1,n)\ bij = 0$ and $sum(i=1,n)\ ai = 1$.

The derivation of the estimated cost share equations, with the above restrictions imposed, is detailed in appendix 3.A; and the paramater estimates of the cost share equations are detailed in appendix 3.B.

It is useful to know that one can derive the Allen partial elasticities of substitution (oij) and the price elasticity of demand (nij) very easily by using the parameter estimates from the translog cost share equations. The following formulae indicate how the summary measures are calculated:
oii = (bii + Si^2 - Si) / Si^2, oij = (bij + Si*Sj) / Si*Sj, nii = Si*oii, nij = Sj*oij . The calculated own and cross price elasticities of demand are contained in appendix 3.B.

In order to increase the number of observation points available for estimation, and in order to explain regional differences in energy usage, pooled cross-section and time series data were used from 1958 to 1973 for five regions in Canada. These regions are Atlantic, Quebec, Ontario, Prairies and B.C. & Yukon. Data on the quantity of each of the primary fuels in each region are available in a Statistics Canada document, entitled Detailed Energy Supply and Demand in Canada. The only data available on the corresponding prices are average prices obtained by dividing total expenditure by the quantity purchased. All of these average prices have been obtained from various Statistics Canada publications, as documented in appendix 3-E. Some of these average prices are wellhead prices, which must be transformed into market prices by adding the transport tariff. Data for crude oil transportation tariffs have been obtained from the Canadian Petroleum Association,

Statistical Yearbook up to 1971. The lack of readily available data for natural gas and coal transportation tariffs has led to the assumption that during the estimation period the tariffs have been constant in nominal terms.[6] From the available data the electricity price can be derived only in the retail market, whereas all other prices are measured in the wholesale (city-gate) market. A transformation coefficient for the price of electricity is derived using an average of the transfer price between Ontario Hydro and Toronto Hydro.

All of the prices and quantities have been adjusted so that they are measured in units called 'output' Btu. This unit is created in two stages: first the natural units are converted into 'input' Btu, using the conversion factors reported by Statistics Canada. Then the input Btu are converted to output Btu using factors which capture the relative efficiency of energy conversion among the different fuels and appliances used in the same end-use sector. These efficiency factors, which are taken to be constant over time and region, were derived from a study by Gorbet for the Department of Energy, Mines, and Resources [63]. The methodology and data are contained in appendix 3.C.

Even though the only end-use utilization efficiency factors at my disposal are constant over time and region, the derived average fuel efficiency factors do vary by region and over time

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[6] Since I have only been able to find natural gas tariff rates for a few years this assumption was neccesary, but it is not an unreasonable approximation to the actual behaviour of tariffs, as is shown in Helliwell and Lester [78]. Details are contained in appendix 3.E.

because of different fuel usage across region and shifts in fuel usage over time. By examining Table 3 in appendix 3.C it is possible to compare the average efficiency of fuel usage across region and over time. The efficiency of electricity does not vary over time or region because it is equally efficient in all end-use sectors. Over time the average use of oil and natural gas has become more efficient in the Atlantic, Quebec and Ontario regions. In the Prairies the efficiency of oil has fallen slightly over time and remained constant for natural gas; and in B.C. the efficiency of oil has remained constant over time and increased slightly for natural gas. The slight increase over time in the efficiency of oil and natural gas implies a combination of a shift to a larger market share for the industrial and commercial end-use sectors, and a shift in usage away from less efficient fuels. The reverse is true for oil efficiency in the Prairies. The shift in fuel shares toward the industrial and commercial sectors is reported in Gorbet [63] and Berndt [17]. Across regions the efficiency of oil usage is highest in Quebec, slightly lower in the Atlantic and Ontario, marginally lower in B.C., and quite a bit lower in the Prairies. The oil efficiency in the Prairies is the lowest because the region consumes the largest share of crude oil products in the form of diesel oil. Across regions the efficiency of natural gas usage is highest in Quebec, marginally lower in Ontario and slightly lower in the Prairies and B.C. The natural gas efficiency is slightly higher in Quebec and Ontario because a relatively larger share is used in the industrial sector.

The structure of the demand model requires two sets of

estimation equations. The set of equations accounting for the interdependent nature of the system consists of fuel cost share equations. The other set of equations determines the aggregate expenditure on total energy in each region. The amounts of each fuel used to generate thermal electricity have been removed from the main demand equations described above. This has been done to avoid double-counting both the thermal electicity and the fuels used to generate it. In order to estimate the quantities of fuel used to generate thermal electricity, an auxiliary demand model of similar design was used: i.e. it consists of a set of fuel cost share equations, and a total expenditure equation.

The main non-thermal demand equations have the quantities of losses and adjustments and of energy supply use taken out of the data. These data were extracted because it is believed that they do not represent components of final energy demand, but instead represent components of intermediate demand. Even though these quantities are subtracted from the main demand quantities, they must be estimated in order to determine the desired supply. The losses component is estimated as a simple proportion of sales or, in the case of the producing regions, as a proportion of production. The results of the estimation procedure for energy supply use and losses are reported in appendix 3.D. The list of the variables and coefficients used in the losses sector are reported in appendix 1.D; and the actual simulation equations are reported in appendix 2.D.

Using Table 1, Table 2 and Table 3 in appendix 3.D, one can compare the estimated losses coefficients across regions. The proportion of losses to regional demand for crude oil products

in Quebec, Ontario, and the Prairies is between .08 and .1; whereas in the Atlantic and B.C. it is approximately .05. The smaller proportion in the Atlantic reflects the lower amount of pipeline losses. The simple proportion equation does not fit the B.C. data very well, and by comparison with the other regions, I feel that the estimated coefficient is probably too low. The estimated parameters representing the proportion of losses to demand for electricity are approximately .09 in the Atlantic, Quebec and Ontario regions, slightly higher at .14 in the Prairies region, and slightly lower at .08 in B.C. The estimated parameters representing the proportion of losses to demand, or losses to production in producing regions, of natural gas vary considerably across regions. In the Quebec region the coefficient is actually negative because for some reason the losses and adjustment data have consistently been negative and larger in absolute value than the energy supply use data. In Ontario the proportion is approximately .06 representing mostly pipeline losses. Since energy supply usage of natural gas is rather large in a producing region, the proportion is .17 in the Prairies and .28 in B.C. It is not clear to me why the coefficient should be so different for the two producing regions.

The quantities of crude oil that are imported into the Atlantic and Quebec regions for re-export as petroleum products are not included in the data for domestic demand. These imports were only included in the equation used to predict the subsidy payments for imported crude oil (GFSUBO). I did not include the refined products in the export equation (OILEXPT) nor the crude

oil in the import equation (OILIMPT) because refined products are not introduced anywhere in the model. In retrospect, I believe that I should have left the re-exports out of the subsidy equation because the export tax on refined products is probably set to cover any subsidy payment on the imported crude oil.

The fact that almost no natural gas is used in the Atlantic region implies that the substitution possibilities must be estimated separately for this region. Similar regional differences in fuel usage for thermal electricity generation have led to the assumption that only coal and crude oil products are substitutable in the Atlantic and Quebec regions, only natural gas and crude oil products are substitutable in the B.C. & Yukon region, whereas in Ontario and the Prairies natural gas, crude oil products and coal are all potential substitutes. For greater efficiency of estimation, the proportionate effects of changes in relative prices are constrained to be the same in each region. The prices themselves, of course, are different in each region, primarily because of transport costs. Other regional differences in demand are captured by using a regional shift factor.

Since energy usage is usually associated with the utilization of some form of capital stock, one would expect the adjustment of both total energy consumption and shifts among fuels to take some time. The energy fuel prices used in the cost share equations are expected prices, not current prices. Each expected price is a moving weighted average of the current price and prices of the previous three years. The equation which

estimates the total constant (1961 dollar) energy expenditure is a log linear function of both real (1961 dollar) gross national expenditure and a 4-year weighted average relative price term.[7] The relative price term has a current-weighted composite energy price (Paasche index) relative to the price deflator for gross national expenditure.

Since natural gas has not always been available in every market area due to a lack of pipeline facilities, it is desirable to have a variable to represent the shift to natural gas once it becomes available. For this reason each regional set of share equations has a variable which represents the miles of natural gas distribution pipeline.

The submodel which explains the fuels used to generate thermal electricity is slightly different from the model described above. The equation used to predict the total current dollar expenditure on fuels has no relative price term and uses the total current dollar expenditure on thermal electricity as the activity variable. The quantity of thermal electricity demanded is assumed to be determined as a residual: total electricity demand, determined in the main demand system, is satisfied first by an exogenous supply of hydro and nuclear generated electricity, and then by the endogenous thermal generated electricity. The share equations use current prices only, which reflects the fact that some utilities have the

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[7] I experimented with a production framework that included capital and labour but rejected it in favour of the rather simple function described above because it provided a better fit over the historical period. The choice was also influenced by the fact that the variables in the simple function were relatively easy to forecast.

capacity to switch quickly between oil and gas fired generators. The conversion factor from input Btu to output Btu is the factor for the industrial sector only, rather than an average factor calculated over all end-use sectors.

The system of demand equations is flexible enough to permit different substitution possibilities between each pair of fuels, with a corresponding complexity of results. Useful statistics which summarize the response characteristics of the demand equations are the price elasticities (both own and cross) of demand. Since the price elasticities are a function of the cost share, they need not be constant over the estimation period. However, in the results which are reported in appendix 3.B, most of the price elasticities are relatively stable over the estimation period. In all of the main (non-thermal electric) demand equations the own price elasticities for each region are negative, between 0 and -1; while the cross price elasticities for each region are all positive, between 0 and +1. In all of the auxiliary (thermal electric) demand equations the own price elasticities for each region are negative, usually between 0 and -1; while the cross elasticities for each region are all positive, usually between 0 and +1.

The statistical fit of each of the estimated equations and the parameters within the equations are quite good for the total expenditure equation and the main (non-thermal) demand system; but not quite as good for the auxiliary (thermal) demand system.

As part of appendix 3.B, graphs are presented which indicate total energy expenditure, the actual and estimated fuel expenditure shares, the own and cross Allen partial elasticities

of demand for each region over the historical estimation period. More specific comments about the graphs will follow: first about those in the non-thermal sectors, and then about those in the thermal sector.

The following comments refer to the graphs which portray the estimation of the main non-thermal demand system. The current dollar expenditure on primary energy fuels in the Atlantic region began to rise very sharply after 1969. This occured because simultaneously the share and price of oil rose, and the share of electricity fell as its price remained constant. This awkward state of affairs was one reason that led me to estimate the Atlantic region separately in both the share system and total expenditure system. In fact, only by imposing some coefficient values in the Atlantic share system could I obtain sensible elasticity estimates.

The own and cross demand elasticity estimates in Quebec, Ontario, Prairies and B.C. are fairly similar because the price coefficients in the share system were constrained to be the same. The coefficients were constrained to be equal across regions because the estimation data were pooled across the regions to increase the number of observations. The variation in the own and cross demand price elasticities across regions is due to regional differences in the fuel expenditure shares. Some of the regional differences in expenditure shares are captured by including a regional shift parameter in the estimation equations. Similarly, the coefficients of the total expenditure equation are constrained to be the same across regions (except the Atlantic), with some of the regional differences being

captured by a regional shift parameter. In both systems, regional differences are also explained by differences in prices. Unfortunately, in the total expenditure system, regional differences are not captured due to variations in the real gross provincial expenditure because no data were available. Instead the national real GNE data were used for all regions.

Comparing the regional current dollar expenditures, one notes that the Atlantic expenditure is slightly smaller than the approximately equal B.C. and Prairie expenditure, and the expenditure in all three regions is approximately one-half of the expenditure in Ontario or Quebec. Comparing the regional primary energy expenditure shares, one notes that on average, in the Atlantic 50% of the share is oil and 50% is electricity; in Quebec 50% of the share is oil, about 4% is natural gas, and 46% is electricity; in Ontario about 35% of the share is oil, about 20% is natural gas, and 45% is electricity; in the Prairies about 45% of the share is oil, about 15% is natural gas, and 40% is electricity; and in B.C. about 30% of the share is oil, about 5% is natural gas, and 65% is electricity. The expenditure shares quoted above are a function of the relative energy prices. Therefore the expenditure shares do not indicate the fuel quantity shares, measured in a common Btu unit.

The following comments refer to the graphs which visualize some of the parameters of the thermal demand system. In examining the total expenditure on primary fuels and the actual fuel expenditure shares in each region, one is struck by the wide variation over the historical period. For instance, over the 1960-1973 period, in the Atlantic region the expenditure

share of oil erratically rose from 30% to 75%; in Quebec the expenditure share of oil rose in an irregular fashion from 70% to 100%; in Ontario the expenditure share of coal increased from 85% to 95% and then fell to 75%; in the Prairies the expenditure share of coal rose in an erratic manner from 50% to 75%; and in B.C. the expenditure share of oil fell from 80% to 55%, then rose to 85%, and finally fell to 55%. Also it becomes quite clear when examining the actual and estimated shares that the estimated equations do not fit too well. Part of the problem may stem from the fact that most of the parameter estimates are constrained to be equal across the regions that have similar fuel usage: i.e. coal and oil in Atlantic and Quebec; coal, oil and natural gas in Ontario and Prairies; and oil and natural gas in B.C. However, differences in provincial legislation with regard to the sulfur content of coal burned may account for some of the variation in coal usage across regions which is not captured by relative prices.

In examining the own and cross demand elasticities of fuels used for thermal generation of electricity one notes that in Quebec the elasticities involving the quantity of coal are very erratic after 1966 because the actual share of coal is zero for a majority of the observations; in Ontario the own elasticity of natural gas and oil are very elastic and the cross elasticities of oil and natural gas with respect to coal are large; whereas in the Prairies it is only the own oil elasticity which is elastic and the cross elasticity of oil with respect to coal which is large. I suppose the high elasticity of the demand for oil and natural gas compared with coal reflects the marginal

nature of using oil and natural gas in Ontario or oil in Prairies to generate electricity. In order to obtain economically sensible elasticity estimates during the estimation of the share system in B.C. I imposed unitary Allen elasticities of substitution between fuels. Hence the own and cross price elasticities are directly related to the actual fuel shares.

The system of demand equations has been coded into a simulation model as a separate sector of the integrated model. A list of the endogenous and exogenous variables and coefficients used in the demand sector are reported in appendix 1.A; and a list of the actual simulation equations are reported in appendix 2.A.

In order to have the estimated equations represent the actual historical values during simulation, the residuals of the estimation prodedure are added back. These 'add factors' are also included in all the estimated equations for 1974-1976, for which preliminary or estimated data are available. It is assumed that the last add factor that is necessary to tune the estimated values to the preliminary data is used for the rest of the simulation period. The 'add factors' are listed as part of the model equations in appendix 2.A.

2.4 The Techniques Used During Estimation

The expenditure share equations and parameter restrictions which result from the indirect translog cost function are detailed in appendix 3.A. To each equation in the share system an additive stochastic disturbance term is appended to reflect errors in cost minimization. The system of expenditure share equations has cross-equation restrictions imposed during estimation. Hence the system is estimated simultaneously.

Since the sum of the expenditure shares must always be equal to unity, the sum of the disturbance terms for these equations must sum to zero at every observation. Therefore the variance-covariance matrix of the disturbances is singular, and cannot be inverted. However, when one of the expenditure share equations is dropped, the iterative Zellner method of estimation can be used. It should be noted that the parameter estimates are independent of which equation is dropped. The Zellner method will estimate a system of equations in which there exists a contemporaneous correlation in the disturbances between equations. The iterative Zellner method involves using successive approximations to the variance-covariance matrix until the generalized least squares parameter estimates converge to within a preset tolerance level. The initial elements in the variance-covariance matrix are calculated using the single equation residuals with arbitrary initial parameter values. The estimate of the variance-covariance matrix is used to form the generalized least squares estimator, which is then used to generate the residuals, and then elements of successive

variance-covariance matrices until convergence is reached. The iterative Zellner method is equivalent to maximum likelihood.

During the formation of the translog cost share equations there have been two types of modifications which affect the duality between cost and production. The variable used to represent the miles of distribution pipeline miles was added to the expenditure share equations to explain the shift in fuel shares once natural gas had penetrated new market areas. Weighted prices are used in the non-thermal fuel expenditure share equations to capture an adjustment process in which shares respond instanteously to the expected weighted prices, but respond with a lag to current prices.[8] The more common lagged adjustment model was not used because it leads to estimation equations which are non-linear in the parameters. The actual values for the weights were not estimated, but chosen from a number of possible combinations that were examined.[9] Despite the fact that these two modifications spoil the theoretical foundation for the translog, I felt that they were necessary to explain the demand for energy.

During the process of estimating the demand systems,

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[8] To assess the impact of using weighted prices in the non-thermal fuel expenditure share equations, the parameter estimates from this system using weighted prices were compared to parameter estimates from a system using current prices. The parameters did not differ by very much between the estimations, probably because there has been relatively little price movement over the estimation period. However, the parametric fit in the total energy expenditure equation was better with the weighted prices.

[9] I did attempt to estimate the weights using an adaptive expectations model, but the non-linear model failed to converge.

certain parameter restrictions were imposed. In the main non-thermal system for the Atlantic region, the value for the coefficient boo is imposed because this was the only way I could obtain sensible elasticity results, as explained in the last section. In the main non-thermal demand system for the other regions the value for the coefficient bgg is imposed at zero because when freely estimated it was so close to zero that the iterative Zellner method failed to converge; the value for the coefficient bgo is imposed at zero because when freely estimated it was slightly negative and implied complementarity between oil and gas; and the value for the coefficient cl is imposed at zero because the freely estimated value was insignificant and positive, contrary to expectations. In the thermal demand system for the B.C. region the value for the coefficient boo is imposed at zero[10] because the freely estimated coefficient did not yield sensible elasticity estimates, as explained in the last section.

The previous section contained a general description of the in-sample fitting errors for the demand systems. Another useful measure of the reliability of econometric equations is the out-of-sample fitting errors. To provide a quantitative measure of the out-of-sample fitting errors, the 'add factors' for 1974 onward have been set equal to zero, and all exogenous variables left unchanged. Then I compare the 1974 and 1975 estimated energy aggregates with the preliminary actual data available. Only the energy aggregates for energy expenditure, energy

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[10] By imposing a value of zero for the coefficient boo, this makes the factor demand equation equivalent to that which would be derived from the Cobb-Douglas production function.

demand, oil, gas and electricity demand are reported because the regional data are much more difficult to obtain in preliminary form. The aggregate demand for coal is not mentioned because preliminary data were unavailable.

All of the 1974 and 1975 out-of-sample fitting errors are reported below as a percentage of the preliminary actual values. The estimated total current dollar expenditure by Canadians on non-thermal energy fuels (TOT$) is too low by 10.5% in 1974 and 12.9% in 1975 relative to the preliminary actual values. The estimated total Canadian demand for primary energy (OBTU) is too low by 12.9% in 1974 and 15.1% in 1975. The estimated total expenditure variable TOT$ does not decline, in percentage terms, as much as the estimated total primary energy demand OBTU because the fuel prices remain unaltered and only the quantities change between experiments. The percentage change, relative to the preliminary actual values, for the individual fuels are as follows: the estimated Canadian demand for crude oil (QOIL) is too low by 21.7% in 1974 and 23.3% in 1975; the estimated Canadian demand for natural gas (QGAS) is too low by 19.7% in 1974 and 22.4% in 1975; and the estimated Canadian demand for electricity (QELEC) is too high by 8.7% in 1974 and 5.8% in 1975. In general, when comparing the percentage changes one notes that the demand for oil and natural gas are lower than the overall primary energy demand, and the demand for electricity is actually higher. If the percentage error in QOIL is broken down into erorrs in QOILEAST and QOILWEST, then one finds that the errors in QOILEAST are approximately twice as large as in QOILWEST.

It is not possible to report very accurate out-of-sample fitting errors for 1976 because all of the data are not yet available. When adjusting the add factors to be used in the solution for 1976, I was aiming at approximately a 4% growth rate, as some National Energy Board and Department of Energy Mines and Resources forecasts were predicting. It now seems possible, according to the latest 1976 estimates reported in Oilweek, that domestic demand for crude oil will rise at only 1.2% (p. 29, Oilweek, February 14,1977), and that domestic demand for natural gas will rise at only 0.1% (p. 37, Oilweek, February 14,1977). The demand system, using no add factors after 1973, predicts that the percentage change in demand, of 1976 over 1975, for total primary energy (OBTU) is a 0.84% increase, for crude oil (QOIL) is an increase of 3.3%, and for natural gas is a decline of 1.1%. In general, when comparing the year over year changes in the errors one notes that the demand system does not predict too well during 1974, but does predict better in 1975 and 1976.

The resulting errors for 1974 and 1975 can be summarized in the following table. For the sake of comparison the errors for the last year of estimation (1973) are given.

Year	TOT$	OBTU	QOIL	QGAS	QELEC
1973	-2.9%	-2.8%	-7.9%	-0.7%	+3.5%
1974	-10.5%	-12.9%	-21.7%	-19.7%	+8.7%
1975	-12.9%	-15.1%	-23.3%	-22.4%	+5.8%

year	QOILWEST	QOILEAST
1973	-2.1%	-13.8%
1974	-13.9%	-29.6%
1975	-16.1%	-30.9%

2.5 The Forecast Results Using the Demand Model

In order to produce a forecast of energy demands it is necessary to specify the future values of only the exogenous variables. These future excgenous variables have been obtained from numerous sources. A detailed description of the assumptions used to produce the base case forecast is contained in appendix 5.A; and the results of the base case forecast are contained in appendix 5.B. A summary of the growth rates of the major exogenous variables is as follows: the annual rate of growth for real gross national expenditure (UGNE) is 5.4% to 1981, then 4.5%; the annual rate of growth of the implicit gross national expenditure price index (PGNE) is 10% in 1975, 8% in 1976, 6% in 1977 and 4% thereafter. The landed price of offshore crude oil is estimated to be $13/bbl in 1976, and to increase thereafter at the general rate of inflation. In the current simulations, the Canadian and world price levels are assumed to march more or less in step, and the exchange rate to remain constant at $1 Canadian per $1 US. The model is set up, however, so that any induced change in the exchange rate (for example, due to some change in energy trade policy) immediately causes a corresponding change in the landed Canadian price of offshore crude oil. It is further assumed that all Canadian energy prices increase in real terms until 1980: the crude oil price is based on the assumption that it will reach the world level by 1980; and the natural gas price is based on the assumption that a Btu equivalence will be reached with crude oil in Toronto by 1981. The average assumed price increase of electricity is 20% per

year from 1974 to 1976, then 15% per year to 1980. All energy prices rise at the underlying rate of inflation (4%) after 1981. The average annual growth of hydro and nuclear generated electricity supply is between 2%-4%. The annual growth of natural gas distribution pipeline miles is 3%-4% for Ontario, Prairies, and B.C., and 8% for Quebec.

Figures 1 to 3 indicate the main features of our energy demand forecasts based on the assumptions outlined above. Figure 1 shows the total projected demand for primary energy in Canada, with the difference between the numbered lines showing the split of national demand among the five consuming regions. Figure 2 shows the projected shares of the four primary energy sources in providing for the total demand. The fact that the shares do not shift much is consistent with the fact that the relative prices do not shift very much - especially after 1981. These shares reflect demand rather than supply, and thus exclude energy production exported and include all energy imported for domestic use. Given the price assumptions mentioned above and the projected energy demand outlined in Figure 1, one can visualize the resulting current dollar energy expenditure in Figure 3.

2.6 A Comparison of my Demand Forecast with Others

In this section I will compare the results of my demand forecast with the results of recent forecasts published by the National Energy Board [34,35,36], the Department of Energy Mines and Resources [31,32], and Gorbet [63].

Although attention will be mainly focussed on the latest Department of Energy Mines and Resources report [32] and the latest National Energy Board report on crude oil [36] and the latest National Energy Board report on natural gas [35], brief mention will be given to some earlier forecasts by the Department of Energy Mines and Resources [31], the National Energy Board [34], and Gorbet [63]. The 1973 Department of Energy Mines and Resources report, An Energy Policy for Canada: Phase 1 contains a standard forecast for energy demand [31, Volume I-chapter 3, Volume II-chapter 1]. The framework underlying the demand forecast is as follows:

> The standard forecast is essentially a sector forecast. Forecasts for each sector were made separately, based on the relationships of energy use to obvious parameters....Although the forecasts made in the sectors were in general based on the same population forecasts, no attempt was made to relate energy consumption to overall economic growth....Since the forecasts are made individually, the projections of the various sectors could be inconsistent from a general economic point of view [31, Volume II, page 6].

In view of the above self-criticism and the fact that the 'obvious parameters' did not include relative prices, I will concentrate below on the forecasts from the latest Department of Energy Mines and Resources report [32] which has corrected some of these drawbacks.

In 1974 the National Energy Board released a report [34]

dealing with the exportation of crude oil. The section of the report which commented on crude oil demand forecasts that crude oil and equivalent "will grow at an average annual rate of 3.2% during the next 20 years" [34, p 3-5]. Although no mention was made of how the growth rate was determined, a list was provided to indicate some possible influences on the trend. The list included conservation, change in the market areas served, development of new energy intensive industry equipment, and availability of competitive fuels. No specific mention was made of the influence of the underlying economic growth and relative prices, although the latter effect could come under the broad heading of 'conservation'. Instead of comparing my results with this 1974 report, I will compare them below with the latest National Energy Board report on crude oil requirements.

The study by Gorbet [63] sets forth the methodology and estimation framework used to generate the results reported in An Energy Strategy for Canada: Policies for Self-Reliance [32]. The energy price assumptions and underlying macro assumptions are not directly comparable with my model: Gorbet assumes an adjustment toward a real crude oil wellhead price of $9.00/bbl in 1974 dollars by 1978, whereas I assume an adjustment towards a real crude oil wellhead price of $10.25/bbl in 1974 dollars by 1980; the growth of real GNE that I assume falls between the case A and case B assumptions made by Gorbet. The results in table 4 are difficult to compare with my results because Gorbet converts the total primary energy demand into input Btu, but does not give an historical value so that I can coordinate the results. Since the Department of Energy Mines and Resources

study [32] has utilized more recent data, and has listed values from the last historical period (1975) I will use it as a basis for comparison.

The results reported in An Energy Strategy for Canada: Policies for Self-Reliance [32] are associated with a combination of two alternative energy price assumptions and two alternative economic activity assumptions. The energy price assumptions in my model closely parallel the 'high price' Department of Energy Mines and Resources scenario which assumes the following:

> Oil prices increase relatively faster than the prices of other goods and services until about 1978, when they reach a level that is roughly equivalent to the current international price (about $13.00 per barrel landed in Montreal in 1975 dollars). Prices for electricity and coal are assumed to increase at the same rate as oil prices, and the price of natural gas is again assumed to adjust to 'commodity-equivalent' value with crude oil ($2.25/Mcf at the Toronto city-gate, in 1975 dollars) by the late 1970's. After 1978, all energy prices are assumed to increase at only the general rate of inflation. [32, p.49]

The forecast assumptions in my model are very similar, with the major exception that all energy prices rise in real terms until 1980 - or 1981 in the case of natural gas. Also I have assumed that the international price of crude oil is $13.00/bbl in 1976, leading to a commodity-equivalent Toronto city-gate price of $2.20/Mcf in 1976 dollars.

The growth rate of real GNE used in my model falls between the high and low Department of Energy Mines and Resources assumption. I have used the Department of Energy Mines and Resources average annual growth rate from 1976-1980, but for the post-1980 period I have used the National Energy Board assumption [36, p.33 and 35, p.13-14]. The 1974 National Energy

Board report [34] on the exportation of oil did not outline any specific assumption about the underlying growth of the Canadian economy.

If I adjust the model variable which represents the total Canadian demand for primary energy (OBTU) so that it is consistent with the Department of Energy Mines and Resources 1975 estimate [32, p.51] then I can compare the results. The model-generated result for OBTU appears in output Btu's whereas the Department of Energy Mines and Resources result appears in input Btu's. The adjustment factor will therefore represent an aggregate input to output Btu conversion factor. This adjustment factor will be used each year a comparison is made, thus it is implicitly assumed that within the control solution the fuel shares do not shift very much (see Figure 2). The adjusted simulation value for OBTU in 1990 is only 3.2% smaller than the average of the high and low activity values for the Department of Energy Mines and Resources high price scenario [32, p.51]. But the adjusted simulation value for OBTU in 1980 was 9.6% lower, and in 1985 was 7.2% lower. The projections of primary energy demand from my model are substantially lower in the initial years because the relative energy price increases from 1974 to 1980 affect the total demand for energy with a negative price elasticity of approximately -.41 (-.63 for Atlantic). After about 1981, when the energy prices remain constant in real terms, the growth in total primary energy demand is driven by the growth in real GNE. The elasticity of energy demand with respect to real GNE is 1.08 (1.12 in Atlantic). Although the Department of Energy Mines and Resources report does not mention

the underlying elasticity of energy demand with respect to real GNE, Gorbet mentions that for the two scenarios which use the growth in historical economic activity as the basis for the forecast period "the implicit elasticity of total primary energy requirements with respect to GNE is slightly less than unity" [63, p.166], and for the scenario which uses lower future growth rates than in the historical period the income elasticity is slightly greater than unity. It is not clear from the Department of Energy Mines and Resources results exactly what value is used for the price elasticity of energy demand. But the price response must be fairly weak to permit an average annual growth in primary energy of 4.5% between 1976-1980 for the high-price scenario [32, p.51].

The Department of Energy Mines and Resources report disaggregates the total demand for energy into the demand for oil, natural gas, electricity, and coal. The numbers used by Department of Energy Mines and Resources for oil demand include liquefied petroleum gases (LPG), hence the Department of Energy Mines and Resources forecast result will be larger than my model forecast result for oil. In order to ensure reasonable comparability of the results in 1975, it is necessary to estimate the Canadian demand for liquefied petroleum gas.[11] If

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[11] The latest available data are the 1973 and 1974 data for Canadian production of LPG from the CPA Statistical Yearbook, and the 1973 Canadian consumption (production minus exports) from the Statistics Canada Detailed Energy Supply and Demand in Canada. If I assume that the 1975 Canadian production for LPG remains unchanged compared to 1974, as was the case between 1973 and 1974, and use the 1973 ratio of Canadian demand to production for the assumed 1975 production then I arrive at a 1975 Canadian demand for LPG of 46.6 Mbbl/d.

the assumed 1975 LPG demand of 46.6 Mbbl/d is added to the 1975 model generated value for crude oil demand of 1684.5 Mbbl/d[12] then my result is just 1% lower than the base year Department of Energy Mines and Resources estimated crude oil demand of 1749 Mbbl/d [32, p.55]. In comparing my forecast results with the Department of Energy Mines and Resources forecast I will add to my model forecast the implicit 1975 demand for LPG of 64.5 Mbbl/d, compounded forward by the Department of Energy Mines and Resources average annual growth rate for oil demand. The model-generated result for crude oil demand plus the assumed LPG demand is approximately 11% lower in 1980 than the average of the high and low activity values for the Department of Energy Mines and Resources high-price scenario, 8.4% lower in 1985, and virtually equivalent in 1990 [32, p.55]. When one compares the differences in the oil results with the differences in the total energy demand results, one notes that by implication, I apportion a smaller share to oil from 1975 to 1985, and then sometime between 1985 and 1990 I apportion a larger share to oil.

In order to compare my model results with the Department of Energy Mines and Resources results for natural gas demand it is necessary to deflate my model forecast[13] by 3% so that the two results are identical for 1975. The adjusted model- generated

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[12] The crude oil demand value is derived by adding QOILEAST, QOILWEST, LOILEAST and LOILWEST and then dividing by .365 to convert milions of barrels to thousands of barrel per day.

[13] The natural gas demand value is derived by adding QGAS and .345* LOSSGAS.

result for natural gas demand is approximately 10.2% lower in 1980 than the average of the high and low activity values for the Department of Energy Mines and Resources high-price scenario, 7.2% lower in 1985, and 5.3% lower in 1990 [32, p.56]. When one compares the difference in the natural gas results with the difference in the total energy demand, one notes that roughly the same natural gas share is used in both results from 1975 to 1985, and then sometime between 1985 and 1990 my model forecasts a slightly smaller share than the EMR model.

I will now compare my results for electricity demand with the Department of Energy Mines and Resources results. I do not have a printout variable for my electricity energy supply use and losses. During the historical estimation period the average ratio of the electricity energy supply use and losses over electricity demand was about .10. When this ratio is used to calculate the total electricity demand[14] in 1975 one arrives at exactly the same result as the Department of Energy Mines and Resources estimate. But the model- generated result for electricity demand is approximately 20.3% lower in 1980 than the average of the high and low activity values for the Department of Energy Mines and Resources high-price scenario, 20.5% lower in 1985, and 20.7% lower in 1990 [32, p.58]. When one compares the difference in the electricity demand results with the difference in the total energy demand, one notes that the share of electricity derived in my model is substantially below the share derived in the Department of Energy Mines and Resources

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[14] The electricity demand is calculated as (1.1*QELEC)/1000.

model.

For the sake of completeness one notes that the Department of Energy Mines and Resources forecast of the growth in the industrial and other demand for coal is an average annual rate of 4% per year over the 1975-1990 period [32, p.60]. Hence the assumed rate of growth of 4% per year for this exogenous category in my model is comparable. I do not print out the demand for coal, but in order to have the shares adding to 100 % the coal share would have to be higher than the Department of Energy Mines and Resources share.

I will also compare my crude oil and natural gas forecasts against those published in two separate reports by the National Energy Board [35,36]. In comparing their results to those of the National Energy Board, the Department of Energy Mines and Resources report states the following:

> The projections for oil and gas demand presented in Table 4 and 5 differ from recent, higher, estimates prepared by the National Energy Board. The two sets of estimates are not strictly comparable since they have been prepared using different methods and assumptions. The EMR projections are based on a 'total energy' framework related to specific assumptions with regard to demographic and economic activity, energy prices, and market shares. The NEB projections were derived from detailed analysis of the domestic oil and gas markets on the basis of submissions received at public hearings and independent analysis [32, p.57].

Although the National Energy Board report Canadian Oil: Supply and Requirements [36] specifies some major assumptions with regard to real GNE growth, population growth, and the price of natural gas and crude oil [36, p.33], it is not clear how these assumptions enter the final demand projections. The National Energy Board demand projections from 1974-1994 are in terms of average annual growth rates: between 2.5% and 3.2% east

of the Ottawa Valley depending upon the impact of conservation programs; between 3.6% and 4.3% west of the Ottawa Valley, depending upon the impact of conservation. The National Energy Board forecast for total Canadian oil demand, including the effect of conservation, is an average annual growth rate of 3.1% over the period 1974-1994 [36, p.42-43], which is virtually identical to its 1974 projection.

I will use 1975 as a base year in which to match the model-generated Canadian demand against the National Energy Board estimate. The model- generated demand for crude oil in 1975 is 2.5% higher than the National Energy Board estimate. The model-generated result for Canadian crude oil demand is approximately 13.5% lower in 1980 than the National Energy Board forecast, 11.7% lower in 1985, and 3.0% lower in 1990 [36, p.89]. It is difficult to compare the National Energy Board forecast and the Department of Energy Mines and Resources forecast because of the inclusion of LPG demand in the Department of Energy Mines and Resources projection, but it appears that the National Energy Board forecast and the average of the high and low activity values in the high price Department of Energy Mines and Resources forecast for crude oil are very similar.

As in the National Energy Board oil report, the National Energy Board report Canadian Natural Gas: Supply and Requirements [35] specifies some major assumptions with regard to real GNE growth and the price of natural gas and crude oil [35, p.2 and p.12-14] for three scenarios, but the relationship between the assumptions and the demand forecasts is not clearly specified. In each of the National Energy Board's three

scenarios it is assumed that a Btu price equivalence between crude oil and natural gas will be established. The major differences in the assumptions behind the three forecasts are "different expectations as to the extent that higher energy prices will affect economic activity, and different assumptions as to how great the effort to conserve energy will be" [35, p.13]. The National Energy Board continues to argue for the necessity of proposing a range of scenarios because "the assumptions as to the elasticity of total energy demand with respect to higher energy prices and the elasticity of the demand for gas with respect to the prices of gas and other fuels are necessarily a matter of judgement since a precise quantitative estimate cannot be reliably calculated at this time" [35, p.13]. Although I agree that a wide range of error may occur in any attempt to forecast elasticities, I believe that a precisely specified relationship is superior to judgemental assumptions because only with a specific relationship can one continue to make predictions under different economic conditions.

I will compare my results with scenario II, the National Energy Board medium forecast, and scenario III, the National Energy Board low forecast [35, p. 13-14]. The medium forecast assumes that higher energy prices reduce economic activity and induce conservation efforts. The real GNP growth after 1980 is forecast to be 4.5% per annum. The market share of natural gas is assumed to increase to 1980 and then gradually decrease. The average annual growth in natural gas sales in this scenario is 8.5% from 1974-1980, and 3.5% from 1981-1995. The scenario III assumptions are identical, except that it is stated that

stringent conservation measures are adopted. The forecast of natural gas sales is roughly the same for scenario III as for scenario II from 1974-1980. However, the stringent conservation measures reduce the growth in natural gas sales to 3% per annum from 1980 to 1995.

Once again I match up my 1974 value for natural gas sales with the National Energy Board value to facilitate the comparison of results. The model- generated value for net natural gas sales (QGAS) is 1.6% lower than the National Energy Board value. The adjusted model- generated result for QGAS is approximately 9.4% lower in 1975 than the National Energy Board scenario II (medium) forecast, 25.3% lower in 1980, 21.9% lower in 1985, 14.8% lower in 1990 and 8.5% lower in 1995 [36, p.19]. The adjusted model- generated result for QGAS is approximately 9.4% lower in 1975 than the National Energy Board scenario III (low) forecast, 23.4% lower in 1980 16.5% lower in 1985, 7.4% lower in 1990 and .9% higher in 1995. The National Energy Bcard forecast for 1975 and 1976 is extremely high, and at odds with the estimate of 1.2% growth in domestic sales for 1975 and forecast of 1.2% growth in domestic sales for 1976 reported in Oilweek (p.44, February 16, 1976). The lack of price responsiveness in the National Energy Board forecast is noted in an interesting comparison by Helliwell [81] of the 1969 National Energy Board report on energy supply and demand in Canada [33], the 1975 National Energy Board report on natural gas supply and requirements [35], and a preliminary version of my demand model.

In general I can state that my forecast, when compared to the forecasts of the Department of Energy Mines and Resources

[32] and the Naticnal Energy Board [35,36], is substantially lower during the period 1975-1980, and thereafter usually grows at a slighly higher rate. Most of this discrepancy is a result of the equation predicting total energy demand. This equation has a substantial negative relative price elasticity and a rather large GNE elasticity. In the approximate comparison of the relative fuel shares between my forecast and the Department of Energy Mines and Resources forecast one notes that in the initial years I apportion a smaller share to oil and then in the later years a larger share, roughly the same share to natural gas in the earlier years and then a slightly lower share in the later years, a smaller share to electricity throughout the period, and probably a higher share to coal. It is not easy to compare energy shares when examining the National Energy Board results.

3. Modelling the Supply of Crude Oil and Natural Gas

The relevant economic supply literature for the petroleum sector[15] will be described in four sections. The first three sections contain comments on three fairly distinctive aspects of the supply process: production, development, and exploration. The fourth section contains a brief summary of research examining the regulation of crude oil and natural gas supply. Within each of the first three sections I will survey the economic studies that relate to the desire to build a supply sector for both Canadian crude oil and natural gas; and I will also indicate what I would like to do, if it is different from what was done. The actual supply models for non-frontier crude oil and natural gas are detailed in the following two chapters.

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[15] Occasionally I will find it convenient to use the term petroleum sector to refer to the sector of the economy which supplies both crude oil and natural gas.

3.1 The Production of Crude Oil and Natural Gas

It was reported in the 1973 EMR study that a normal production profile from a pool exhibits a rather rigid skewed pattern. The detailed pattern is given for a typical pool of crude oil and of natural gas [31, Vol.II, p.80]. For crude oil the assumption of a fixed pattern is probably not historically accurate, mainly due to the excess capacity that existed in the industry. For natural gas the peak rate (rate-of-take) is set by long-term contracts. This fact leads to a fairly uniform production pattern. The Alberta Energy Resources Conservation Board (AERCB) reports that for natural gas in both the Foothills System and the Plains System the constraint on production is felt through pipeline capacity, because the processing plant and adjusted wellhead capacity both have been larger than the pipeline capacity [7, p.12.18].

Even though a fixed extraction pattern is assumed over the life of a pool, economic conditions certainly have some influence, as documented by Bradley [20], Cornelson [42] and Watkins [154]. Bradley [20, p.28] has emphasized the fact that production from a given pool involves depletion of a fixed volume, therefore the production pattern should be chosen to maximize the asset value of the resource. Even so, he assumes a fixed declining production pattern, with the rate of decline being estimated. The initial decision to develop a pool involves capital expenditure decisions to drill wells (and possibly utilize enhanced recovery equipment), to build gathering systems, and to build processing plants (for natural gas only).

After the capital investment is in place the economic decision about the life time of a pool must be made on the marginal unit extracted: production should continue as long as the marginal revenue of each unit extracted is greater than or equal to the marginal variable cost. Market conditions can easily affect the amount of recoverable reserves (ultimate economic recovery) and hence affect the life of a pool. The production profile must be altered if demand pro-rationing is imposed. The production pattern can also be altered due to a change in economic conditions through additional development drilling or enhanced recovery. But these procedures are better analysed as decisions about reserve development, discussed in section 3.2.

As indicated later, in sections 4.1 and 5.1, a fixed profile has been chosen for the production of crude oil and natural gas. But the use of a fixed production profile explicitly rules out any effect on the rate of exploitation through the user cost, which has been discussed by Davidson [46,48] and Scott [126,127]. The user cost can be defined as "the highest present value of marginal future profits given up by producing that barrel of oil [or unit of natural gas] currently rather than in the future" [48, p.416]. Davidson [46] has identified three types of user cost associated with the petroleum industry: the user cost inherent in all non-renewable materials, the user cost related to ultimate recovery, and the user cost due to the rule of capture. Alberta, which produces about 85% of the crude oil in Canada, has had pro-rationing and unitization regulations in effect (see Crommelin [43, p.42-46]) to avoid user costs associated with the rule of capture.

Regulations in effect prevent producers from extracting their resource at a rate that is greater than the maximum efficient rate, hence the user cost associated with ultimate recovery will be zero.

A user cost accompanies the production of any raw material due to the finite nature of the resource stock: the more used today, ceteris paribus, the less there will be available tomorrow. Hence under the profit maximization assumption marginal revenue must cover the marginal user cost plus all other marginal costs - including royalty payments. Therefore if the price is expected to rise substantially in the future such that the user cost is positive[16] then current production will tend to be restricted. On the other hand, the expectation of a decline in price substantial enough to make the user cost negative, will tend to expand current production.

The unsubstantiated claim has been made that "in absence of developed futures markets, producers' subjective expectations of the user costs inherent in all raw materials are major determining factors in the rate of exploitation of energy resources" [48, p.420]. I plan to ignore the effect of user cost on the fixed production pattern because to model the producers' forward behaviour so that future marginal profits can be discounted is a very difficult task. For the period 1973 to present the natural gas and crude oil prices have both risen faster than the interest rate. But producers have also

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[16] The price must be expected to increase relative to production costs at an annual rate greater than the expected rate of interest. The converse is true for negative user costs.

experienced rising costs through increased royalty payments, and increased federal taxation because royalty payments are non-deductible. Even so, there has probably been a positive user cost associated with production over the last two years. Until Canadian crude oil prices are based on a parity with international prices, and until Canadian natural gas prices are based on a commodity parity with crude oil prices, the Canadian crude oil and natural gas prices will probably rise at the wellhead over the next few years. Hence over this period positive user costs might be expected (depending upon cost increases, of course).

3.2 Development of Natural Gas and Crude Oil Resources

Once production commences from petroleum reserves, the product is sold at the market price. Any margin between the unit price and the unit real factor cost for land, labour and capital, all of which must be paid their opportunity costs in the next best alternative use, is economic rent which must be divided among governments and the producers. The true economic costs which are relevant for the decision about the supply price[17] do not include royalties, lease payments and certain taxes which are all means that governments use to collect economic rent.

But before production occurs development decisions must be made.[18] A crucial determinant in the development decision is the adequate rate of return on capital invested in obtaining the output of the reserve. Development decisions fall under the general heading of investment decisions because the nature of petroleum production requires expenditures to occur at a different period of time from the output. To calculate the supply price a present value calculation must be used to impute a per unit cost that is necessary to repay the initial investment and other factor payments for a given output stream. The following formula is used for the supply price:[19]

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[17] The term supply price shall be used to indicate the price necessary to pay all factors their opportunity costs over the life of the production pattern.

[18] One of the most comprehensive economic analysis of development decisions has been done by Bradley [20].

[19] The formulation is adapted from Bradley [20, p.18].

$$SP = \left(\sum_{t=1}^{T} (I(t) + OP(t))/(1+R)^{t}\right) \Big/ \left(\sum_{t=1}^{T} Y(t)/(1+R)^{t}\right)$$

where:

SP = supply price, constant $/unit
I(t) = investment expenditure in time t, constant $
OP(t) = operating expenditure in time t, constant $
Y(t) = output at time t, units[20]
R = real discount rate
T = length of output stream.

There have not been many studies using Canadian data that calculate the development supply price. A study by Watkins [154] uses the above formulation in order to get a reserve-weighted average development supply price for enhanced recovery projects. An earlier article by Watkins and Sharp [153] calculates a general supply price for conventional Alberta crude oil that includes both exploration and development costs. But they are only interested in calculating a supply price for existing reserves, and hence set to zero exploration costs in the forecast period.

It would be desirable to formulate a per unit development cost function for crude oil and for natural gas which is a function of an activity variable such as drilling footage or number of wells drilled. It would be necessary to relate the effort variable both to the amount of reserve additions (through a geological-type model) and to the asscciated costs. Once the development ccst, operating cost and quantity of reserve additions are known it is possible to calculate the develcpment supply price. The effort variable could then be adjusted to close the gap between the discounted expected wellhead price and

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[20] If the actual output stream differs from the expected then the investor will experience capital gains or capital lcsses on the develcpment expenditure.

the total supply price plus the unit royalty and rental payments.

In examining development decisions about crude oil reserves, one must consider the possibility of either development drilling or enhanced recovery. As documented by the Alberta Energy Conservation Board, enhanced recovery schemes seem to be an important element of the supply in Alberta: as of the end of 1973, 11.2 Bbbl of crude oil are estimated to be recoverable under current technology and price; but only 7.5 Bbbl will be produced by primary extraction, and the other 3.7 Bbbl will be recovered through enhanced recovery operations [7, p.2.78]. Without detailed data, of the sort Watkins [154] used, it would be very difficult to distinguish between reserve appreciation due to development drilling or enhanced recovery. Even if we were able to distinguish between the two types of reserve additions, we would be faced with adjusting the production profile in the case of enhanced recovery. A simplified approach to the problem of adjusting the production pattern would leave the profile unaltered, but would include any reserve appreciation or any increase in recoverable reserves (through enhanced recovery or additional drilling) as new reserve additions which are exploited according to the fixed production profile. Watkins [154, p.4] indicates a pattern of extraction from enhanced recovery techniques which is similar to the profile described in sections 4.1 and 5.1.

But lack of readily available data, and lack of time have prevented me from continuing to work on this aspect of the supply model. The treatment of development supply and costs used

in the dissertation are contained in Chapter 4 (sections 4.1 and 4.2) and Chapter 5 (sections 5.1 and 5.2).

3.3 Exploration for Crude Oil and Natural Gas Reserves

It would be desirable to develop a supply price that will cover the exploration expenditure necessary to discover a unit of petroleum reserve. The exploration function is perhaps the most difficult to estimate; but it is the crucial element of the long-run supply of output. An attempt must be made to predict not only the forthcoming supply of new discoveries but also the marginal cost of additional discoveries. Given the cost and amount of new discoveries it is then possible to calculate a supply price which is capable of being added to the supply price for the development of reserves. This total supply price can then be compared to the present value of future expected wellhead prices, with the difference being shared between the government through royalties and rental payments, and the producer through extra profits.

This sort of framework would allow one to analyse the impact on exploration effort, and hence on long-run supply, through a change in the royalty rate or a change in the wellhead price. If the wellhead price increases, net of any corresponding increase in the royalty, then exploration effort should increase until the supply price is equal to the net wellhead price. Therefore to evaluate the long-run supply one must predict the future wellhead prices and royalty rates.

Within the supply model, I wish to distinguish between exploration for crude oil and for natural gas. But the geological and geophysical exploration efforts are probably aimed more toward the discovery of hydrocarbon deposits in

general than toward a particular type of deposit. Even during the drilling stage the type of deposit may not be known beforehand. Therefore, as Watkins [153] points out: "the intention of exploration is the discovery of hydrocarbon deposits...and in strict economic terms, a specific cost of oil [or gas] does not exist" [153, p.1]. In order to separate the exploration expenses into expenses for crude oil and for natural gas, the joint nature of the exploration cost function must be ignored. To separate the joint costs betweeen crude oil and natural gas I used an allocative function discussed generally in sections 4.2 and 5.2, and specifically in appendix 4.B.

There have been few empirical attempts to measure the supply of new discoveries. An economic model for crude oil discovery in the United States has been estimated by Erickson [52] and Fisher [55]. The Erickson-Fisher model contains three regression equations which describe new field wildcats, the success rate and the average size of discovery all in terms of price, geological knowledge and a measure of costs. The model predicts a long-run price elasticity of new crude oil reserves discovered equal to +0.93 .[21] Uhler has criticised their approach because "the models are not specified to allow shifts in the supply relationship caused by growing geological knowledge and the exhaustion of remaining reservoirs in the region" [147, p.22].

Another approach to the long-run supply of United States crude oil reserves, which focuses on the impact of tax changes,

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[21] The Erickson-Fisher estimate has been quoted in Erickson [52, p.42], and the regression results reported in Burrows and Domencich [27, p.220-227].

has been explored by Erickson, Millsaps and Spann [54]. They postulate a desired long-run equilibrium level of reserves in terms of expected prices, user cost,[22] and production restrictions. The tax incentives enter the oil supply picture through their effect on the user cost. They postulate a stock adjustment process whereby the actual reserves approach the desired level. Using United States data they estimate that the long-run price elasticity of reserves is +1.0; and that the long-run user cost elasticity of reserves is -0.71. The adjustment coefficient is approximately 0.1, indicating that 10% of the gap between desired and actual is closed each year. Their empirical estimates have omitted a potentially important variable by assuming that the finding cost is constant. It is a valuable contribution to the analysis of tax effects on supply, but I feel that too much emphasis is placed on the flow of output without adequate account being taken of the fact that a fixed stock is being depleted.

Using Canadian data there have only been three studies of the exploration process of which I am aware: by Ryan [123,124], Uhler [147] and Eglington [51]. All of these studies have focused on Alberta only.[23] Ryan presents his postulate that "the rate of crude oil discovery is proportional to the accumulated geological knowledge and the amount of undiscovered oil" [123,

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[22] The term user cost is used in the Jorgenson sense of being a measure of the implicit price to the firm of capital embodied in oil reserves.

[23] At present Alberta has 90% of Canada's recoverable reserves, and 86% of Canada's productive capacity from conventional non-frontier sources of crude oil [8, p.2, table II]; and 84% of Canada's recoverable reserves of natural gas [8, p.2, table III].

p.219]. He uses a logistic function to describe geological knowledge in terms of the number of wells drilled. He uses a non-linear least squares fitting technique to estimate the parameters of his model. He obtains an excellent fit between the cumulative new field wildcats and the cumulative initial recoverable (and initial-in-place) crude oil reserves. But Ryan has not used any economic variables in his analysis.[24]

One of the parameters of the Ryan model is the stock of ultimate reserves. When he fits the model with appreciated reserves the results are that 13-15 Bbbls of ultimate recoverable reserves and 38-42 Bbbls of ultimate oil-in-place reserves exist in Alberta, assuming that no new major plays are found [124, p.242, table 2 and table 3]. The Ryan extimate is rather low in comparison with the 1973 estimate by the Geological Survey of Canada (GSC) which is reported in the EMR study [31, Vol.I]. The GSC, using a geological survey of sedimentary basins, indicates 16.3 Bbbls of ultimate recoverable crude oil.[25]

Uhler has developed a model which specifically examines both the costs and supply of new reserves through the exploration process. He postulates that the number of new reservoirs discovered "can be treated as a Poisson process and that its mean rate (intensity) depends upon the amount of resources allocated to searching effort" [147, p.75]. The amount

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[24] It would have been relatively simple for him to assume a constant cost per well and then derive a function showing the increasing marginal cost per bbl of newly discovered reserves.
[25] The GSC reports only a total for Alberta, Saskatchewan and Manitoba (18.3) and northern B.C. (1.6). I assumed that Alberta's share was 90% of the above total (see a preceeding footnote).

of resources allocated will, in turn, depend strongly on economic factors and on the maturity of the region. The mean rate of discovery is postulated to be a function of exploratory drilling footage/period (measure of effort) and the cumulative exploratory footage/unit area (measure of accumulated knowledge and maturity of a region). It is assumed that the sizes of the reservoirs discovered are lognormally distributed with respect to cumulative drilling footage. Since Uhler never fully utilizes his stochastic Poisson production function, his most important contribution is the derivation of a total and marginal expected cost function.[26]

Uhler estimates his model for various regions in Alberta, and uses the results to forecast increases in the cost of finding additional crude oil and natural gas. Assuming an exploration drilling cost of $25 per foot, Uhler finds that in one region the cost of gas reserve discoveries rises by fourfold over 6 years from $0.038/Mcf in 1972 to $0.132/Mcf in 1977 (with an additional 1.2 Tcf discovered) [147, p.88]; and in the same region the cost of crude oil reserve discoveries rises from $.28/bbl to $.72/bbl (with an additional 107 MMbbl discovered) over the same period [147, p.89].[27] Allowing for one standard

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[26] His cost curves come from assuming a constant cost per foot of exploration drilling. He interprets the marginal cost curves as the relationship between the supply price of reserves-in-place and the expected reserve discoveries in each period. If the supply price is calculated on an output basis then a price is obtained that can be added to the development supply price. His analysis also very neatly explains the marginal cost curve shifting over time due to exhaustion.

[27] All reserve estimates reported are initial in-place and not initial recoverable reserves, because these tend to fluctuate less due to market conditions and recovery technology. Uhler uses recovery factors of .7 for gas and .3 for oil [147, p.88-89].

deviation on the size of expected discoveries, which is quite large, still implies rapidly rising marginal costs for the area under study.

These rapidly rising marginal cost curves are the result of continual exploratory effort in regions that are mature. But it is not clear if it is appropriate to use the parameters estimated for the region in the Uhler study for other regions that are underexplored. Some measure of the marginal cost curve that is associated with additional discoveries from the non-frontier area is needed if one is to calculate the supply price.

It would be desirable to be able to relate an effort variable, such as drilling footage or number of wells drilled, to both the discovery cost and the size of discovery. Then it would be possible to calculate the marginal cost associated with the discovery of an additional unit of reserves. Neither the Uhler nor Ryan studies can be used without extension because the Uhler study covers only part of Alberta's southern basin for crude oil and natural gas; while the Ryan study covers all of Alberta for crude oil only. It could be possible to use Uhler's parameter estimates in other regions if the exogenous effort variable were normalized to the same area size. This type of extrapolation is clearly risky because there will be no statistical basis upon which to base the implicit assumption that the mean rate of discovery and the mean size of discovery will follow the same pattern with cumulative drilling footage. The work of Ryan would have to be extended by calculating a marginal cost function, by formulating a function that describes

the cost per well drilled, and by developing estimates for natural gas reserve discoveries. To get results for all of western Canada the same parameter estimates of the marginal cost function would be imposed for the larger region.

Time did not permit me to implement any of these exploration or development functions. Instead, for exploration I have used the National Energy Board estimates for gross reserve additions of both crude oil and natural gas; and for development I have used the assumption that reserves are developed as needed to meet demand. As explained in sections 4.2 and 5.2, the marginal costs of development and exploration are aggregated together, and made a function of cumulative reserve discoveries. In a way this is unfortunate because the supply functions used in the model are not sensitive to price changes.

3.4 The Economic Regulation of Crude Oil and Natural Gas Supply

This section will end the somewhat lengthy survey of various models describing aspects of the supply of crude oil and natural gas. The initial impact of most government regulations tends to influence the supply side of the market[28] (explained in Hamilton [69], Kahn [92], Mitchell [112], and Ritchie [122]). Government policies are enacted through regulations like the restriction of supply through pro-rationing of market demand in the crude oil industry (documented by Khoury [98] and Lovejoy [101]), the imposition of import quotas on United States crude oil industry (described in Adelman [3,4], Manes [111], and the United States Task Force report [149]), the creation in Canada of the National Oil Policy line in 1961 (Anderson [9], Debanne [50], and Hamilton and Schwartz [68]). The tax and royalty structure can influence the supply through affecting the rate of return on investment. Royalty payments are discussed in Gainer and Powrie [61], Hyndman and Bucovetsky [88], and Waverman [159]; and tax concessions to both crude oil and natural gas producers through the depletion allowance and immediate write-off provisions for most exploration and development expenses are discussed in Bucovetsky [25], Burton [28], Davidson [47], Jenkins [89], and McDonald [105].

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[28] The demand for crude oil or natural gas can be affected initially through direct government manipulation of prices: for example, the Federal Power Commission price ceiling imposed on natural gas in the United States, and the price freeze on crude oil in Canada since 1973.

4. Non-frontier Natural Gas Production

The non-frontier natural gas production sector[29] explains the annual production flows; the costs of discovering, developing and producing; the net producer income, taxation payments and royalty payments; the rents accruing to the major participants in natural gas production and consumption; and the accumulation of certain stock variables.

Historical data, obtained from the Canadian Petroleum Association Statistical Yearbook , have been used from 1947-1974. All of the model variables which accumulate over time have been carried forward from simulations which cover the pre-1974 period.

A list of the endogenous and exogenous variables and coefficients used in the non-frontier natural gas production sector are reported in appendix 1.B. A list of the actual simulation equations contained in the natural gas sector are reported in appendix 2.B. The construction of most of the exogenous data in the natural gas sector are contained in appendix 4.A. The construction and sources for the coefficients used in the natural gas sector are contained in appendix 4.B and appendix 4.C. The results of the forecast solution are contained in appendix 5.B.

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[29] The non-frontier natural gas supply model was developed from a model used by Helliwell [75] in his study of the Mackenzie Valley pipeline.

4.1 A Description of the Production Process

The production of non-frontier natural gas is assumed to conform to a rigid skewed pattern reported in An Energy Policy for Canada- Phase 1 [31, Vol. II, p.80]. The detailed production profile for a typical pool of natural gas consists of production at the peak rate for the first 15 years, followed by 13 years of production declining at 15% per year.[30] The peak rate is the usual contractual rate of 1 mcf per day for each 7300 mcf of initial recoverable pipeline gas reserves (1:7300 ratio). By using this contractual rate for 15 years (by which time 75% of the ultimate recoverable gas has been produced), followed by almost as many years of declining production, a pattern is developed which is similar to that used by the Alberta Energy Resources Conservation Board [7, (ERCB 74-18), p.12-21].

The model does allow an alternative production profile, for newly hocked-up reserves, which has a faster recovery rate. A maximum rate of 1:3650 was found by McDaniel [57, Vol II] to increase the present values of production from almost all of the sixty major Alberta pools examined. The 1:3650 rate is maintained until one-third of the initial recoverable reserves

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[30] The production pattern has been altered slightly from that reported in the EMR study [31] so that by the 29th year of production, 100% of recoverable natural gas will be extracted. This was necessary because even as time approached infinity the recoverable reserves were not all extracted under the profile assumed in the EMR study. The main alteration has been to use the more usual non-frontier peak rate of 1 Mcf/d for each 7300 Mcf of initial recoverable pipeline gas reserves (1:7300 ratio) used in Cornelson [42, p.20] rather than 1:8000 ratio used for frontier pools in the EMR study [31].

have been extracted, after which the rate declines by 10% per year. The production life is 17 years. The McDaniel maximum extraction rate is approximately the same as the maximum practicable unconstrained pool capacity of 1:4000 reported by the Alberta Energy Resources Conservation Board [7, (ERCB 74-18), p.12-21].

For all the main policy simulations the slower 1:7300 rate is used rather than the 1:3650 rate. The potential for profitably faster extraction is therefore left as a safety margin in case demand should grow unexpectedly fast.

Production in the current year draws gas from reserves hooked up in each of the preceding 29 years. Since the policy simulation runs typically start well after the initial development of Canadian non-frontier reserves, a variable (GASMAX73 for runs starting in 1974) is defined that represents potential future annual production from all reserves connected before the simulation begins.

As an alternative to the model-generated values for the variable GASMAX73 the National Energy Board values for the deliverability forecast of established reserves from conventional producing areas with no reserve additions [35, p.60] could be used. But there seems to be a discrepancy between the cumulative production that the National Energy Board assumes from the end-1973 reserve base and the size of the end-1973 reserve base. If one assumes a 10% annual rate of production decline after 1995, the last year of published National Energy Board production from previously established reserves, then one discovers that the cumulative production from end-1973

established reserves is approximately 50 tcf by the year 2005 [35, p.60]. But the National Energy Board has stated earlier in its report that "The Board's estimate of remaining established reserves, 60.6 tcf, is based on detailed evaluation of specific pools containing 70 per cent of the reserves in Western Canada together with a more general treatment of the other reserves" [35, p.33]. Although the National Energy Board end-1973 reserve base is approximately 4% lower than my model-generated value of 63.2 tcf, the National Energy Board end-1973 reserve base is approximately 10 tcf greater than the implicit end-1973 reserve base obtained from accumulating the production mentioned above.[31] Part of this discrepancy could be explained if the National Energy Board did not include in its deliverability forecast the 5 tcf of unconnected and non-producing established reserves known to exist at the end of 1973 [35, p.53]. If this is indeed the case then it seems curious that the National Energy Board deliverability forecast increases during the initial four years. This could be explained by an under-utilization of current capacity, or a production profile which has a five year build-up to peak capacity for new pools. The confusion about the National Energy Board deliverability series means that I cannot compare the model-generated GASMAX73 against the National Energy Board series.

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[31] This discrepancy does not entirely prevent me from using the National Energy Board deliverability forecast. I could still use the model-generated end-1973 reserve base, the National Energy Board deliverability forecast as GASMAX73, and then set the model variable RESEXES to be equal to the implicit residual stock of unconnected reserves.

If current demand, both Canadian and export, exceeds the total production available from past hocked-up reserves then new reserves are hooked up as needed. These new connections can proceed as long as there remains a stock (RESEXCES in the model) of discovered reserves that are not producing at their potential rates. New additions to the available stock of reserves are provided by increments to proven reserves (RESDISCV) . These new additions can be forecast exogenously (the National Energy Board forecasts are currently used) or assumed to come forth as required (both subject to increasing costs and an ultimate upper limit).

The driving force behind the annual amount of natural gas production is domestic demand by Canada and export demand by the United States. The demand for natural gas by Canadians is explained within the demand sector of the energy model. The export demand is an exogenous series representing the actual quantities for the past and scheduled exports under approved contracts for the future.

The model keeps track of several other variables. The accumulated production of non-frontier natural gas is recorded in the GASACUM variable. The non-frontier natural gas proven reserve variable (RESBASE) accumulates the annual differences between new discoveries and production. The export value of non-frontier natural gas is included in the current account balance equation for oil and gas (XBALGC$) .

Figure 4 shows the forecast for domestic natural gas demand, for export demand under approved contracts, and non-frontier production based on the procedures outlined above.

As can be seen from Figure 4, the large drop in natural gas exports in 1990 leads to shut-in capacity, i.e. production capacity is greater than the demand. It can also be seen that by 1993 the projected demand cannot be met from the projected non-frontier supply. This shortage could be avoided by a combination of augmenting supply through the use of frontier natural gas and curtailing the demand through price increases.

4.2 A Description of the Price and Cost Variables

The major prices used in the sector are the price of natural gas at the wellhead, which is derived from the regulated Toronto price by taking away the transportation cost; the regulated natural gas price in Toronto, which is obtained by assuming a continuing closing of the Btu equivalence gap between natural gas and crude oil; and the commodity based opportunity price for natural gas (in relation to oil) in the Toronto market. These prices are used in the income, taxation, royalty, and rent equations.

For the income, taxation, and rent equations it is necessary to know the costs to the producers of finding, developing, and processing the natural gas reserves. The model variable RESCOST attempts to measure the combined cost for reserves being held by estimating a cost function relating marginal cost to the stock of accumulated discoveries. The variable GASCOSTM is defined to represent the marginal real (1976 dollar) cost of discovering, developing, and producing the next mcf of natural gas. The cost relationship is such that 29 tcf of post-1973 additions to reserves will increase the constant-dollar marginal cost to 1.3 times its 1973 value. This cost relationship is quite rough, and will soon be

disaggregated.[32]

The construction of the cost data and the results of the estimation equations are detailed in appendix 4.B. As described in the appendix, the first task was to disaggregate the non-frontier petroleum expenditure data into crude oil and natural gas expenditure data. I used the ratio of the development drilling footage for natural gas to the total development drilling footage to obtain a splitting ratio for exploration, development, and land acquisition expenditures. I used the ratio of the cumulative number of yearly completions of productive natural gas wells over the cumulative total number of productive wells to obtain a pro-rationing factor for disaggregating the petroleum operating expenditures. All of the resulting current dollar natural gas expenditures were converted into constant dollar costs using the PGNE deflator. The natural gas expenditure data were separated into four main categories: exploration and development, processing plants, land acquisition and rentals, and operating. The historical constant dollar per unit data in each of these categories were used as dependent variables in separate estimation equations. The actual data used in the estimation equations are reported in part V of appendix 4.B.

The ratio of the constant dollar expenditure on exploration

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[32] To make the cost relationship more precise it will probably be necessary to separate B.C. and Alberta, and to treat exploration, development, and gathering and processing as three separate phases in order to provide a better economic and technical basis for forecasting future costs and availability of non-frontier natural gas. This research is currently being done by Bruce Duncan.

and development of natural gas reserves to the gross reserve additions of natural gas is regressed against a linear function of the cumulative sum of gross natural gas reserve additions. The data set was divided into two periods: 1958-1966 and 1967-1974. The data set was split in 1967 because of a structural shift in costs which was evident from the data. The second period has an average marginal cost which is about four times that of the first period. The parameter estimates from the second period are used for the forecast period.

The expenditures on natural gas plants are estimated separately. The ratio of the constant dollar expenditure on natural gas plants to incremental demand for natural gas is assumed to be constant. This functional relationship is very approximate. The natural gas plant expenditure is probably related to the price of the natural gas by-products, the sourness of the gas, and to projected future demand. The proportion, estimated over the 1958-1973 period, is used for the forecast period. During the forecast period the demand for natural gas occasionally declines and then increases again, due to the irregularity of the export contracts. Whenever the demand for natural gas declines, the expenditure on natural gas plants is set to zero and the current amount of excess capacity is added to any excess capacity that has accumulated from previous years. If the demand for natural gas should increase again, then the accumulated excess capacity declines by the amount of the demand increase; and as long as there exists some excess capacity, the expenditure on natural gas plants is set to zero.

The ratio of the constant dollar expenditure on land

acquisition and rentals of natural gas to the production of natural gas is assumed to be constant. Once again, the functional relationship is very approximate. The expenditure on land acquisition and rentals is probably related to the discounted stream of expected rents associated with the land. Nevertheless, the crude relationship yields an average value over the 1958-1974 period of 2.5 1961 cents per Mcf, which is used for the forecast period.

The ratio of the constant dollar operating expenditure for natural gas to the wellhead production of marketable natural gas is estimated to be a linear function of accumulated production. Over the estimation period the per unit operating costs fell slightly, due, I suppose, to increased technological efficiency. However, during the forecast period I assume that the estimated operating cost of 5.4 1961 cents per Mcf for the last data point will remain constant.

4.3 A Description of the Tax and Rent Equations

The model calculates the profits and taxes associated with the production of natural gas. The gross production profits are found by multiplying the output by the net wellhead price. The net wellhead price is the gross wellhead price with the following per unit costs subtracted: operating costs, land acquisition costs and prior to 1974, the royalty payments. Royalty payments have continued to be allowable as a deduction for provincial tax accruals. In the post-1974 period the producers are allowed to receive a weighted average wellhead price for natural gas, using both the domestic and the export price. The capital cost allowance for the investment expenditure in discovering and developing the reserve stock is subtracted from the gross production profits to get the net taxable production profits. The tax payments depend upon the corporate tax schedule for the petroleum industry, and the depletion allowance rate. The November 1974 federal budget introduced the earned depletion allowance (but allowed accumulated post-1969 expenditures) and lowered the maximum depletion rate from 33 and 1/3% to 25%. The November 1974 federal budget also lowered the marginal corporate tax rate, and reduced the 100% writeoff provision for development outlays to a 30% rate, while maintaining the 100% writeoff provision for exploration outlays. The June 1975 federal budget introduced a special resource abatement which affects the marginal tax rate. In the post-1974 period several transfer payments from provincial governments to producers were introduced: namely, the Alberta selective royalty

reduction, and the B.C. indemnification of federal taxes to be paid by producers. More details about the taxation and royalty equations are contained in appendix 4.D.

The economic rent equations for the non-frontier natural gas sector are calculated separately for the provincial governments, the federal government, producers, and Canadian and United States consumers. Each rent equation accumulates the year-by-year flows of net returns after deducting the amount that each party would have obtained from his most obvious alternative. The cumulative net rents to each party are compounded forward over the simulation period using the nominal social time preference factor, STPNOM, which has a value of approximately 11.4%. At the end of the simulation period, the accumulated future values of net costs or benefits are discounted back at the same nominal social rate of time preference to obtain net present values, as at the end of 1976, measured in terms of 1976 prices.

Since most of the simulation periods start in 1974, the cumulative value of net returns to each party are calculated for the historical period to provide kick-off values for each rent equation at the end of 1973. Thus, the rent equations accumulate rents from 1955 in the natural gas model.

The rent accruing to the provincial government includes the land acquisition payments, royalty payments and the provincial share of the difference between the actual tax payments and the tax payments which would accrue on the capital invested elsewhere, using the average tax return on industrial capital. In the post-1973 period the rents accruing to the provincial

government are net of the Alberta royalty reduction transfer and the B.C. indemnification transfer. The rent accruing to the federal government is the federal share of the difference between the actual tax payments and the opportunity cost measure of the average tax paid on an equal capital investment elsewhere in the economy.

The total rent accruing to the producer is the net taxable production profit minus the corporate tax payments and minus the opportunity cost of investing elsewhere the capital tied up in the holding of reserves, using the average supply price of capital to business. In the post-1973 period the rents accruing to the producers are augmented by the Alberta royalty reduction transfer and the B.C. indemnification transfer.

Economic rents from non-frontier production accrue to Canadian and United States consumers, as well as to provincial governments, the federal government and producers. Canadian users of non-frontier gas earn rents to the extent that the regulated price of gas at the Toronto city-gate is less than the commodity based opportunity price in Toronto; United States users of non-frontier gas earn rents to the extent that the export price plus the transportation cost to the Chicago market is less than the commodity based opportunity price of gas in Toronto.

For most of the historical period, Canadian users of non-frontier gas earn no rents because I assumed that the delivered price of gas at Toronto is equal to the commodity based price of gas in Toronto; and, given our transportation cost assumptions, United States users of non-frontier gas earn

rents to the extent that the transportation cost from the field to Chicago is less than the transportation cost from the field tc Toronto.

When the natural gas price is regulated the rents to consumers are overstated. The excess is a function of the extent that the commodity based opportunity price of natural gas is greater than the regulated price at which the user makes his consumption chcice. Were he actually charged the true opportunity value, his consumption would be less than at the regulated price. Hence, our current measures of consumer rents are insensitive to the price elasticity of demand for natural gas.[33]

In addition to calculating rents to each of the respective parties, an independent total rent calculation for all production is made using full commodity based pricing. This equation, KRENTGAS, determines total rents from non-frontier natural gas production. It provides a check of the model's internal consistency because it should equal the summation cf the individual rent components.

In order to calculate the net benefit to Canada from natural gas production, the total rent KRENTGAS has subtracted from it the rents accruing to United States consumers (KRENTC2$) and the propcrtion of foreign rents accruing in the non-frontier producer rents (KRENTNF$), based on the percentage of foreign ownership. The average percentage of

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[33] Ken Hendricks is working on this problem by calculating the area under the demand curve.

foreign ownership in petrcleum prcducticn is 78.5%.

To provide an example, we shall describe in detail cne rent equation. KRENTNF$, the example, calculates rents to producers of non-frontier natural gas. The term J1L*KRENTNF$*STPNOM simply compounds annual net returns forward at the nominal social time preference rate. To this one adds gross income, 3.65* GASPRC*PGASW (PGASNF in 1974), and deducts current operating costs and land acquisitiocn expenditures, 3.65*GASPRO*(A(1909)+A(1906))* PEXOG /1.56. One then deducts royalties, TROYLG, corporation tax, TCGASNF , an opportunity cost of capital, A(1890)* PEXOG*RESCOST , and depreciation, .365* GASPRO / J1L* RESBASE*PEXOG* RESCCST ; and one adds the Alberta selective royalty reduction, REBATE, and the British Columbia indemnification, BCINDM. The rent for each year is expressed as an end-of-year value by multiplying by STPNOM**.5 . At the end of the final simulation year KRENTNF$ is discounted back to yield a net present value as at the end of 1976, measured in terms of average 1976 prices. The equation that performs this operation is IF K7=M9 THEN KRENTNF$=KRENTNF$/(STPNOM **(K7-3)).

In order to get a feeling for the relative magnitudes cf the various rent variables, I will report the discounted present value of all the rents, expressed in end-1976 dollars. The total rent accruing from the production of non-frontier natural gas, KRENTGAS, is approximately 51 billion end-1976 dollars. Of this total, approximately 39 billion end-1976 dollars, or 76%, accrued to Canadians. As mentioned above, the sum of the rents accruing to the producers, federal government, provincial

governments, Canadian consumers and United States consumers equals KRENTGAS. For convenience, the rents will be reported as a percentage of KRENTGAS. The rents to the producers of non-frontier natural gas amount to approximately 19%; to the provincial governments, 42%; to the federal government, 15%; to the Canadian consumer, 15%; and to the United States consumer, 9%.

5. Non-frontier Conventional Crude Oil Production

The non-frontier conventional crude oil production sector explains the annual production flows; the costs of discovering, developing and producing; the net producer incomes, taxation payments, and royalty payments; the rents accruing to the major participants in crude oil production and consumption; and the accumulation of certain stock variables. The historical data, up to 1974, which were used to evaluate the variables in the model were obtained from the Canadian Petroleum Association, Statistical Yearbook . This sector only explains production and associated variables from non-frontier conventional sources. Therefore the production variable is net of any production from Great Canadian Oil Sands (GCOS), Syncrude, and other synthetic oil projects.

A list of the endogenous and exogenous variables and coefficients used in the non-frontier conventional crude oil production sector are reported in appendix 1.C. A list of the actual simulation equations contained in the crude oil sector are reported in appendix 2.C. The construction of the historical data and forecast assumptions used in the crude oil sector are contained in appendix 4.A. The construction and sources for the coefficients used in the crude oil sector are contained in appendix 4.B and appendix 4.C. The results of the forecast solution are contained in appendix 5.B.

5.1 A Description of the Production Process

The production of crude oil is assumed to conform to a rigid skewed pattern which was reported in An Energy Policy for Canada-Phase 1 [31, Vol II, p.80]. The detailed production profile for a typical pool of crude oil consists of a one year build-up to the peak annual rate of 7.3% of initial recoverable reserves. The peak rate lasts for 8 years, followed by an exponential decline of 15% per year until all of the initial recoverable reserves are extracted after 25 years.[34]

Production in the current year draws units from reserves hooked-up in each period over the last 25 years. Since the simulation experiments typically start well after the initial development of Canadian non-frontier reserves, a variable (OILMAX74) is defined to represent potential future annual production from all reserves connected before the simulation begins. The option exists to use either a model-generated or an exogenous series for OILMAX74. For the current policy simulations I am using an exogenous forecast by the National Energy Board [36, p. 87]. The National Energy Board forecast of crude oil producibility from established reserves is used because it has been derived from pool-by-pool data. The reserve base used by the National Energy Board is approximately 2.5% lower than the reserve base calculated from the historical

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[34] The only alteration to the pattern reported in the EMR study [31] was to cut the initial build-up from 2 years to 1 year which is consistent with other studies (AERCB [7] and Kalymon and Quirin [93]).

simulation of the crude oil model. The pattern of producibility decline is slightly greater in our model than the National Energy Board decline pattern.

If the current demand for Canadian non-frontier crude oil exceeds production available from past hocked-up reserves then new reserves are added as needed. If current demand is less than OILMAX74 then the difference is added to the variable OILREXES which represents the stock of discovered reserves that are not presently hooked-up. This condition prevails for some time after 1974 because exports to the United States are declining much more rapidly than Canadian demand is increasing. The extent of the shut-in capacity can be observed by comparing the difference between OILMAX and OILPRO in the base case forecast recorded in appendix 5.B. If current demand for Canadian oil is less than the production available from OILMAX74 plus reserves hooked up during the simulation run, then the production provided by reserves connected in each of the previcus years is reduced by a certain percentage so that the demand is just met. The production that has been shut-in by this method is used to increase all subsequent flows from the reserve increments in question, by amounts that total the current excess capacity. Thus there exists two methods for treating excess capacity, one applying to production from reserves hocked up during the simulation, and the other coming into play only if demand is less than potential production (e.g. OILMAX74) from reserves hooked up before the start of the simulation.

New connections can be made as long as there exists a stock of discovered unccnnected reserves, OILREXES. New additions to

the available stock of proven reserves are currently provided by an exogenous discovery variable, OILRDISC, which has been obtained by using the Gulf series reported in the National Energy Board 1975 report, Canadian Oil: Supply and Requirements [36, p.26]. The accumulation of the new discoveries from 1975-1994, reported by Gulf is 2.019 billion barrels (Bbbl) compared with 1.533 Bbbl forecast by the National Energy Board [36, p.26] and 6.2 Bbbl of post-1973 additions forecast in 1973 by the Department of Energy, Mines, and Resources [31, Vol 1, p.89].

The desired flow of non-frontier production is based on Canadian demand west of the Ottawa Valley line, approved exports of crude oil, and desired pipeline throughput to Montreal, less any production forthcoming from Great Canadian Oil Sands (GCOS), Syncrude, and any possible subsequent oil sands plants. The export demand is an exogenous series representing the actual quantities during the historical period, and the National Energy Board (1975) export forecast during the future period. Exports of crude oil are forecast to decline very sharply, being almost completely eliminated by 1981 (National Energy Board 1975, p.46). The Canadian demand for crude oil is explained within the demand sector of the energy model. It is assumed that as long as possible Canadian production will be used to satisfy demand west of the Ottawa Valley line, and beginning in mid-1976 to supply 250 thousand barrels per day to the Montreal market. As soon as Canadian production can no longer satisfy all of these markets, the Sarnia-Montreal pipeline flow eastward is assumed to decline until the whole of the western market cannot be met from

Canadian production, in which case the Sarnia-Montreal pipeline reverses its flow to provide offshore oil to Ontario. It is assumed that the demand for crude oil in the eastern regions of Atlantic and Quebec will be met by offshore sources (Middle-east and Venezula), except to the extent that western Canadian oil is made available through the Montreal pipeline.

The model keeps track of several other variables. The accumulated production of non-frontier crude oil is recorded in the OILACUM variable. The non-frontier crude oil proved reserve variable (OILRBASE) accumulates the annual difference between new discoveries and production. The export and import values for crude oil are included in the current account balance equation for oil and gas (XBALGO$) .

The model contains variables which represent the federal government subsidy payments to eastern Canadian consumers (GFSUBO) and the federal government revenue from the export tax on crude oil (TXOIL). From 1975-1980 the subsidy payments will exceed the export tax revenues by 200-400 million dollars. The federal government covers part of this deficit with revenue from the excise tax on gasoline sales [32, p.114-117], a variable which is not included in the model. The latest Department of Energy Mines and Resources report provides estimates for the trade account balance for each major energy fuel, but unfortunately the forecast values are expressed in constant 1975 dollars [32, p.112-114]. For the sake of comparison, I used the model-generated PGNE series to convert the Department of Energy Mines and Resources values from 1975 dollars to current dollars. From 1974-1980, the model-generated forecast for XBALGO$ is

slightly lower than the Department of Energy Mines and Resources forecast. I have assumed a slightly lower profile of natural gas exports and slightly longer adjustment period for the natural gas export price, and a lower domestic demand for crude oil. The latter difference is, I believe, especially important in leading to a growing divergence between the two results, such that by 1985 the Department of Energy Mines and Resources value is approximately 1,400 million dollars above my value. The model-generated forecast indicates that the deficit in the current account balance of oil and gas trade will increase as exports of both oil and gas decline to zero and the imports of oil increase as the Montreal-Sarnia pipeline flows westward.

Figure 5 shows the pattern of desired production, available capacity, domestic and export demand, and Montreal pipeline throughput obtained using the assumptions and procedures described above. The amount of shut-in crude oil production can be seen by examining the difference between line 1 and line 2 up to 1981. The shut-in capacity is due to the sharp fall in exports to the United States, as can be seen by viewing line 4. If one continues to examine line 1 and line 2 then one observes that from 1984 they again diverge, but this time production capacity is less than desired production. This apparent shortage is made up by adjusting the flow through the Montreal-Sarnia pipeline. By examining line 5 one observes that the flow through the Montreal-Sarnia pipeline is constant at 250 Mbbl/d from 1977 to 1984, and then begins to decline as crude oil originally destined for Montreal is used to satisfy the shortfall in western demand (line 2 minus line 1), and finally after about

1988 the pipeline flow is reversed and offshore crude oil is used to satisfy western demand. Line 3 represents the demand for crude oil west of the Ottawa Valley, and line 6 represents total Canadian demand, hence the difference between line 6 and line 3 is the demand east of the Ottawa Valley. The sum of western Canadian demand (line 3), export demand (line 4) and the Montreal-Sarnia eastward pipeline flow (line 5) equals the non-frontier conventional crude oil production (line 2) minus the oil sands production (not separately shown on the graph). It can be seen that after 1984 the difference between western Canadian demand (line 3) and desired non-frontier conventional production (line 2) is supplied by oil sands production (GCOS and CPROSUM).

5.2 A Description of the Price and Cost Variables

Since late 1973 the Canadian federal government has enforced a two-price policy for crude oil: the Canadian crude oil price has been lower than the international price. As part of this system, the federal government has made subsidy payments to eastern refineries using offshore oil. Since Canada charges the international price for exports of crude oil to the United States, the federal government collects revenue through the export tax. The export tax is set endogenously so that Canadian crude oil is priced competitively, after allowing for transportation tariffs, with the international crude oil in the Chicago market. The assumption is made that the Canadian non-frontier crude oil price (measured in the eastern market) will be increased to the international crude oil price by 1980. It is also assumed that the international crude oil price will remain fixed in real terms at $13/bbl in 1976 dollars. When the Canadian price has increased to the international price, the subsidy payments and export tax receipts effectively drop to zero.

For the taxation and rent equations it is necessary to know the costs to producers of finding and developing past and future crude oil reserves. The model variable OILRCOST attempts to measure the combined cost of holding reserves by estimating a cost function relating marginal costs to the stock of accumulated discoveries. The variable OILCOSTM is defined to represent the marginal real (1976 dollar) cost of discovering, developing and producing the next barrel of crude oil. The cost

relationship is such that 2.2 billion barrels of post-1973 additions to reserves will increase the constant-dollar marginal cost tc 2.2 times its 1973 value.

The construction of the cost data and the results of the estimation equations are detailed in appendix 4.B. As described in the appendix, the first task was to disaggregate the non-frontier petrcleum expenditure data into crude oil and natural gas expenditure data. I used the ratio of the development drilling footage for crude cil to the total development drilling footage to obtain a splitting ratic for exploration, development, and land acquisition expenditures. I used the ratio of the cumulative number of yearly completicns of productive crude oil wells over the cumulative total number of productive wells tc obtain a pro-rationing factor for disaggregating the petroleum operating expenditures. All of the resulting current dollar crude oil expenditures were converted into constant dollar costs using the PGNE deflator. The crude oil expenditure data were separated intc three main categcries: exploration and development, land acquisition and rentals, and operating. The historical constant dollar per unit data in each of these categories were used as dependent variables in separate estimation equaticns. The actual data used in the estimation equations are reported in part V of appendix 4.B.

The ratio of the constant dollar expenditure on exploration and development of crude cil reserves tc the gross reserve additions of crude oil is regressed against a linear functicn of the cumulative sum of gross crude oil reserve additions. The data set was divided into two periods: 1958-1966 and 1967-1974.

The marginal cost actually fell very slightly, on average, during the first period. But during the second period, the marginal cost rose quite sharply. The parameter estimates from the second period are used for the forecast period.

The ratio of the constant dollar expenditure on land acquisition and rentals of crude oil to the production of crude oil is assumed to be a linear function of cumulative production. The functional relationship is very approximate. The expenditure on land acquisition and rentals is probably related to the discounted stream of expected rents associated with the land. For the forecast period the last estimated value of .08 1961 $ per barrel is used.

The ratio of the constant dollar operating expenditure for crude oil to the wellhead production of crude oil is estimated to be a linear function of accumulated production. Over the estimation period the per unit operating costs fell slightly, due, I suppose, to increased technological efficiency. However, during the forecast period it was assumed that the last estimated operating cost of .20 1961 $ per barrel will remain constant. Due to the fact that oil wells will probably be operating with excess capacity from 1975 to 1980, I should probably have assumed that the last historical value of .26 1961 $ per barrel would remain constant.

5.3 A Description of the Tax and Rent Equations

The taxation and rent equations for crude oil production have been developed analogously to the natural gas taxation and rent equations. Hence the general description of the taxation and rent equations contained in chapter 4, section 4.3, and in appendix 4.D are applicable to this section.

Economic rents accrue to Canadian consumers of non-frontier oil, but not to United States consumers. The United States users of non-frontier oil do not earn rents because I assume that the oil export tax equals the difference between the price of international oil delivered to United States markets and the delivered price of non-frontier oil. During the historical period, Canadian users of non-frontier oil earn negative rents to the extent that the domestic oil price is less than the international price of oil delivered to Canadian markets east of the Ottawa Valley; and, United States consumers of non-frontier oil earn no rents because it is assumed that the Canadian wellhead price of oil was set competitively with the United States domestic crude oil price.

In order to get a feeling for the relative magnitudes of the various rent variables, I will report the discounted present value of all the rents, expressed in end-1976 dollars. The total rent accruing from the production of non-frontier conventional crude oil, KRENTOIL, is approximately 61 billion end-1976 dollars. Of this total, approximately 58 billion end-1976 dollars, or 96%, accrued to Canadians. The sum of the rents accruing to the producers, federal government, provincial

governments, and Canadian consumers equals KRENTOIL. For convenience, the rents will be reported as a percentage of KRENTOIL. The rents to the producers of non-frontier conventional crude oil amount to approximately 5%; to the provincial governments, 65%; to the federal government, 11%; and to the Canadian consumer, 20%.

6. Policy Analysis

As indicated in the introduction, the annual energy model is set up to facilitate the analysis of the effects of different pricing, taxation, and development strategies for Canadian natural gas and crude oil. Using so-called 'base case' assumptions about world and Canadian energy prices, and assumptions about future reserve additions and costs, I have computed a forecast to 1995 which is reported in appendix 5.B. The detailed assumptions behind the base case forecast are contained in appendices 4 and 5.A. This 'control solution' is used as a basis for measuring the effects on economic costs and benefits of the various policy alternatives.

The major policy thrusts of the Canadian government, as mentioned in the Department of Energy Mines and Resources report [32, part IV, ch. 3-4], are to ensure appropriate energy pricing, to encourage energy conservation, to foster appropriate interfuel substitution, and to develop new delivery systems. The specific targets of these policy thrusts are to move oil prices towards international levels and move gas prices to an appropriate competitive relationship with oil prices over the next 2-4 years; to reduce overall energy growth to an average annual rate of 3.5%; to reduce dependence on imported oil in 1985 to one-third of our total oil demand; and to construct the Sarnia-Montreal pipeline by mid-1976 and to construct a Mackenzie pipeline when desired. As a policy prescription I have used the federal government's assumptions about appropriate energy pricing in the base case model solution. With regard to

the annual 3.5% target rate of energy demand growth, one notes that the federal government is assuming a 3.6% average annual rate of growth of real GNP (with no relative price changes), whereas in my base case forecast I have approximately a 4.7% average annual growth rate in total energy demand with a 4.5% average annual rate of growth of real GNE (with no relative price changes). In the base case forecast the model predicts that the percentage of oil imports to total oil demand is approximately 38% in 1985, but this percentage rises quickly after 1985 as the Sarnia-Montreal pipeline reverses its flow as western crude oil production declines. I include the Sarnia-Montreal pipeline in the base case forecast, but test the implications of delaying its existence until a westward flow is needed. I will experiment with variations of these and other policies.

As explained by Crommelin [43, p.6-16], the split in government jurisdiction, between federal and provincial, over petroleum resources is such that the provinces own the resource; but the split in legislative authority is such that powers of management and sale rest with the provinces, and the control over interprovincial and external trade and commerce, pricing, taxation and interprovincial pipeline transportation rest with the federal government. I am not interested in exploring any policy alternatives relating to the management decisions of the provincial governments. I am interested in most areas of federal government control, with the notable exception of taxation policy. Taxation policy is ignored because I have not yet specified endogenous behaviour for the exploration and

development functions in the petroleum supply sector. The only policy variation that I consider with regard to interprovincial pipeline transportation relates to the construction of the Sarnia-Montreal pipeline. Therefore I intend to concentrate the experimentation with federal government policy alternatives relating to energy pricing and external trade.

In order to compare the results of the various policy alternatives, which will probably have different time paths, I will often refer to a present value measure. The present value measure quantifies into a single number the time stream of results for a variable. As a summary of the policy effects I will often refer to the present value of the economic rents accruing to the major participants: producers, governments, and consumers. The construction of the rent measures are described in section 4.3 and section 5.3.

6.1 Background Literature on Trade and Price Policies

Firstly I will examine the literature which deals with government policies relating to trade flows, and then examine the literature which relates to pricing policies. Most of the literature describing trade flows in crude oil and natural gas between Canada and the United States has emphasized the restrictions placed on the free flow of products. The quantity of natural gas exports has been restricted through the National Energy Board's exportable surplus policy (Bradley [21], and Hamilton [67]); the quantity of crude oil exports has been limited somewhat by the United States quota in 1959 and from 1967-1973, and by the Canadian quotas in 1975 (NEB [34], Debanne [50], McDougall [106], United States Task Force report [149], and Waverman [157]); and the quantity of imports of crude oil has been limited by the creation of the National Oil Policy in 1961 (Debanne [50], Hamilton and Schwartz [68], Ritchie [122], and Waverman [157]). A few studies examine the problem of market allocation of domestic production among domestic use, export or import replacement (Anderson[9], Hamilton and Schwartz [68], Powrie and Gainer [118], and Waverman [155,156]). The major difficulty associated with most of these studies is that they only estimate the net cost for one year, ignoring replacement cost due to depletion.

The Royal Commission on Energy [37] recommended that the NEB be established[35] to regulate natural gas exports through

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[35] The NEB was established in 1959.

licensing, so that only natural gas which is surplus to the reasonable foreseeable requirements of Canada would be exported. The NEB calculates its exportable surplus as any excess of established reserves over Canadian requirements.[36] Clearly there must be an implicit assumption that the production flow of natural gas has a lifetime of 30 years because the exportable surplus rule compares a stock with a flow. Bradley [21] has criticized the rule for failing to take account of interfuel substitution and technical change in forecasting consumption, for failing to take any account of price elasticity of reserves supplied, and for failing to appreciate the significance of the cost of holding a large working inventory of reserves.

The Royal Commission on Energy [37] also recommended an expansion of domestic crude oil production which would be used to displace imports in the Ontario market. This recommendation led to the government establishing the National Oil Policy in 1961 which guaranteed domestic producers a marketing area west of the Ottawa Valley. From 1959-1974 the NEB placed no controls on crude oil exports because no shortage was envisioned. In fact, the government encouraged the expansion of Canadian exports of crude oil to the United States. Bradley [22] explains a possibility for the government actively trying to expand the market for domestic production. Pro-rationing, although eliminating some of the physical waste in the 'rule of capture',

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[36] Established reserves are defined as all current proved reserves and a fraction, usually 50%, of current estimated probable reserves. Canadian requirements are defined as 30 times the current consumption for Alberta, and 25 times the estimated fourth year consumption for the rest of the country [21, p.8].

still tends to lead to economic waste in terms of overinvestment in drilling. This excess capacity has led to government action in Canada to expand the market size; and incidently the same excess capacity phenomenon has led to a protected United States market through import quotas. Another possible reason for the government attempting to both increase crude oil exports and decrease crude oil imports by restricting the Ontario market was to help alleviate the current account deficit that was relatively large from 1956-1961.

The balance of payments effects due to different levels in the current account have been discussed in McDougall [106] and Laxer [100]. They argue for a curtailment of Canadian exports of natural gas and crude oil to the United States because over the past few years the Canadian dollar has been appreciating due to the current account surplus. The exchange rate appreciation is causing Canadian manufacturing exports to become less competitive, which is alleged to have detrimental effects to the aggregate employment and income levels in Canada.

A study by Powrie and Gainer [118] examines the implications of alternative policy options (quotas, export tax, subsidies, laissez-faire) with regard to projected trade patterns in crude oil and natural gas in 1980. They consider the production implied for each element of a matrix with different growth rates for imports and exports, given the assumption of a constant growth rate in domestic demand of 5.5% per year. They limit the choice of import-export growth rates by examining the historical growth in reserves and extrapolating for 1972-1980, and then assuming a minimum reserves/production ratio of 10/1.

They have not considered the costs associated with different levels of production; they have not assessed the impact of price changes on the supply or demand; they have not examined the possibility of substitution between crude oil and natural gas; nor have they provided a quantitative measure of the macroeconomic impact.

Next I will examine two studies which indicate the potential importance of a Canadian pricing policy involving the use of an export tax on crude oil. Schwartz [125] presents an assessment of the effect that various levels of an export tax would have on the United States demand for Canadian crude oil. For the year 1969 he calculated the optimal export tax: the tax that maximizes the total export sales revenue (i.e. the export tax revenue plus the producers net revenue). The United States demand schedule is constructed by postulating that the elasticity of demand is determined by the competitive position of Canadian crude oil relative to United States crude oil. He examines the sources and costs of crude oil from various producing regions for five major refining areas currently served by Canadian exports. The export tax is assumed not to affect the Canadian wellhead price, or the United States wellhead price. For 1969 the optimal export tax is $.46/bbl (in Canadian dollars), which would yield a tax revenue of $86 million. In a somewhat broader study of Canadian pricing policies, Anderson [9] claims that an average annual net gain of $101 million could have been obtained over the period 1963-1970 by the removal of protection of the National Oil Policy and the addition of an export tax.

The actual government export policies have tended to favour quotas: for example, curtailing the issue of new export licences for natural gas, and phasing out of crude oil exports. Since 1974 there has been both an export tax and an export quota on crude oil. Of course, only one of these constraints can bind; and if it is the quantity constraint that binds then the policy is sub-optimal.

It would be desirable to estimate equations that represent the United States demand for Canadian exports of crude oil and natural gas. If one had such United States demand equations then it would be possible to quantify the effect on the export demand through any Canadian government policy which affects the export price - an export tax, for example; and it would be possible to compare the desired export level (for given Canadian prices) to the actual level of exports if the Canadian government policy is to restrict the quantity of exports through quotas rather than price adjustments. But these desired United States demand equations are difficult to formulate without undertaking a careful study of a set of demand equations for all substitutable primary fuels in the northern United States region. A wide range of market restrictions, in the form of both a quota and export tax, have been imposed by both the United States and Canada over most of the historical estimation period [9]. The problem of quantities restricted by quotas, coupled with the difficulty of obtaining regional United States data on energy prices and demands has unfortunately led me to abandon any attempt to estimate United States demand equations.

The federal government pricing policy initatives have begun

only recently. Prior to August 1973, the federal government played no direct role in oil or gas price setting. In the EMR study [31] it is reported that "for all intents and purposes foreign purchasers of Canadian crude oil pay the posted price plus freight to destination. Posted prices in Canada are set at Edmonton. The prices are such as to make the product competitive when laid down in the Chicago market" [31, Vol.I, p.250]. But since October 1973 the wellhead price of crude oil in Canada has been held below the world price. The domestic wellhead price was frozen at $3.80/bbl from September 1973, and increased to $6.50/bbl in May 1974, and then to $8.00/bbl in July 1975. From May 1974 the price for crude oil has been regulated such that in all regions of Canada it is equal to the wellhead price plus transportation, through federal government subsidy payments to regions which import crude oil. Since 1974 the federal government has regulated the Toronto city-gate natural gas price. The federal government has also been involved in regulating the export price through imposing an export tax on crude oil and altering contracted natural gas export prices. Most of the post-1973 policy initatives are summarized in the latest Department of Energy Mines and Resources report [32].

The market price used in simulating the demand for the primary products will be determined from exogenous data. The price of crude oil will be based on the offshore price, or else will be set at the level determined by the federal government for all regions of Canada. The price of natural gas will be related to the price of crude oil through assuming various degrees of Btu equivalence in the central Canadian market. But

if the wellhead price is derived from exogenous data how can a long-run equilibrium situation be possible? The long-run equilibrium would be characterized by all consumers (Canadian and United States consumers of Canadian production, and Canadian consumers of foreign production) having their demands satisfied, and all producers just meeting the desired demand at the market prices. In the case of crude oil it appears as if government policy has tried to shift the demand for imports or exports to lead to an equilibrium situation. If the wellhead price is too high it may lead to an excess discovery of new reserves. This will lead to a combination of the following government policies: pro-rationing of demand among producers, expanding the export market or expanding the domestic market through import replacement. If the wellhead price is not high enough to encourage the exploration for sufficient new reserves then the available supply must be rationed among the domestic and export market, or the import market must expand. In the case of natural gas there will not be any adjustment possible through the import market. Some of the history of Canadian policy in crude oil and natural gas from 1958 onward, summarized earlier in this section, verifies that the Canadian government policy has actually followed some of these quantity adjustment options.

6.2 The Simulated Energy Demand Elasticities

The major impacts of alternative energy pricing policies are felt through changes in the distribution of economic rents and changes in the quantities of energy fuels demanded. With regard to the latter effect it is useful to know the own and cross price elasticities of demand. The knowledge of the elasticities will give one some idea about the size and direction of energy pricing policies. The demand model described in chapter 2 and appendix 1.A, appendix 2.A, and appendix 3 is used to generate the effects of a 10% decrease in energy prices holding all other exogenous variables constant. The simulation results for the year 1985 are reported in Table 1.[37] The table consists of two parts: the first part contains the effects on the final demand for primary energy fuels (excluding the fuels used to generate thermal electricity); the second part contains the effects on the energy use of primary energy fuels (including the fuels used to generate thermal electricity). Each part of Table 1 contains the percentage quantity effect for each of the primary fuels (along each row) for a given percentage price change for each of the fuels.

The numbers in Table 1 are not labelled as demand elasticities[38] even though they represent a percentage change in

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[37] The simulations necessary to generate the values in Table 1 were run by Ken Hendricks.

[38] For expositional purposes I will refer to the ratio of the percentage quantity adjustment over the percentage price change as a 'simulation elasticity'. It is derived by dividing the elements reported in Table 1 by -10.

quantity induced by a percentage change in price because the price change induces both a shift in the total demand for energy and a shift in the relative shares. Therfore the simulation elasticities reported in Table 1 are not equivalent to those reported in appendix 3.B. But other difficulties exist in attempting a direct comparison of the elasticities: for example, the numbers in Table 1 are aggregated for all Canada, whereas the appendix 3.B elasticities are regional; and the price elasticities can vary over time. Since the elasticity of total energy demand with respect to the energy price index is negative, this implies that increases or decreases in energy fuel prices will lead to simulation elasticities that are larger in absolute value than the partial elasticities reported in appendix 3.B when the partial elasticities are negative, and may be larger or smaller when the partial elasticities are positive.

In examining the first part of Table 1 one notices that a change in the price of coal has no effect on any other fuels and that a change in any of the fuel prices has no effect on the quantity of coal demanded. Since the first part of Table 1 only includes the final energy demand and since coal is endogenously modelled only in the market for the thermal generation of electricity, price changes have no effect on the demand for coal. I assumed that coal does not compete as a substitute in the non-thermal markets, hence its price does not enter into the demand equations for other fuels.

Continuing to examine the first part of Table 1 one notices that the own simulation elasticities are -.483 for electricity, -1.08 for natural gas, and -.54 for crude oil. The simulation

cross price elasticity of electricity with respect to natural gas is +.066 and with respect to crude oil is -.089. The simulation cross price elasticity of natural gas with respect to electricity is +.277 and with respect to crude oil is +.267. The simulation cross price elasticity of crude oil with respect to electricity is +.028 and with respect to natural gas is +.059. All of the simulation cross price elasticities indicate substitution between fuels, except for the cross price elasticity of electricity with respect to crude oil. The reason for the negative sign, when the price of crude oil falls, is that the increase in the demand for electricity due to the increase in the overall energy demand is greater than the decline in the demand for electricity due to substitution of crude oil for electricity.

Still examining the first part of Table 1 one notices that the simulation price elasticity of total energy consumption with respect to electricity is -.029, with respect to natural gas is -.269, with respect to crude oil is -.164, and with respect to all energy prices is -.448. The overall decrease in the price of all energy fuels, through its effect of increasing total energy demand, leads to simulation elasticities of electricity with respect to all prices of -.438, of natural gas with respect to all prices of -.542, and of crude oil with respect to all prices of -.462.

In examining the second part of Table 1 one notices that coal is endogenously determined, and that coal is considered as a substitute for other fuels. But the price of coal still has no effect on the demand for electricity because coal does not enter

as a substitute for electricity itself, only as a substitute for the fuels used to generate thermal electricity. The own simulation elasticity for coal is -.63. The simulation cross price elasticity of coal with respect to electricity is -.121, with respect to natural gas is +.241, and with respect to crude oil is +.412. The simulation cross price elasticity of natural gas with respect to coal is +.034, and of crude oil with respect to coal is +.01. All of these simulation cross price elasticities relating to coal indicate substitutability between fuels except the simulation cross price elasticity of coal with respect to electricity. The reason for the seemingly complementary relationship between coal and electricity is that the decline in the price of electricity leads to an increase in the demand for electricity and hence an increase in the demand for coal used to produce thermal electricity, but by assumption does not lead to a counteracting fall in the demand for coal in the non-thermal markets. Similarily the seemingly complementary relationship between crude oil and electricity stems from the fact that the decline in the price of electricity leads to an increase in the demand for crude oil used to generate thermal electricity which is greater than the decline in the demand for crude oil due to the substitution of electricity for crude oil. The other entries in the second part of Table 1 are very similar to the corresponding entries in the first part of Table 1, described above.

Using the second part of Table 1 one can conclude that a 10% decrease in the price of electricity will lead to a 4.8% increase in the amount of electricity demanded. Using both parts

of Table 1 it is possible to calculate that a 10% decrease in the price of electricity will lead to approximately the following increases in fuels used to generate thermal electricity: a 0.9% increase in crude oil, a 1.2% increase in coal, and a 0.6% increase in natural gas.

The simulation elasticities reported in Table 1 are all approximately within the bounds of Canadian demand elasticities reported in the survey by Berndt [17]. It is difficult to compare the elasticities generated from my model to other models because I have aggregated energy use across all end-use sectors, whereas most other studies distinguish between sectors.

From the relative sizes of the numbers reported in the second part of Table 1 one can observe the following: the own simulation price elasticity of natural gas is approximately twice as large as either crude oil or electricity; the cross simulation price elasticities of both crude oil and electricity with respect to natural gas are approximately the same size and very small; both the simulation cross price elasticities of electricity with respect to crude oil and of crude oil with respect to electricity are very small and indicate complementarity; the simulation cross price elasticity of natural gas with respect to both electricity and crude oil are relatively large and roughly of the same magnitude. Hence one observes that the only cross demand effects of any significance to arise from pricing decisions involving crude oil, natural gas, and electricity will be the effect on the demand for natural gas due to changes in the price of either electricity or crude oil.

Table 1[1]

Effects of a 10% Decrease in Energy Prices on Energy Demand

percentage change in quantities demanded

price change	Coal	Elect	Gas	Oil	Energy
Coal[2]	0	0	0	0	0
Elect	0	+4.83	- 2.77	- .28	+ .29
Gas	0	- .66	+10.80	- .59	+2.69
Oil	0	+ .89	- 2.67	+5.40	+1.64
All	0	+4.38	+ 5.42	+4.62	+4.48

Effects Of A 10% Decrease In Energy Prices On Energy Use
(including fuels used in generation of thermal electricity)

percentage change in quantities demanded

price change	Coal	Elect	Gas	Oil
Coal	+6.30	0	- .34	- .10
Elect	+1.21	+4.82	- 2.13	+ .65
Gas	-2.41	- .66	+10.14	- .62
Oil	-4.12	+ .90	- 2.23	+5.60
All	+4.85	+4.37	+ 5.52	+5.55

where: elect is used to represent electricity,
gas is used to represent natural gas,
oil is used to represent crude oil.

[1] The year 1985 is chosen for the calculation to permit all lagged effects to be worked out. Consequently the federal government's policy of reaching world-level price equivalence by 1981 will have no impact on the calculations. The base case assumes a price level consistent, in terms of commodity value, with the world oil price.

[2] The model assumes that coal is an intermediate fuel used only in the generation of thermal electricity. Hence the nil effect of price changes on the demand for coal.

6.3 A Sensitivity Analysis of Some Factors Affecting the Demand System

The description of the exact changes made to the demand sector in order to generate the six sensitivity experiments is contained in appendix 6.A. The results of the six sensitivity experiments are reported in the first part of appendix 6.B.

The rate of growth of real GNE is a very important variable in the demand system, especially after 1981 when there is virtually no change in relative prices. Consequently, the first three sensitivity experiments measure the impact of alternative growth rates for UGNE. The first experiment uses the 4.5% per year growth rate for UGNE, which is the rate assumed by the National Energy Board. The second experiment uses the post-1981 growth rate of 3.6% per year, which is the low economic growth rate assumed by the Department of Energy Mines and Resources; and the third experiment uses the post-1981 growth rate of 5.2% per year, which is the high economic growth rate assumed by the Department of Energy Mines and Resources.

Analyzing the results of sensitivity experiment 1, one notes the following: the percentage change in all of the energy expenditures and demand variables grow until 1981 and then remain constant. The reason for the constancy after 1981 is that after this year UGNE is also assumed to grow at 4.5% per year in the control solution. The expenditure and demand variables gradually build up to roughly a 5.4% divergence with the control solution, which is the UGNE coefficient A(2026) multiplied by the average percentage change in the six year divergence between

a 5.4% growth path and a 4.5% growth path. The total Canadian demand for oil and gas (OBTU.O and OBTU.G) has declined in percentage terms more than the non-thermal demand for oil and gas reported in Ontario because less fuel is demanded for thermal electricity generation. The drop in Canadian demand for oil and gas leads to a decline in Canadian production. The production of oil and gas does not decline as much in percentage terms as the Canadian demand because the exports of oil and gas have not changed. The production of both oil and gas are lower than the control value in the initial period and then higher because the ultimate stock of reserves is not depleted as soon as in the control case. The decline in the demand for oil products in eastern Canada leads to lower imports , lower subsidy payments, and an increase in the oil and gas trade account. The decline in the demand for oil products in western Canada leads to an increase in the potential flow of Canadian oil through the Sarnia-Montreal pipeline. The production decline implies that all rent components for both oil and gas are below the control solution rents. The percentage decline in producer rents is larger for crude oil producers because a larger percentage of oil production is for the domestic market.

In analysing the results of experiment 2, one notes the following: The pattern of all the variables is very similar to experiment 1, except that the lower growth does not begin until 1982, and the divergence continues to grow throughout the experiment. Even though the production decline of natural gas in percentage terms is larger after 1986 in experiment 2, all of the rent components are smaller in absolute value because of the

discounting procedure. The crude oil rent components are much less negative in experiment 2 because the production decline does not begin until 1982, after which it is only three years until all western Canadian demand cannot be met from Canadian sources.

In experiment 3, the growth of GNE is 5.2% from 1981, compared with the control growth of 4.5%. The results indicate an increase in the demand for all energy fuels. The higher growth begins in 1982, and the divergence continues to grow throughout the experiment. Even though all of the demand variables have the opposite sign to those in experiment 2, all of the comments made about the pattern and relative sizes of the variables are applicable in experiment 3. The increase in natural gas demand in the post-1982 period leads to a deficit situation from non-frontier production in 1992, rather than in 1993. The increase in western Canadian demand for oil means that less oil can be shipped eastward through the Sarnia-Montreal pipeline. The increase in eastern Canadian demand leads to a larger deficit in the oil and gas trade account. The production increase implies that all of the rent components for both oil and gas will increase relative to the control solution. Although of opposite sign, the relative size of the oil and gas rents are similar between experiment 3 and experiment 2.

A major source of uncertainty in any forecast of energy prices is the landed offshore crude oil price. And the offshore crude oil price plays an important role in the model. It is used as the opportunity cost measure for all crude oil sales. It is assumed that the Canadian oil price will reach the international

price by 1980. The offshore crude oil price is also used as the basis for evaluating the Btu equivalent natural gas price. The Btu equivalent variable is used as the opportunity cost measure for all natural gas sales, and as the price which the regulated Toronto city-gate price will reach by 1982.

The fourth sensitivity experiment assumes that the nominal price of offshore crude oil remains at its 1980 level, instead of growing at 4% per year. Since the Canadian energy prices are assumed to adjust to world prices not sooner than 1980, there is no effect until 1981. It should be noted that a change in the offshore price does not automatically lead to any change in the natural gas price in B.C., or the electricity price in any of the regions. The decrease in the price of oil and gas leads to increases in the quantity of oil and gas demanded, and a decrease in the quantity of electricity demanded. The increase in domestic demand for natural gas leads to a deficit situation from non-frontier sources occurring two years earlier. Despite the increased production of both oil and gas, the percentage price decline is larger, leading to a fall in the taxable income from oil and gas production. The balance of oil and gas trade is at first negative, and then positive. In the 1981-1988 period the negative trade effect of the decrease in the value of Canadian natural gas exports more than offsets the positive effect of the decrease in the value of Canadian imports of crude oil. As the quantity of natural gas exports falls rapidly in the early 1990's, the balance of trade on oil and gas increases relative to the control value. Once again, the producers suffer the brunt of the decline in the rents generated from oil and gas

production.

In the fifth sensitivity experiment it is assumed that the nominal price of offshore crude oil increases at 10% per year after 1981. Such increase in the real oil price could arise if a supply shortage were likely to occur in the 1980's. The variables have essentially the same pattern in this experiment as in the previous experiment, except with an opposite sign.

In the last sensitivity experiment one can examine the effects of increasing the efficiency factors for oil and gas in the non-thermal market uses. I hypothesize that improvements in gasoline mileage in the transportation sector, improvements in building insulation, and the use of energy-efficient appliances in the residential and commercial sectors will lead to more efficient use of oil and gas. Arbitrarily, I have chosen to study the effects of an efficiency increase of .5% per year for both oil and gas. The Department of Energy Mines and Resources report [32, p.131-132] mentions increases in efficiency of energy use higher than .5% per year, but their increases relate only to new capital goods. This shock leads to a decrease in the price per output Btu of both oil and gas, hence to an increase in the number of output Btu of oil and gas demanded and to a decrease in the quantity of electricity demanded. However, the proportionate increase in the output Btu demand for oil and gas is less than the proportionate increase in the the efficiency factor, so that the demand for oil and gas declines when measured in natural units. Hence the production of oil and gas declines. The western Canadian production decline leads to an increase in the eastward flow through the Sarnia-Montreal

pipeline; and the decline in eastern Canadian demand leads to a decline in imports and federal government subsidies, and to an improvement in the oil and gas trade accounts. All of the rent components are negative due to the production declines. The crude oil producers are affected more than the natural gas producers for the same reason as given in experiment 1.

In general, these sensitivity experiments indicate the potentially large variation in the base case forecast due to changes in certain key exogenous variables. Another key exogenous variable which is likely to have a wide range of uncertainty is the price of foreign exchange, PFX. If the trade balance on the oil and gas account is at all realistic for the late 1980's and 1990's (assuming PFX=1.0), then the variable PFX will almost certainly depreciate. But the interactions surrounding the foreign exchange rate are complicated enough that I did not feel confident in suggesting alternative values.

6.4 An Analysis of Some Energy Pricing Policies

I wish to use the model to examine the implications of various federal government energy pricing policies. The description of these pricing policies are contained in appendix 6.A, and the results in appendix 6.B. The first policy option is to constrain the natural gas price to be lower than the base case price. The policy may be desirable because the substitution away from crude oil products towards natural gas will reduce the need to reverse the Montreal- Sarnia pipeline after 1988, and will hence reduce the deficit in the balance of energy trade, although it will lead to an earlier indicated start-up date for frontier natural gas. Indeed it was stated, without evidence, in the latest Department of Energy Mines and Resources report [32] that "substantial opportunities exist for reducing our future oil imports, through policies directed at ... encouraging the substitution of domestic energy sources for imported oil" [32, p.123]. Specifically, the natural gas price is constrained to be 85% of the commodity-equivalent Toronto city-gate price (85% is the actual ratio existing in 1976).

Before examining the detailed outcome of this experiment, one should glance at the second part of Table 1 to obtain an idea as to the direction and relative size of the impact that the price shock will have on the demand for the major primary fuels. The numbers recorded in Table 1 indicate that the own-price elasticity within the complete model is about -1.0. All cross-price elasticities are positive, and all negligible in size, except for coal. Hence the results of the policy

experiment should not exhibit much substitution of crude oil products for natural gas, but should indicate a substantial increase in the demand for natural gas. The outcome of the experiment on the demands for the major primary fuels can be examined in Figure 6 as a shift in the fuel shares and in Figure 7 as a shift in the demands. The results portrayed in the figures are consistent with the results reported in Table 1. The share of crude oil and electricity fall, and the share of natural gas rises. The largest demand shift is through the own-price effect on natural gas. The shock minus control results are seen to reach their maximum effect after 1981, when the price differential reaches its maximum.

The increased demand for natural gas leads to a two year earlier indicated start-up date for frontier natural gas. When examining the production variables, one notices that they always reverse sign part way through the experiment. Since a fixed resource stock and a fixed rate of discovery is assumed, any change in the early years of production must be followed by a change of opposite sign in the later years of production. The decline in crude oil demand leads to slightly more western Canadian oil being shipped eastward and slightly lower imports. The rents to natural gas consumers increase significantly; and the rents to natural gas producers decline somewhat; but overall there is a net benefit to Canadians.

The second policy experiment involves restricting the wellhead price of crude oil to 85% of its control value. The supposition behind this experiment is that the consuming provinces in Canada would convince the federal government

continually to hold Canadian oil prices below the world level. Since the transportation tariff from the Prairies to Ontario is not altered this implies that the Ontario crude oil price falls by sightly less than 15%. Once again, the shifts in fuel demands look very similar to those reported in Table 1. The negative value of OILPIPEM in 1974 indicates that desired increases in western Canadian crude oil demand would have to be imported. However, from 1975 to 1981 the excess capacity in oil production is sufficient to meet the increase in demand without the need for imports into western Canada or a cut-back in the Sarnia-Montreal pipeline flow. The increased imports cause a fairly substantial decline in the balance of energy trade. The rent to the crude oil producers declines sharply, and the rent to Canadian consumers increases considerably. The substitution away from natural gas leads to a slightly lower rent for natural gas producers. The very large rent increase to Canadian consumers of natural gas is incorrect, and should be ignored.[39]

The results of these experiments would vary considerably under any of the six sensitivity changes. I do not propose to test all of the combinations available. It is possible to obtain some feel for a combination by examining the separate experiments. For instance, if a pricing policy were to hold natural gas prices down by 15% under conditions of a 4.5% growth in real GNE then the results of policy experiment 1 would

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[39] This condition occurs because I shut off only part of the response which automatically adjusts the natural gas price to a Btu equivalence with the new crude oil price. The automatic response was shut off so that I could isolate the response to only the change in the oil price.

indicate an increase in demand for natural gas of 10% and a decrease in the demand for crude oil of about 7.5%.

6.5 An Analysis of Some Oil and Gas Export Policies

The third and fourth policy experiments involve respectively reducing and increasing the exports of natural gas by 10%. Since none of the next six policy experiments affect any of the demand variables, as can be seen by examining the OBTU variable, I have shortened the output of the results in appendix 6.B. In the third policy experiment the only variables affected are natural gas production and taxable income, the balance of trade, and the natural gas rents. The effect on each of these variables decreases over time, as the quantity of exports declines in the control solution. The corresponding variables in the two experiments are almost identical in magnitude, but opposite in sign. A 10% increase in the exports of Canadian natural gas leads to an increase in total resource rents of about 3.4%, although only a 2.2% increase in the rents accrue to Canadians. The largest gainers are the producers who get an 8.5% increase and United States consumers who get a 5.3% increase. The rents to United States consumers increase because they receive more natural gas in the early years of the experiment when they pay less than the opportunity cost.

The fifth and sixth policy experiments involve altering the export flow of crude oil and altering the eastward flow through the Sarnia-Montreal pipeline. Specifically, the fifth policy experiment increases oil exports by 250 Mbbl/d and sets the Sarnia-Montreal pipeline eastward flow to zero. The lack of excess oil production capacity in 1974 means that in order to increase exports in 1974 by 250 Mbbl/d, it was necessary to

increase imports into western Canada by 242 Mbbl/d. Since the Sarnia-Montreal pipeline flow is only 100 Mbbl/d in 1976, the oil production must be increased by 150 Mbbl/d to meet the increased export requirement. From 1977 to 1984 the export-import swap can easily be observed: imports have increased by 250 Mbbl/d, no oil flows through the Sarnia-Montreal pipeline and no extra oil production is required. The increased oil imports and exports lead to increases in both export tax receipts and in subsidy payments. Since the export tax receipts are greater than the subsidy payments, the balance of trade improves and the rent to the federal government increase significantly. The per unit export tax is greater than the subsidy because the export tax is based on the price of offshore crude oil shipped to the Chicago market. Oil imports increase by more than 250 Mbbl/d after 1984 because offshore oil must be shipped into western Canada; and hence the balance of energy trade declines relative to the control value. In general, such a policy would lead to an increase in overall rents to Canadians, with the major beneficiaries being the producers and the federal government.

In the sixth policy experiment I attempt to explore the implications of reducing to zero the post-1975 exports of crude oil and increasing the Sarnia-Montreal pipeline flow to 350 Mbbl/d after 1976. The decline in oil production becomes smaller over time as the quantity of exports declines in the control solution more than the increase in the pipeline flow; and from 1979 to 1983 the increase in oil production becomes larger over time as the fixed increase in the pipeline flow becomes larger

than the continually declining exports in the control solution. The capacity constraint reached by 1984 causes the increased eastward flow of 100 Mbbl/d to decline steadily. The balance of trade becomes more negative, and the export tax receipts drop more than the subsidy payments from 1976 to 1979 because the drop in exports is larger than the increase in import replacement. After 1979 the situation reverses between the export and import replacement flows, and this leads to the balance of trade becoming more positive. The rent to producers declines by 16% because the large drop in oil production in the early years more than offsets the increased oil production in later years. The large decline in the present value of 1.5 billion 1976 dollars in the federal government rent is caused by the larger decline in export tax receipts than in subsidy payments.

In general, with these trade policies that alter production directly, any increase in production in the early years tends to lead to an increase in all rent components and the reverse for a decline in production in the early years. Since most of the federal rent is derived from taxable production income, export tax receipts, less import subsidy payments, the net federal total can vary considerably under these experiments. The relative change in exports and imports will determine the effect on the balance of trade. Although the direction of change in production and the balance of trade is clear in the natural gas policies it is slightly more subtle in the crude oil policies because of the simultaneous change in the import replacement facilities of the Sarnia-Montreal pipeline.

6.6 An Analysis of Alternative Montreal Pipeline Flows

The last two policy experiments measure the implications of alternative flows through the Sarnia-Montreal pipeline. The federal government policy with regard to the Sarnia-Montreal pipeline, as outlined in the Department of Energy Mines and Resources report, is:

> Self-reliance means reducing our vulnerability. It means supplying Canadian energy requirements from domestic resources to the greatest extent practicable... It recognizes, however, that the policies we will adopt have costs as well as benefits and a balance that provides the maximum advantage to Canadians must be found [32, p.124].

Although I do not propose to discover a policy that provides 'the maximum advantage to Canadians', I will indicate two alternative proposals.

The seventh policy experiment assumes that the Sarnia-Montreal pipeline will not be built until it is needed to import offshore oil into Ontario. The accumulation of the oil that is not shipped eastward leads to a delay in the imports of oil into Ontario from 1989 to 1990. The substantial drop in oil production is the cause of the large drop in rents to oil producers. The 'shock minus control' values of OILPRO and OILPIPEM are identical in this experiment. Of course, the imports of oil increase to the same extent that the flow through the Sarnia-Montreal pipeline decreases. Initially the balance of trade becomes more negative as the imports increase; but becomes more positive after 1989 when the production increases relative to the control value. The overall rents to Canadians decline by about 8% with this policy. From the point-of-view of the balance

of payments, the increase in the balance of trade in the 1990's would certainly help to mitigate the large balance of trade deficit.

The last policy experiment assumes that the post-1976 flow through the Sarnia-Montreal pipeline will be 350 Mbbl/d. In general, production increases until 1984, after which time the production gradually decreases. The pattern of the balance of trade is, quite naturally, opposite in sign and smaller in magnitude than the previous experiment. The production increase in the early years of the experiment leads to a substantial increase in the rent to producers; but only a modest increase in the total rents to Canadians.

Although these last two experiments allow one to observe the response to a change in only one variable (CILPIPEM), I believe that it is more realistic to expect the pipeline flow to be altered in conjunction with the export flows, as in experiments 5 and 6. For instance, when the exports are increased by 250 Mbbl/d at the same time as the eastward flow of the Sarnia-Montreal pipeline is set to zero, the net benefit to Canadians increases by 3%, whereas with no change in exports the net benefit to Canadians decreases by 8%. When the exports are set to zero at the same time as the eastward flow through the Sarnia-Montreal pipeline is increased to 350 Mbbl/d, the net benefit to Canadians decreases by 3%, whereas with no change in exports the net benefit to Canadians increases by 2%.

7. Summary

In the latest documentation of government energy policy, An Energy Strategy for Canada: Policies for Self-Reliance [32], considerable emphasis is placed on energy pricing policies; and somewhat less emphasis is placed on the new delivery capability of the Sarnia-Montreal oil pipeline extention. The strategy for oil and gas prices are mentioned freguently, although the pricing policy toward natural gas is more vague: for instance, it is stated that "future pricing policies for natural gas should reflect ... a relationship to the price of oil that is appropriate in the light of the relative supplies of these energy sources and the desire to facilitate energy self-reliance through the encouragement of interfuel substitution" [32, p.136]. A policy of using electricity prices "to encourage medium to long term substitution of electrical energy for more scarce forms" [32, p.129] is not really dealt with at all, probably because the federal government has little control over the electrical utility companies. With regard to the Sarnia-Montreal pipeline policy, the federal government considers its existence to enhance the security of supply in eastern Canada and to provide an acceptable degree of emergency preparedness.

The major aim of this thesis is to provide an independent analysis of the type of energy policy questions raised in the Department of Energy Mines and Resources report. The effect of the alternative policies will, of course, depend upon the underlying state of nature. Since there exists a considerable

degree of uncertainty about the future trend in a number of variables, I have provided the results of some sensitivity experiments. The Department of Energy Mines and Resources report also recognizes that "we are dealing in probabilities, not certainties" [32, p.4] and hence enumerates a few key areas of uncertainty [32, p.3], and provides results of various scenarios, especially in the chapter on demand.

The potential importance of pricing policies on energy demand led to considerable effort being expended on specifying and estimating a demand system. The 'base-case' forecast of the demand model is analysed in sections 2.4, 2.5, and 2.6. In general, the out-of-sample properties of the demand system indicate that it performs rather poorly in 1974, but reasonably well in 1975 and 1976. The 'base-case' forecast for oil and gas grows at a substantially lower rate than both the Department of Energy Mines and Resources and National Energy Board forecast during the 1976-1980 period, and grows at a slightly higher rate thereafter. The response in the demand system due to price changes are reported in section 6.2, and summarized in Table 1. The results of Table 1 indicate rather small cross price elasticities for crude oil; however, the cross price elasticities of natural gas with respect to electricity and crude oil are comparatively large. The implication of the size of the cross price elasticities reported in Table 1 is that any attempt at a pricing policy aimed at interfuel substitution away from crude oil is going to fail. Of course, the own price elasticity of crude oil is large enough to facilitate a demand shift away from crude oil. In fact such a demand shift would

probably occur if the Canadian dollar were to depreciate due to a deficit in the energy trade balance. A depreciation of the Canadian dollar would cause a rise in the import price of crude oil, which would in turn cause a rise in the Canadian wellhead price due to the assumption of equating the domestic price with the foreign price (after 1980).

The results of the sensitivity and policy experiments are reported in sections 6.3, 6.4, 6.5 and 6.6. The sensitivity experiments indicate the possible existence of a fairly wide range of outcomes from the demand system. The demand variables in the energy pricing policy experiments indicate the same elasticities as reported in Table 1. However, through the use of the integrated energy model, the results of the energy pricing experiments trace out the full consequences. For instance, in the second policy experiment the inelastic demand for crude oil implies that net taxable income will fall. However, in the first policy experiment the net taxable income from natural gas falls despite the fact that there is a unitary demand elasticity for natural gas. This situation arises from the extra costs associated with increased production. All of the interactions arising from altering export flows, and in some cases, altering in conjunction the Sarnia-Montreal oil pipeline flow are displayed in the rest of the policy experiments. In all of these experiments the gainers and losers can be identified by examining the rent variables.

To properly assess the policy results of this model, an answer must be given to the following question: how reliable are the results? Naturally, this is a difficult question to answer.

I feel relatively confident about the response of the demand equations. However, the system does have weaknesses: the dynamic response mechanism is not derived theoretically, the estimation parameters in the expenditure share system for thermal electricity do not fit too well, and the specification of the total energy expenditure equation is weak. Of course, the predicted levels of future demand are crucially dependent upon the assumptions for the exogenous variables. Despite these shortfalls in the demand system, it is the supply side of the model which is, I believe, less reliable. The major areas of weakness in the supply models arise from the lack of behavioural assumptions regarding the exploration reserve additions and the costs of development and exploration. The gross reserve additions are exogenous, and the costs of development and exploration are a function of the reserve additions; and hence they do not adjust during the policy experiments. Therefore the amount of new discoveries is not related to price or cost.

I will conclude by stating what I believe to be the three main contributions of the dissertation. I believe that the specification and estimation of the aggregate demand system is a useful contribution. I believe that the process of building a model which integrates the petroleum supply and demand relationships, and details the costs, rents and trade flows has been successful. And I have been successful in using the integrated energy system to generate quantitative results under alternative policies.

FIGURE 1: CANADIAN ENERGY DEMAND DIVIDED BY REGION
1 = ATLANTIC
2-1 = QUEBEC
3-2 = ONTARIO
4-3 = PRAIRIES
5-4 = BC
5 = TOTAL ENERGY DEMAND FOR CANADA

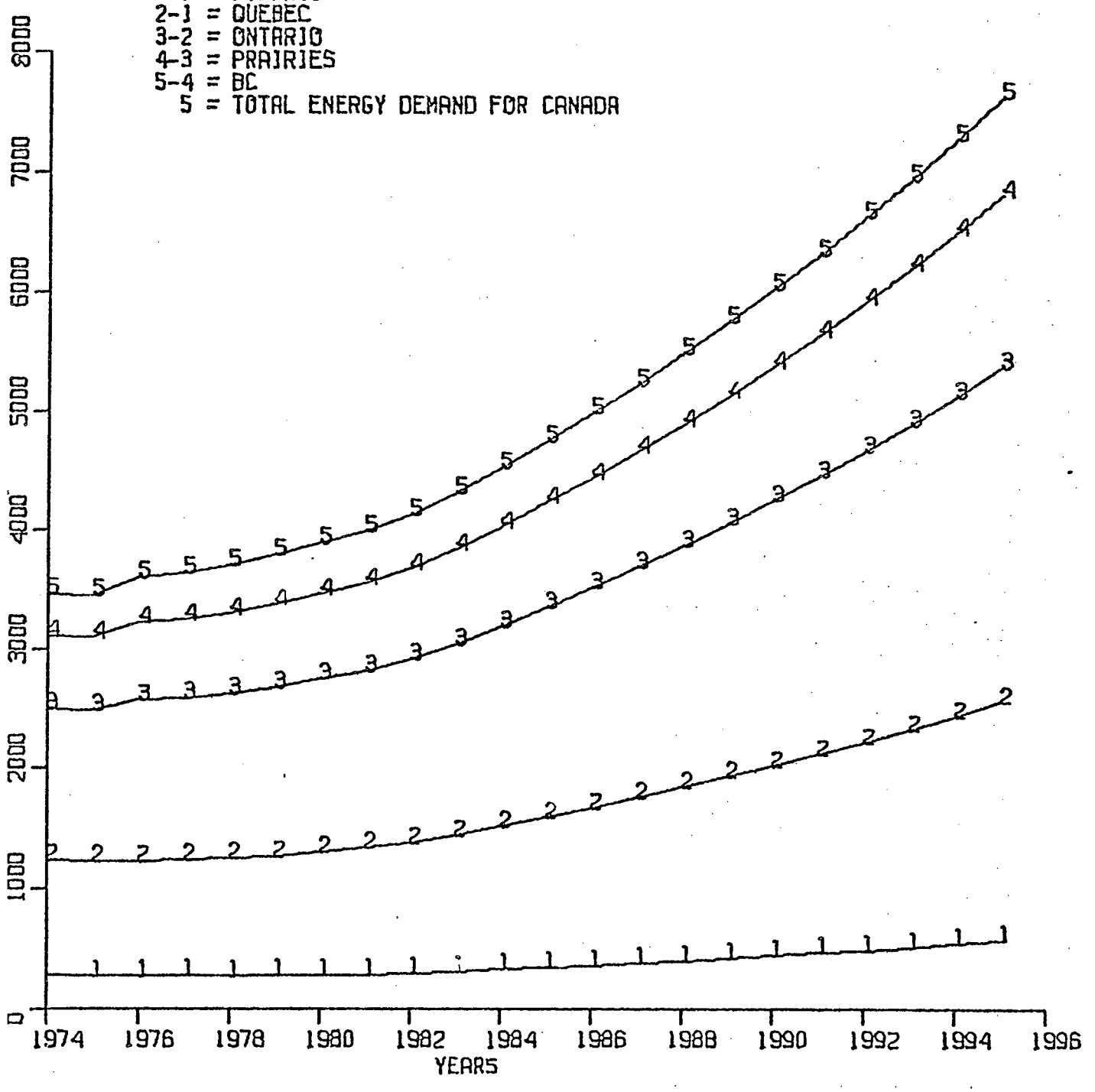


FIGURE 2: SHARES OF PRIMARY ENERGY FUELS DEMANDED IN CANADA

1 = CRUDE OIL 2-1 = NATURAL GAS

3-2 = ELECTRICITY 4-3 = COAL

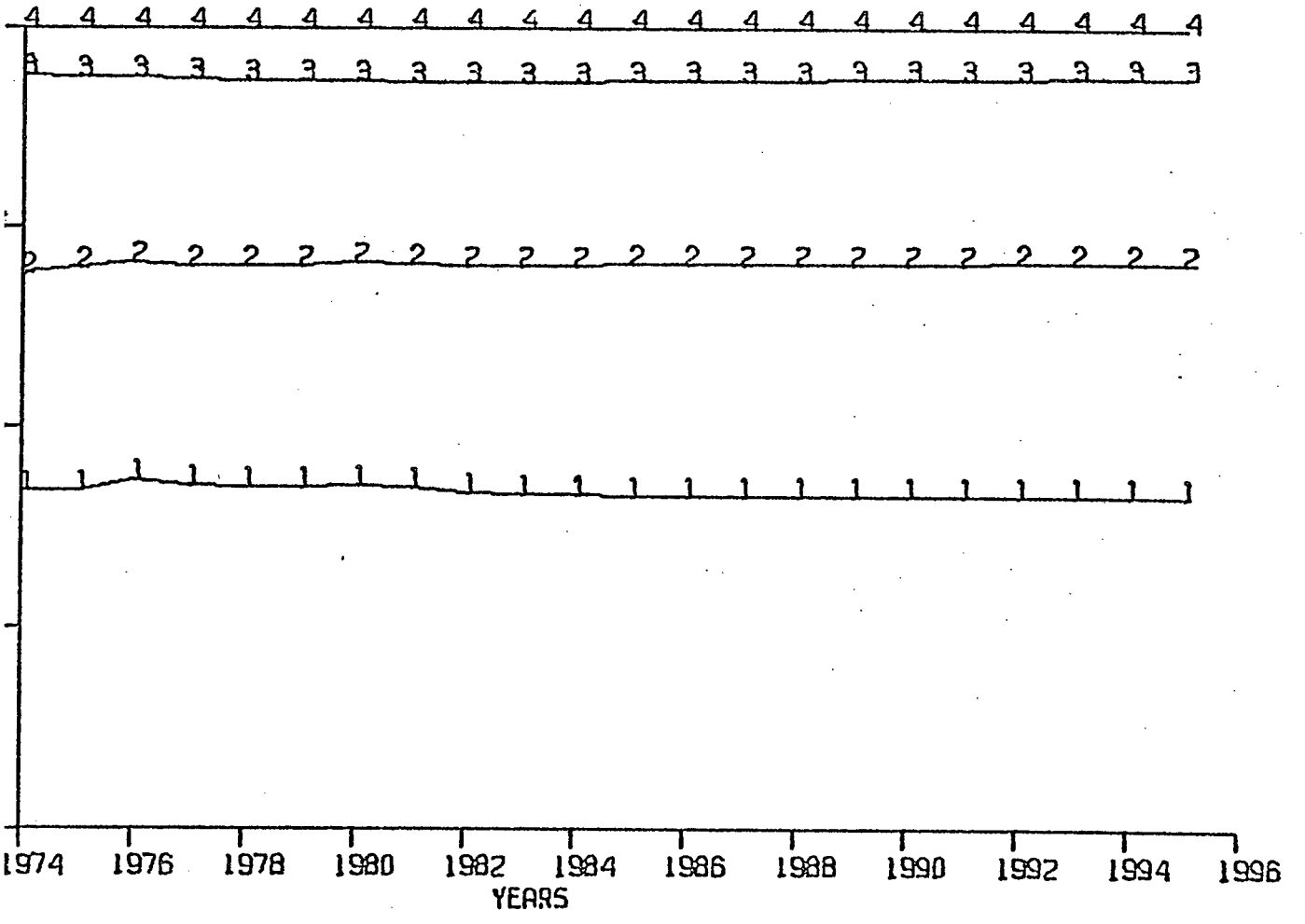


FIGURE 3: CURRENT $ EXPENDITURE ON ENERGY ACCUMULATED BY REGION

1 = ATLANTIC
2-1 = QUEBEC
3-2 = ONTARIO
4-3 = PRAIRIES
5-4 = BC
5 = TOTAL FOR CANADA

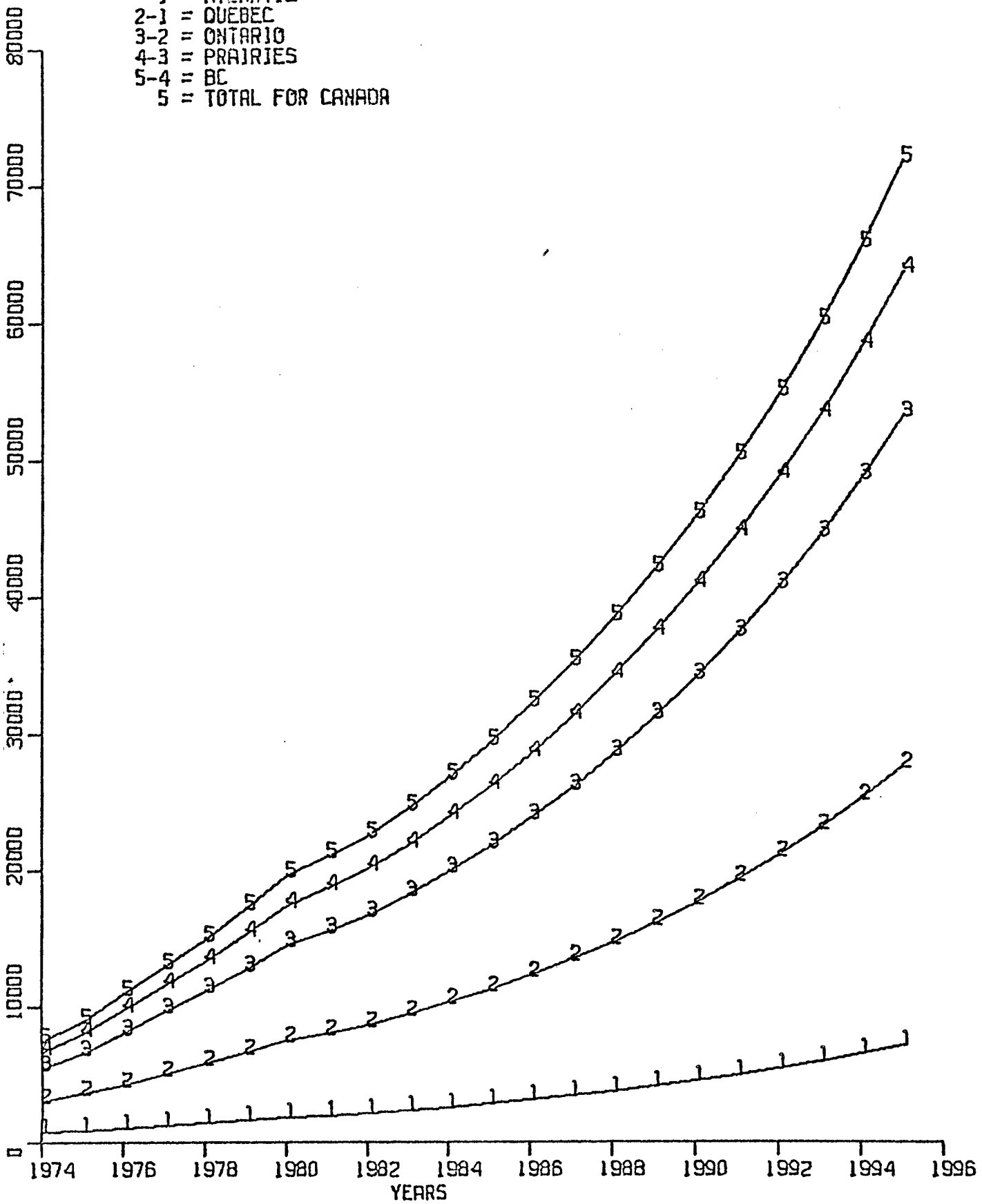


FIGURE 4: NATURAL GAS DEMAND AND NON-FRONTIER PRODUCTION
1=DOMESTIC DEMAND BASED ON EQUATIONS ESTIMATED FOR TOTAL PRIMARY ENERGY DEMAND AND ENERGY SHARES
2=DOMESTIC DEMAND + APPROVED EXPORTS
3=SUPPLY USING 1:7300 FLOW AND 114 TCF ULTIMATE RESERVES
4=APPROVED EXPORTS

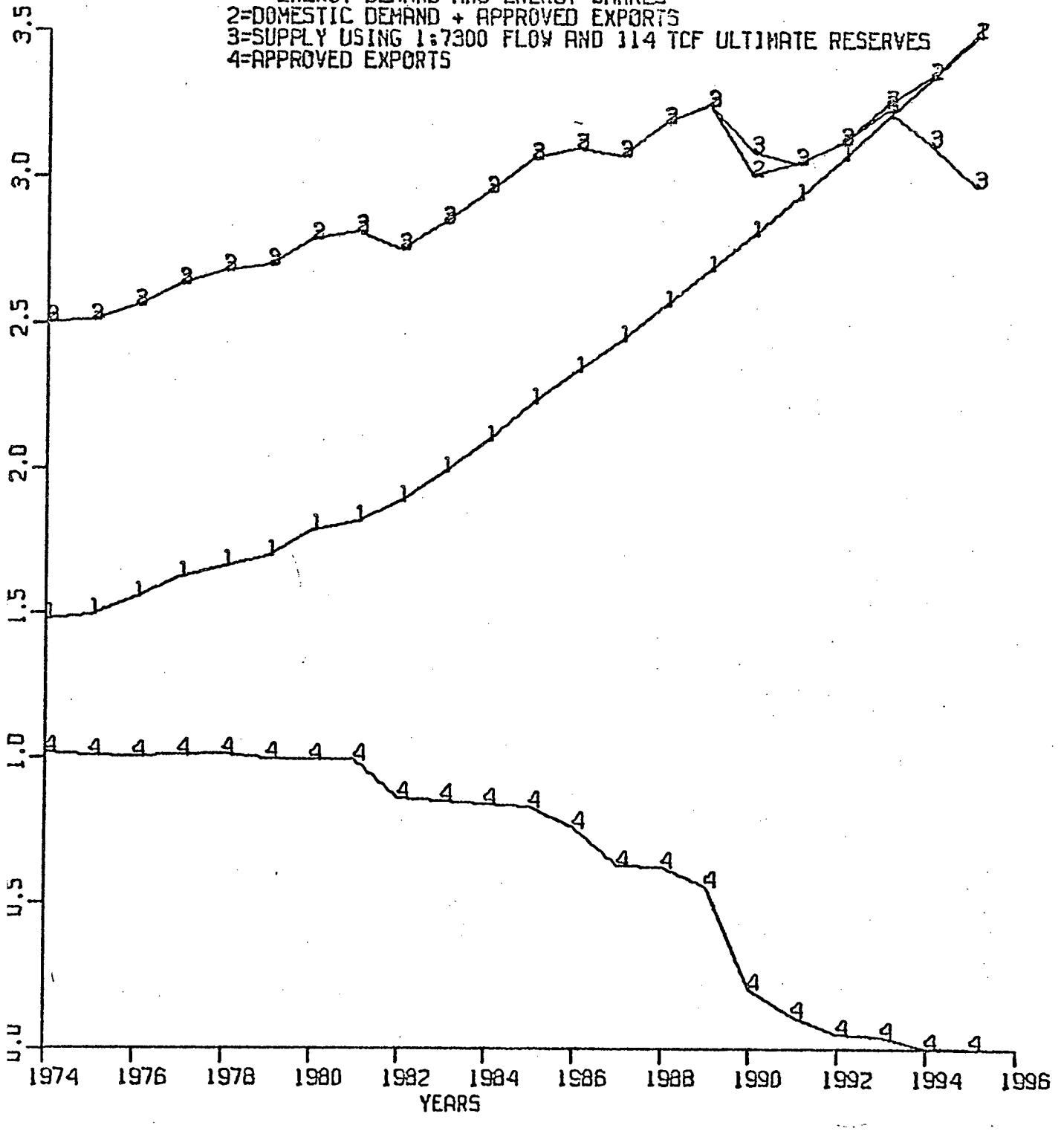


FIGURE 5: CRUDE OIL DEMAND, PRODUCTION AND FLOW THROUGH MONTREAL PIPELINE (-IF WESTBOUND)

1=CRUDE OIL PRODUCTION CAPACITY
2=DESIRED PRODUCTION
3=WESTERN CRUDE OIL DEMAND
4=APPROVED EXPORTS
5=MONTREAL PIPELINE THROUGHPUT
6=TOTAL CANADIAN DEMAND

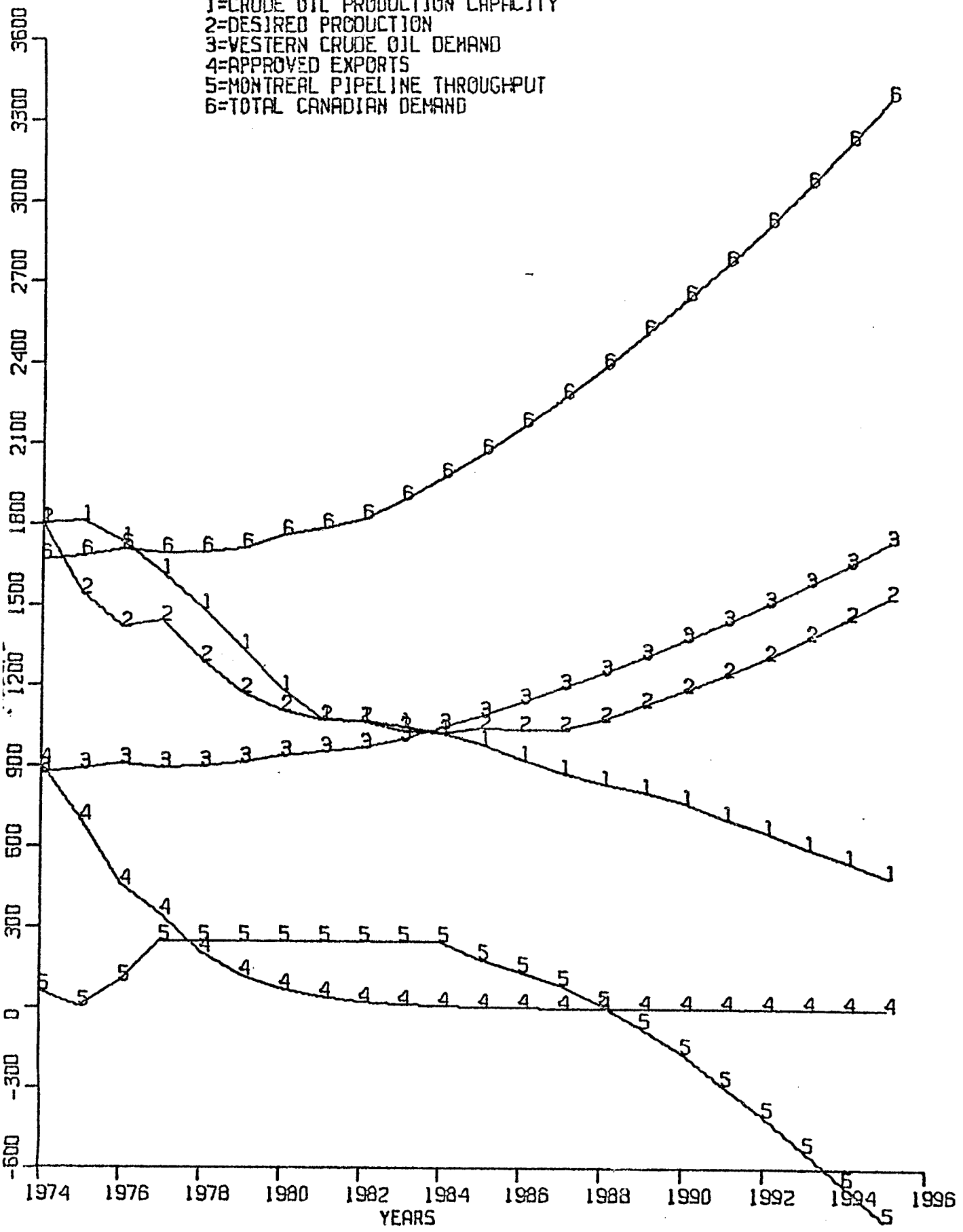


FIGURE 6: SHARES OF PRIMARY FUELS DEMANDED BEFORE AND AFTER 15% FALL IN PG
BEFORE: 1 = CRUDE OIL 3-1 = NATURAL GAS 5-3 = ELECTRICITY 7-5 = COAL
AFTER: 2 = CRUDE OIL 4-2 = NATURAL GAS 6-4 = ELECTRICITY 7-6 = COAL

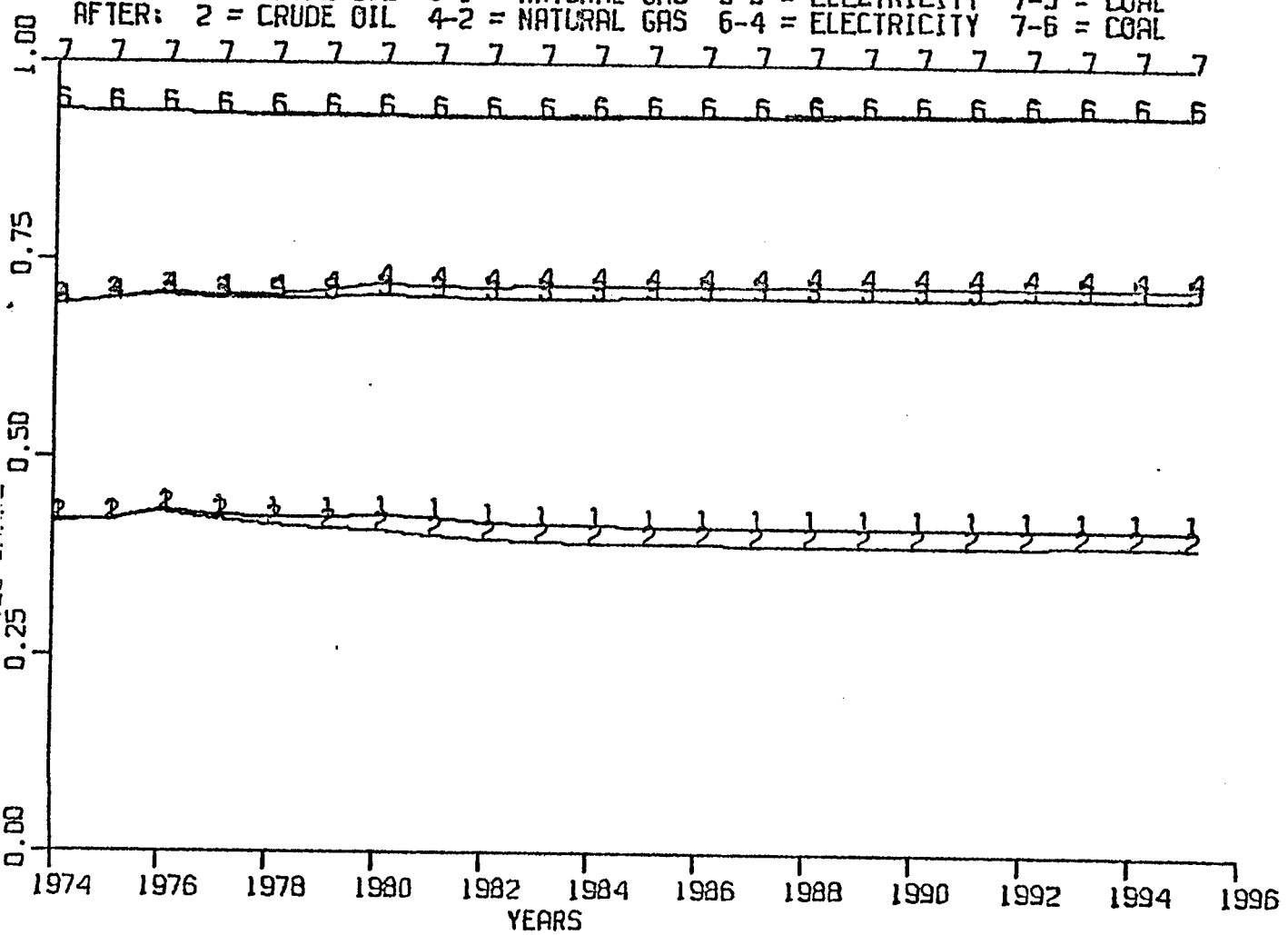
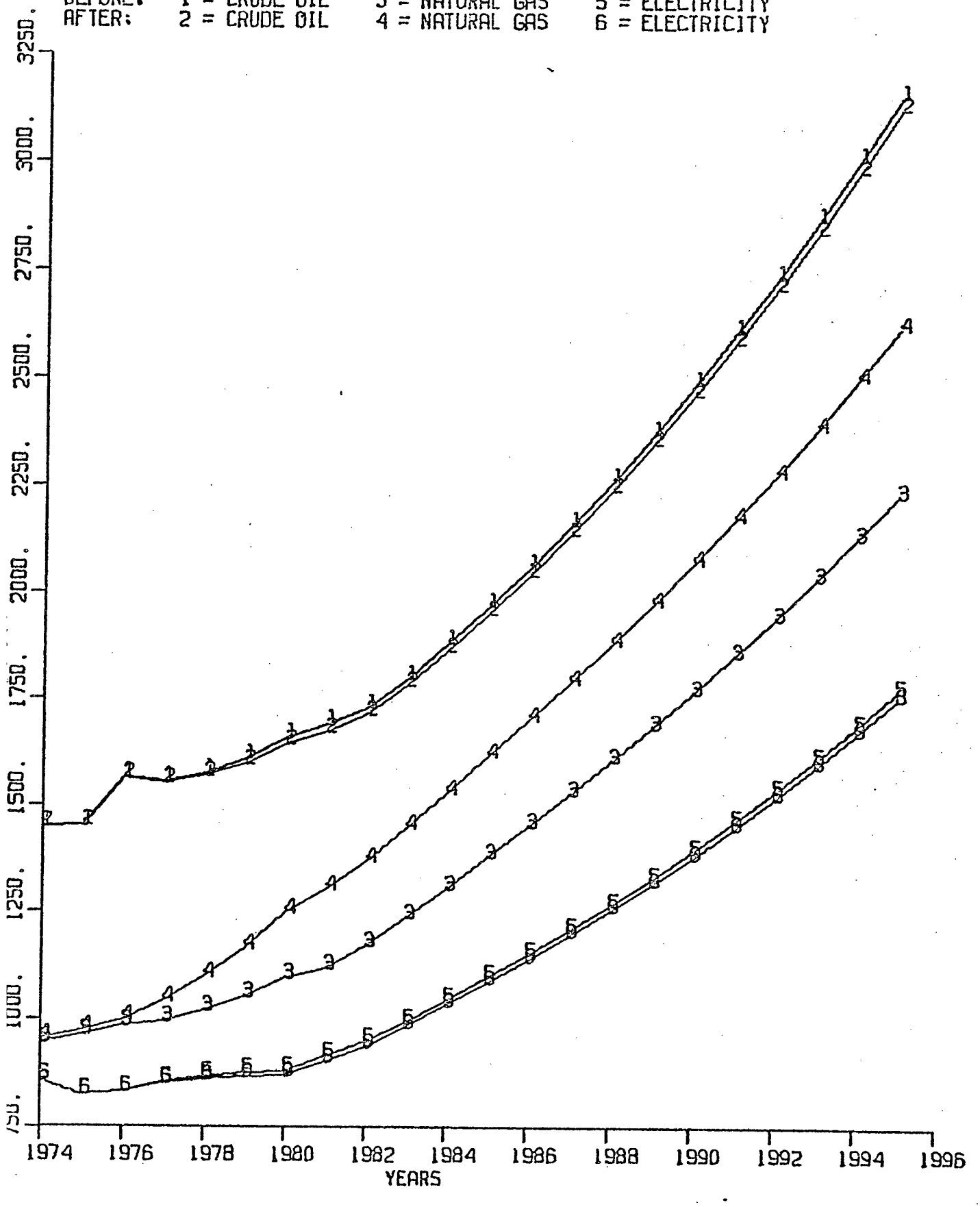


FIGURE 7: PRIMARY FUELS DEMANDED BEFORE AND AFTER 15% DROP IN GAS PRICE
BEFORE: 1 = CRUDE OIL 3 = NATURAL GAS 5 = ELECTRICITY
AFTER: 2 = CRUDE OIL 4 = NATURAL GAS 6 = ELECTRICITY



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APPENDICES

1. List of Variables, Coefficients, and Definitions

This combined list of variables and coefficients has been compiled sector by sector for the total energy model. It is intended to be used as an aid to the reader in interpreting the equations which simulate Canada's various energy supply and demand components. In all there are four sections to this list. The first deals with the demand model; the remaining three relate to the supply of energy, covering, respectively, non-frontier gas, non-frontier oil, and the loss factors linking recorded production and city-gate deliveries of crude oil, natural gas, and electricity.

1.A Demand Sector

1. endogenous variables

name	description
GFSUBC	federal government subsidy payments to eastern consumers of foreign crude oil, millions of $
OBTU	primary energy used in Canada, trillions of output Btu
OBTU.AT	primary energy used in Atlantic, trillions of output Btu
OBTU.BC	primary energy used in B.C., trillions of output Btu
OBTU.C	total coal used in Canada, trillions of output Btu
OBTU.G	total natural gas used in Canada, trillions of output Btu
OBTU.L	total electricity used in Canada, trillions of output Btu
OBTU.O	total crude oil used in Canada, trillions of output Btu
OBTU.ON	primary energy used in Ontario, trillions of output Btu
OBTU.PR	primary energy used in Prairies, trillions of output Btu
OBTU.QU	primary energy used in Quebec, trillions of output Btu
PEN.AT	price index for primary energy in Atlantic, 1961=1.0
PEN.BC	price index for primary energy in B.C., 1961=1.0
PEN.ON	price index for primary energy in Ontario, 1961=1.0
PEN.PR	price index for primary energy in Prairies, 1961=1.0
PEN.QU	price index for primary energy in Quebec, 1961=1.0
PC.AT	price of coal in Atlantic, $/million output Btu
PC.BC	price of coal in B.C., $/million output Btu
PC.ON	price of coal in Ontario, $/million output Btu
PC.PR	price of coal in Prairies, $/million output Btu
PC.QU	price of coal in Quebec, $/million output Btu
PG.BC	price of natural gas in B.C., $/million output Btu
PG.ON	price of natural gas in Ontario, $/million output Btu
PG.PR	price of natural gas in Prairies, $/million output Btu
PG.QU	price of natural gas in Quebec, $/million output Btu
PL.AT	price of electricity in Atlantic, $/million output Btu

PL.BC	price of electricity in B.C., $/million output Btu
PL.CN	price of electricity in Ontario, $/million output Btu
PL.PR	price of electricity in Prairies, $/million output Btu
PL.QU	price of electricity in Quebec, $/million output Btu
PO.AT	price of crude oil in Atlantic, $/million output Btu
PO.BC	price of crude oil in B.C., $/million output Btu
PO.CN	price of crude oil in Ontario, $/million output Btu
PO.PR	price of crude oil in Prairies, $/million output Btu
PO.QU	price of crude oil in Quebec, $/million output Btu
QCOAL	quantity of coal demanded in Canada, millions of tons
QCL.AT	quantity of coal used to generate thermal electricity in Atlantic, trillion output Btu
QCL.BC	quantity of coal used to generate thermal electricity in B.C., trillion output Btu
QCL.CN	quantity of coal used to generate thermal electricity in Ontario, trillion output Btu
QCL.PR	quantity of coal used to generate thermal electricity in Prairies, trillion output Btu
QCL.QU	quantity of coal used to generate thermal electricity in Quebec, trillion output Btu
QC.AT	quantity of coal demanded in Atlantic, trillion output Btu
QC.BC	quantity of coal demanded in B.C., trillion output Btu
QC.ON	quantity of coal demanded in Cntario, trillion output Btu
QC.PR	quantity of coal demanded in Prairies, trillion output Btu
QC.QU	quantity of coal demanded in Quebec, trillion output Btu
QGAS	quantity of natural gas demanded in Canada, Bcf
QGL.BC	quantity of natural gas used to generate thermal electricity in B.C., trillion output Btu
QGL.ON	quantity of natural gas used to generate thermal electricity in Ontario, trillion output Btu
QGL.PR	quantity of natural gas used to generate thermal electricity in Prairies, trillion output Btu
QGL.QU	quantity of natural gas used to generate thermal electricity in Quebec, trillion output Btu
QG.BC	quantity of natural gas demanded in B.C., trillion output Btu
QG.ON	quantity of natural gas demanded in Ontario, trillion output Btu
QG.PR	quantity of natural gas demanded in Prairies, trillion output Btu
QG.QU	quantity of natural gas demanded in Quebec, trillion output Btu
QELEC	quantity of electricity demanded in Canada, millions of Kwh
QL.AT	quantity of electricity demanded in Atlantic, trillion output Btu
QL.BC	quantity of electricity demanded in B.C., trillion output Btu
QL.ON	quantity of electricity demanded in Ontario, trillion output Btu
QL.PR	quantity of electricity demanded in Prairies, trillion output Btu
QL.QU	quantity of electricity demanded in Quebec, trillion output Btu
QOIL	quantity of crude oil demanded in Canada, millions of bbl
QOILEAST	quantity of crude oil demanded east of the Ottawa valley, millions of bbl

QOILWEST	quantity of crude oil demanded west of the Ottawa valley, millions of bbl
QOL.AT	quantity of crude oil used to generate thermal electricity in Atlantic, trillion output Btu
QOL.BC	quantity of crude oil used to generate thermal electricity in B.C., trillion output Btu
QOL.ON	quantity of crude oil used to generate thermal electricity in Ontario, trillion output Btu
QOL.PR	quantity of crude oil used to generate thermal electricity in Prairies, trillion output Btu
QOL.QU	quantity of crude oil used to generate thermal electricity in Quebec, trillion output Btu
QO.AT	quantity of crude oil demanded in Atlantic, trillion output Btu
QO.BC	quantity of crude oil demanded in B.C., trillion output Btu
QO.ON	quantity of crude oil demanded in Ontario, trillion output Btu
QO.PR	quantity of crude oil demanded in Prairies, trillion output Btu
QO.QU	quantity of crude oil demanded in Quebec, trillion output Btu
QSL.AT	quantity of thermal (secondary) electricity used in Atlantic, trillion output Btu
QSL.BC	quantity of thermal (secondary) electricity used in B.C., trillion output Btu
QSL.ON	quantity of thermal (secondary) electricity used in Ontario, trillion output Btu
QSL.PR	quantity of thermal (secondary) electricity used in Prairies, trillion output Btu
QSL.QU	quantity of thermal (secondary) electricity used in Quebec, trillion output Btu
TEL$	total expenditure on fuels used for generating thermal electricity in Canada, millions of current $
TEL$AT	total expenditure on fuels used for generating thermal electricity in Atlantic, millions of current $
TEL$BC	total expenditure on fuels used for generating thermal electricity in B.C., millions of current $
TEL$ON	total expenditure on fuels used for generating thermal electricity in Ontario, millions of current $
TEL$PR	total expenditure on fuels used for generating thermal electricity in Prairies, millions of current $
TEL$QU	total expenditure on fuels used for generating thermal electricity in Quebec, millions of current $
TOTSL$	total expenditure on thermal electricity in Canada, millions of $
TOTSL$AT	total expenditure on thermal electricity in Atlantic, millions of $
TOTSL$BC	total expenditure on thermal electricity in B.C., millions of $
TOTSL$ON	total expenditure on thermal electricity in Ontario, millions of $
TOTSL$PR	total expenditure on thermal electricity in Prairies, millions of $
TOTSL$QU	total expenditure on thermal electricity in Quebec, millions of $

TOT$	total expenditure on primary energy fuels (excluding fuels used to generate thermal elec) in Canada, millions of $
TOT$AT	total expenditure on primary energy fuels (excluding fuels used to generate thermal elec) in Atlantic, millions of $
TOT$BC	total expenditure on primary energy fuels (excluding fuels used to generate thermal elec) in B.C., millions of $
TOT$ON	total expenditure on primary energy fuels (excluding fuels used to generate thermal elec) in Ontario, millions of $
TOT$PR	total expenditure on primary energy fuels (excluding fuels used to generate thermal elec) in Prairies, millions of $
TOT$QU	total expenditure on primary energy fuels (excluding fuels used to generate thermal elec) in Quebec, millions of $

2. exogenous variables

name	description
DPETRO	demand for natural gas petrochemical feedstock
GPM.BC	natural gas distribution pipeline miles in B.C.
GPM.ON	natural gas distribution pipeline miles in Ontaric
GPM.PR	natural gas distribution pipeline miles in Prairies
GPM.QU	natural gas distribution pipeline miles in Quebec
PCW.AT	price of coal at the wellhead in Atlantic, $/ton
PCW.PR	price of coal at the wellhead in Prairies, $/ton
PCW.BC	price of coal at the wellhead in B.C., $/ton
PCW.US	price of U.S. coal at Ontario border, $/ton
PFX	price of foreign exchange, $ Canadian per $ U.S.
PGNE	price index for gross national expenditure, 1961=1.0
PGW.BC	price of natural gas at the wellhead in B.C., $/Mcf
PGW.PR	price of natural gas at the wellhead in Prairies, $/Mcf
PLR.AT	price of electricity at the retail level in Atlantic, $/thousand Kwh
PLR.BC	price of electricity at the retail level in B.C., $/thousand Kwh
PLR.ON	price of electricity at the retail level in Ontario, $/thousand Kwh
PLR.PR	price of electricity at the retail level in Prairies, $/thousand Kwh
PLR.QU	price of electricity at the retail level in Quebec, $/thousand Kwh
POW.PR	price of crude oil at the wellhead in Prairies, $/bbl
PO.OFF	price of offshore crude oil, $/bbl
QHL.AT	quantity of hydro electricity in Atlanttic, trillions of output Btu
QHL.BC	quantity of hydro electricity in B.C., trillions of output Btu
QHL.ON	quantity of hydro electricity in Ontario, trillions of output Btu
QHL.PR	quantity of hydro electricity in Prairies, trillions of output Btu
QHL.QU	quantity of hydro electricity in Quebec, trillions of output Btu
QOILREAT	quantity of petroleum re-exports from Atlantic, MMbbl
QOILREQU	quantity of petroleum re-exports from Quebec, MMbbl

UGNE real Canadian gross national expenditure, millions of 1961 $

3. coefficients

no.	value	name	description
1920	.75	PLCONV	factor used to convert from retail to city-gate price for electricity
1921	5.803	IN/UN.O	factor used to convert from natural units to input Btu for crude oil
1922	3.412	IN/UN.L	factor used to convert from natural units to input Btu units for electricity
1923	1.0	IN/UN.G	factor used to convert from natural units to input Btu for natural gas
1924	25.183	IN/UN.C.AT	factor used to convert from natural units to input Btu for coal in Atlantic
1925	25.511	IN/UN.C.QU	factor used to convert from natural units to input Btu for coal in Quebec
1926	25.417	IN/UN.C.ON	factor used to convert from natural units to input Btu for coal in Ontario
1927	14.919	IN/UN.C.PR	factor used to convert from natural units to input Btu for coal in Prairies
1928	24.340	IN/UN.C.BC	factor used to convert from natural units to input Btu for coal in B.C.
1929	1.0	OUT/IN.L	factor used to convert from input Btu to output Btu for electricity
1930	.607	OUT/IN.CAT	factor used to convert from input Btu to output Btu for coal in Atlantic
1931	.853	OUT/IN.CQU	factor used to convert from input Btu to output Btu for coal in Quebec
1932	.767	OUT/IN.CON	factor used to convert from input Btu to output Btu for coal in Ontario
1953	.607	OUT/IN.CPR	factor used to convert from input Btu to output Btu for coal in Prairies
1954	.796	OUT/IN.CBC	factor used to convert from input Btu to output Btu for coal in B.C.
1955	.495	OUT/IN.OAT	factor used to convert from input Btu to output Btu for crude oil in Atlantic
1956	.543	OUT/IN.OQU	factor used to convert from input Btu to output Btu for crude oil in Quebec
1957	.474	OUT/IN.OON	factor used to convert from input Btu to output Btu for crude oil in Ontario
1958	.315	OUT/IN.OPR	factor used to convert from input Btu to output Btu for crude oil in Prairies
1959	.426	OUT/IN.OBC	factor used to convert from input Btu to output Btu for crude oil in B.C.
1960	.814	OUT/IN.GQU	factor used to convert from input Btu to output Btu for natural gas in Quebec
1981	.810	OUT/IN.GON	factor used to convert from input Btu to output Btu for natural gas in Ontario
1982	.798	OUT/IN.GPR	factor used to convert from input Btu to output Btu for natural gas in Prairies
1983	.802	OUT/IN.GBC	factor used to convert from input Btu to output Btu for natural gas in B.C.

1984	.86	OUT/IN.OL	factor used to convert from input Btu to output Btu for crude oil used in generating thermal electricity
1985	.87	OUT/IN.CL	factor used to convert from input Btu to output Btu for coal used in generating thermal electricity
1986	.85	OUT/IN.GL	factor used to convert from input Btu to output Btu for natural gas used in generating thermal electricity
1987		PCT.AA	tariff to transport coal within Atlantic, $/ton
1988		PCT.AQ	tariff to transport coal from Atlantic to Quebec, $/ton
1989		PCT.USQ	tariff to transport coal from U.S. to Quebec, $/ton
1990		PCT.USO	tariff to transport coal from U.S. to Ontario, $/ton
1991		PCT.PP	tariff to transport coal within Prairies, $/ton
1992		PCT.BB	tariff to transport coal within B.C., $/ton
1993		POT.PO	tariff to transport cride oil from Prairies to Ontario, $/bbl
1994		POT.PP	tariff to transport crude oil within Prairies, $/bbl
1995		POT.PB	tariff to transport crude oil from Prairies to B.C., $/bbl
1996		POT.BB	tariff to transport crude oil within B.C., $/bbl
1997		PGT.PQ	tariff to transport natural gas from Prairies to Quebec, $/Mcf
1998		PGT.PO	tariff to transport natural gas from Prairies to Ontario, $/Mcf
1999		PGT.PP	tariff to transport natural gas within Prairies, $/Mcf
2000		PGT.BB	tariff to transport natural gas within B.C., $/Mcf
2001	.686751	PC61.AT	price of coal in Atlantic in 1961, $/million output Btu
2002	.987394	PO61.AT	price of crude oil in Atlantic in 1961, $/million output Btu
2003	3.64228	PL61.AT	price of electricity in Atlantic in 1961, $/million output Btu
2004	.607893	PC61.QU	price of coal in Quebec in 1961, $/million output Btu
2005	.964029	PO61.QU	price of crude oil in Quebec in 1961, $/million output Btu
2006	.544603	PG61.QU	price of natural gas in Quebec in 1961, $/million output Btu
2007	1.60243	PL61.QU	price of electricity in Quebec in 1961, $/million output Btu
2008	.470626	PC61.ON	price of coal in Ontario in 1961, $/million output Btu
2009	1.03761	PO61.ON	price of crude oil in Ontario in 1961, $/million output Btu
2010	.484769	PG61.ON	price of natural gas in Ontario in 1961, $/million output Btu

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2011 1.94534 PI61.CN    price of electricity in Ontario
                          in 1961, $/million output Btu
2012 .860738 PC61.PR    price of coal in Prairies
                          in 1961, $/million output Btu
2013 1.20075 PC61.PR    price of crude oil in Prairies
                          in 1961, $/million output Btu
2014 .186447 PG61.PR    price of natural gas in Prairies
                          in 1961, $/million output Btu
2015 3.04001 PI61.PR    price of electricity in Prairies
                          in 1961, $/million output Btu
2016 .751445 PC61.BC    price of coal in B.C. in 1961,
                          $/million output Btu
2017 1.07553 PO61.BC    price of crude oil in B.C.
                          in 1961, $/million output Btu
2018 .249456 PG61.BC    price of natural gas in B.C.
                          in 1961, $/million output Btu
2019 3.29060 PI61.BC    price of electricity in B.C.
                          in 1961, $/million output Btu
2020 .347               share of Quebec coal imported from Atlantic,
                          average of 1969 to 1972 values
2021                    first coefficient from estimated equations
...

2111                    last coefficient from estimated equations
2040 .04                growth of coal demand in Quebec after 1972
2041 .04                growth of coal demand in Ontario after 1972
2042 .04                growth of coal demand in Prairies after 1972
2043 .04                growth of coal demand in B.C. after 1972
2065 .04                growth of coal demand in Atlantic after 1972
2112 .045               growth of real Canadian GNE
2113 .04                growth of price index for GNE
2114 .08                growth of GPM.QU
2115 .04                growth of GPM.ON
2116 .03                growth of GPM.PR
2117 .04                growth of GPM.BC
2118 .20                growth of retail electricity prices after 1973
2119 .15                growth of retail electricity prices after 1976
2120 .04                growth of retail electricity prices after 1980
2121 .36                growth of coal wellhead prices after 1973
2122 .10                growth of coal wellhead prices after 1976
2123 .04                growth of coal wellhead prices after 1980
2124 .02                growth of hydro generated elec in Atlantic
2125 .04                growth of hydro generated elec in Quebec
2126 .02                growth of hydro generated elec in Ontario
2127 .02                growth of hydro generated elec in Prairies
2128 .03                growth of hydro generated elec in B.C.
2129 0.                  Indicates that price of crude oil in east
                          is based on foreign prices with no subsidy
     1.                 Indicates that federal subsidy to eastern
                          crude oil consumers is in effect
2130 0.                 'control' values for POW.PR, PGW.PR,
                          PGW.BC and A(1941) are used in model
     1.                 Read in PCW.PR; PGW.PR, PGW.BC and A(1941)
                          are set to 'control' value
     2.                 Read in PCW.PR; PGW.PR, PGW.BC are set to
                          'control' value; A(1941)=0
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      3.          Read in PGW.PR and PGW.BC; POW.PR and A(1941)
                    are set to 'control' value
      4.          Read in PGW.PR, PGW.BC, POW.PR ;
                    A(1941) is set to 'control' value
      5.          Read in PGW.PR, PGW.BC, POW.PR ; A(1941)=0.0
      6.          Read in POW.PR, A(1941) is set to 'control'
2131  0.          Use endogenous QGAS and QOIL in supply models
      1.          Use exogenous crude oil demand series
      2.          Use exogenous natural gas demand series
2137              adjustment to offshore oil price in GFSUBO
2140              used to select a policy experiment
```

1.B Non-frontier Natural Gas Production

1. endogenous variables

all variable names ending with $ are measured in millions of current $

name	description
CAN.REQ.	Canadian domestic demand, Tcf/yr
DEFICIT	excess of desired production over maximum, Bcf/d
EXPORTS	non-frontier gas exported, Tcf/yr
GASACUM	accumulated gas production in non-frontier regions, in Tcf
GASADD	non-frontier gas reserves coming into production, in Tcf/yr
GASADT	total non-frontier gas discoveries from 1973, in Tcf
GASCOSTM	marginal cost of non-frontier gas, in 1976 cents/Mcf
GASMAX	available production from non-frontier reserves, in Bcf/d
GASMAXA	available production from non-frontier sources, Tcf/yr
GASPLANT	expenditure on natural gas processing plants, millions 1961$
GASPRC	production from non-frontier reserves, in Bcf/d
KEDPNF$	stock of non-frontier expenditure depletable for tax
KRENTC1$	rents accruing to Canadian consumers of gas, millions $
KRENTC2$	rents accruing to U.S. consumers of Canadian gas, millions $
KRENTGAS	total rents accruing from natural gas production, millions $
KRENTNF$	rents to producers of non-frontier gas
KRNFGF$	rents accruing to federal government from non-frontier gas
KRNFGP$	rents accruing to provincial government from gas
PGASNF	wellhead price of non-frontier gas, in cents/Mcf
REDPA	rate of depletion allowance on non-frontier production
RENTCANT	total rents accruing to Canadians from frontier and non-frontier gas and the Mackenzie Valley pipeline
RESBASE	remaining stock of proven non-frontier reserves, both hooked-up and excess, in Tcf
RESCOST	cost of remaining stock of proven non-frontier reserves, in millions of 1961 $
RESDISCV	discoveries of new reserves of non-frontier gas, Tcf
RESEXCES	stock of excess reserves of non-frontier gas, Tcf
SUM	desired Canadian production, Tcf/yr
TCGASNF	corporation tax on non-frontier gas production, millions $
YGASNFT	taxable profits from non-frontier gas production, millions $

2. exogenous variables

name	description
DEMAND	Canadian domestic gas requirements, in Bcf/d
DEMANDA	optional series for overriding demand series, Bcf/yr
EGASD	Mackenzie gas production at upper end of pipeline, Bcf/d
EGASXD	delta gas sold for export, proportion of exports
EXCAPGAS	excess capacity in natural gas processing plants, Tcf
EXGASNF	non-frontier gas exported under approved contracts, Bcf/d
GASCADJ	estimation residuals for exploration and development costs
GASLADJ	estimation residuals for the land acquisition coefficient

GASMAX73	available production frcm pre-1972 hocked-up reserves, Bcf/d
GASOPADJ	estimaticn residuals for operating expenditure coefficient
GASPLADJ	estimaticn residuals for gas plant expenditure coefficient
GMAXA	optional series for overriding GASMAX73 series, Bcf/yr
PEXOG	price index equal to 2.11 in 1976, rising at 4% thereafter
PEXPORTG	price of natural gas exported to the U.S., cents/Mcf
PGAS	value of gas in central Canadian and U.S. market, cents/Mcf
PGASREG	regulated price cf gas in central Canadian market, cents/Mcf

3. coefficients

no.	value	description
1860		fraction of commodity value paid for natural gas in Toronto
1888	.43	marginal corporation income tax rate on gas production
1890	.0744	average real supply price of capital to business
1894	.0744	annual real social time preference rate
1895	.03	average real annual tax return on industrial capital
1901	42.	delivery cost from Alberta border tc Toronto, 1975 cents/Mcf
1902	.198	puts capital cost of new reserves on delivery basis
1904	.25	royalty/wellhead price of non-frontier gas
1906		land acquisition costs for non-frontier, 1961 cents/Mcf
1907		1907 and 1908 are coefficients in the cost function for
1908		discovery and development of new non-frontier reserves
1909		operating costs for gas production, 1961 cents/Mcf
1910	.05	initial gas flow as proportion of total recovery
1911		proportion of delta gas exported
1916	.2624	provincial share of corporation tax on gas production
1918	0.0	if >0 allows GASMAX73 to use all previous reserves
1919	114.	total stock of recoverable non-frontier gas, Tcf
1972	.04	the assumed rate of inflation
2136	.655	fraction of natural gas losses in excess of amount used to calculate marketable natural gas
2138		transport tariff to border for gas exports, cents/Mcf
2139		transport tariff to Chicago from border, cents/Mcf
2141	443.1	expenditure on natural gas plants, millions 1961$/Tcf

1.C Non-frontier Conventional Crude Oil Production

1. endogenous variables

name	description
CPROSUM	total production from oil sands plants, Mbbl/d
GFSUBO	federal government subsidy payments to eastern consumers of foreign crude oil, millions of $
KOILEDP$	stock of held over non-frontier depletable expenditure for taxation, millions of current $
KRENTOIL	total rents accruing from oil production, millions $
KROILC1$	rents accruing to Canadian consumers, millions $
KROILCAN	total rents accruing to Canadians from non-frontier oil production, millions $
KROILGF$	rents accruing to Canadian federal government from non-frontier oil production, millions of current $
KROILGP$	rents accruing to provincial governments from non-frontier oil production, millions of current $
KROILP$	rents accruing to producers of non-frontier oil, millions of current $
OILACUM	accumulated oil production in non-frontier regions, MMbbl
OILADD	oil reserves that are hooked-up for production, MMbbl
OILADT	total discoveries of oil from beginning of simulation, MMbbl
OILCAND	Canadian demand for crude oil, Mbbl/d
OILCOSTM	marginal cost of non-frontier oil, 1976 $/bbl
OILDEF	the deficit in oil supply minus oil demand, Mbbl/d
OILIMPT	imports of crude oil, Mbbl/d
OILLAG	OILADD lagged nine years
OILMAX	available production from non-frontier reserves, Mbbl/d
OILPIPEM	throughput of Montreal pipeline, Mbbl/d (- if westbound)
OILPRC	production demanded from non-frontier reserves, Mbbl/d
OILRBASE	remaining stock of proven non-frontier reserves, MMbbl
OILRCOST	cost of remaining stock of proven non-frontier reserves, millions of 1961 $
OILRDISC	discoveries of new reserves of non-frontier oil, MMbbl
OILREDPA	rate of avaiable depletion allowance on production
OILREXES	stock of excess reserves of non-frontier oil, MMbbl
OILSUM	sum of Canadian demand and net exports, Mbbl/d
OILXTOT	crude oil exports, Mbbl/d
RTOILEXP	tax rate on exports of crude oil, $/bbl
TCOILNF	corporation tax on oil production, millions of current $
TXOIL	federal government export tax revenue, millions current $
XBALGO$	current trade account balance for oil and gas, millions $
YOILNFT	taxable profits from oil production, millions of current $

2. exogenous variables

name	description
EXCESS	excess production given past hooked-up reserves

GCOSPRO	Great Canadian Oil Sands production, Mbbl/d
OILCADJ	estimation residuals for exploration and development costs
OILEXPT	non-frontier oil exported, Mbbl/d
OILLADJ	estimation residuals for the land acquisition coefficient
OILMAX74	production from pre-1974 hooked-up reserves, Mbbl/d
OILOPADJ	estimation residuals for operating expenditure coefficient
OILPROLD	oil production from pre-1973 hooked-up reserves
PEXOG	price index equal to 2.11 in 1976, rising at 4% thereafter
POILUS	price of crude oil in U.S. central market, $/bbl

3. coefficients

no.	value	description
1890	.0744	average real supply price of capital to business
1894	.0744	annual real social time preference rate
1895	.03	average real annual tax return on industrial capital
1933		slope of cost function for discovery and development
1934		intercept of linear cost function
1935	1.74	capital cost of new reserves on a delivery basis
1936		operating costs for oil production, 1961$/bbl
1937	19900.	ultimate non-frontier oil production, MMbbl
1938	.55	transport cost from U.S. east coast to U.S. mid-west, 1973$/bbl
1940	.50	transport cost from U.S. mid-west to prairies, 1973$/bbl
1941	250.	throughput of Montreal pipeline, Mbbl/d (+ if eastbound)
1942	.073	maximum oil flow as proportion of total recovery
1944		land acquiition costs for non-frontier region, 1961$/bbl
1945	.40	royalty/wellhead price on non-frontier oil
1946	.43	marginal corporate income tax rate on oil production
1947	.333	maximum rate of depletion allowance
1948		used to generate oilmax'k', where k is coefficient value
1949	.34	used as critical ratio to test if capacity increased
1950	.10	used as critical ratio to test if capacity increased
1951	.15	capacity increase in current period reserve addition
1952	.2624	provincial share of corporation tax on oil production

1.D Fuel Losses and Energy Supply Use

1. endogenous variables

name	description
LGASBC	natural gas losses and energy supply use in B.C., Bcf/yr
LGASON	natural gas losses and energy supply use in Ontario, Bcf/yr
LGASPR	natural gas losses and energy supply use in Prairies, Bcf/yr
LGASQU	natural gas losses and energy supply use in Quebec, Bcf/yr
LOSSGAS	natural gas losses and energy supply use in Canada, Bcf/yr
LOILAT	crude oil losses and energy supply use in Atlantic, MMbbl/yr
LOILBC	crude oil losses and energy supply use in B.C., MMbbl/yr
LOILON	crude oil losses and energy supply use in Ontario, MMbbl/yr
LOILPR	crude oil losses and energy supply use in Prairies, MMbbl/yr
LOILQU	crude oil losses and energy supply use in Quebec, MMbbl/yr
LOILEAST	crude oil losses and energy supply use east of the Ottawa valley line, MMbbl/yr
LOILWEST	crude oil losses and energy supply use west of the Ottawa valley line, MMbbl/yr
LOSSL.AT	electricity losses in Atlantic, trillion kwh
LOSSL.BC	electricity losses in B.C., trillion kwh
LOSSL.ON	electricity losses in Ontario, trillion kwh
LOSSL.PR	electricity losses in Prairies, trillion kwh
LOSSL.QU	electricity losses in Quebec, trillion kwh

2. coefficients

no.	value	description
2046	.0487	losses coefficient for crude oil in Atlantic
2047	.0804	losses coefficient for crude oil in Quebec
2050	.0889	losses coefficient for crude oil in Ontario
2056	.0883	losses coefficient for electricity in Atlantic
2057	.0921	losses coefficient for electricity in Quebec
2058	.0929	losses coefficient for electricity in Ontario
2059	.1416	losses coefficient for electricity in Prairies
2060	.0776	losses coefficient for electricity in B.C.
2066	.0985	losses coefficient for crude oil in Prairies
2069	.0500	losses coefficient for crude oil in B.C.
2074	-.0507	losses coefficient for natural gas in Quebec
2133	.0586	losses coefficient for natural gas in Ontario
2134	.1744	losses coefficient for natural gas in Prairies
2135	.2812	losses coefficient for natural gas in B.C.

2.A DEMAND SECTOR

DEMAND EQUATIONS FOR PRIMARY ENERGY PRODUCTS: GAS,OIL,ELECTRICITY AND COAL

1. EQUATIONS FOR ENDOGENOUS VARIABLES

```
DEFINE THE PRICES PER MILLION BTU FOR ALL OF THE FUELS IN EACH REGION
     PC.AT=(PCW.AT+PCT.AA)/(A(1924)*A(1930))
     PC.QU=(A(2020)*(PCW.AT+PCT.AQ)+(1.-A(2020))*
       (PC.US+PCT.USQ))/(A(1925)*A(1931))
     PC.ON=(PC.US+PCT.USO)/(A(1926)*A(1932))
     PC.PR=(PCW.PR+PCT.PP)/(A(1927)*A(1953))
     PC.BC=(PCW.BC+PCT.BB)/(A(1928)*A(1954))
     PO.AT=(PO.OFF-.1*(QO.QU/(QO.QU+QO.AT)))/(A(1921)*A(1955))
     PO.QU=(PO.OFF-.1*(QO.QU/(QO.QU+QO.AT))+.1)/(A(1921)*A(1956))

THE ATLANTIC AND QUEBEC CRUDE OIL PRICE CAN BE SUBSIDIZED FROM 1974
     IF A(2129)=1 AND NTIME>=74 THEN
       PO.AT=(POW.PR+POT.PO)/(A(1921)*A(1957))
     IF A(2129)=1 AND NTIME>=74 THEN
       PO.QU=(POW.PR+POT.PO)/(A(1921)*A(1957))
     PO.ON=(POW.PR+POT.PO)/(A(1921)*A(1957))
     PO.PR=(POW.PR+POT.PP)/(A(1921)*A(1958))
     PO.BC=(POW.PR+POT.PB)/(A(1921)*A(1959))
     PG.QU=(PGW.PR+PGT.PQ)/(A(1923)*A(1960))
     PG.ON=(PGW.PR+PGT.PO)/(A(1923)*A(1981))
     PG.PR=(PGW.PR+PGT.PP)/(A(1923)*A(1982))

THE NATURAL GAS PRICE IN THE PRAIRIES IS DISCOUNTED FROM 1975
     IF NTIME=75 THEN  PG.PR=PG.PR*.97
     IF NTIME=76 THEN  PG.PR=PG.PR*.75
     IF NTIME=77 THEN  PG.PR=PG.PR*.65
     IF NTIME=78 THEN  PG.PR=PG.PR*.60
     IF NTIME=79 THEN  PG.PR=PG.PR*.57
     IF NTIME>=80 THEN  PG.PR=PG.PR*.55
     PG.BC=(PGW.BC+PGT.BB)/(A(1923)*A(1983))
     PL.AT=(A(1920)*PLR.AT)/A(1922)
     PL.QU=(A(1920)*PLR.QU)/A(1922)
     PL.ON=(A(1920)*PLR.ON)/A(1922)
     PL.PR=(A(1920)*PLR.PR)/A(1922)
     PL.BC=(A(1920)*PLR.BC)/A(1922)

THE VARIABLES REPRESENT THE CURRENT $ EXPENDITURE FOR ENERGY BY REGION
     T$AT=PO.AT*QO.AT+PL.AT*QL.AT
     T$QU=PO.QU*QO.QU+PG.QU*QG.QU+PL.QU*QL.QU
     T$ON=PO.CN*QO.ON+PG.ON*QG.ON+PL.ON*QL.CN
     T$PR=PO.PR*QO.PR+PG.PR*QG.PR+PL.PR*QL.PR
     T$BC=PO.BC*QO.BC+PG.BC*QG.BC+PL.BC*QL.BC

CALCULATE A PASCHE PRICE INDEX FOR ENERGY IN EACH REGION
     PEN.AT=T$AT/(PO61.AT*QO.AT+PL61.AT*QL.AT)
     PEN.QU=T$QU/(PO61.QU*QO.QU+PG61.QU*QG.QU+PL61.QU*QL.QU)
     PEN.ON=T$CN/(PO61.ON*QO.CN+PG61.ON*QG.ON+PI61.CN*QL.ON)
     PEN.PR=T$PR/(PO61.PR*QO.PR+PG61.PR*QG.PR+PL61.PR*QL.PR)
     PEN.BC=T$BC/(PO61.BC*QO.BC+PG61.BC*QG.BC+PL61.BC*QL.BC)

CALCULATE THE CURRENT $ EXPENDITURE FOR ENERGY BY REGION AND FOR CANADA
      TOT$AT=PEN.AT*EXP(A(2021)+A(2072)*ALOG(UGNE)
```

```
      +A(2073)*ALOG(.33333*PEN.AT/PGNE
      +.33333*J1L*PEN.AT/J1L*PGNE+.33333*J2L*PEN.AT/J2L*PGNE)
      +TEMP(TOT$AT))
    TOT$QU=PEN.QU*EXP(A(2022)+A(2026)*ALOG(UGNE)+A(2027)*
      ALOG(.15*PEN.QU/PGNE+.35*J1L*PEN.QU/J1L*PGNE
      +.35*J2L*PEN.QU/J2L*PGNE+.15*J3L*PEN.QU/J3L*PGNE)
      +TEMP(TOT$QU))
    TOT$ON=PEN.ON*EXP(A(2023)+A(2026)*ALOG(UGNE)+A(2027)*
      ALOG(.15*PEN.ON/PGNE+.35*J1L*PEN.ON/J1L*PGNE
      +.35*J2L*PEN.ON/J2L*PGNE+.15*J3L*PEN.ON/J3L*PGNE)
      +TEMP(TOT$ON))
    TOT$PR=PEN.PR*EXP(A(2024)+A(2026)*ALOG(UGNE)+A(2027)*
      ALOG(.15*PEN.PR/PGNE+.35*J1L*PEN.PR/J1L*PGNE
      +.35*J2L*PEN.PR/J2L*PGNE+.15*J3L*PEN.PR/J3L*PGNE)
      +TEMP(TOT$PR))
    TOT$BC=PEN.BC*EXP(A(2025)+A(2026)*ALOG(UGNE)+A(2027)*
      ALOG(.15*PEN.BC/PGNE+.35*J1L*PEN.BC/J1L*PGNE
      +.35*J2L*PEN.BC/J2L*PGNE+.15*J3L*PEN.BC/J3L*PGNE)
      +TEMP(TOT$BC))
  TOT$=(TOT$AT+TOT$QU+TOT$CN+TOT$PR+TOT$BC)

CALCULATE THE MOVING WEIGHTED FUEL PRICES BY REGION
  JWPCAT=.33333*PC.AT+.33333*J1L*PC.AT+.33333*J2L*PC.AT
  JWPOAT=.33333*PO.AT+.33333*J1L*PO.AT+.33333*J2L*PO.AT
  JWPOQU=.15*PO.QU+.35*J1L*PO.QU+.35*J2L*PO.QU+.15*J3L*PO.QU
  JWPOCN=.15*PO.ON+.35*J1L*PO.ON+.35*J2L*PO.ON+.15*J3L*PO.ON
  JWPOPR=.15*PO.PR+.35*J1L*PO.PR+.35*J2L*PO.PR+.15*J3L*PO.PR
  JWPOBC=.15*PO.BC+.35*J1L*PO.BC+.35*J2L*PO.BC+.15*J3L*PO.BC
  JWPGQU=.15*PG.QU+.35*J1L*PG.QU+.35*J2L*PG.QU+.15*J3L*PG.QU
  JWPGON=.15*PG.ON+.35*J1L*PG.ON+.35*J2L*PG.ON+.15*J3L*PG.ON
  JWPGPR=.15*PG.PR+.35*J1L*PG.PR+.35*J2L*PG.PR+.15*J3L*PG.PR
  JWPGBC=.15*PG.BC+.35*J1L*PG.BC+.35*J2L*PG.BC+.15*J3L*PG.BC
  JWPLAT=.33333*PL.AT+.33333*J1L*PL.AT+.33333*J2L*PL.AT
  JWPLQU=.15*PL.QU+.35*J1L*PL.QU+.35*J2L*PL.QU+.15*J3L*PL.QU
  JWPLCN=.15*PL.ON+.35*J1L*PL.ON+.35*J2L*PL.ON+.15*J3L*PL.ON
  JWPLPR=.15*PL.PR+.35*J1L*PL.PR+.35*J2L*PL.PR+.15*J3L*PL.PR
  JWPLBC=.15*PL.BC+.35*J1L*PL.BC+.35*J2L*PL.BC+.15*J3L*PL.BC

CALCULATE THE QUANTITIES OF FUEL (IN TRILLION BTU) DEMANDED BY REGION
  QG.QU=TOT$QU/PG.QU*(A(2028)
    +A(2044)*ALOG(JWPOQU)+A(2061)*ALOG(JWPGQU)
    +A(2045)*ALOG(JWPLQU)+A(2054)*1E-5*GPM.QU
    +TEMP(QG.QU))
  QO.QU=TOT$QU/PO.QU*(A(2032)
    +A(2048)*ALOG(JWPOQU)+A(2044)*ALOG(JWPGQU)
    +A(2049)*ALOG(JWPLQU)+A(2055)*1E-5*GPM.QU
    +TEMP(QO.QU))
  QL.QU=TOT$QU/PL.QU*(A(2036)
    +A(2051)*ALOG(JWPOQU)+A(2052)*ALOG(JWPGQU)
    +A(2053)*ALOG(JWPLQU)+A(2062)*1E-5*GPM.QU
    +TEMP(QL.QU))
  IF NTIME>72 THEN  QC.QU=(1.+A(2040))*J1L*QC.QU
  QG.CN=TOT$ON/PG.CN*(A(2029)
    +A(2044)*ALOG(JWPOON)+A(2061)*ALOG(JWPGON)
    +A(2045)*ALOG(JWPLCN)+A(2054)*1E-5*GPM.ON
    +TEMP(QG.ON))
  QO.ON=TOT$ON/PO.CN*(A(2033)
    +A(2048)*ALOG(JWPOCN)+A(2044)*ALOG(JWPGON)
    +A(2049)*ALOG(JWPLCN)+A(2055)*1E-5*GPM.ON
    +TEMP(QO.ON))
```

```
      QL.CN=TOT$ON/PL.CN*(A(2037)
        +A(2051)*ALOG(JWPOON)+A(2052)*ALOG(JWPGON)
        +A(2053)*ALOG(JWPLON)+A(2062)*1E-5*GPM.ON
        +TEMP(QL.ON))
      IF NTIME>72 THEN  QC.ON=(1.+A(2041))*J1L*QC.ON
      QG.PR=TOT$PR/PG.PR*(A(2030)
        +A(2044)*ALOG(JWPOPR)+A(2061)*ALOG(JWPGPR)
        +A(2045)*ALOG(JWPLPR)+A(2054)*1E-5*GPM.PR
        +TEMP(QG.PR))
      QO.PR=TOT$PR/PO.PR*(A(2034)
        +A(2048)*ALOG(JWPOPR)+A(2044)*ALOG(JWPGPR)
        +A(2049)*ALOG(JWPLPR)+A(2055)*1E-5*GPM.PR
        +TEMP(QO.PR))
      QL.PR=TOT$PR/PL.PR*(A(2038)
        +A(2051)*ALOG(JWPOPR)+A(2052)*ALOG(JWPGPR)
        +A(2053)*ALOG(JWPLPR)+A(2062)*1E-5*GPM.PR
        +TEMP(QL.PR))
      IF NTIME>72 THEN  QC.PR=(1.+A(2042))*J1L*QC.PR
      QG.BC=TOT$BC/PG.BC*(A(2031)
        +A(2044)*ALOG(JWPOBC)+A(2061)*ALOG(JWPGBC)
        +A(2045)*ALOG(JWPLBC)+A(2054)*1E-5*GPM.BC
        +TEMP(QG.BC))
      QO.BC=TOT$BC/PO.BC*(A(2035)
        +A(2048)*ALOG(JWPOBC)+A(2044)*ALOG(JWPGBC)
        +A(2049)*ALOG(JWPLBC)+A(2055)*1E-5*GPM.BC
        +TEMP(QO.BC))
      QL.BC=TOT$BC/PL.BC*(A(2039)
        +A(2051)*ALOG(JWPOBC)+A(2052)*ALOG(JWPGBC)
        +A(2053)*ALOG(JWPLBC)+A(2062)*1E-5*GPM.BC
        +TEMP(QL.BC))
      IF NTIME>72 THEN  QC.BC=(1.+A(2043))*J1L*QC.BC
      QO.AT=TOT$AT/PO.AT*(A(2063)
        +A(2067)*ALOG(JWPOAT)+A(2068)*ALOG(JWPLAT)
        +TEMP(QO.AT))
      QL.AT=TOT$AT/PL.AT*(A(2064)
        +A(2070)*ALOG(JWPOAT)+A(2071)*ALOG(JWPLAT)
        +TEMP(QL.AT))
      IF NTIME>72 THEN  QC.AT=(1.+A(2065))*J1L*QC.AT

CALCULATE THE QUANTITY OF SECONDARY ELECTRICITY DEMANDED AS A RESIDUAL
      QSL.AT=QL.AT+A(1922)*LOSSL.AT-QHL.AT
      IF QSL.AT<=0.0 THEN  QSL.AT=1.0E-30
      QSL.QU=QL.QU+A(1922)*LOSSL.QU-QHL.QU
      IF QSL.QU<=0.0 THEN  QSL.QU=1.0E-30
      QSL.ON=QL.ON+A(1922)*LOSSL.ON-QHL.ON
      IF QSL.CN<=0.0 THEN  QSL.ON=1.0E-30
      QSL.PR=QL.PR+A(1922)*LOSSL.PR-QHL.PR
      IF QSL.PR<=0.0 THEN  QSL.PR=1.0E-30
      QSL.BC=QL.BC+A(1922)*LOSSL.BC-QHL.BC
      IF QSL.BC<=0.0 THEN  QSL.BC=1.0E-30

CALCULATE THE CURRENT $ EXPENDITURE (MILLIONS) FOR THERMAL ELECTRICITY
      TOTSL$AT=PL.AT*QSL.AT
      TOTSL$QU=PL.QU*QSL.QU
      TOTSL$ON=PL.ON*QSL.ON
      TOTSL$PR=PL.PR*QSL.PR
      TOTSL$BC=PL.BC*QSL.BC
      TOTSL$=(TOTSL$AT+TOTSL$QU+TOTSL$CN+TOTSL$PR+TOTSL$BC)

CALCULATE THE CURRENT $ EXPENDITURE  FOR FUELS TO GENERATE  ELECTRICITY
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```
      TEL$AT=.000001*EXP(A(2075)+A(2080)*ALOG(1000000.*TOTSL$AT)
        +TEMP(TEL$AT))
      TEL$QU=.000001*EXP(A(2076)+A(2080)*ALOG(1000000.*TOTSL$QU)
        +TEMP(TEL$QU))
      TEL$ON=.000001*EXP(A(2077)+A(2080)*ALOG(1000000.*TOTSL$ON)
        +TEMP(TEL$ON))
      TEL$PR=.000001*EXP(A(2078)+A(2080)*ALOG(1000000.*TOTSL$PR)
        +TEMP(TEL$PR))
      TEL$BC=.000001*EXP(A(2079)+A(2080)*ALOG(1000000.*TOTSL$BC)
        +TEMP(TEL$BC))
      TEL$=(TEL$AT+TEL$QU+TEL$ON+TEL$PR+TEL$BC)

C CALCULATE THE FUEL PRICES IN $ PER MILLION OUTPUT BTU
      PCLAT=PC.AT*(A(1930)/A(1985))
      PCLQU=PC.QU*(A(1931)/A(1985))
      PCLON=PC.ON*(A(1932)/A(1985))
      PCLPR=PC.PR*(A(1953)/A(1985))
      POLAT=PO.AT*(A(1955)/A(1984))
      POLQU=PO.QU*(A(1956)/A(1984))
      POLON=PO.ON*(A(1957)/A(1984))
      POLPR=PO.PR*(A(1958)/A(1984))
      POLBC=PO.BC*(A(1959)/A(1984))
      PGLQU=PG.QU*(A(1960)/A(1986))
      PGLON=PG.ON*(A(1981)/A(1986))
      PGLPR=PG.PR*(A(1982)/A(1986))
      PGLBC=PG.BC*(A(1983)/A(1986))

C CALCULATE THE QUANTITY OF FUELS USED IN GENERATING THERMAL ELECTRICITY
      QGL.QU=0.0
      QOL.QU=TEL$QU/POLQU*(A(2084)+A(2100)*ALOG(PCLQU)
        +A(2101)*ALOG(POLQU)+TEMP(QOL.QU))
      QCL.QU=TEL$QU/PCLQU*(A(2087)+A(2103)*ALOG(PCLQU)
        +A(2104)*ALOG(POLQU)+TEMP(QCL.QU))
      QGL.ON=TEL$ON/PGLON*(A(2082)+A(2090)*ALOG(PCLON)
        +A(2091)*ALOG(POLON)+A(2092)*ALOG(PGLON)+TEMP(QGL.ON))
      QOL.ON=TEL$ON/POLON*(A(2085)+A(2093)*ALOG(PCLON)
        +A(2094)*ALOG(POLON)+A(2095)*ALOG(PGLON)+TEMP(QOL.ON))
      QCL.ON=TEL$ON/PCLON*(A(2088)+A(2096)*ALOG(PCLON)
        +A(2097)*ALOG(POLON)+A(2098)*ALOG(PGLON)+TEMP(QCL.ON))
      QGL.PR=TEL$PR/PGLPR*(A(2083)+A(2090)*ALOG(PCLPR)
        +A(2091)*ALOG(POLPR)+A(2092)*ALOG(PGLPR)+TEMP(QGL.PR))
      QOL.PR=TEL$PR/POLPR*(A(2086)+A(2093)*ALOG(PCLPR)
        +A(2094)*ALOG(POLPR)+A(2095)*ALOG(PGLPR)+TEMP(QOL.PR))
      QCL.PR=TEL$PR/PCLPR*(A(2089)+A(2096)*ALOG(PCLPR)
        +A(2097)*ALOG(POLPR)+A(2098)*ALOG(PGLPR)+TEMP(QCL.PR))
      QOL.AT=TEL$AT/POLAT*(A(2099)+A(2100)*ALOG(PCLAT)+A(2101)*ALOG(POLAT)
        +TEMP(QOL.AT))
      QCL.AT=TEL$AT/PCLAT*(A(2102)+A(2103)*ALOG(PCLAT)+A(2104)*ALOG(POLAT)
        +TEMP(QCL.AT))
      QGL.BC=TEL$BC/PGLBC*(A(2107)+A(2111)*ALOG(POLBC)
        +A(2110)*ALOG(PGLBC)+A(2108)*ALOG(GPM.BC)+TEMP(QGL.BC))
      QOL.BC=TEL$BC/POLBC*(A(2105)+A(2109)*ALOG(POLBC)
        +A(2111)*ALOG(PGLBC)+A(2106)*ALOG(GPM.BC)+TEMP(QOL.BC))

C TABULATE THE TOTAL OUTPUT BTU DEMANDED FOR EACH REGION AND FOR CANADA
      OBTU.AT=(QC.AT+QO.AT+QL.AT)
      OBTU.QU=(QC.QU+QO.QU+QG.QU+QL.QU)
      OBTU.ON=(QC.ON+QO.ON+QG.ON+QL.ON)
      OBTU.PR=(QC.PR+QO.PR+QG.PR+QL.PR)
      OBTU.BC=(QC.BC+QO.BC+QG.BC+QL.BC)
```

```
      OBTU=(OBTU.AT+OBTU.QU+OBTU.ON+OBTU.PR+CBTU.BC)

TABULATE THE TOTAL OUTPUT BTU DEMANDED FOR EACH FUEL ACROSS ALL REGIONS
      OBTU.C=(QC.AT+QC.QU+QC.ON+QC.PR+QC.BC
        +QCL.AT+QCL.QU+QCL.ON+QCL.PR)
      OBTU.O=(QO.AT+QO.QU+QO.ON+QO.PR+QO.BC
        +QOL.AT+QOL.QU+QOL.CN+QCL.PR+QCL.BC)
      OBTU.G=(QG.QU+QG.ON+QG.PR+QG.BC+QGL.QU
        +QGL.CN+QGL.PR+QGL.BC)
      OBTU.L=(QL.AT+QL.QU+QL.ON+QL.PR+QL.BC)

CALCULATE THE QUANTITIES OF EACH FUEL DEMANDED IN NATURAL UNITS

QUANTITY OF COAL DEMANDED IN MILLIONS OF TONS
      QCOAL=(QC.AT/(A(1930)*A(1924))+QC.QU/(A(1931)*A(1925))
        +QC.ON/(A(1932)*A(1926))+QC.PR/(A(1953)*A(1927))
        +QC.BC/(A(1954)*A(1928))+QCL.AT/(A(1985)*A(1924))
        +QCL.QU/(A(1985)*A(1925))+QCL.ON/(A(1985)*A(1926))
        +QCL.PR/(A(1985)*A(1927)))

QUANTITY OF NATURAL GAS DEMANDED IN BCF
      QGAS=(QG.QU/(A(1960)*A(1923))+QG.ON/(A(1981)*A(1923))
        +QG.PR/(A(1982)*A(1923))+QG.BC/(A(1983)*A(1923))
        +QGL.QU/(A(1986)*A(1923))+QGL.ON/(A(1986)*A(1923))
        +QGL.PR/(A(1986)*A(1923))+QGL.BC/(A(1986)*A(1923)))
        +DPETRC

QUANTITY OF ELECTRICITY DEMANDED IN MILLIONS OF KWH
      QELEC=1000.*(QL.AT/A(1922)+QL.QU/A(1922)+QL.ON/A(1922)
        +QL.PR/A(1922)+QL.BC/A(1922))

QUANTITY OF CRUDE OIL DEMANDED IN THE EAST, WEST AND CANADA IN MILLIONS BBL
      QOILEAST=(QO.AT/(A(1955)*A(1921))+QO.QU/(A(1956)*A(1921))
        +QOL.AT/(A(1984)*A(1921))+QOL.QU/(A(1984)*A(1921)))
      QOILWEST=(QO.ON/(A(1957)*A(1921))+QO.PR/(A(1958)*A(1921))
        +QO.BC/(A(1959)*A(1921))+QOL.ON/(A(1984)*A(1921))
        +QOL.PR/(A(1984)*A(1921))+QOL.BC/(A(1984)*A(1921)))
      QOIL=QOILEAST+QOILWEST

CALCULATE THE SUBSIDY PAYMENTS MADE TO EASTERN OIL CONSUMERS
      QOILAT=QC.AT/(A(1955)*A(1921))+QOL.AT/(A(1984)*A(1921))+QOILREAT
      QOILQU=QC.QU/(A(1956)*A(1921))+QOL.QU/(A(1984)*A(1921))+QOILREQU
      GFSUBO=QOILAT*(PC.OFF+A(2137)-.1*(QO.QU/(QO.QU+QO.AT))
        -(POW.PR+POT.PO))+(QOILQU-.365*A(1941))*
        (PC.OFF+A(2137)-.1*(QO.QU/(QO.QU+QO.AT))+.1
        -(POW.PR+POT.PO))
        +LOILEAST*(PO.OFF+A(2137)-(POW.PR+POT.PO))
      IF NTIME<=73 THEN  GFSUBO=0.0
      IF GFSUBO<0.0 THEN  GFSUBO=0.0
```

2. EQUATIONS FOR EXOGENOUS VARIABLES

```
 SET TRANSPORTATION COEFFICIENTS FOR ALL FUELS
    IF NTIME=69 THEN  PCT.AA=1.90
    IF NTIME=70 THEN  PCT.AA=1.61
    IF NTIME=71 THEN  PCT.AA=2.50
    IF NTIME>=73 THEN  PCT.AA=2.50*PEXOG/1.56
    PCT.AQ=3.20
    IF NTIME>=73 THEN  PCT.AQ=3.20*PEXOG/1.56
    PCT.USQ=4.70
    IF NTIME>=73 THEN  PCT.USQ=4.70*PEXOG/1.56
    PCT.USO=3.50
    IF NTIME>=73 THEN  PCT.USO=3.50*PEXOG/1.56
    PCT.PP=4.20
    IF NTIME>=73 THEN  PCT.PP=4.20*PEXOG/1.56
    IF NTIME=69 THEN  PCT.BB=5.03
    IF NTIME=70 THEN  PCT.BB=3.96
    IF NTIME=71 THEN  PCT.BB=3.60
    IF NTIME>=73 THEN  PCT.BB=3.60*PEXOG/1.56
    POT.PO=.51
    IF NTIME>75 THEN  POT.PO=.51*(PEXOG/1.95)
    POT.PP=.10
    IF NTIME>75 THEN  POT.PP=.10*(PEXOG/1.95)
    POT.PB=.40
    IF NTIME>75 THEN  POT.PB=.40*(PEXOG/1.95)
    POT.BB=.59
    IF NTIME>75 THEN  POT.BB=.59*(PEXOG/1.95)
    PGT.PO=.30
    IF NTIME=73 THEN  PGT.PO=.35
    IF NTIME>=74 THEN  PGT.PO=1.16*.01*A(1901)*(PEXOG/1.95)
    PGT.PQ=.36
    IF NTIME>=73 THEN  PGT.PQ=PGT.PO+.06*PEXOG/1.95
    PGT.PP=.04
    IF NTIME>75 THEN  PGT.PP=.04*(PEXOG/1.95)
    PGT.BB=.12
    IF NTIME>=73 THEN  PGT.BB=.20
    IF NTIME>75 THEN  PGT.BB=.20*(PEXOG/1.95)

DECREASE GROWTH IN GAS DISTRIBUTION PIPELINE MILES
    IF NTIME>=83 THEN  A(2114)=.75*A(2114)
    IF NTIME>=81 THEN  A(2115)=.75*A(2115)
    IF NTIME>=83 THEN  A(2116)=.75*A(2116)
    IF NTIME>=83 THEN  A(2117)=.75*A(2117)

SET UGNE AND PGNE
    IF NTIME=75 THEN  UGNE=J1L*UGNE*(1.002)
    IF NTIME>75 THEN  UGNE=J1L*UGNE*(1.054)
    IF NTIME>81 THEN  UGNE=J1L*UGNE*(1.+A(2112))
    IF NTIME=75 THEN  PGNE=J1L*PGNE*1.1017
    IF NTIME=76 THEN  PGNE=J1L*PGNE*1.082
    IF NTIME=77 THEN  PGNE=J1L*PGNE*1.06
    IF NTIME>77 THEN  PGNE=J1L*PGNE*(1.+A(2113))

DETERMINE THE GAS DISTRIBUTION PIPELINE MILES
    IF NTIME>74 THEN  GPM.QU=J1L*GPM.QU*(1.+A(2114))
    IF NTIME>74 THEN  GPM.ON=J1L*GPM.ON*(1.+A(2115))
    IF NTIME>74 THEN  GPM.PR=J1L*GPM.PR*(1.+A(2116))
    IF NTIME>74 THEN  GPM.BC=J1L*GPM.BC*(1.+A(2117))
```

```
 DETERMINE THE VALUES FOR THE RETAIL PRICE OF ELECTRICITY
      IF NTIME>73 THEN  PLR.AT=J1L*PLR.AT*(1.30)
      IF NTIME>76 THEN  PLR.AT=J1L*PLR.AT*(1.+A(2119))
      IF NTIME>80 THEN  PLR.AT=J1L*PLR.AT*(1.+A(2120))
      IF NTIME>73 THEN  PLR.QU=J1L*PLR.QU*(1.+A(2118))
      IF NTIME>76 THEN  PLR.QU=J1L*PLR.QU*(1.+A(2119))
      IF NTIME>80 THEN  PLR.QU=J1L*PLR.QU*(1.+A(2120))
      IF NTIME>73 THEN  PLR.ON=J1L*PLR.ON*(1.+A(2118))
      IF NTIME>76 THEN  PLR.ON=J1L*PLR.ON*(1.+A(2119))
      IF NTIME>80 THEN  PLR.ON=J1L*PLR.ON*(1.+A(2120))
      IF NTIME>73 THEN  PLR.PR=J1L*PLR.PR*(1.+A(2118))
      IF NTIME>76 THEN  PLR.PR=J1L*PLR.PR*(1.+A(2119))
      IF NTIME>80 THEN  PLR.PR=J1L*PLR.PR*(1.+A(2120))
      IF NTIME>73 THEN  PLR.BC=J1L*PLR.BC*(1.+A(2118))
      IF NTIME>76 THEN  PLR.BC=J1L*PLR.BC*(1.+A(2119))
      IF NTIME>80 THEN  PLR.BC=J1L*PLR.BC*(1.+A(2120))

 DETERMINE THE COAL PRICES AT THE WELLHEAD AND THE US IMPORT PRICE
      IF NTIME>73 THEN  PCW.AT=J1L*PCW.AT*(1.+A(2121))
      IF NTIME>76 THEN  PCW.AT=J1L*PCW.AT*(1.+A(2122))
      IF NTIME>80 THEN  PCW.AT=J1L*PCW.AT*(1.+A(2123))
      IF NTIME>73 THEN  PCW.PR=J1L*PCW.PR*(1.62)
      IF NTIME>76 THEN  PCW.PR=J1L*PCW.PR*(1.+A(2122))
      IF NTIME>80 THEN  PCW.PR=J1L*PCW.PR*(1.+A(2123))
      IF NTIME>73 THEN  PCW.BC=J1L*PCW.BC*(1.52)
      IF NTIME>76 THEN  PCW.BC=J1L*PCW.BC*(1.+A(2122))
      IF NTIME>80 THEN  PCW.BC=J1L*PCW.BC*(1.+A(2123))
      IF NTIME>73 THEN  PC.US=J1L*PC.US*(1.+A(2121))
      IF NTIME>76 THEN  PC.US=J1L*PC.US*(1.+A(2122))
      IF NTIME>80 THEN  PC.US=J1L*PC.US*(1.+A(2123))

  DETERMINE THE LANDED PRICE OF OFFSHORE CRUDE OIL
      IF NTIME=75 THEN  PO.OFF=PFX*A(1974)
      IF NTIME=76 THEN  A(1974)=13.00
      IF NTIME=76 THEN  PO.OFF=PFX*A(1974)
      IF NTIME>76 THEN  PO.OFF=PFX*J1L*PO.OFF*(1.+A(1972))*(1.+A(1973))
      IF A(2130)=6 THEN  GO TO 11
      IF A(2130)>=4 THEN  GO TO 20
      IF A(2130)=1 OR A(2130)=2 THEN  GO TO 10

 DETERMINE THE WELLHEAD PRICE OF CRUDE CIL IN PRAIRIES
      IF NTIME=75 THEN  POW.PR=7.25
      IF NTIME=76 THEN  POW.PR=8.53
      IF NTIME=77 THEN  POW.PR=10.25
      IF NTIME=78 THEN  POW.PR=11.75
      IF NTIME=79 THEN  POW.PR=13.25
      IF NTIME>=80 THEN  POW.PR=PO.OFF-POT.PO
10    IF A(2130)=3 THEN  GO TO 20

 DETERMINE THE WELLHEAD PRICE OF NATURAL GAS IN PRAIRIES AND BC
11    IF NTIME>=76 THEN  PGASREG=100.*A(1860)*(POW.PR+POT.PO)/A(1921)
      IF NTIME>=74 THEN  PGW.PR=.01*PGASREG-PGT.PO
      IF A(2130)=6 THEN  GO TO 20
      IF NTIME=75 THEN  PGW.BC=.255
      IF NTIME=76 THEN  PGW.BC=J1L*PGW.BC*1.40
      IF NTIME>76 THEN  PGW.BC=J1L*PGW.BC*1.20
      IF NTIME>78 THEN  PGW.BC=J1L*PGW.BC*1.15
      IF NTIME>80 THEN  PGW.BC=J1L*PGW.BC*(1.06)
20    IF A(2130)=2 OR A(2130)=5 THEN  A(1941)=0.0
```

```
DETERMINE THE QUANTITES OF HYDRO ELECTRICITY AVAILABLE IN EACH REGION
    IF NTIME>74 THEN  QHL.AT=J1L*QHL.AT*(1.+A(2124))
    IF NTIME>74 THEN  QHL.QU=J1L*QHL.QU*(1.+A(2125))
    IF NTIME>74 THEN  QHL.ON=J1L*QHL.ON*(1.+A(2126))
    IF NTIME>74 THEN  QHL.PR=J1L*QHL.PR*(1.+A(2127))
    IF NTIME>74 THEN  QHL.BC=J1L*QHL.BC*(1.+A(2128))

 ALLOW FOR SHIFT IN BC AND PRAIRIES AWAY FROM DIESEL FUEL
    IF NTIME>73 THEN  A(1958)=A(1958)*(.47/A(1958))**.2
    IF NTIME>73 THEN  A(1959)=A(1959)*(.47/A(1959))**.2

ALLOW FOR EXTRA SUBSIDY PAYMENTS FROM 1976 TO 1980
    IF NTIME=75 THEN  A(2137)=.45
    IF NTIME>=76 THEN  A(2137)=.30*(PO.OFF-POW.PR-POT.PO)/4.00
```

```
3. THE FOLLOWING ARE THE 'TEMP' ADJUSTMENTS TO THE ESTIMATED EQUATIONS
    IF NTIME=69 THEN  TEMP(QG.QU)=+.00499
    IF NTIME=70 THEN  TEMP(QG.QU)=+.00192
    IF NTIME=71 THEN  TEMP(QG.QU)=+.000185
    IF NTIME=72 THEN  TEMP(QG.QU)=-.00108
    IF NTIME>=73 THEN  TEMP(QG.QU)=-.000628
    IF NTIME>=74 THEN  TEMP(QG.QU)=0.0
    IF NTIME>=75 THEN  TEMP(QG.QU)=+.005+.01*(1.-1./EXP((NTIME-75)/4.))
    IF NTIME=69 THEN  TEMP(QO.QU)=-.0277
    IF NTIME=70 THEN  TEMP(QC.QU)=-.0343
    IF NTIME=71 THEN  TEMP(QC.QU)=+.00882
    IF NTIME=72 THEN  TEMP(QC.QU)=+.0311
    IF NTIME>=73 THEN  TEMP(QO.QU)=+.0549
    IF NTIME>=74 THEN  TEMP(QC.QU)=+.11
    IF NTIME>=75 THEN  TEMP(QO.QU)=+.095-.04*(1.-1./EXP((NTIME-75)/4.))
    IF NTIME=69 THEN  TEMP(QL.QU)=+.0227
    IF NTIME=70 THEN  TEMP(QL.QU)=+.0324
    IF NTIME=71 THEN  TEMP(QL.QU)=-.00900
    IF NTIME=72 THEN  TEMP(QL.QU)=-.0301
    IF NTIME>=73 THEN  TEMP(QL.QU)=-.0542
    IF NTIME>=74 THEN  TEMP(QL.QU)=-.11
    IF NTIME>=75 THEN  TEMP(QL.QU)=-.10+.03*(1.-1./EXP((NTIME-75)/4.))
    IF NTIME=69 THEN  TEMP(QG.ON)=+.00603
    IF NTIME=70 THEN  TEMP(QG.ON)=+.0110
    IF NTIME=71 THEN  TEMP(QG.ON)=+.00981
    IF NTIME=72 THEN  TEMP(QG.ON)=+.0137
    IF NTIME>=73 THEN  TEMP(QG.ON)=+.0115
    IF NTIME>=74 THEN  TEMP(QG.ON)=+.03
    IF NTIME=69 THEN  TEMP(QO.ON)=-.0128
    IF NTIME=70 THEN  TEMP(QO.ON)=-.0205
    IF NTIME=71 THEN  TEMP(QO.ON)=-.0228
    IF NTIME=72 THEN  TEMP(QC.ON)=-.0320
    IF NTIME>=73 THEN  TEMP(QO.ON)=-.0110
    IF NTIME>=74 THEN  TEMP(QO.ON)=+.03
    IF NTIME=69 THEN  TEMP(QL.ON)=+.00678
    IF NTIME=70 THEN  TEMP(QL.ON)=+.00951
    IF NTIME=71 THEN  TEMP(QL.ON)=+.0130
    IF NTIME=72 THEN  TEMP(QL.ON)=+.0183
    IF NTIME>=73 THEN  TEMP(QL.ON)=-.000510
    IF NTIME>=74 THEN  TEMP(QL.ON)=-.06
    IF NTIME=69 THEN  TEMP(QG.PR)=+.00309
    IF NTIME=70 THEN  TEMP(QG.PR)=-.00708
    IF NTIME=71 THEN  TEMP(QG.PR)=-.0101
    IF NTIME=72 THEN  TEMP(QG.PR)=-.0102
    IF NTIME>=73 THEN  TEMP(QG.PR)=-.0354
    IF NTIME>=74 THEN  TEMP(QG.PR)=+.01
    IF NTIME=69 THEN  TEMP(QC.PR)=-.0303
    IF NTIME=70 THEN  TEMP(QC.PR)=-.0332
    IF NTIME=71 THEN  TEMP(QC.PR)=-.0213
    IF NTIME=72 THEN  TEMP(QC.PR)=-.0215
    IF NTIME>=73 THEN  TEMP(QO.PR)=+.0197
    IF NTIME>=74 THEN  TEMP(QC.PR)=0.04
    IF NTIME=69 THEN  TEMP(QL.PR)=+.0272
    IF NTIME=70 THEN  TEMP(QL.PR)=+.0403
    IF NTIME=71 THEN  TEMP(QL.PR)=+.0314
    IF NTIME=72 THEN  TEMP(QL.PR)=+.0317
    IF NTIME>=73 THEN  TEMP(QL.PR)=+.0157
    IF NTIME>=74 THEN  TEMP(QL.PR)=-.05
    IF NTIME=69 THEN  TEMP(QG.BC)=+.00583
    IF NTIME=70 THEN  TEMP(QG.BC)=+.00148
```

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IF NTIME=71 THEN  TEMP(QG.BC)=+.00488
IF NTIME=72 THEN  TEMP(QG.BC)=+.00339
IF NTIME>=73 THEN  TEMP(QG.BC)=+.0163
IF NTIME>=74 THEN  TEMP(QG.BC)=+.02
IF NTIME=69 THEN  TEMP(QO.BC)=-.0202
IF NTIME=70 THEN  TEMP(QC.BC)=+.00280
IF NTIME=71 THEN  TEMP(QC.BC)=-.0112
IF NTIME=72 THEN  TEMP(QC.BC)=-.000254
IF NTIME>=73 THEN  TEMP(QO.BC)=+.0280
IF NTIME>=74 THEN  TEMP(QC.BC)=+.04
IF NTIME=69 THEN  TEMP(QL.BC)=+.0144
IF NTIME=70 THEN  TEMP(QL.BC)=-.00428
IF NTIME=71 THEN  TEMP(QL.BC)=+.00634
IF NTIME=72 THEN  TEMP(QL.BC)=-.00314
IF NTIME>=73 THEN  TEMP(QL.BC)=-.0443
IF NTIME>=74 THEN  TEMP(QL.BC)=-.06
IF NTIME=69 THEN  TEMP(QO.AT)=-.0477
IF NTIME=70 THEN  TEMP(QC.AT)=-.0733
IF NTIME=71 THEN  TEMP(QC.AT)=+.0175
IF NTIME>=72 THEN  TEMP(QO.AT)=+.0625
IF NTIME>=73 THEN  TEMP(QO.AT)=+.10
IF NTIME>=74 THEN  TEMP(QC.AT)=+.14
IF NTIME=69 THEN  TEMP(QL.AT)=+.0477
IF NTIME=70 THEN  TEMP(QL.AT)=+.0733
IF NTIME=71 THEN  TEMP(QL.AT)=-.0175
IF NTIME>=72 THEN  TEMP(QL.AT)=-.0625
IF NTIME>=73 THEN  TEMP(QL.AT)=-.10
IF NTIME>=74 THEN  TEMP(QL.AT)=-.14
IF NTIME=69 THEN  TEMP(QGL.ON)=-.0153
IF NTIME=70 THEN  TEMP(QGL.ON)=-.0300
IF NTIME=71 THEN  TEMP(QGL.ON)=-.00461
IF NTIME=72 THEN  TEMP(QGL.ON)=+.114
IF NTIME>=73 THEN  TEMP(QGL.ON)=+.151
IF NTIME=69 THEN  TEMP(QCL.ON)=+.0365
IF NTIME=70 THEN  TEMP(QCL.ON)=+.0137
IF NTIME=71 THEN  TEMP(QCL.ON)=+.0000152
IF NTIME=72 THEN  TEMP(QCL.ON)=-.0166
IF NTIME>=73 THEN  TEMP(QCL.ON)=+.00472
IF NTIME=69 THEN  TEMP(QCL.ON)=-.0212
IF NTIME=70 THEN  TEMP(QCL.ON)=+.0163
IF NTIME=71 THEN  TEMP(QCL.ON)=+.00460
IF NTIME=72 THEN  TEMP(QCL.CN)=-.0978
IF NTIME>=73 THEN  TEMP(QCL.ON)=-.156
IF NTIME=69 THEN  TEMP(QGL.PR)=+.0123
IF NTIME=70 THEN  TEMP(QGL.PR)=-.0409
IF NTIME=71 THEN  TEMP(QGL.PR)=-.0887
IF NTIME=72 THEN  TEMP(QGL.PR)=-.103
IF NTIME>=73 THEN  TEMP(QGL.PR)=-.0859
IF NTIME>=74 THEN  TEMP(QGL.PR)=-.02
IF NTIME=69 THEN  TEMP(QCL.PR)=-.000362
IF NTIME=70 THEN  TEMP(QCL.PR)=-.0265
IF NTIME=71 THEN  TEMP(QCL.PR)=-.0439
IF NTIME=72 THEN  TEMP(QCL.PR)=-.0545
IF NTIME>=73 THEN  TEMP(QCL.PR)=-.0275
IF NTIME>=74 THEN  TEMP(QOL.PR)=+.01
IF NTIME=69 THEN  TEMP(QCL.PR)=-.0119
IF NTIME=70 THEN  TEMP(QCL.PR)=+.0675
IF NTIME=71 THEN  TEMP(QCL.PR)=+.133
IF NTIME=72 THEN  TEMP(QCL.PR)=+.158
IF NTIME>=73 THEN  TEMP(QCL.PR)=+.113
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IF NTIME>=74 THEN  TEMP(QCL.PR)=+.01
IF NTIME=69 THEN  TEMP(QCL.AT)=+.0658
IF NTIME=70 THEN  TEMP(QCL.AT)=+.182
IF NTIME=71 THEN  TEMP(QOL.AT)=+.158
IF NTIME=72 THEN  TEMP(QCL.AT)=+.198
IF NTIME>=73 THEN  TEMP(QOL.AT)=+.250
IF NTIME=69 THEN  TEMP(QCL.AT)=-.0658
IF NTIME=70 THEN  TEMP(QCL.AT)=-.182
IF NTIME=71 THEN  TEMP(QCL.AT)=-.158
IF NTIME=72 THEN  TEMP(QCL.AT)=-.198
IF NTIME>=73 THEN  TEMP(QCL.AT)=-.250
IF NTIME=69 THEN  TEMP(QOL.QU)=+.0927
IF NTIME=70 THEN  TEMP(QCL.QU)=+.0634
IF NTIME=71 THEN  TEMP(QCL.QU)=+.0359
IF NTIME=72 THEN  TEMP(QOL.QU)=+.112
IF NTIME>=73 THEN  TEMP(QOL.QU)=+.110
IF NTIME>=74 THEN  TEMP(QCL.QU)=0.05
IF NTIME=69 THEN  TEMP(QCL.QU)=-.0927
IF NTIME=70 THEN  TEMP(QCL.QU)=-.0634
IF NTIME=71 THEN  TEMP(QCL.QU)=-.0359
IF NTIME=72 THEN  TEMP(QCL.QU)=-.112
IF NTIME>=73 THEN  TEMP(QCL.QU)=-.110
IF NTIME>=74 THEN  TEMP(QCL.QU)=-.05
IF NTIME=69 THEN  TEMP(QOL.BC)=-.0139
IF NTIME=70 THEN  TEMP(QCL.BC)=-.0418
IF NTIME=71 THEN  TEMP(QCL.BC)=+.208
IF NTIME=72 THEN  TEMP(QCL.BC)=+.112
IF NTIME>=73 THEN  TEMP(QOL.BC)=-.116
IF NTIME=69 THEN  TEMP(QGL.BC)=+.0139
IF NTIME=70 THEN  TEMP(QGL.BC)=+.0418
IF NTIME=71 THEN  TEMP(QGL.BC)=-.208
IF NTIME=72 THEN  TEMP(QGL.BC)=-.112
IF NTIME>=73 THEN  TEMP(QGL.BC)=+.116
IF NTIME=69 THEN  TEMP(TEL$AT)=-.109
IF NTIME=70 THEN  TEMP(TEL$AT)=-.0513
IF NTIME=71 THEN  TEMP(TEL$AT)=+.0701
IF NTIME>=72 THEN  TEMP(TEL$AT)=+.141
IF NTIME>=73 THEN  TEMP(TEL$AT)=+.231
IF NTIME=69 THEN  TEMP(TEL$QU)=-.274
IF NTIME=70 THEN  TEMP(TEL$QU)=-.277
IF NTIME=71 THEN  TEMP(TEL$QU)=-.121
IF NTIME=72 THEN  TEMP(TEL$QU)=+.0845
IF NTIME>=73 THEN  TEMP(TEL$QU)=+.212
IF NTIME=69 THEN  TEMP(TEL$ON)=-.111
IF NTIME=70 THEN  TEMP(TEL$ON)=+.0000153
IF NTIME=71 THEN  TEMP(TEL$ON)=-.0109
IF NTIME=72 THEN  TEMP(TEL$ON)=+.0125
IF NTIME>=73 THEN  TEMP(TEL$ON)=+.0396
IF NTIME=69 THEN  TEMP(TEL$PR)=-.0396
IF NTIME=70 THEN  TEMP(TEL$PR)=+.0634
IF NTIME=71 THEN  TEMP(TEL$PR)=+.195
IF NTIME=72 THEN  TEMP(TEL$PR)=+.261
IF NTIME>=73 THEN  TEMP(TEL$PR)=+.290
IF NTIME>=75 THEN  TEMP(TEL$PR)=+.290-.17*(1.-1./EXP((NTIME-75)/5.))
IF NTIME=69 THEN  TEMP(TEL$BC)=+.0262
IF NTIME=70 THEN  TEMP(TEL$BC)=-.00542
IF NTIME=71 THEN  TEMP(TEL$BC)=+.144
IF NTIME=72 THEN  TEMP(TEL$BC)=+.201
IF NTIME>=73 THEN  TEMP(TEL$BC)=+.236
IF NTIME>=75 THEN  TEMP(TEL$BC)=+.236-.13*(1.-1./EXP((NTIME-75)/5.))
```

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    IF NTIME=69 THEN  TEMP(TOT$AT)=-.0585
    IF NTIME=70 THEN  TEMP(TOT$AT)=-.0573
    IF NTIME=71 THEN  TEMP(TOT$AT)=+.0508
    IF NTIME>=72 THEN  TEMP(TOT$AT)=+.138
    IF NTIME>=73 THEN  TEMP(TOT$AT)=+.22
    IF NTIME>=74 THEN  TEMP(TOT$AT)=+.30
    IF NTIME>=75 THEN  TEMP(TOT$AT)=+.33
    IF NTIME>=76 THEN  TEMP(TOT$AT)=+.37
    IF NTIME>=77 THEN  TEMP(TOT$AT)=+.42
    IF NTIME=69 THEN  TEMP(TOT$QU)=-.0483
    IF NTIME=70 THEN  TEMP(TOT$QU)=+.0154
    IF NTIME=71 THEN  TEMP(TOT$QU)=-.0148
    IF NTIME=72 THEN  TEMP(TOT$QU)=+.00112
    IF NTIME>=73 THEN  TEMP(TOT$QU)=+.00566
    IF NTIME>=74 THEN  TEMP(TOT$QU)=+.09
    IF NTIME>=75 THEN  TEMP(TOT$QU)=+.13
    IF NTIME>=76 THEN  TEMP(TOT$QU)=+.14
    IF NTIME=69 THEN  TEMP(TOT$ON)=+.000785
    IF NTIME=70 THEN  TEMP(TOT$ON)=+.0382
    IF NTIME=71 THEN  TEMP(TOT$ON)=-.000268
    IF NTIME=72 THEN  TEMP(TOT$ON)=+.0165
    IF NTIME>=73 THEN  TEMP(TOT$ON)=+.0166
    IF NTIME>=74 THEN  TEMP(TOT$ON)=+.03
    IF NTIME>=75 THEN  TEMP(TOT$ON)=+.06
    IF NTIME>=76 THEN  TEMP(TOT$ON)=+.14
    IF NTIME=69 THEN  TEMP(TOT$PR)=+.00296
    IF NTIME=70 THEN  TEMP(TOT$PR)=-.0000544
    IF NTIME=71 THEN  TEMP(TOT$PR)=-.00876
    IF NTIME=72 THEN  TEMP(TOT$PR)=+.00912
    IF NTIME>=73 THEN  TEMP(TOT$PR)=+.00455
    IF NTIME>=74 THEN  TEMP(TOT$PR)=+.05
    IF NTIME>=75 THEN  TEMP(TOT$PR)=+.09
    IF NTIME>=76 THEN  TEMP(TOT$PR)=+.12
    IF NTIME=69 THEN  TEMP(TOT$BC)=+.0219
    IF NTIME=70 THEN  TEMP(TOT$BC)=-.0264
    IF NTIME=71 THEN  TEMP(TOT$BC)=+.00447
    IF NTIME=72 THEN  TEMP(TOT$BC)=+.00882
    IF NTIME>=73 THEN  TEMP(TOT$BC)=+.00496
    IF NTIME>=74 THEN  TEMP(TOT$BC)=+.05
    IF NTIME>=75 THEN  TEMP(TOT$BC)=+.07
    IF NTIME>=76 THEN  TEMP(TOT$BC)=+.12

THE FOLLOWING ARE THE 'TEMP' ADJUSTMENTS TO THE LOSSES EQUATIONS
    IF NTIME=69 THEN  TEMP(LOILAT)=-.698
    IF NTIME=70 THEN  TEMP(LCILAT)=+.990
    IF NTIME=71 THEN  TEMP(LOILAT)=+.757
    IF NTIME=72 THEN  TEMP(LCILAT)=-1.26
    IF NTIME>=73 THEN  TEMP(LOILAT)=-.123
    IF NTIME>=74 THEN  TEMP(ICILAT)=0.0
    IF NTIME=69 THEN  TEMP(LCSSL.AT)=-.0764
    IF NTIME=70 THEN  TEMP(LOSSL.AT)=+.0595
    IF NTIME=71 THEN  TEMP(LOSSL.AT)=-.0799
    IF NTIME=72 THEN  TEMP(LCSSL.AT)=+.0425
    IF NTIME>=73 THEN  TEMP(LOSSL.AT)=+.100
    IF NTIME=69 THEN  TEMP(LCILQU)=+2.21
    IF NTIME=70 THEN  TEMP(LCILQU)=+.696
    IF NTIME=71 THEN  TEMP(LCILQU)=-.0392
    IF NTIME=72 THEN  TEMP(LCILQU)=-.872
    IF NTIME>=73 THEN  TEMP(LOILQU)=-.261
    IF NTIME>=74 THEN  TEMP(LCILQU)=0.0
```

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IF NTIME=69 THEN  TEMP(LGASQU)=+.276
IF NTIME=70 THEN  TEMP(LGASQU)=-.330
IF NTIME=71 THEN  TEMP(LGASQU)=-.902
IF NTIME=72 THEN  TEMP(LGASQU)=+.548
IF NTIME>=73 THEN  TEMP(LGASQU)=-.391
IF NTIME>=74 THEN  TEMP(LGASQU)=0.0
IF NTIME=69 THEN  TEMP(LOSSL.QU)=-.340
IF NTIME=70 THEN  TEMP(LOSSL.QU)=-.231
IF NTIME=71 THEN  TEMP(LOSSL.QU)=+.361
IF NTIME=72 THEN  TEMP(LOSSL.QU)=-.350
IF NTIME>=73 THEN  TEMP(LOSSL.QU)=+.177
IF NTIME=69 THEN  TEMP(LOILON)=-3.36
IF NTIME=70 THEN  TEMP(LOILON)=+.754
IF NTIME=71 THEN  TEMP(LOILON)=+1.86
IF NTIME=72 THEN  TEMP(LOILON)=-1.60
IF NTIME>=73 THEN  TEMP(LOILON)=-.0826
IF NTIME>=74 THEN  TEMP(LOILON)=0.0
IF NTIME=69 THEN  TEMP(LGASON)=+.808
IF NTIME=70 THEN  TEMP(LGASON)=+2.48
IF NTIME=71 THEN  TEMP(LGASON)=-.841
IF NTIME=72 THEN  TEMP(LGASON)=-2.91
IF NTIME>=73 THEN  TEMP(LGASON)=-4.29
IF NTIME>=74 THEN  TEMP(LGASON)=0.0
IF NTIME=69 THEN  TEMP(LOSSL.ON)=-.230
IF NTIME=70 THEN  TEMP(LOSSL.ON)=-.0195
IF NTIME=71 THEN  TEMP(LOSSL.ON)=-.213
IF NTIME=72 THEN  TEMP(LOSSL.ON)=+.495
IF NTIME>=73 THEN  TEMP(LOSSL.ON)=-.408
IF NTIME>=74 THEN  TEMP(LOSSL.ON)=0.0
IF NTIME=69 THEN  TEMP(LOILPR)=-.150
IF NTIME=70 THEN  TEMP(LOILPR)=-1.04
IF NTIME=71 THEN  TEMP(LOILPR)=+1.25
IF NTIME=72 THEN  TEMP(LOILPR)=-2.14
IF NTIME>=73 THEN  TEMP(LOILPR)=-.387
IF NTIME>=74 THEN  TEMP(LOILPR)=0.0
IF NTIME=69 THEN  TEMP(LGASPR)=-11.7
IF NTIME=70 THEN  TEMP(LGASPR)=+14.2
IF NTIME=71 THEN  TEMP(LGASPR)=-21.1
IF NTIME=72 THEN  TEMP(LGASPR)=-2.75
IF NTIME>=73 THEN  TEMP(LGASPR)=+9.47
IF NTIME>=74 THEN  TEMP(LGASPR)=0.0
IF NTIME=69 THEN  TEMP(LOSSL.PR)=-.153
IF NTIME=70 THEN  TEMP(LOSSL.PR)=+.158
IF NTIME=71 THEN  TEMP(LOSSL.PR)=-.0390
IF NTIME=72 THEN  TEMP(LOSSL.PR)=+.0304
IF NTIME>=73 THEN  TEMP(LOSSL.PR)=+.00554
IF NTIME=69 THEN  TEMP(LOILBC)=-.167
IF NTIME=70 THEN  TEMP(LOILBC)=-.551
IF NTIME=71 THEN  TEMP(LOILBC)=+1.22
IF NTIME=72 THEN  TEMP(LOILBC)=-1.12
IF NTIME>=73 THEN  TEMP(LOILBC)=-.597
IF NTIME>=74 THEN  TEMP(LOILBC)=0.0
IF NTIME=69 THEN  TEMP(LGASBC)=+28.3
IF NTIME=70 THEN  TEMP(LGASBC)=+33.3
IF NTIME=71 THEN  TEMP(LGASBC)=+16.1
IF NTIME=72 THEN  TEMP(LGASBC)=-19.6
IF NTIME>=73 THEN  TEMP(LGASBC)=-21.4
IF NTIME>=74 THEN  TEMP(LGASBC)=0.0
IF NTIME=69 THEN  TEMP(LOSSL.BC)=-.119
IF NTIME=70 THEN  TEMP(LOSSL.BC)=+.175
```

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      IF NTIME=71 THEN  TEMP(LCSSL.BC)=-.360
      IF NTIME=72 THEN  TEMP(LOSSL.BC)=+.423
      IF NTIME>=73 THEN  TEMP(LOSSL.BC)=+.416
      IF NTIME>=75 THEN  TEMP(LOILEAST)=10.
      IF NTIME=74 THEN  TEMP(LCILWEST)=+19.6
      IF NTIME=75 THEN  TEMP(LCILWEST)=+26.
      IF NTIME>=76 THEN  TEMP(LOILWEST)=0.0

PFX IS DEFINED TO BE 1.0 DURING CONTROL
      PFX=1.0

DPETRO SERIES CONTINUES AT ITS 1996 VALUE
      IF NTIME>95 THEN  DPETRO=J1L*DPETRO

SET THE NATURAL GAS COMMODITY DISCOUNT FACTOR
      A(1860)=.85+.03*(NTIME-76)
      IF A(1860)>=1.0 THEN  A(1860)=1.0

SET THE AMOUNT OF RE-EXPORTS OF PETROLEUM PRODUCTS IN ATLANTIC AND QUEBEC
      IF NTIME=73 THEN  QOILREAT=18.524
      IF NTIME>=74 THEN  QOILREAT=27.552
      IF NTIME=73 THEN  QOILREQU=14.715
      IF NTIME>=74 THEN  QOILREQU=4.272

SET THE GROWTH IN QUEBEC HYDRO ELECTRICITY
      IF NTIME>=75 THEN  A(2125)=0.
      IF NTIME>=78 THEN  A(2125)=.04
```

```
1. EQUATIONS FOR ENDOGENOUS VARIABLES

SET THE NOMINAL DISCCUNT RATE
    STP1=1.+A(1890)*((1.+A(1890))**.5)
    STP2=1.+A(1890)*(STP1**.5)
    A(1894)=A(1890)*(STP2**.5)
    STPNOM=(1.+A(1894))*(1.+A(1972))
    IF NTIME=74 THEN  STPNOM=(1.+A(1894))*(1.77/1.56)
    IF NTIME=75 THEN  STPNOM=(1.+A(1894))*(1.95/1.77)
    IF NTIME=76 THEN  STPNOM=(1.+A(1894))*(2.11/1.95)

EITHER USE THE ENDOGENOUS OR EXOGENOUS DEMAND SERIES
    IF A(2131)=0 THEN  GO TO 10
    QGAS=365.*DEMAND-(1.-A(2136))*LOSSGAS

EQUATIONS FOR NCN-FRONTIER GAS PRODUCTION
10  GASPRO=EXGASNF+(QGAS+(1.-A(2136))*LOSSGAS)/365.
       -(1.-EGASXD)*.889*EGASD
    IF GASMAX=0. THEN  GASMAX=GASMAX73
    IF GASPRO>GASMAX THEN  GASPRO=GASMAX
    IF .365*GASPRO>J1L*RESBASE THEN  GASPRO=(J1L*RESBASE)/.365

THE RESERVE BASE IS DEFINED
    RESBASE=J1L*RESBASE+RESDISCV-.365*GASPRO

GASACUM IS THE CUMULATIVE PRODUCTION IN THE SIMULATION
    GASACUM=J1L*GASACUM+.365*GASPRO

GASPLANT IS THE NATURAL GAS PROCESSING PLANT EXPENDITURE
    GASPLANT=A(2141)*(.365*(GASPRO-J1L*GASERO)-J1L*EXCAPGAS)
    IF GASPLANT<0. THEN  EXCAPGAS=-.365*(GASPRO-J1L*GASPRO)+J1L*EXCAPGAS
    IF GASPLANT<0. THEN  GASPLANT=0.
    IF GASPLANT>0. THEN  EXCAPGAS=0.

RESCOST REPRESENTS THE COST OF HOLDING RESERVES
    RESCOST=J1L*RESCOST*(1.-.365*GASPRO/(J1L*RESBASE))  +(A(1907)*
     (GASACUM+RESBASE)-A(1908)+GASCADJ)*RESDISCV+GASPLANT

CALCULATE THE OPERATING EXPENDITURE
    IF NTIME<=74 THEN  A(1909)=.1*(65.4881-.467668*GASACUM+GASOPADJ)
    IF NTIME>=75 THEN  A(1909)=5.4

GASCOSTM IS THE MARGINAL COST, IN 1976 CENTS/MCF, OF NEW NON-FRONTIER GAS
    GASCOSTM=2.11*(A(1907)*(GASACUM+RESBASE)-A(1908)+GASCADJ)*
     A(1902)  +A(1909)*2.11
    IF RESBASE+GASACUM>=.9999*A(1919) THEN  GASCOSTM=0.

PGASNF IS THE WELLHEAD PRICE OF NATURAL GAS (IN CENTS PER MCF)
    PGASNF=100.*PGW.PR

PGASREG IS BASED ON THE TORONTO CRUDE CIL PRICE
    IF NTIME>=76 THEN  PGASREG=100.*A(1860)*(PCW.PR+POT.PO)/A(1921)

PGAS IS THE COMMODITY BASED CPPORTUNITY PRICE OF NATURAL GAS IN TORONTO
    IF NTIME<=73 THEN  PGAS=PGASREG
    IF NTIME>=74 THEN  PGAS=100.*PO.OFF/A(1921)

THE FOLLCWING SWITCH INDICATES THE TYPE OF PRODUCTION PROFILE
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      IF A(1910)=.1 THEN  GO TO 31

 ESTABLISH PRODUCTION FROM ALREADY HOCKED-UP RESERVES
      GASLAG=J14L*GASADD
      DI=A(1910)
      DF=DI*.15272*(.85)**13
      S2=0.
      DO 40 I=1,14
      J1=LO(I)
 40   S2=S2 + JIL*GASADD*DI
      S2=S2+GASADD*DI
      S3=0.
      DO 50 I=1,13
      J1=LC(I)
 50   S3=S3 + JIL*GASLAG*DI*(.85**I)
      S4=0.
      J1=LO(14)
      S4=S4 + JIL*GASLAG*DF
      GO TO 61

 PRODUCTION PATTERN USING MCDANIEL EXTRACTION RATE
31    GASLAG=J3L*GASADD
      DI=A(1910)
      DF=.95*DI
      S2=0.
      DO 41 I=1,2
      J1=LC(I)
41    S2=S2 + JIL*GASADD*DI
      S2=S2 + GASADD*DI + J3L*GASADD*DF
      S3=0.
      DO 51 I=1,13
      J1=LC(I)
51    S3=S3 + JIL*GASLAG*DF*(.90**I)
      S4=0.
61    GASMAX=GASMAX73 + (S2+S3+S4)/.365
      DFLOW=GASMAX-GASADD*DI/.365+EGASD*(1.-EGASXD)*.889

 DETERMINE THE STOCK OF NEW RESERVES THAT MUST BE HOOKED-UP THIS YEAR
      GASADD=((QGAS+(1.-A(2136))*LOSSGAS)/365.+EXGASNF-DFLOW)*.365/DI
      IF A(1918)<=0.0 AND GASADD>J1L*RESEXCES THEN  GASADD=J1L*RESEXCES
      IF A(1948)>0.0 AND NTIME>A(1948) THEN  GASADD=0.0

 REMD IS THE REMAINING STOCK OF UNDISCOVERED RESERVES
      IF K7=1 THEN  REMD=A(1919)-J1L*RESBASE-J1L*GASACUM
      IF (J1L*GASADT+RESDISCV)>=REMD THEN  RESDISCV=REMD-J1L*GASADT
      IF A(1918)>0.0 AND (J1L*GASADT+GASADD)>=REMD THEN  GASADD=REMD-J1L*GASA
      IF RESDISCV<0.0 THEN  RESDISCV=0.0
      IF GASADD<.01 THEN  GASADD=0.

 GASADT REPRESENTS THE CUMULATIVE RESERVE DISCOVERIES
      GASADT=J1L*GASADT +RESDISCV

 DISCOVERIES FROM 1975 ARE NFB ESTIMATES FROM 1975 REPORT
      IF (J1L*GASADT+RESDISCV)>=REMD THEN  GC TO 21

 DISCOVERIES 1955-1974 ARE ACTUAL SERIES (USE PROBABLE FROM 1963)
      IF NTIME=55 THEN  RESDISCV=2.1554
      IF NTIME=56 THEN  RESDISCV=2.8072
      IF NTIME=57 THEN  RESDISCV=1.2144
      IF NTIME=58 THEN  RESDISCV=2.5866
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      IF NTIME=59 THEN  RESDISCV=3.3586
      IF NTIME=60 THEN  RESDISCV=4.0409
      IF NTIME=61 THEN  RESDISCV=3.2359
      IF NTIME=62 THEN  RESDISCV=2.5176
      IF NTIME=63 THEN  RESDISCV=3.216
      IF NTIME=64 THEN  RESDISCV=8.329
      IF NTIME=65 THEN  RESDISCV=1.958
      IF NTIME=66 THEN  RESDISCV=3.941
      IF NTIME=67 THEN  RESDISCV=2.897
      IF NTIME=68 THEN  RESDISCV=4.628
      IF NTIME=69 THEN  RESDISCV=4.836
      IF NTIME=70 THEN  RESDISCV=4.600
      IF NTIME=71 THEN  RESDISCV=3.628
      IF NTIME=72 THEN  RESDISCV=.835
      IF NTIME=73 THEN  RESDISCV=5.108
      IF NTIME=74 THEN  RESDISCV=4.8
      IF NTIME=75 THEN  RESDISCV=3.0
      IF NTIME=76 THEN  RESDISCV=3.0
      IF NTIME=77 THEN  RESDISCV=2.5
      IF NTIME=78 THEN  RESDISCV=2.5
      IF NTIME=79 THEN  RESDISCV=2.0
      IF NTIME=80 THEN  RESDISCV=2.0
      IF NTIME=81 THEN  RESDISCV=1.5
      IF NTIME=82 THEN  RESDISCV=1.5
      IF NTIME=83 THEN  RESDISCV=1.0
      IF NTIME=84 THEN  RESDISCV=1.0
      IF NTIME>=85 THEN  RESDISCV=0.5

 WHEN GENERATING GASMAX73 SERIES, SET RESDISCV=0
      IF A(1948)>0.0 AND NTIME>A(1948) THEN  RESDISCV=0.0

 RESEXCES IS THE STOCK OF UNHOOKED-UP EXCESS RESERVES
21    RESEXCES=J1L*RESEXCES+RESDISCV-GASADD
      IF RESEXCES<0.0 THEN  RESEXCES=0.0

 TAXATION EQUATIONS FOR NON-FRONTIER GAS PRODUCTION

 EFFECTIVE FEDERAL AND PROVINCIAL CORPORATE TAX RATES
      IF NTIME=74 THEN  ETXRTF=.30
      IF NTIME=75 THEN  ETXRTF=.28
      IF NTIME>=76 THEN  ETXRTF=.234
      IF NTIME=74 THEN  ETXRTP=.1116
      IF NTIME=75 THEN  ETXRTP=.1134
      IF NTIME>=76 THEN  ETXRTP=.07579

 PEXPORTG - SERIES FOR THE EXPORT PRICE OF GAS
      IF NTIME=74 THEN  PEXPORTG=52.
      IF NTIME=75 THEN  PEXPORTG=123.34
      IF NTIME=76 THEN  PEXPORTG=166.67
      IF NTIME=77 THEN  PEXPORTG=194.0
      IF NTIME>=78 THEN  PEXPORTG=J1L*PEXPORTG*1.15
      IF NTIME>78 AND PEXPORTG>PGAS THEN
       PEXPORTG=PGAS

 WEIGHTED GAS PRICE TO NON-FRONTIER PRODUCERS - EXPORT VS. DOMESTIC
      IF NTIME>=74 THEN
       PGASW=(PEXPORTG-.66*A(1901)*PEXOG/1.95)*EXGASNF
       /GASPRO+PGASNF*(GASPRO-EXGASNF)/GASPRO

 YGASNFT - TAXABLE INCOME FOR NON-FRONTIER GAS PRODUCTION
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```
     IF NTIME<=73 THEN  YGASNFT=3.65*GASPRO*(PGASNF-(A(1909)
      +A(1906))*PGNE-A(1904)*PGASNF)-(.365*GASPRO
      /J1L*RESBASE)*RESCOST*PEXOG
     IF NTIME=74 THEN  YGASNFT=3.65*GASPRO*(PGASNF-(A(1909)
      +A(1906))*PGNE)-(.365*GASPRO/J1L*RESBASE)*RESCOST
      *PEXOG
     IF NTIME>=75 THEN  YGASNFT=3.65*GASPRO*(PGASW-(A(1909)
      +A(1906))*PGNE)-(.365*GASPRO/J1L*RESBASE)*RESCOST
      *PEXOG

FRACTION OF TAXABLE PROFITS ALLOWED FOR EARNED DEPLETION
     IF NTIME>=74 THEN
      DEPLE=(PEXOG*.333*(A(1907)*(GASACUM+RESBASE)-A(1908)
      +GASCADJ)*RESDISCV+GASPLANT*PGNE+J1L*KEDPNF$)/YGASNFT
     IF NTIME<=73 THEN  REDPA=.333
     IF NTIME>=74 AND DEPLE<=.25 THEN  REDPA=DEPLE
     IF NTIME>=74 AND DEPLE>.25 THEN  REDPA=.25

KEDPNF$ - STOCK OF UNCLAIMED EARNED DEPLETION
     IF NTIME>=70 AND NTIME<=73 THEN
      KEDPNF$=PEXOG*.333*(A(1907)*(GASACUM+RESBASE)-A(1908)
      +GASCADJ)*RESDISCV+GASPLANT*PGNE+J1L*KEDPNF$
     IF NTIME>=74 THEN
      KEDPNF$=(DEPLE-REDPA)*YGASNFT

TCGASNF - CORPORATION TAX ON NON-FRONTIER GAS PRODUCTION
     IF NTIME<=73 THEN  TROYLG=0.
     IF TROYLG<0. THEN  TROYLG=0.
     IF NTIME=74 THEN  TROYLG= (GASPRO-GASMAX73)*(8.54+.35*(PGASNF
      -36.))+(GASMAX73*(9.22+.50*(PGASNF-36.)))*3.65
      -.35*(.04*PEXOG/1.77*RESDISCV)
     IF NTIME>=75 THEN  TROYLG= (GASPRO-GASMAX73)*(8.54+.35*(PGASW
      -36.))+(GASMAX73*(9.22+.50*(PGASW-36.)))*3.65
      -.45*(.04*PEXOG/1.77*RESDISCV)
     IF NTIME<=73 THEN  TCGASNF=A(1888)*(1.-REDPA)*YGASNFT
     IF NTIME>=74 THEN  TCGASNF=ETXRTF*(1.-REDPA)*YGASNFT
      +ETXRTP*(1.-REDPA)*(YGASNFT-TROYLG)

RENT EQUATIONS FOR NON-FRONTIER GAS PRODUCTION

B.C. INDEMNIFICATION OF FEDERAL TAXES PAID BY PRODUCERS
 RE:  GAS ROYALTIES (DEEMED AND ACTUAL)
     IF NTIME=74 THEN  BCINDM=ETXRTF*.1394*TROYLG
     IF NTIME>=75 THEN  BCINDM=ETXRTF*.16*TROYLG

ALBERTA SELECTIVE ROYALTY REDUCTION, A CASH TRANSFER TO PRODUCERS
     IF NTIME>=74 THEN  REBATE=15.+.0262*TROYLG

KRNFGP$ - PROVINCIAL GOVERNMENT RENT EQUATIONS
     IF NTIME<=73 THEN  KRNFGP$=J1L*KRNFGP$*STPNOM
      +((A(1906)*PGNE+A(1904)*PGASNF)*3.65*GASPRO
      +A(1916)*(TCGASNF-A(1895)*PEXOG*RESCOST)
      )*(STPNOM**.5)
     IF NTIME=74 THEN  KRNFGP$=J1L*KRNFGP$*STPNOM+(A(1906)*PGNE
      *3.65*GASPRO+TROYLG+ETXRTP*(1.-REDPA)*(YGASNFT
      -TROYLG)+(PEXPORTG-PGASNF-.66*A(1901)*PEXOG/1.95)
       *EXGASNF*3.65*(1.-ETXRTF)
      -BCINDM-REBATE-(A(1895)*PEXOG*RESCOST)*A(1916)
      )*(STPNOM**.5)
     IF NTIME>74 THEN  KRNFGP$=J1L*KRNFGP$*STPNOM+(A(1906)*PGNE
```

```
      *3.65*GASPRO+TROYLG+ETXRTP*(1.-REDPA)*(YGASNFT
      -TROYLG)
      -BCINDM-REBATE-(A(1895)*PEXOG*RESCOST)*A(1916)
      )*(STPNOM**.5)

KRNFGF$ - FEDERAL GOVERNMENT RENT EQUATIONS
     IF NTIME<=73 THEN  KRNFGF$=J1L*KRNFGF$*STPNOM+((1.-A(1916))
      *(TCGASNF-A(1895)*PEXOG*RESCOST)
      )*(STPNOM**.5)
     IF NTIME=74 THEN  KRNFGF$=J1L*KRNFGF$*STPNOM
      +(ETXRTF*(1.-REDPA)*YGASNFT
      -(A(1895)*PEXOG*RESCOST)*(1.-A(1916))
      +ETXRTF*3.65*(PEXPORTG-PGASNF-.66*A(1901)*PEXOG/1.95)
       *EXGASNF)*(STPNOM**.5)
     IF NTIME>74 THEN  KRNFGF$=J1L*KRNFGF$*STPNOM
      +(ETXRTF*(1.-REDPA)*YGASNFT
      -(A(1895)*PEXOG*RESCOST)*(1.-A(1916))
      )*(STPNOM**.5)

KRENTNF$ - PRODUCER RENT EQUATIONS
     IF NTIME<=73 THEN  KRENTNF$=J1L*KRENTNF$*STPNOM+(3.65*GASPRO
      *(PGASNF-(A(1909)+A(1906))*PGNE-A(1904)
      *PGASNF)
      -TCGASNF
      -(A(1890)+.365*GASPRO/J1L*RESBASE)*PEXOG*RESCOST
      )*(STPNOM**.5)
     IF NTIME=74 THEN  KRENTNF$=J1L*KRENTNF$*STPNOM+(3.65*GASPRO
      *(PGASNF-(A(1909)+A(1906))*PGNE)
      -TROYLG-TCGASNF+BCINDM+REBATE
      -(A(1890)+.365*GASPRO/J1L*RESBASE)*PEXOG*RESCOST
      )*(STPNOM**.5)
     IF NTIME>=75 THEN  KRENTNF$=J1L*KRENTNF$*STPNOM+(3.65*GASPRO
      *(PGASW-(A(1909)+A(1906))*PGNE)
      -TROYLG-TCGASNF+BCINDM+REBATE
      -(A(1890)+.365*GASPRO/J1L*RESBASE)*PEXOG*RESCOST
      )*(STPNOM**.5)

KRENTC1$   RENTS TO CANADIAN USERS OF NON-FRONTIER GAS
     KRENTC1$=(3.65*(PGAS-PGASREG)*(GASPRO-EXGASNF)
      )*(STPNOM**.5)+J1L*KRENTC1$*(STPNOM)
     IF KRENTC1$<1. THEN  KRENTC1$=0.

KRENTC2$ - RENTS TO AMERICAN USERS OF CANADIAN NON-FRONTIER GAS
     KRENTC2$=J1L*KRENTC2$*STPNOM+(3.65*EXGASNF
      *(PGAS-PEXPORTG-A(2139))
      )*(STPNOM**.5)

KRENTGAS - TOTAL RENTS FROM NON-FRONTIER GAS PRODUCTION
     IF NTIME<=73 THEN  A(2138)=PEXPORTG-PGASNF
     IF NTIME>=74 THEN  A(2138)=.66*A(1901)*PEXOG/1.95
     IF NTIME<=73 THEN  A(2139)=11.
     IF NTIME>=74 THEN  A(2139)=11.*PEXOG/1.56
     KRENTGAS=J1L*KRENTGAS*STPNOM+(3.65*GASPRO
      *PGAS-(A(1890)+A(1895)+.365*GASPRO/J1L*RESBASE)
      *PEXOG*RESCOST-3.65*(GASPRO-EXGASNF)*1.16
      *A(1901)*PEXOG/1.95-3.65*EXGASNF*(A(2138)+A(2139))
      -3.65*GASPRO*A(1909)*PGNE
      )*(STPNOM**.5)

CALCULATE THE PRESENT VALUE OF THE RENTS IN THE LAST SIMULATION YEAR
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      IF K7=M9 THEN  KRENTNF$=KRENTNF$/(STPNOM**(K7-3))
      IF K7=M9 THEN  KRNFGP$=KRNFGP$/(STPNOM**(K7-3))
      IF K7=M9 THEN  KRNFGF$=KRNFGF$/(STPNOM**(K7-3))
      IF K7=M9 THEN  KRENTC1$=KRENTC1$/((STPNOM)**(K7-3))
      IF K7=M9 THEN  KRENTC2$=KRENTC2$/(STPNOM**(K7-3))
      IF K7=M9 THEN  KRENTGAS=KRENTGAS/(STPNOM**(K7-3))

RENTCANT - TOTAL RENTS ACCRUING TO CANADIANS FROM NON-FRONTIER AND
 FRONTIER GAS, AND THE MACKENZIE VALLEY PIPELINE
      RENTCANT=RENTCAN$+KRENTGAS-.785*KRENTNF$-KRENTC2$

EXPORTS
      EXPORTS=EXGASNF*.365

XBALGO$ IS THE TRADE ACCOUNT BALANCE ON OIL AND GAS
      XBALGO$=10.*EXPORTS*PEXPORTG+.365*CILXTOT*POILUS
        -.365*PO.OFF*OILIMPT

CANADIAN REQUIREMENTS FOR NATURAL GAS
      CAN.REQ.=(QGAS+(1.-A(2136))*LOSSGAS)/1000.

THE DESIRED FLOW OF PRODUCTION FROM CANADIAN SOURCES
      SUM=EXPORTS+CAN.REQ.

THE DEFICIT IN NATURAL GAS PRODUCTION
      DEFICIT=SUM/.365-GASMAX-(1.-EGASXD)*.889*EGASD
      IF DEFICIT<=0. THEN  DEFICIT=0.

GASMAXA IS THE ANNUAL FLOW OF GASMAX
      GASMAXA=GASMAX*.365
      IF GASMAXA<.01 THEN  GASMAXA=0.
```

2. EQUATIONS FOR EXOGENOUS VARIABLES

```
SET THE ROYALTY RATE COEFFICIENT
    IF NTIME<74 THEN  A(1904)=.16666667
    IF NTIME>=74 THEN  A(1904)=.25

SET THE COST COEFFICIENTS FOR EXPLORATION AND DEVELOPMENT
    IF NTIME<67 THEN  A(1907)=.162781
    IF NTIME<67 THEN  A(1908)=-3.32951
    IF NTIME>=67 THEN  A(1907)=.637365
    IF NTIME>=67 THEN  A(1908)=16.6332

SET THE COEFFICIENT FOR GAS PLANT EXPENDITURE
    IF NTIME>=58 THEN  A(2141)=443.094+GASPLADJ
    IF NTIME>=74 THEN  A(2141)=443.094

SET THE COEFFICIENT FOR EXPENDITURE ON LAND ACQUISITION
    IF NTIME>=58 THEN  A(1906)=2.51086+GASLADJ
    IF NTIME>=75 THEN  A(1906)=2.51086

PGASREG IS THE REGULATED TORONTO CITY GATE PRICE
    IF NTIME=55 THEN  PGASREG=39.4
    IF NTIME=56 THEN  PGASREG=39.6
    IF NTIME=57 THEN  PGASREG=40.0
    IF NTIME=58 THEN  PGASREG=38.5
    IF NTIME=59 THEN  PGASREG=38.6
    IF NTIME=60 THEN  PGASREG=39.0
    IF NTIME=61 THEN  PGASREG=41.9
    IF NTIME=62 THEN  PGASREG=42.6
    IF NTIME=63 THEN  PGASREG=43.8
    IF NTIME=64 THEN  PGASREG=44.4
    IF NTIME=65 THEN  PGASREG=44.4
    IF NTIME=66 THEN  PGASREG=45.1
    IF NTIME=67 THEN  PGASREG=45.6
    IF NTIME=68 THEN  PGASREG=45.7
    IF NTIME=69 THEN  PGASREG=45.7
    IF NTIME=70 THEN  PGASREG=46.4
    IF NTIME=71 THEN  PGASREG=46.2
    IF NTIME=72 THEN  PGASREG=46.9
    IF NTIME=73 THEN  PGASREG=53.3
    IF NTIME=74 THEN  PGASREG=82.
    IF NTIME=75 THEN  PGASREG=100.

PEXOG IS THE ASSUMED RATE OF INFLATION
    IF NTIME<=73 THEN  A(1972)=.037752
    IF NTIME>=74 THEN  A(1972)=.04
    IF NTIME<=72 THEN  PEXOG=(1.+A(1972))**(NTIME-61)
    IF NTIME=73 THEN  PEXOG=1.56
    IF NTIME=74 THEN  PEXOG=1.77
    IF NTIME=75 THEN  PEXOG=1.95
    IF NTIME=76 THEN  PEXOG=2.11
    IF NTIME>76 THEN  PEXOG=J1L*PEXOG*(1.+A(1972))

SET THE NATURAL GAS TRANSPORTATION TARIFF
    IF NTIME<=72 THEN  A(1901)=30.*1.95/1.16/PEXOG
    IF NTIME=73 THEN  A(1901)=35.*1.95/1.16/PEXOG
    IF NTIME>=74 THEN  A(1901)=42.
```

```
IF APPLICABLE, DEMAND IS THE EXOGENOUS DEMAND SERIES
     IF NTIME=73 THEN  DEMAND=3.937
     IF NTIME=74 THEN  DEMAND=4.216
     IF NTIME=75 THEN  DEMAND=4.347
     IF NTIME>=76 THEN  DEMAND=1.08*J1L*DEMAND
     IF NTIME>=77 THEN  DEMAND=5.070*((1.05)**(NTIME-77))
      *((49.10*J3L*PEXOG/J3L*PGASREG)**.2)

DEMANDA INTRODUCES SPECIFIC DEMAND FORECASTS
     IF NTIME>=91 THEN  DEMANDA=J1L*DEMANDA*1.047
     IF DEMANDA>0.0 THEN  DEMAND=DEMANDA/365.

EXGASNF IS THE APPROVED EXPORT SERIES FOR NATURAL GAS
     IF NTIME=55 THEN  EXGASNF=11.16/365.
     IF NTIME=56 THEN  EXGASNF=10.64/365.
     IF NTIME=57 THEN  EXGASNF=21.34/365.
     IF NTIME=58 THEN  EXGASNF=90.26/365.
     IF NTIME=59 THEN  EXGASNF=83.71/365.
     IF NTIME=60 THEN  EXGASNF=110.37/365.
     IF NTIME=61 THEN  EXGASNF=164.34/365.
     IF NTIME=62 THEN  EXGASNF=339.18/365.
     IF NTIME=63 THEN  EXGASNF=355.57/365.
     IF NTIME=64 THEN  EXGASNF=386.38/365.
     IF NTIME=65 THEN  EXGASNF=390.92/365.
     IF NTIME=66 THEN  EXGASNF=391.18/365.
     IF NTIME=67 THEN  EXGASNF=463.03/365.
     IF NTIME=68 THEN  EXGASNF=519.75/365.
     IF NTIME=69 THEN  EXGASNF=645.82/365.
     IF NTIME=70 THEN  EXGASNF=772.44/365.
     IF NTIME=71 THEN  EXGASNF=898.27/365.
     IF NTIME=72 THEN  EXGASNF=999.16/365.
     IF NTIME=73 THEN  EXGASNF=1017.9/365.
     IF NTIME=74 THEN  EXGASNF=2.80
     IF NTIME=75 THEN  EXGASNF=2.77
     IF NTIME=76 THEN  EXGASNF=2.76
     IF NTIME=77 THEN  EXGASNF=2.77
     IF NTIME=78 THEN  EXGASNF=2.78
     IF NTIME=79 THEN  EXGASNF=2.74
     IF NTIME=80 THEN  EXGASNF=2.73
     IF NTIME=81 THEN  EXGASNF=2.72
     IF NTIME=82 THEN  EXGASNF=2.37
     IF NTIME=83 THEN  EXGASNF=2.34
     IF NTIME=84 THEN  EXGASNF=2.32
     IF NTIME=85 THEN  EXGASNF=2.29
     IF NTIME=86 THEN  EXGASNF=2.09
     IF NTIME=87 THEN  EXGASNF=1.72
     IF NTIME=88 THEN  EXGASNF=1.71
     IF NTIME=89 THEN  EXGASNF=1.54
     IF NTIME=90 THEN  EXGASNF=.57
     IF NTIME=91 THEN  EXGASNF=.32
     IF NTIME=92 THEN  EXGASNF=.15
     IF NTIME=93 THEN  EXGASNF=.13
     IF NTIME=94 THEN  EXGASNF=.02
     IF NTIME=95 THEN  EXGASNF=.02
     IF NTIME>=96 THEN  EXGASNF=0.

GMAXA IS USED TO READ IN AN OPTIONAL GASMAX73 SERIES
     IF GMAXA>0.0 THEN  GASMAX73=GMAXA/365.
```

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2.C    NON FRONTIER CONVENTIONAL CRUDE OIL PRODUCTION

1. EQUATIONS FOR ENDOGENOUS VARIABLES

THE SWITCH ALLOWS EITHER AN ENDOGENOUS OR EXOGENOUS DEMAND SERIES
     IF A(2131)=0 THEN  GO TO 10
     IF NTIME=73 THEN  QOILEAST=319.121-LOILEAST
     IF NTIME=74 THEN  QOILEAST=326.131-LOILEAST
     IF NTIME=73 THEN  QOILWEST=297.006-LOILWEST
     IF NTIME=74 THEN  QOILWEST=319.626-LOILWEST

NEB DEMAND GROWTH ASSUMPTIONS - TO BE USED IF DEMAND IS EXOGENOUS
     IF NTIME>=75 THEN  QOILEAST=1.031*J1L*QOILEAST
     IF NTIME>=75 THEN  QOILWEST=1.031*J1L*QOILWEST

OIL PRODUCTION
10   OILPRO=(QOILWEST+LOILWEST)/.365 +A(1941)+OILEXPT-GCOSPRO-CPROSUM

DESPRO IS THE DESIRED PRODUCTION
     DESPRO=OILPRO
     IF OILPRO>OILMAX THEN  OILPRO=OILMAX
     IF .365*CILPRO>J1L*OILRBASE THEN  OILPRO=J1L*OILRBASE/.365

OIL RESERVE BASE
     OILRBASE=J1L*OILRBASE+OILRDISC-.365*OILPRO

ACCUMULATION OF OIL PRODUCTION
     OILACUM=J1L*CILACUM+.365*OILPRO

COST OF HOLDING RESERVES
     OILRCOST=J1L*OILRCOST*(1.-.365*OILPRO/J1L*CILRBASE)
       +(A(1933)*(OILACUM+OILRBASE)-A(1934)+OILCADJ)*OILRDISC

SET THE OPERATING COST COEFFICIENT
     IF NTIME<=74 THEN  A(1936)=.449909-.0000330268*OILACUM+OILOPADJ
     IF NTIME>=75 THEN  A(1936)=.20

SET THE COEFFICIENT FOR LAND ACQUISITION EXPENDITURE
     IF NTIME>=58 THEN  A(1944)=.690395-.0000911148*OILACUM+OILLADJ
     IF NTIME>=75 THEN  A(1944)=.08214

MARGINAL COST OF FINDING, DEVELOPING AND PRODUCING OIL RESERVES
     OILCOSTM=2.11*(A(1933)*(OILACUM+OILRBASE)-A(1934)+OILCADJ)
       *A(1935)+A(1936)*2.11
     IF (OILACUM+OILRBASE)>=A(1937) THEN  OILCOSTM=0.0

US MID-WEST PRICE OF OIL; AND EXPORT TAX RATE, $/BBL
     POILUS=PO.OFF+A(1938)*PEXOG/1.56
     IF NTIME>=74 THEN  RTOILEXP=POILUS-POW.PR-A(1940)*PEXOG/1.56

TXOIL IS THE FEDERAL GOVERMENT REVENUE FROM THE EXPORT TAX
     TXOIL=.365*OILXTOT*RTOILEXP

CALCULATE MAXIMUM FLOW FROM EXISTING STOCK OF RESERVES
     OILLAG=J8I*CILADD
     DI=A(1942)
     DF=DI*.30892915*(.85)**15
     DH=.5*DI
     IF (OILPRO-J1L*OILPRO)/J1L*OILPRO>A(1949) AND NTIME<=56 THEN
        DH=(.5+A(1951))*DI
```

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      IF (OILPRO-J1L*OILPRO)/J1L*CILPRO>A(1950) AND NTIME>=57 THEN
         DH=(.5+A(1951))*DI
      S2=DH*OILADD
      DO 40 I=1,8
      J1=LO(I)
40    S2=S2+JIL*OILADD*DI
      S3=0.0
      DO 50 I=1,15
      J1=LO(I)
50    S3=S3+JIL*OILLAG*DI*(.85**I)
      S4=0.0
      J1=LO(16)
      S4=S4+JIL*OILLAG*DF
      OILMAX=OILMAX74+(S2+S3+S4)/.365

 IF EXCESS  CAPACITY EXISTS THEN REDUCE FLOW FROM PREVIOUS OILADD'S
      IF OILMAX-OILADD*DH/.365>DESPRO THEN  EXCESS=
        (OILMAX-DESPRO)/((S2+S3+S4)/.365)
      IF OILMAX-OILADD*DH/.365>DESPRO THEN  OILADD=0.0

 OILPIPEM IS THE THROUGHPUT OF THE MONTREAL PIPELINE
      OILPIPEM=A(1941)
      IF DESPRO>OILMAX THEN  OILPIPEM=OILMAX-DESPRO+A(1941)

 MAXIMUM PRODUCTION FLOW NET OF ANY CURRENT ADDITIONS
      OILFLO=OILMAX-OILADD*DH/.365

 CALCULATE AMOUNT OF RESERVES TO BE HOOKED UP TO MEET CURRENT DEMAND
      IF DESPRO>=OILFLO THEN  OILADD=(DESPRO-OILFLO)*.365/DH
      IF A(1948)>0.0 AND NTIME>A(1948) THEN  OILADD=0.0

 REMD REPRESENTS THE ULTIMATE STOCK OF UNDISCOVERED RESERVES
      IF K7=1 THEN  REMD=A(1937)-J1L*OILRBASE-J1L*CILACUM

 TOTAL DISCOVERIES OF RESERVES FROM BEGINNING OF SIMULATION
      OILDISCT=J1L*CILDISCT+OILRDISC
      IF OILDISCT>=REMD THEN  GO TO 21

 WHEN GENERATING OILMAX74 SET OILRDISC=0
      IF NTIME>=47 AND NTIME<=50 THEN  OILRDISC=0.0

 DISCOVERIES FROM 1947-1974 ARE ACTUAL SERIES
 DISCOVERIES FROM 1975 ARE THE GULF SERIES FROM NEB(1975) REPORT
      IF NTIME=51 THEN  OILRDISC=221.311
      IF NTIME=52 THEN  OILRDISC=363.409
      IF NTIME=53 THEN  OILRDISC=246.823
      IF NTIME=54 THEN  OILRDISC=457.808
      IF NTIME=55 THEN  OILRDISC=429.427
      IF NTIME=56 THEN  OILRDISC=509.157
      IF NTIME=57 THEN  OILRDISC=206.837
      IF NTIME=58 THEN  OILRDISC=457.495
      IF NTIME=59 THEN  OILRDISC=514.959
      IF NTIME=60 THEN  OILRDISC=372.522
      IF NTIME=61 THEN  OILRDISC=716.055
      IF NTIME=62 THEN  OILRDISC=522.016
      IF NTIME=63 THEN  OILRDISC=657.277
      IF NTIME=64 THEN  OILRDISC=1566.953
      IF NTIME=65 THEN  OILRDISC=825.183
      IF NTIME=66 THEN  OILRDISC=1396.567
      IF NTIME=67 THEN  OILRDISC=721.329
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      IF NTIME=68 THEN  OILRDISC=584.157
      IF NTIME=69 THEN  OILRDISC=631.595
      IF NTIME=70 THEN  OILRDISC=377.198
      IF NTIME=71 THEN  OILRDISC=254.233
      IF NTIME=72 THEN  OILRDISC=205.074
      IF NTIME=73 THEN  OILRDISC=279.668
      IF NTIME=74 THEN  OILRDISC=98.234
      IF NTIME=75 THEN  OILRDISC=181.0
      IF NTIME=76 THEN  OILRDISC=168.0
      IF NTIME=77 THEN  OILRDISC=156.0
      IF NTIME=78 THEN  OILRDISC=147.0
      IF NTIME=79 THEN  OILRDISC=135.0
      IF NTIME=80 THEN  OILRDISC=129.0
      IF NTIME=81 THEN  OILRDISC=118.0
      IF NTIME=82 THEN  OILRDISC=112.0
      IF NTIME=83 THEN  OILRDISC=103.0
      IF NTIME=84 THEN  OILRDISC=95.0
      IF NTIME=85 THEN  OILRDISC=91.0
      IF NTIME=86 THEN  OILRDISC=82.0
      IF NTIME=87 THEN  OILRDISC=76.0
      IF NTIME=88 THEN  OILRDISC=73.0
      IF NTIME=89 THEN  OILRDISC=69.0
      IF NTIME=90 THEN  OILRDISC=65.0
      IF NTIME=91 THEN  OILRDISC=61.0
      IF NTIME=92 THEN  OILRDISC=56.0
      IF NTIME=93 THEN  OILRDISC=52.0
      IF NTIME>=94 THEN  OILRDISC=50.0
      IF A(1948)>0.0 AND NTIME>A(1948) THEN  OILRDISC=0.0
21    IF (J1L*CILDISCT+OILRDISC)>=REMD THEN  OILRDISC=REMD-J1L*OILDISCT
      IF OILRDISC<0.0 THEN  OILRDISC=0.0
      IF OILADD>(J1L*OILREXES+OILRDISC) THEN  OILADD=J1L*OILREXES+OILRDISC
      IF OILADD<0.0 THEN  OILADD=0.0

 EXCESS OIL RESERVES
      OILREXES=J1L*OILREXES+OILRDISC-OILADD

 ADD TO OILREXES IF OILMAX74>CILPRO
      IF OILMAX74>DESPRO THEN  OILREXES=J1L*OILREXES+.365*(OILMAX74-DESPRO)
         +OILRDISC
      IF OILMAX74>DESPRO THEN  EXCESS=0.0
      IF OILREXES<0.0 THEN  OILREXES=0.0

 TAXATION EQUATIONS FOR NON-FRONTIER OIL PRODUCTION

 EFFECTIVE FEDERAL AND PROVINCIAL CORPORATE TAX RATES
      IF NTIME=74 THEN  ETXRTF=.30
      IF NTIME=75 THEN  ETXRTF=.28
      IF NTIME>=76 THEN  ETXRTF=.234
      IF NTIME=74 THEN  ETXRTP=.1116
      IF NTIME=75 THEN  ETXRTP=.1118
      IF NTIME>=76 THEN  ETXRTP=.07306

 TAXABLE INCOME OF NCN-FRONTIER OIL PRODUCTION
      IF NTIME<=73 THEN
       YOILNFT=.365*OILPRO*(POW.PR-A(1936)*PGNE-A(1944)*
       PGNE-A(1945)*POW.PR)-(.365*OILPRO/J1L*CILRBASE)
       *OILRCOST*PEXOG
      IF NTIME>=74 THEN
       YOILNFT=.365*OILPRO*(POW.PR-A(1936)*PGNE-A(1944)*
       PGNE)-(.365*OILPRO/J1L*OILRBASE)*OILRCOST*PEXOG
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FRACTION OF TAXABLE PROFITS ALLOWED FOR EARNED DEPLETION
     IF NTIME>=74 THEN
       DEPLE=(PEXOG*.333*(A(1933)*(OILACUM+OILRBASE)-A(1934)
       +OILCADJ)*OILRDISC+J1L*KOILEDP$)/YOILNFT
     IF NTIME<=73 THEN  OILREDPA=.333
     IF NTIME>=74 AND DEPLE<=.25 THEN  OILREDPA=DEPLE
     IF NTIME>=74 AND DEPLE>.25 THEN  OILREDPA=.25

STOCK OF UNCLAIMED EARNED DEPLETION
     IF NTIME>=70 AND NTIME<=73 THEN
      KOILEDP$=(PEXOG*.333*(A(1933)*(OILACUM+OILRBASE)
       -A(1934)+OILCADJ)*OILRDISC+J1L*KOILEDP$)
     IF NTIME>=74 THEN
      KOILEDP$=(DEPLE-OILREDPA)*YOILNFT

CORPORATION TAX ON NON-FRONTIER OIL PRODUCTION
     IF NTIME<=73 THEN  TROYLO=0.
     IF TROYLO<0. THEN  TROYLO=0.
     IF NTIME=74 THEN  TROYLO=.365*OILPROLD*(.40*POW.PR)
        +.365*(OILPRO-OILPROLD)*(.28*POW.PR)-.35*(.40*OILRDISC)
     IF NTIME>=75 THEN  TROYLO=.365*OILPROLD*(.36*POW.PR)
        +.365*(OILPRO-OILPROLD)*(.27*POW.PR)
        -.45*(.40*OILRDISC*PEXOG/1.77)
     IF NTIME<=73 THEN
      TCOILNF=A(1946)*(1.-OILREDPA)*YOILNFT
     IF NTIME>=74 THEN
      TCOILNF=ETXRTF*(1.-OILREDPA)*YOILNFT+ETXRTP*(1.-OILREDPA)
      *(YCILNFT-TROYLO)

EXPORTS
     OILXTOT=OILEXPT

CANADIAN DEMAND FOR CRUDE OIL
     OILCAND=(QOILEAST+LOILEAST+QOILWEST+LOILWEST)/.365

OIL IMPORTS
     OILIMPT=OILCAND+OILXTOT-OILPRO-CPROSUM-GCOSPRO

XBALGO$ IS THE TRADE ACCOUNT BALANCE ON OIL AND GAS
     XBALGO$=10.*EXPORTS*PEXPORTG+.365*OILXTOT*POILUS
       -.365*PO.OFF*OILIMPT

DESIRED PRODUCTION FROM NON-FRONTIER SOURCES
     OILSUM=DESPRO

OIL DEFICIT FROM NON-FRONTIER SOURCES
     OILDEF=OILSUM-OILPRO

ECONOMIC RENT EQUATIONS FOR NON-FRONTIER OIL PRODUCTION

SET THE NOMINAL DISCOUNT RATE
     STP1=1.+A(1890)*((1.+A(1890))**.5)
     STP2=1.+A(1890)*(STP1**.5)
     A(1894)=A(1890)*(STP2**.5)
     STPNOM=(1.+A(1894))*(1.+A(1972))
     IF NTIME=74 THEN  STPNOM=(1.+A(1894))*(1.77/1.56)
     IF NTIME=75 THEN  STPNOM=(1.+A(1894))*(1.95/1.77)
     IF NTIME=76 THEN  STPNOM=(1.+A(1894))*(2.11/1.95)

B.C. INDEMNIFICATION OF FEDERAL TAXES PAID BY PRODUCERS
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RE:  OIL ROYALTIES
    IF NTIME>=74 THEN  BCINDM=ETXRTF*.032*TROYLO

ALBERTA SELECTIVE ROYALTY REDUCTION, A CASH TRANSFER TO PRODUCERS
    IF NTIME>=74 THEN  REBATE=15.+.0263*TROYLO

PROVINCIAL GOVERNMENT RENT EQUATIONS
    IF NTIME<=73 THEN  KROILGP$=
     J1L*KROILGP$*STPNOM+((A(1944)*PGNE+A(1945)*POW.PR)
     *.365*OILPRO+A(1952)*(TCOILNF-A(1895)*PEXOG*OILRCOST))
     *(STPNOM**.5)
    IF NTIME>=74 THEN
     KROILGP$=J1L*KROILGP$*STPNOM+(A(1944)*PGNE*.365*OILPRO
     +TROYLO+ETXRTP*(1.-OILREDPA)*(YOILNFT-TROYLO)-BCINDM-REBATE
     -(A(1895)*PEXOG*OILRCOST)*A(1952))
     *(STPNOM**.5)

FEDERAL GOVERNMENT RENT EQUATIONS
    IF NTIME<=73 THEN
     KROILGF$=J1L*KROILGF$*STPNOM+(1.-A(1952))*(TCOILNF
     -A(1895)*PEXOG*OILRCOST)
     *(STPNOM**.5)
    IF NTIME>=74 THEN
     KROILGF$=J1L*KROILGF$*STPNOM+(ETXRTF*(1.-OILREDPA)*YOILNFT
     -(A(1895)*PEXOG*OILRCOST)*(1.-A(1952))
     +TXOIL-GFSUBO)*(STPNOM**.5)

PRODUCER RENT EQUATIONS
    IF NTIME<=73 THEN
     KROILP$=J1L*KROILP$*STPNOM+(.365*OILPRO*(POW.PR
     -A(1936)*PGNE-A(1944)*PGNE-A(1945)*POW.PR)
     -TCOILNF-(A(1890)+.365*OILPRO/J1L*OILRBASE)
     *PEXOG*OILRCOST)*(STPNOM**.5)
    IF NTIME>=74 THEN
     KROILP$=J1L*KROILP$*STPNOM+(.365*OILPRO*(POW.PR
     -A(1936)*PGNE-A(1944)*PGNE)
     -TCOILNF-TROYLO+BCINDM+REBATE
     -(A(1890)+.365*OILPRO/J1L*OILRBASE)*PEXOG*OILRCOST)
     *(STPNOM**.5)

RENTS TO CANADIAN OIL CONSUMERS
    KROILC1$=J1L*KROILC1$*STPNOM +(STPNOM**.5)*
     ((OILPRO-OILXTOT)*.365*(PO.OFF-POW.PR-POT.PO)
     +GFSUBO)

TOTAL RENTS FOR NON-FRONTIER OIL PRODUCTION
    IF NTIME<=73 THEN  KRENTOIL=J1L*KRENTOIL*STPNOM+(STPNOM**.5)
     *(.365*OILPRO*(PO.OFF-A(1936)*PGNE)
     -(A(1890)+A(1895)+.365*OILPRO/J1L*OILRBASE)
     *PEXOG*OILRCOST
     -(.365*OILXTOT*(PO.OFF-POW.PR))
     -(.365*(OILPRO-OILXTOT)*POT.PO))
    IF NTIME>=74 THEN  KRENTOIL=J1L*KRENTOIL*STPNOM+(STPNOM**.5)
     *(.365*OILPRO*(PO.OFF-A(1936)*PGNE)
     -(A(1890)+A(1895)+.365*OILPRO/J1L*OILRBASE)
     *PEXOG*OILRCOST
     -(.365*(OILPRO-OILXTOT)*POT.PO))

CALCULATE THE PRESENT VALUE OF THE RENTS IN THE LAST SIMULATION YEAR
    IF K7=M9 THEN  KROILGP$=KROILGP$/(STPNOM**(K7-3))
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      IF K7=M9 THEN  KRCILGF$=KROILGF$/(STPNOM**(K7-3))
      IF K7=M9 THEN  KROILP$=KROILP$/(STPNOM**(K7-3))
      IF K7=M9 THEN  KRCILC1$=KROILC1$/(STPNOM**(K7-3))
      IF K7=M9 THEN  KRENTOIL=KRENTOIL/(STPNOM**(K7-3))

'TOTAL CANADIAN RENTS FROM NON-FRONTIER OIL PRODUCTION
      KROILCAN=KRCILGP$+KRCILGF$+.215*KROILP$+KROILC1$
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2. EQUATIONS FOR EXOGENOUS VARIABLES

SET OILPROLD EQUAL TO FRACTION OF OILMAX74 (USED FOR ROYALTY EQUATION)
    IF NTIME>=74 THEN  OILPROLD=OILMAX74*.99**(NTIME-74)

SET THE COEFFICIENTS FOR THE EXPLORATION AND DEVELOPMENT COSTS
    IF NTIME<67 THEN  A(1933)=-.0000676273
    IF NTIME<67 THEN  A(1934)=-.912365
    IF NTIME>=67 THEN  A(1933)=.000393415
    IF NTIME>=67 THEN  A(1934)=4.41140

SET THE COEFFICIENT FOR THE ROYALTY RATE
    IF NTIME<74 THEN  A(1945)=.140
    IF NTIME<62 THEN  A(1945)=.125
    IF NTIME>=74 THEN  A(1945)=.40

SET GCOSPRO=50 UNTIL 1977, AND THEN =65. AFTER 1977
    IF NTIME>=75 THEN  GCOSPRO=50.0
    IF NTIME>=78 THEN  GCOSPRO=65.0

SET MONTREAL PIPELINE FLOW
    IF NTIME=58 THEN  A(1941)=-11.128
    IF NTIME=59 THEN  A(1941)=-6.534
    IF NTIME=60 THEN  A(1941)=-10.003
    IF NTIME=61 THEN  A(1941)=-6.505
    IF NTIME>=62 AND NTIME<=72 THEN  A(1941)=0.0
    IF NTIME=73 THEN  A(1941)=15.2
    IF NTIME=74 THEN  A(1941)=64.8
    IF NTIME=75 THEN  A(1941)=6.2
    IF NTIME=76 THEN  A(1941)=100.0
    IF NTIME=77 THEN  A(1941)=250.0


    IF J1L*EXCESS<=0.0 THEN  GO TO 12

INCREASE PRODUCIBILITY FOR ONE YEAR DUE TO CUTBACK LAST YEAR
    DO 10 I=1,8
    J1=LO(I)
10  JIL*OILADD=JIL*OILADD*(1.+J1L*EXCESS)
    DO 11 I=1,16
    J1=LC(I)
11  JIL*OILLAG=JIL*OILLAG*(1.+J1L*EXCESS)
12  IF J2L*EXCESS<=0.0 THEN  GO TO 16

RESTORE PRODUCTION RATE AS IT WAS BEFORE INCREASED LAST YEAR
    DO 13 I=1,8
    J1=LC(I)
13  JIL*OILADD=JIL*OILADD/(1.+J2L*EXCESS)
    DO 15 I=1,16
    J1=LC(I)
15  JIL*CILLAG=JIL*OILLAG/(1.+J2L*EXCESS)
16  CONTINUE
    IF K7=1 THEN  GO TO 17
    DI=A(1942)
    IF (J1L*CILPRO-J2L*OILPRO)/J2L*OILPRO>A(1949) AND NTIME<=57 THEN
       J1L*CILADD=((1.-(.5+A(1951))*DI)/(1.-.5*DI))*J1L*OILADD
    IF (J1L*CILPRO-J2L*OILPRO)/J2L*OILPRO>A(1950) AND NTIME>=58 THEN
       J1L*CILADD=((1.-(.5+A(1951))*DI)/(1.-.5*DI))*J1L*OILADD
```

```
17   CONTINUE

 OIL EXPORTS (APPROXIMATE SERIES FROM GRAPH IN NEB(1975) REPORT)
     IF NTIME=76 THEN  OILEXPT=460.0
     IF NTIME=77 THEN  OILEXPT=350.0
     IF NTIME>77 THEN  OILEXPT=.60*J11*CILEXPT
```

2.D EQUATIONS FOR FUEL LOSSES AND ADJUSTMENTS PLUS ENERGY SUPPLY USE

1. EQUATICNS FOR ENDOGENOUS VARIABLES
LOSS FOR GAS IN BCF
LOSS FOR OIL IN MMBBL
LOSS FOR ELECTRICITY IN TRILLIONS KWH

LOSSES FOR ELECTRICITY ARE A PROPORTION OF REGIONAL SALES

```
LOSSL.AT=A(2056)*(QL.AT/A(1922))  +TEMP(LOSSL.AT)
LOSSL.QU=A(2057)*(QL.QU/A(1922))  +TEMP(LOSSL.QU)
LOSSL.ON=A(2058)*(QL.ON/A(1922))  +TEMP(LOSSL.ON)
LOSSL.PR=A(2059)*(QL.PR/A(1922))  +TEMP(LOSSL.PR)
LOSSL.BC=A(2060)*(QL.BC/A(1922))  +TEMP(LOSSL.BC)
```

LOSSES FOR CRUDE OIL ARE A PROPORTION OF REGIONAL SALES

```
LOILAT=A(2046)*QO.AT/(A(1955)*A(1921))  +TEMP(LOILAT)
LOILQU=A(2047)*QO.QU/(A(1956)*A(1921))  +TEMP(LOILQU)
LOILON=A(2050)*QO.ON/(A(1957)*A(1921))  +TEMP(LOILON)
LOILPR=A(2066)*QO.PR/(A(1958)*A(1921))  +TEMP(LOILPR)
LOILBC=A(2069)*QO.BC/(A(1959)*A(1921))  +TEMP(LOILBC)
LOILEAST=LOILAT+LOILQU  +TEMP(LOILEAST)
LOILWEST=LOILON+LOILPR+LOILBC  +TEMP(LOILWEST)
```

LOSSES FOR NATURAL GAS ARE A PROPORTION OF SALES FOR QUEBEC AND ONTARIO;
BUT LOSSES ARE A PROPORTION OF PRODUCTION FOR PRAIRIES AND BC

```
LGASQU=A(2074)*QG.QU/(A(1960)*A(1923))  +TEMP(LGASQU)
LGASON=A(2133)*QG.ON/(A(1981)*A(1923))  +TEMP(LGASON)
LGASPR=A(2134)*(.843*GASPRO*365.)  +TEMP(LGASPR)
LGASBC=A(2135)*(.157*GASPRO*365.)  +TEMP(LGASBC)
LOSSGAS=LGASQU+LGASON+LGASPR+LGASBC  +TEMP(LOSSGAS)
```

3. Description of the Demand Sector

The following description will explain the abreviations and mnemonics that occur throughout the following demand appendicies, especially in appendix A, B and D. In each of the equations, the parameters are in lower case and the variables are in upper case. The following conventions were adapted for structuring the mnemonics for the variables:

- any two letter variable beginning with 'S' denotes a share,
- any two letter variable beginning with 'P' denotes a price,
- any two letter variable beginning with 'Q' denotes a quantity,
- the variable 'C' represents total energy cost,
- any variable beginning with 'DUM' denctes a regional shift variable,
- 'ln' preceding a variable denotes that the variable is in natural logarithms;
- any of the share, price or quantity variables ending in 'O' denotes crude oil,
- any of the share, price or quantity variables ending in 'G' denotes natural gas,
- any of the share, price or quantity variables ending in 'I' denotes electricity,
- any of the share, price or quantity variables ending in 'C' denotes coal;
- any of the variables ending in 'AT' denote the Atlantic region,
- any of the variables ending in 'QU' denote the Quebec region,
- any of the variables ending in 'ON' denote the Ontario region,
- any of the variables ending in 'PR' denote the Prairie region,
- any of the variables ending in 'BC' denote the B.C. region.

The following conventions were adapted for structuring the mnemcnics for the parameters:

- any parameter beginning with an 'a' or 'd' is associated with a regional shift variable,
- any parameter beginning with a 'b' is associated with a price variable,
- any parameter beginning with a 'c' is associated with the pipeline mile variable,
- any parameter beginning with an 'e' is associated with other variable types;
- any of the 'a' or 'd' parameters that end with '1' are associated with the Atlantic region,
- any of the 'a' or 'd' parameters that end with '2' are associated with the Quebec region,
- any of the 'a' or 'd' parameters that end with '3' are associated with the Ontario region,
- any of the 'a' or 'd' parameters that end with '4' are associated with the Prairie region,
- any of the 'a' or 'd' parameters that end with '5' are associated with the B.C. region;
- any of the parameters that contain an 'o' are associated with crude oil,
- any of the parameters that contain a 'g' are associated with natural gas,

any of the parameters that contain an 'l' are associated with electricity,
any of the parameters that contain a 'c' are associated with coal.

The results of all of the estimations have been obtained from the TSP program available at UBC . The following abreviations have been used whenever an estimation procedure has been reported:

log L is the logarithm of the likelihood function,
R^2 is the coefficient of determination, used to measure the goodness of fit for the regression,
dw is the Durbin-Watson statistic, used to measure the degree of autocorrelation,
rho is the first order serial autocorrelation coefficient,
ser is the standard error of the regression,
Y is the mean of the dependent variable,
nobs is the number of observation points used in the regression,
estimation period is the historical time period for the data,
OLS estimation procedure is the ordinary least squares technique,
iterative Zellner estimation procedure is a technique used in a multivariate system, which is equivalent to maximum likelihood estimation,
Cochrane- Orcutt estimation procedure is a technique used to correct autocorrelated residuals.

3.A Derivation of Cost Share Equations

The following derivation is performed for the main (non-thermal) set of demand equations which represent the demand for crude oil, natural gas, and electricity in Quebec, Ontario, Prairies, and B.C. regions. The derivation for the Atlantic region includes only the demand for crude oil and electricity. The derivation of each of the three sets of auxiliary (thermal) demand equations is performed in an analogous manner.

1. Quebec, Ontario, Prairies, B.C. equations:

The basic translog cost share equations are as follows:

SO = (PO*QO)/C = ao2*DUMQU + ao3*DUMON + ao4*DUMPR + ao5*DUMBC + boo*ln PO + bog*ln PG + bol*ln PL + co*GPM

SG = (PG*QG)/C = ag2*DUMQU + ag3*DUMON + ag4*DUMPR + ag5*DUMBC + bgo*ln PO + bgg*ln PG + bgl*ln PL + cg*GPM

SL = (PL*QL)/C = al2*DUMQU + al3*DUMON + al4*DUMPR + al5*DUMBC +blo*ln PO + blg*ln PG + bll*ln PL + cl*GPM .

The restrictions imposed upon the parameters of these equations are as follows:
cost shares sum to unity and linear homogeneity in prices
boo +bgo +blo = 0
bog + bgg +blg = 0
bol + bgl + bll = 0
co + cg + cl = 0
ao2 +ag2 + al2 = 1
ao3 + ag3 + al3 = 1
ao4 + ag4 + al4 = 1
ao5 + ag5 + al5 = 1
symmetry
bog = bgo
bol = blo
bgl = blg .

One of the equations must be dropped from the system during estimation. Arbitrarily the electricity cost share equation (SL) has been chosen. All of the parameters from the omitted equation can be obtained from the constraints:
al2 = 1 - ao2 - ag2
al3 = 1 - ao3 - ag3
al4 = 1 - ao4 - ag4
al5 = 1 - ao5 - ag5
blo = -boo - bgo
blg = -bog - bgg = -bgo - bgg
bll = -bcl - bgl = boo + bgg + 2*bgo
cl = -co - cg .

Using the symmetry conditions and linear homogeneity

conditions one can reduce the number of parameters in the two remaining share equations as follows:
bog = bgo
bol = -boo - bgo
blg = -bgg - bgo .

Hence one is left with estimating the following system cf two equations:

SO = (PO*QO)/C = ao2*DUMQU + ao3*DUMON + ao4*DUMPR + ao5*DUMBC + boo*ln PO + bgo*ln PG + (-boo-bgo)*ln PL + co*GPM

SG = (PG*QG)/C = ag2*DUMQU + ag3*DUMON + ag4*DUMPR + ag5*DUMBC + bgo*ln PO + bgg*ln PG + (-bgg-bgo)*ln PL + cg*GPM .

The parameters to be estimated are: ao2, ao3, ao4, ao5, ag2, ag3, ag4, ag5, boo, bgg, bgo, co, cg.

2. Atlantic equations:

The basic translog cost share equations are as follows:

SO = (PO*QO)/C = ao1*DUMAT + boo*ln PO + bol*ln PL

SL = (PL*QL)/C = al1*DUMAT + blo*ln PO + bll*ln PL .

The restrictions imposed upon the parameters of the equations are as follows:
cost shares sum to unity and linear homogeneity in prices
boo + blo = 0
bol + bll = 0
ao1 + al1 = 1
symmetry
bol = blo .

The electricity cost share equation (SL) is dropped, but the parameters of the equation can be obtained from the estimated parameters as follows:
al1 = 1 - ao1
blo = -boo
bll = -bol = boo .

Using the symmetry conditions and the linear homogeneity conditions the number of parameters in the estimated equation can be reduced as follows:
bol = -boo .

Hence the equation to be estimated has the following form:

SO = ao1 *DUMAT + boo*ln PO - boo*ln PL .

The parameters to be estimated are : ao1, boo.

3.B Parameter Estimates of Demand Equations

I Equations used for main (non-thermal) demand system

1. Total constant $ expenditure on primary energy fuels.
   (a) Atlantic region:

The form of the estimated equation is as follows:

$$\ln VE = d1*DUMAT + e1*\ln UGNE + e2*\ln(jw(PEN/PGNE)),$$

where VE is the real value of energy demand,
in millions of constant 1961$,
DUMAT is a regional dummy variable for the Atlantic,
UGNE is the real value of gross national expenditure,
millions of 1961$,
PEN is the Paasche price index of energy, 1961=1.0,
PGNE is the price index for gross national
expenditure, 1961=1.0,
jw represents a set of moving weights, with values
(.333, .333, .333)[1] .

The parameter estimates, with the t statistic in parenthesis, and equation statistics are as follows:

d1	-7.02688	(-1.287)	R^2 = .9515
e1	+1.11905	(2.188)	dw = .738
e2	- .629771	(1.012)	ser= .0778
			Y = 5.287
			nobs = 12
			estimation period: 1961-1972
			estimation procedure: OLS

(b) Quebec, Ontario, Praires and B.C. regions:

The form of the estimated equation is as follows:

$$\ln VE = d2*DUMQU + d3*DUMCN + d4*DUMPR + d5*DUMBC + e1*\ln UGNE + e2*\ln(jw\ (PEN/PGNE)),$$

where jw represents a set of moving weights, with values (.15, .35, .35, .15).

The parameter estimates, with t-statistic in parenthesis, and equations statistics are as follows:

d2	-5.39193	(-12.519)	R^2 = .9965
d3	-5.24249	(-12.080)	dw = 1.137

---

[1] When reporting a set of moving weights the convention will be used to place the numbers in brackets, with the first number being the weight for the current year, the second number for the preceding year, and so on.

d4	-5.99389	(-13.811)	ser = .0277
d5	-6.11917	(-14.444)	Y = 6.190
e1	+1.08334	(27.008)	nobs = 52
e2	- .406792	(-4.593)	estimation period: 1961-1973
			estimation procedure: OLS

2. System of cost share equations

(a) Atlantic region:

The form of the estimated equation is as follows:

SO = ao1*DUMAT + boo*lnPO - boo*lnPL,

where SO is the cost share of crude oil,
DUMAT is the regional dummy variable for the Atlantic,
PO is the price of crude oil, $/million ouptut Btu,
PL is the price of electricity, $/million output Btu,
both energy prices are a moving weighted average, with weights (.333, .333, .333).

The parameter estimates (including parameters from the dropped SL equation) and equation statistics are as follows:

ac1	.652337	(47.008)	log L = 21.010
a11	.347663		R^2 = .283
boo	.133	imposed	dw = .577
b1o	-.133		ser = .050
b11	.133		Y = .484
			nobs = 13
			estimation period: 1960-1972
			estimation procedure: OLS

(b) Quebec, Ontario, Prairies, and B.C. regions

The form of the estimated equations are as follows:

SG = ag2*DUMQU + ag3*DUMON + ag4*DUMPR + ag5*DUMBC + bgo*lnPO + bgg* lnPG + (-bgg-bgo)*lnPL + cg*GPM

SO = ao2*DUMQU + ao3*DUMON + ao4*DUMPR + ao5*DUMBC + boo*lnPO + bgo*lnPG + (-boo-bgo)*lnPL + co*GPM,

where SG is the cost share of natural gas,
SO is the cost share of crude oil,
DUMQU, DUMON, DUMPR, DUMBC are the regional dummy variables,
GPM is the miles of natural gas distribution pipeline,
PO is the price of crude oil, $/million output Btu,
PG is the price of natural gas, $/million output Btu,
PL is the price of electricity, $/million outut Btu,
each energy price is a moving weighted average, with weights (.15, .35, .35, .15).

The parameter estimates (including parameters from the dropped SL equation) and equation statistics are as follows:

			log L = 88.210
ag2	.0193162	(6.925)	the SO equation statistics:
ag3	.0570739	(5.724)	R^2 = .891
ag4	.0642726	(9.736)	dw = .678
ag5	.0130384	(3.183)	ser = .0238
ao2	.549991	(25.210)	Y = .401
ao3	.545368	(23.222)	nobs = 52
ao4	.594014	(22.774)	estimation period: 1961-1973
ao5	.430827	(15.290)	estimation procedure: iterative Zellner
al2	.430693	(18.848)	
al3	.397558	(17.941)	the SG equation statistics:
al4	.341714	(12.927)	R^2 = .9712
al5	.556134	(18.976)	dw = .485
boo	.102982	(2.994)	ser = .00891
bgg	0	imposed	Y = .0851
bll	.102982	(3.413)	nobs = 52
blo	-.102982	(3.413)	estimation period: 1961-1973
bgo	0	imposed	estimation procedure: iterative Zellner
blg	0		
cg	$.65738*10^{-5}$	(9.410)	
co	$-.65738*10^{-5}$		
cl	0	imposed	

II Equations used for auxiliary (thermal) demand system

1. Total current $ expenditure on primary energy fuels used to generate thermal electricity:

The form of the estimated equation is as follows:

ln TEL$ = d1*DUMAT + d2*DUMQU + d3*DUMON + d4*DUMPR + d5*DUMBC + e1*ln TOTSL$,

where TEL$ is the total current $ value of energy used in generating thermal electricity,
DUMAT, DUMQU, DUMON, DUMPR, DUMBC are regional dummy variables,
TOTSL$ is the total current $ expenditure on thermal electricity.

The parameter estimates and equation statistics are as follows:

d1	.348816	(.735)	R^2 = .9816
d2	.804297	(1.951)	dw = .539
d3	.516754	(1.064)	ser = .166
d4	.210205	(.430)	y =
d5	-.127555	(-.281)	nobs = 70
e1	.942204	(35.362)	estimation period : 1960-1973
			estimation procedure: OLS

2. System of cost share equations
(a) Atlantic and Quebec regions:

The form of the estimated equation is as follows:

SO = ao1*DUMAT + ao2*DUMQU - boo*lnPC + boo*lnPO,

where SO is the cost share of crude oil,
DUMAT, DUMQU are regional dummy variables,
PC is the price of coal, $/million output Btu,
PO is the price of crude oil, $/million output Btu.

The parameter estimates (including the dropped SC equation) and equation statistics are as follows:

ao1	.521315	(13.470)	log L = 16.543
ao2	.888358	(23.126)	R^2 = .6524
ac1	.478685		dw = .219
ac2	.111642		ser = .142
boo	.0227315	(.0748)	Y = .704
bcc	.0227315		nobs = 28
bco	-.0227315		estimation period: 1960-1973
			estimation procedure: OLS

(b) Ontario and Prairies regions

The form of the estimated equations are as follows:

SG = ag3*DUMON + ag4*DUMPR + (-bgo-bgg)*lnPC + bgo*lnPO + bgg*lnPG

SO = ao3*DUMON + ao4*DUMPR + (-boo-bgo)*lnPC + boo*lnPO + bgo*lnPG,

where SG is the cost share of natural gas,
SO is the cost share of crude oil,
DUMON, DUMPR are regional dummy variables,
PC is the price of coal, $/million output Btu,
PO is the price of crude oil, $/million output Btu,
PG is the price of natural gas, $/million output Btu.

The parameter estimates (including parameters from the dropped SC equation) and equation statistics are as follows:

			Log L = 11.957
ag3	.0750434	(4.287)	SO equation statistics:
ag4	.136416	(1.612)	R^2 = .4191
ao3	.0674516	(4.424)	dw = .928
ao4	.0466713	(4.504)	ser = .0267
ac3	.857502	(30.210)	Y = .0485
ac4	.816913	(8.709)	nobs = 28
bgg	-.141199	(-1.772)	estimation period: 1960-1973
boo	-.147012	(-2.797)	estimation procedure: iterative Zellner
bcc	-.288211	(-2.446)	
bgo	0	imposed	SG equation statistics:
bco	.147012	(2.643)	R^2 = .787
bcg	.141199	(1.657)	dw = .396
			ser= .0586

Y = .174
nobs = 28
estimation period: 1960-1973
estimation procedure: iterative Zellner

(c) B.C. region

The form of the estimated equation is as follows:

SO = ao5*DUMBC - boo*lnPG + boo*lnPO + co*lnGPM,

where SO is the cost share of crude oil,
DUMBC is the regional dummy avariable for B.C.,
PG is the price of natural gas, $/million output Btu,
PO is the price of crude oil, $/million output Btu,
GPM is the miles of natural gas distribution pipeline miles .

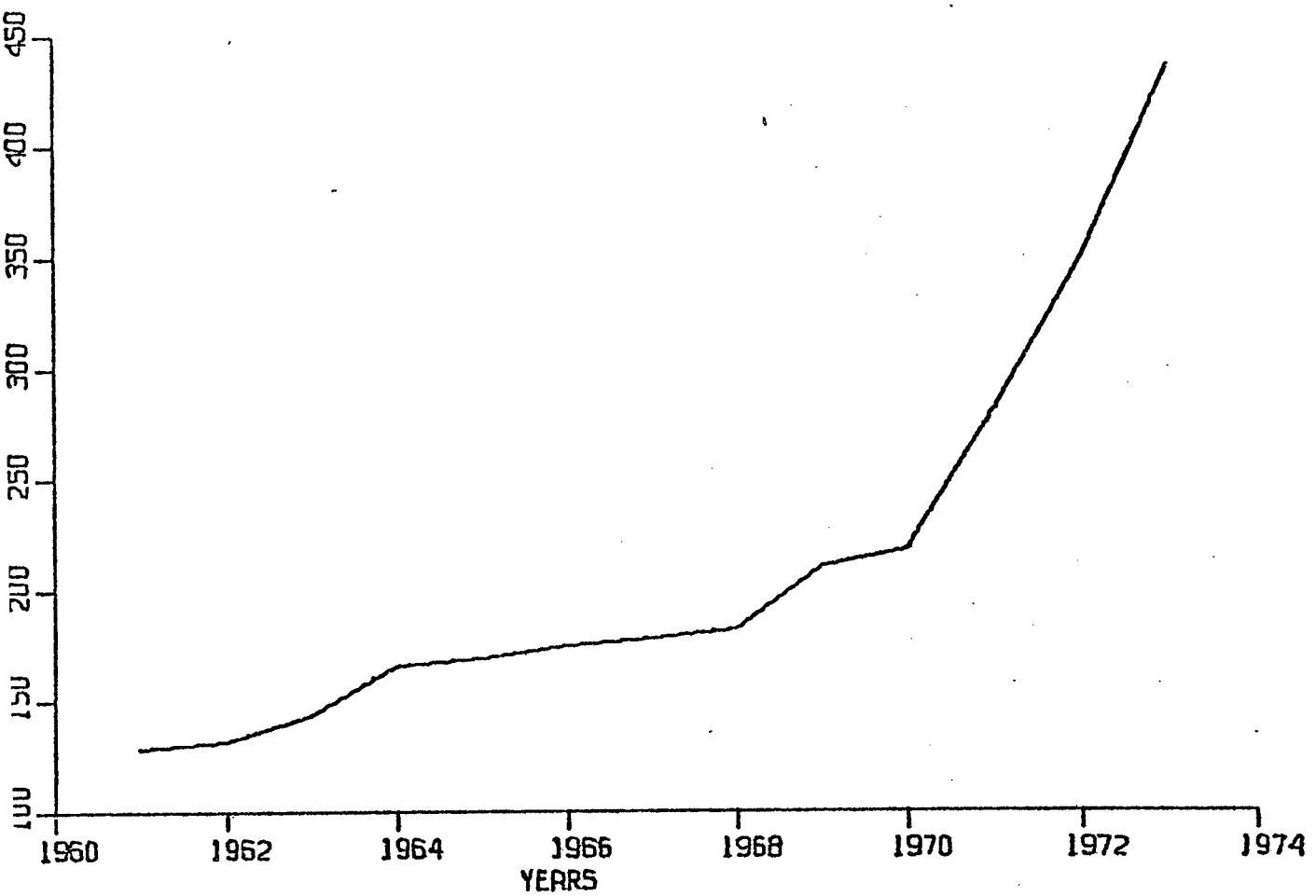
The parameter estimates (including those from the dropped SG equation) and equation statistics are as follows:

ao1	2.76215	(2.780)	log L = 14.257
ag1	-1.76215		R^2 = .2646
co	-.246464	(-2.078)	dw = 1.620
cg	.246464		ser = .0944
boo	0	imposed	Y = .699
bgg	0		nobs = 14
bgo	0		estimation period: 1960-1973
			estimation procedure: OLS

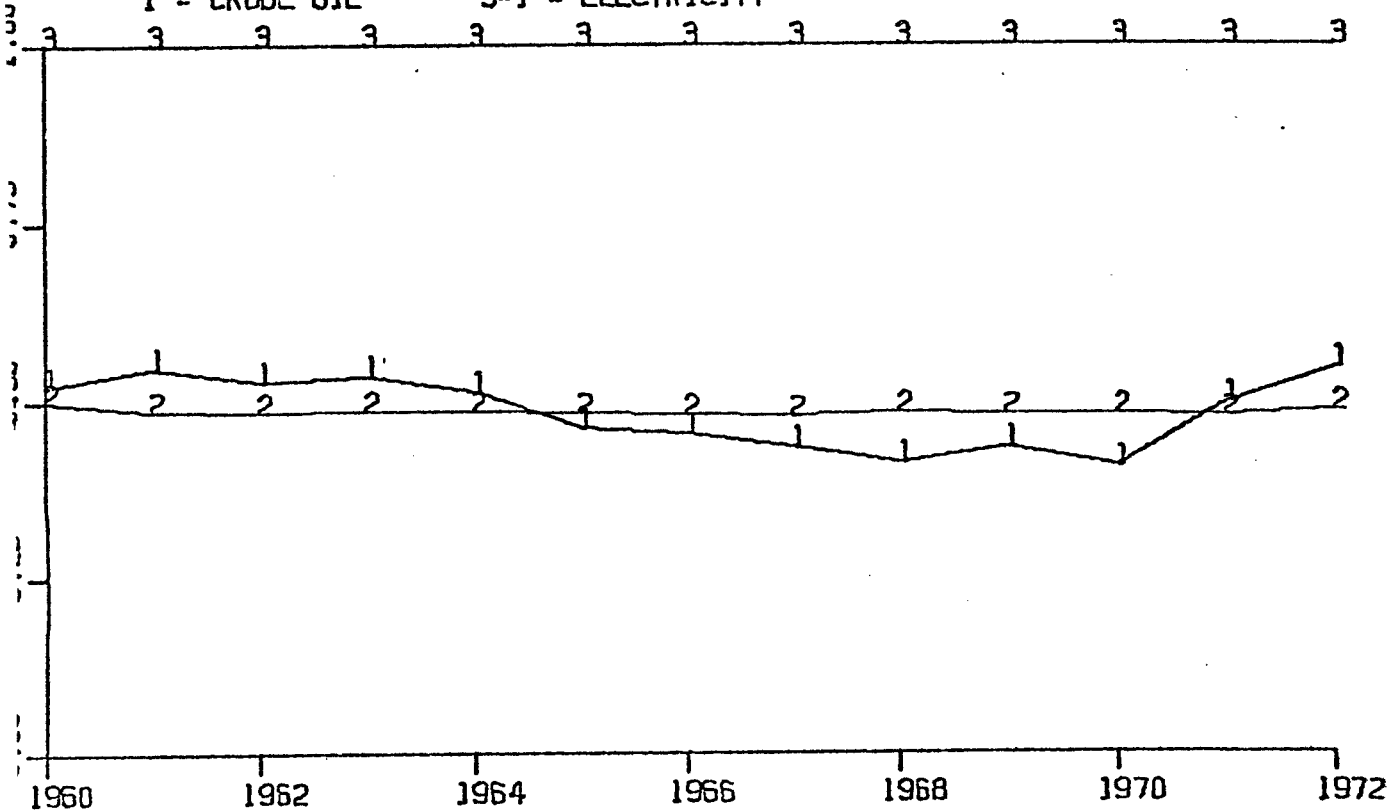
III Visual Display of Regression Results

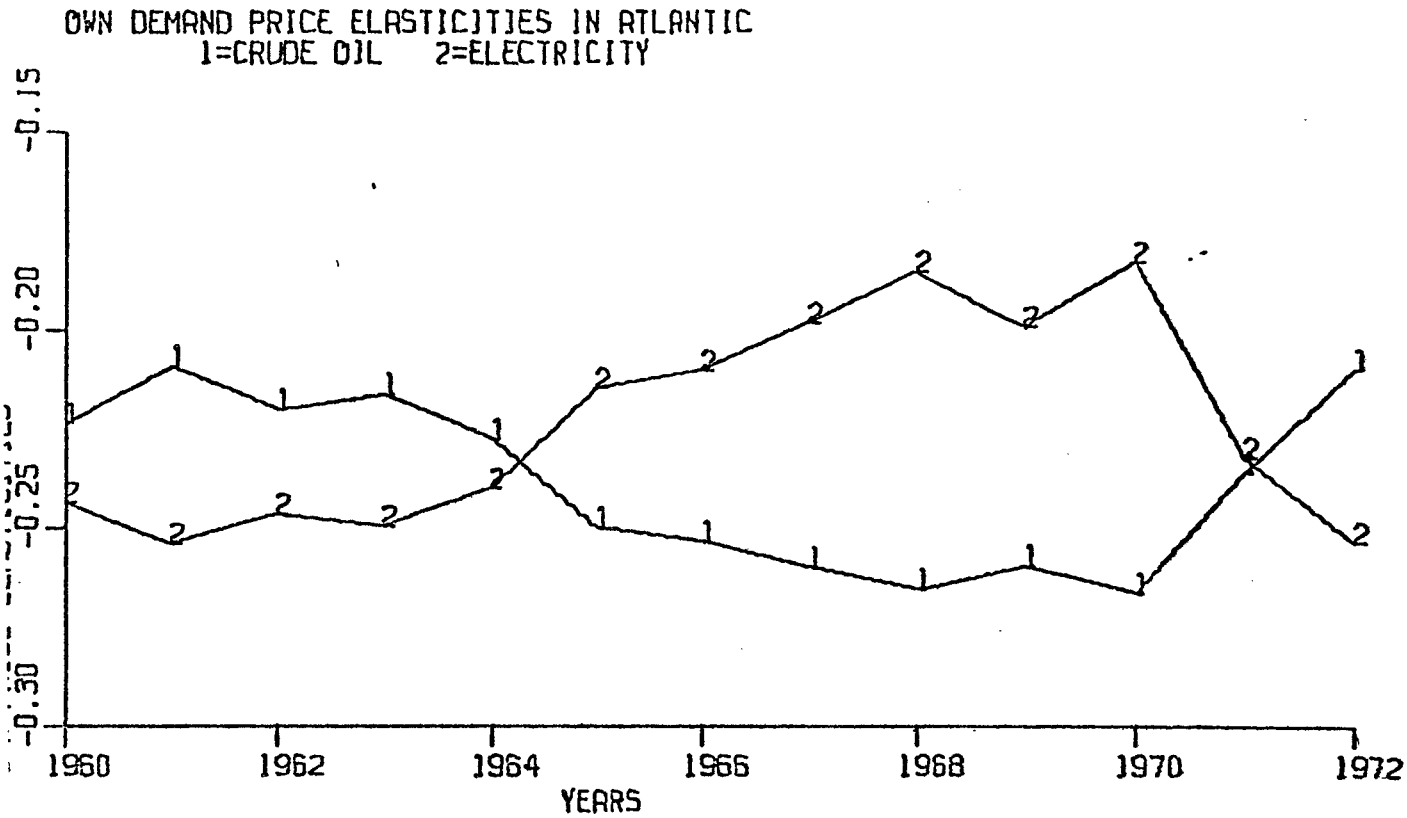
The following graphs indicate the total energy expenditure, the actual and estimated fuel shares, the own and cross price elasticities of demand for each region.

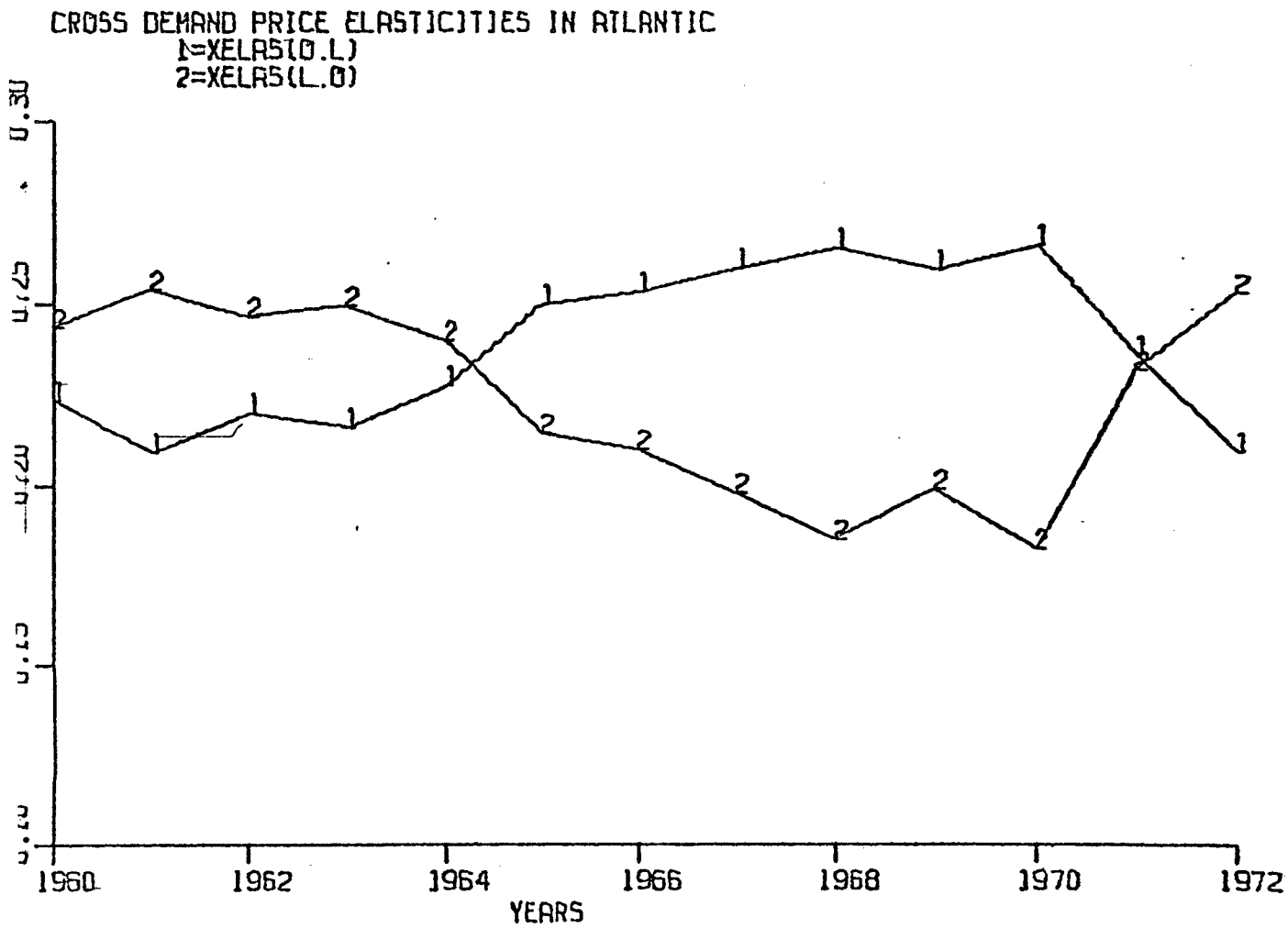
TOTAL EXPENDITURE ON PRIMARY ENERGY IN ATLANTIC
(EXCLUDING ENERGY USED IN GENERATING SECONDARY ELECTRICITY)



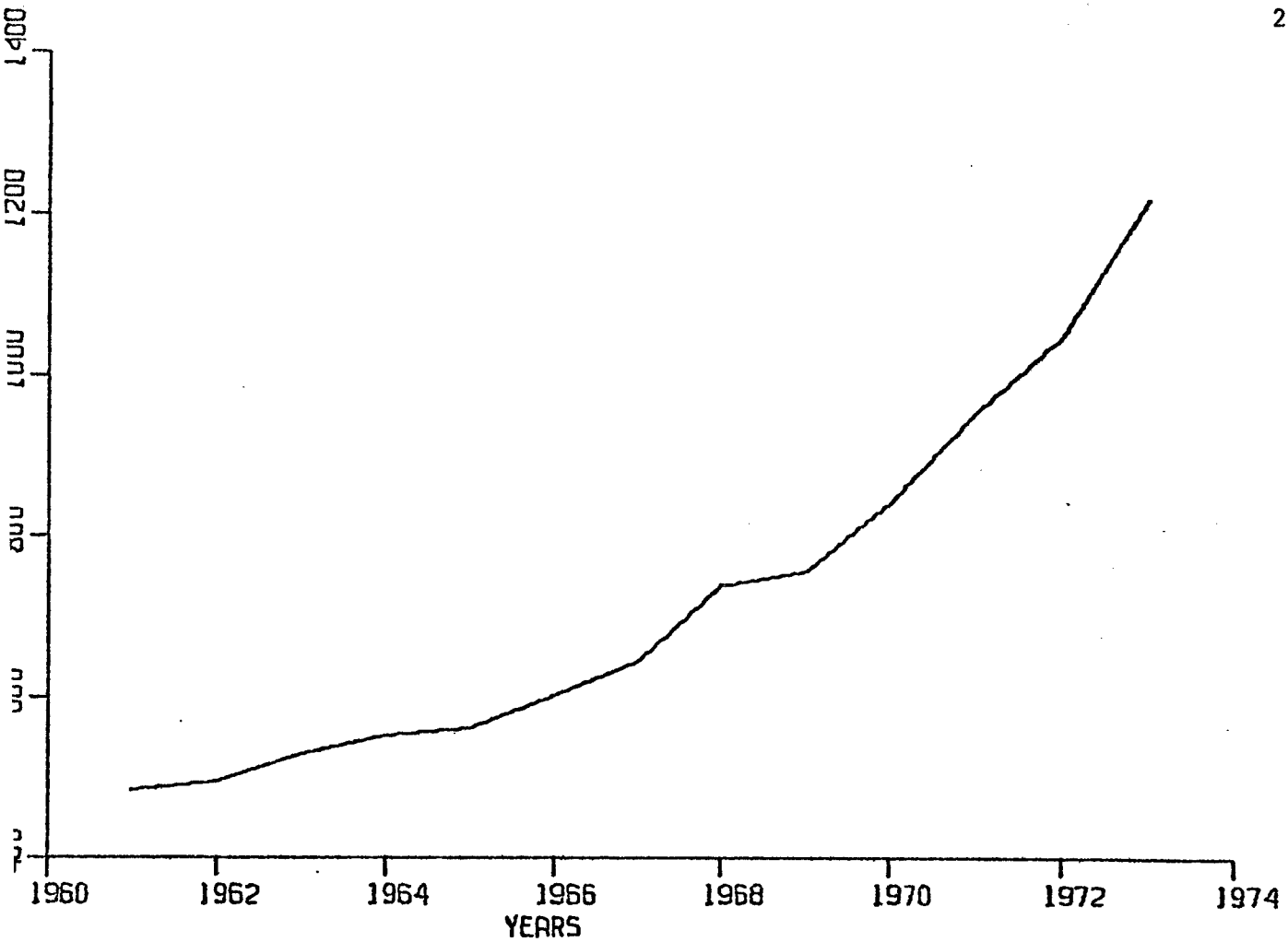
ACTUAL AND ESTIMATED FUEL SHARES FOR ATLANTIC
1.3 = ACTUAL SHARE
2 = ESTIMATED SHARE
1 = CRUDE OIL
3-1 = ELECTRICITY



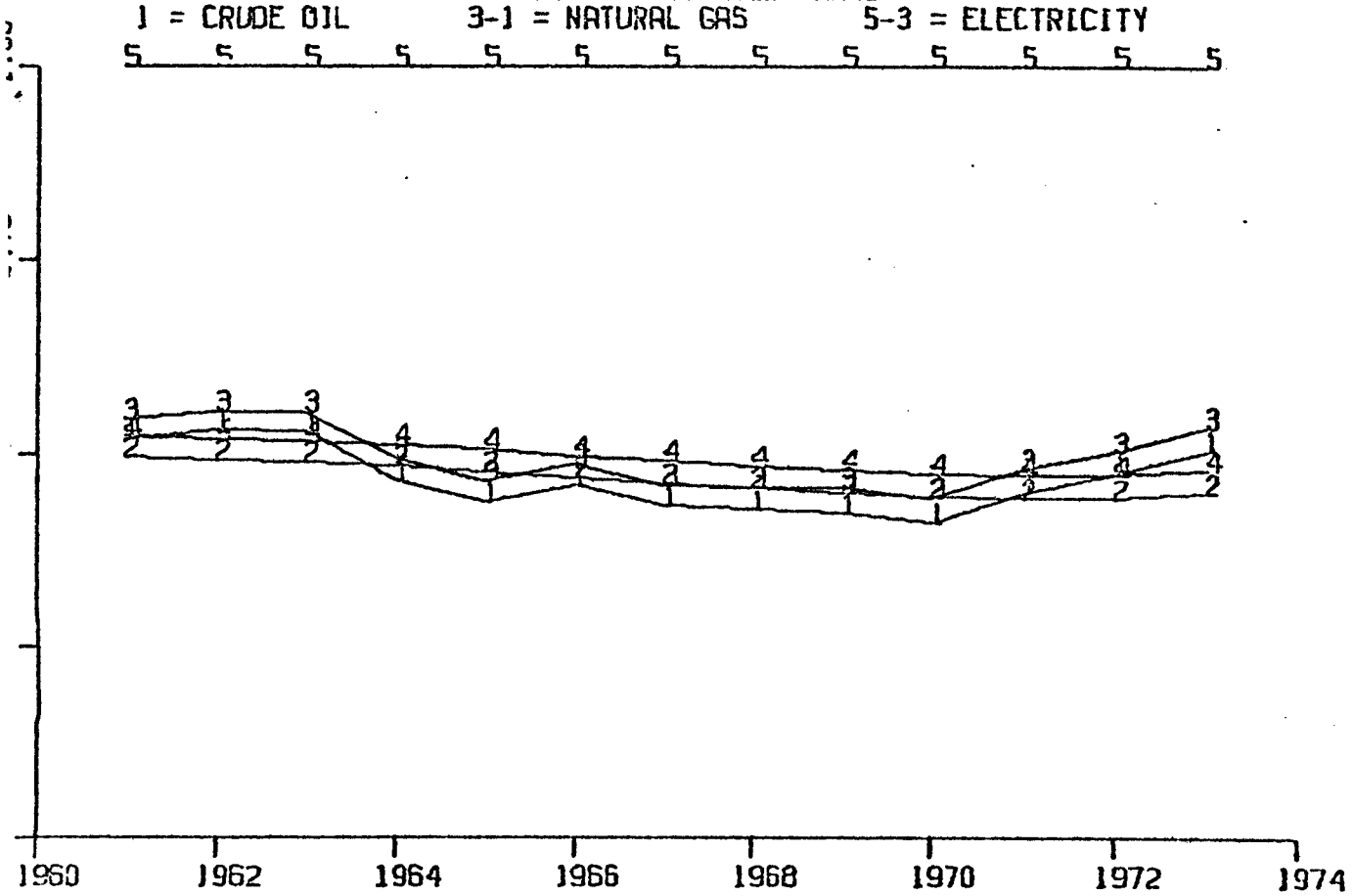

OWN DEMAND PRICE ELASTICITIES IN ATLANTIC
1=CRUDE OIL 2=ELECTRICITY
-0.15
-0.20
-0.25
-0.30
1960
1962
1964
1966
1968
1970
1972
YEARS


CROSS DEMAND PRICE ELASTICITIES IN ATLANTIC
1=XELAS(O,L)
2=XELAS(L,O)
0.30
1960
1962
1964
1966
1968
1970
1972
YEARS

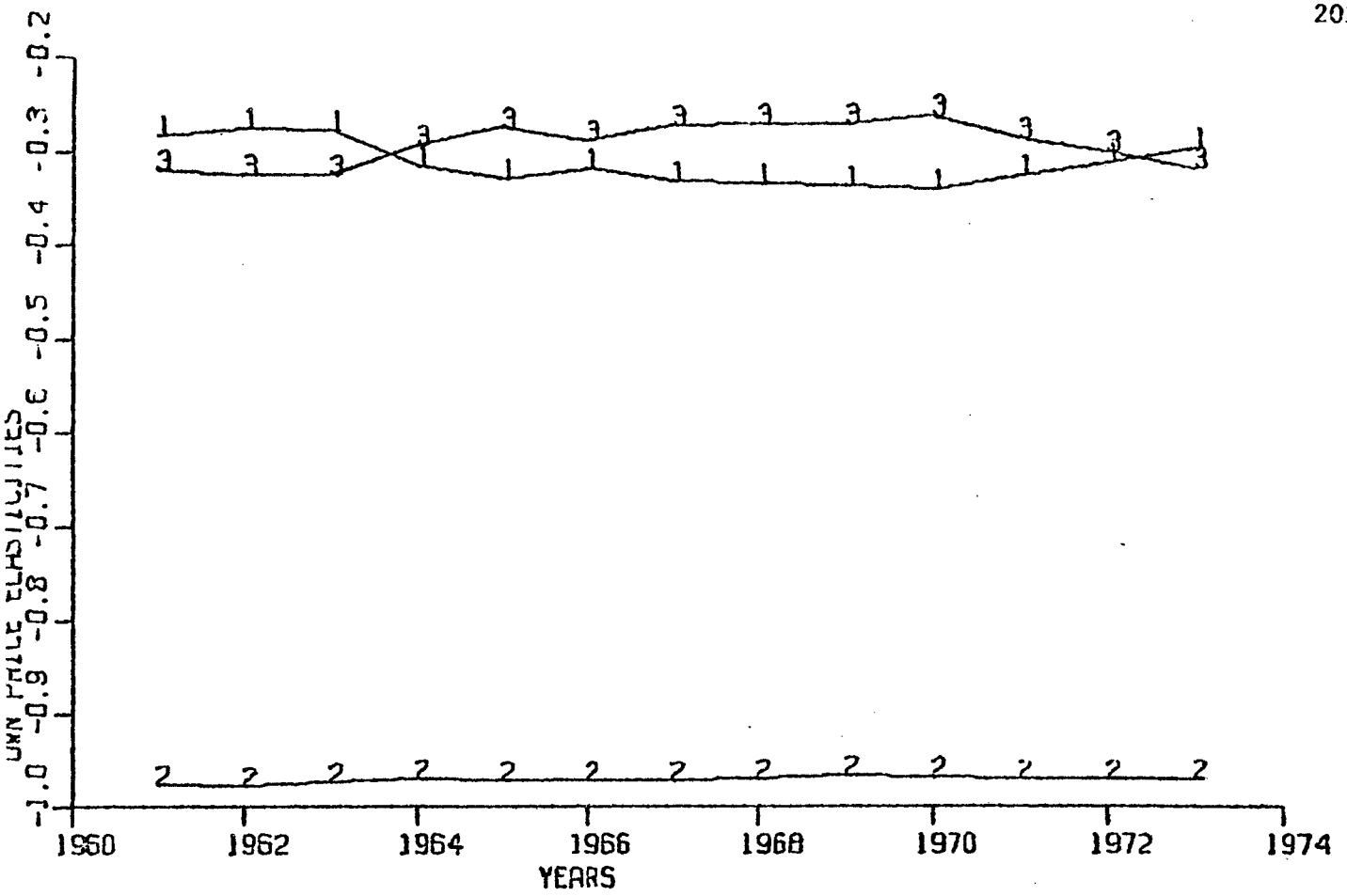
(EXCLUDING ENERGY USED IN GENERATING SECONDARY ELECTRICITY)



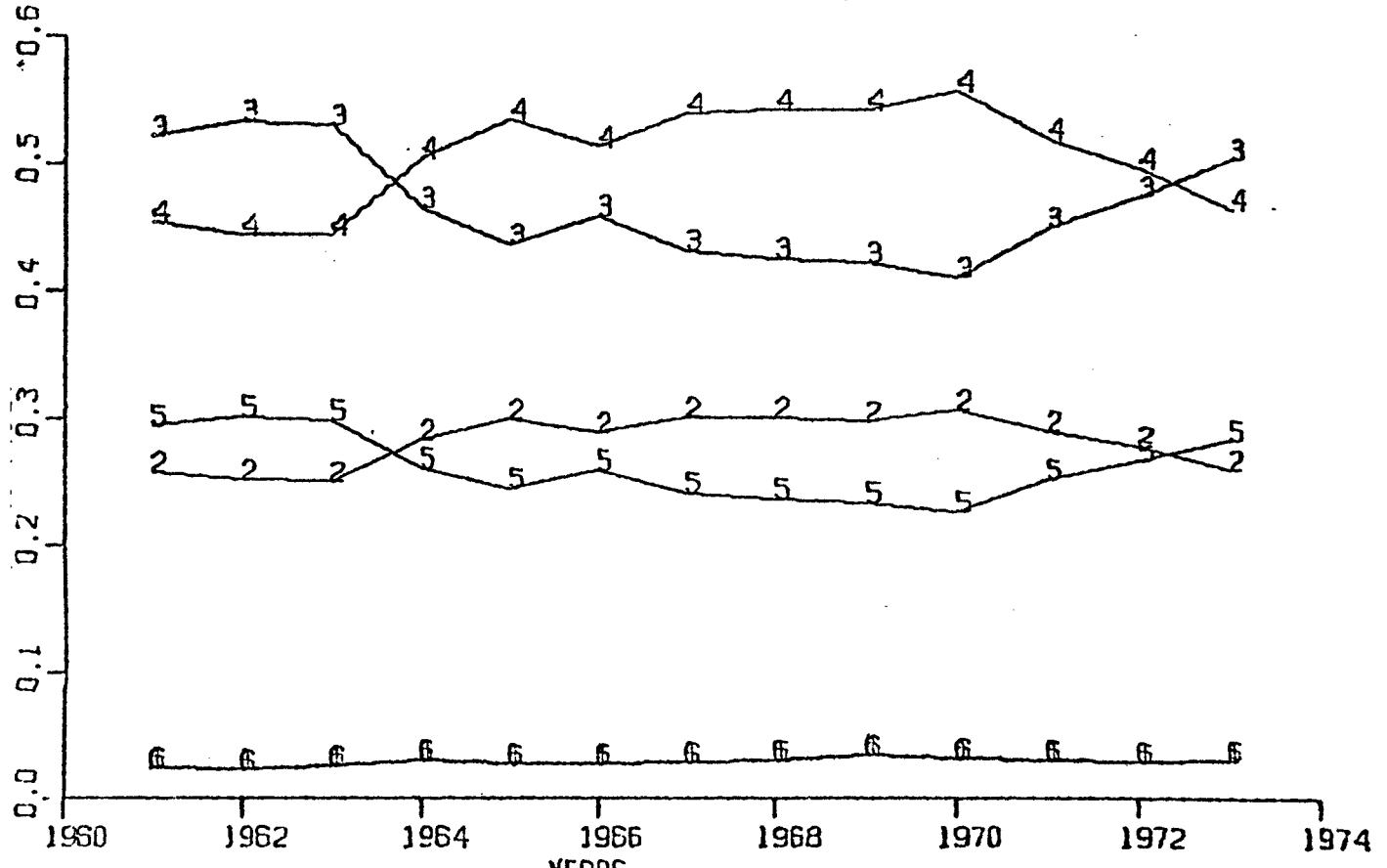
ACTUAL AND ESTIMATED FUEL SHARES FOR QUEBEC
1.3.5 = ACTUAL SHARE 2.4 = ESTIMATED SHARE
1 = CRUDE OIL 3-1 = NATURAL GAS 5-3 = ELECTRICITY



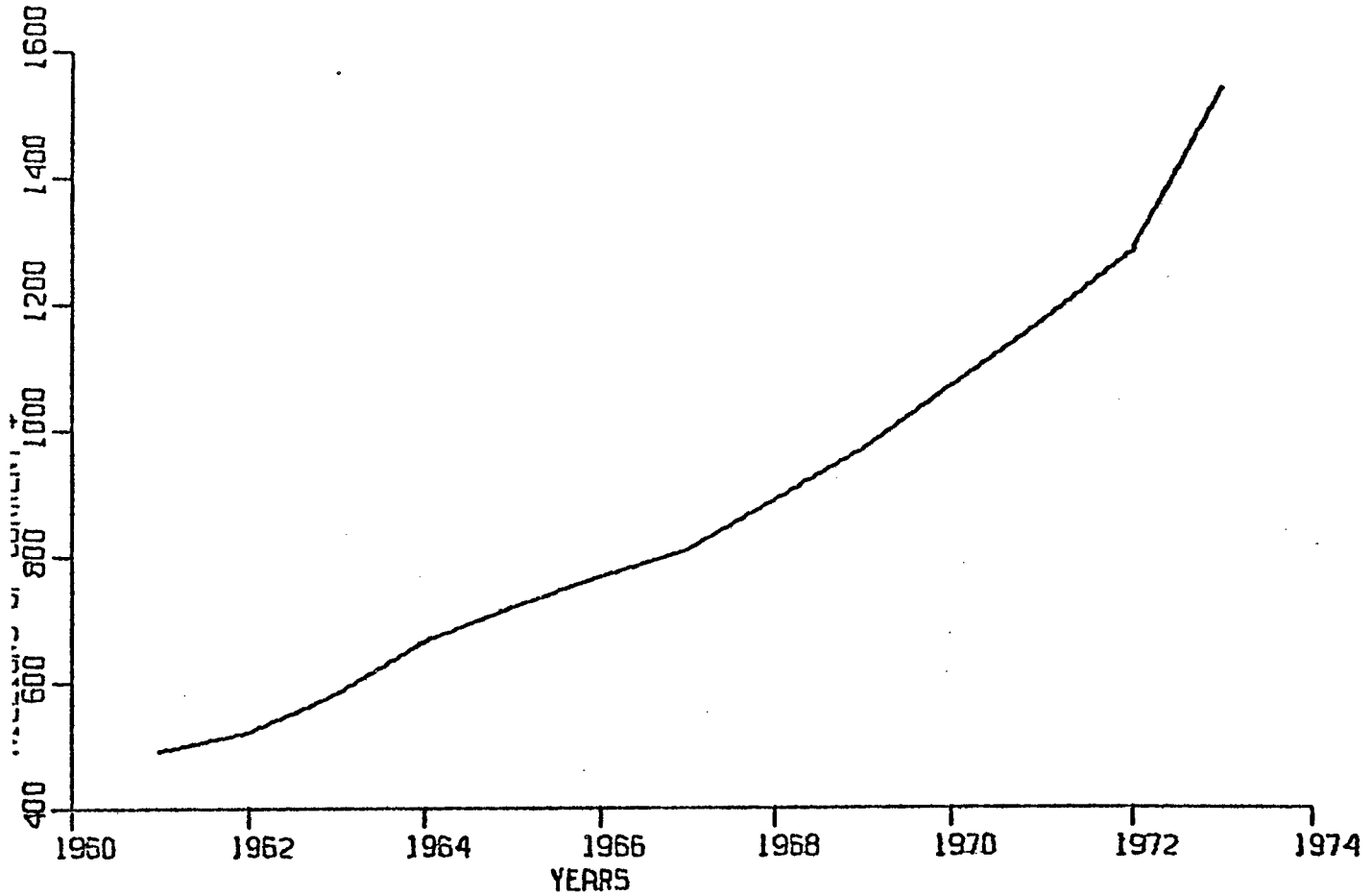
OWN DEMAND PRICE ELASTICITIES IN QUEBEC
1=CRUDE OIL 2=NATURAL GAS 3=ELECTRICITY



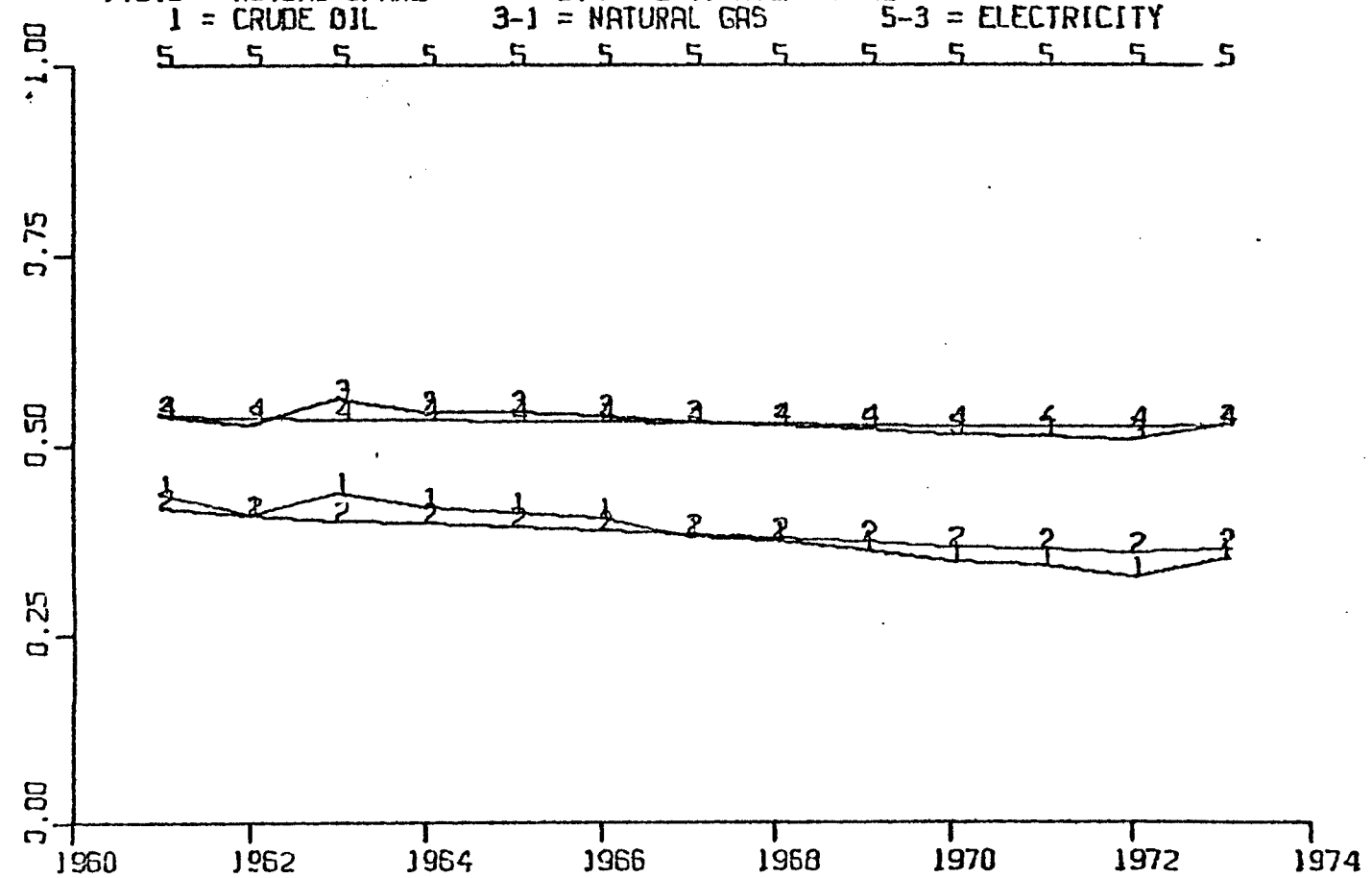
CROSS DEMAND PRICE ELASTICITIES IN QUEBEC
1=XELAS(O.G) 2=XELAS(O.L) 3=XELAS(G.O)
4=XELAS(G.L) 5=XELAS(L.O) 6=XELAS(L.G)



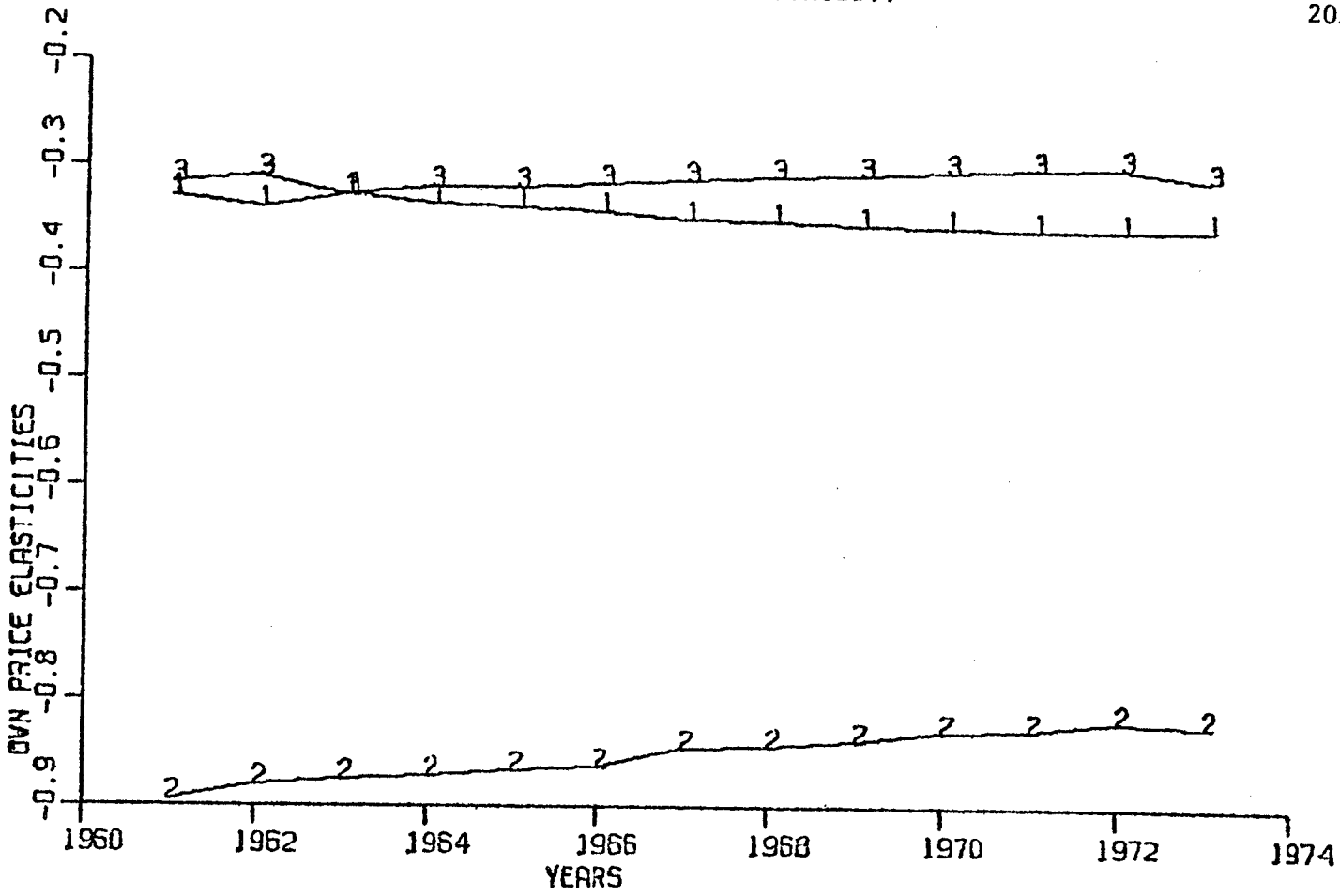
TOTAL EXPENDITURE ON PRIMARY ENERGY IN ONTARIO
(EXCLUDING ENERGY USED IN GENERATING SECONDARY ELECTRICITY)



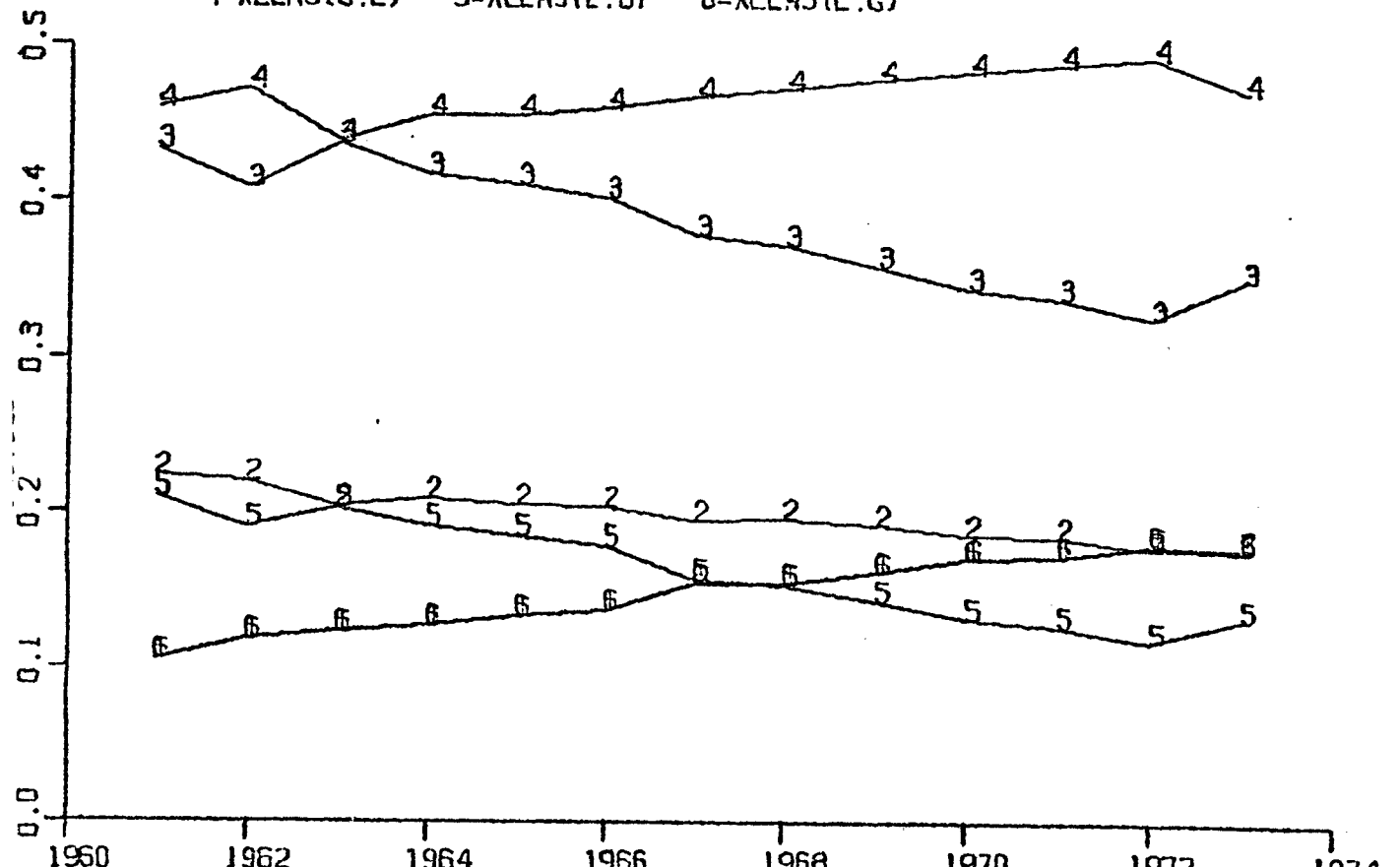
ACTUAL AND ESTIMATED FUEL SHARES FOR ONTARIO
1,3,5 = ACTUAL SHARE 2,4 = ESTIMATED SHARE
1 = CRUDE OIL 3-1 = NATURAL GAS 5-3 = ELECTRICITY



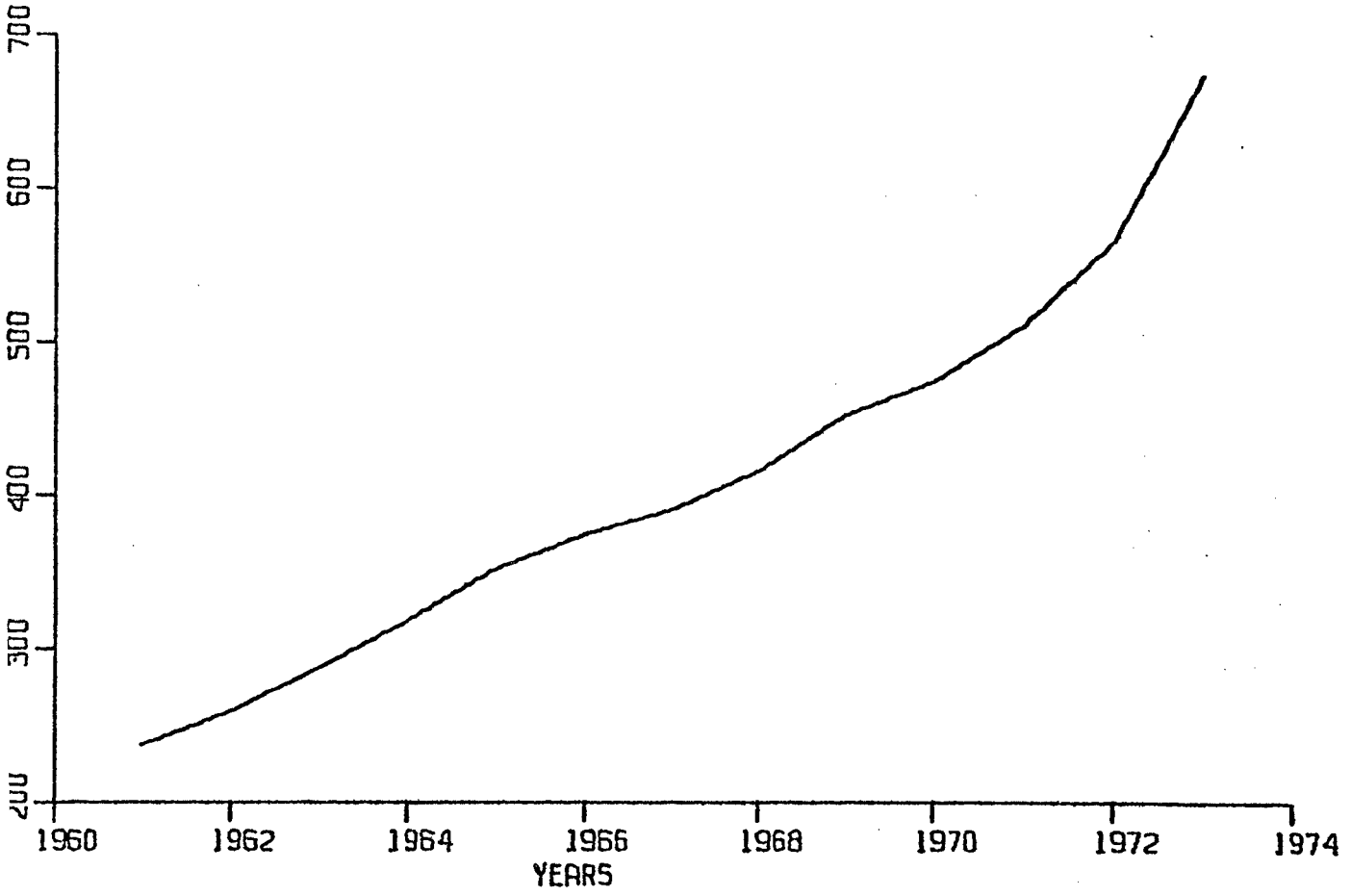
OWN DEMAND PRICE ELASTICITIES IN ONTARIO
1=CRUDE OIL 2=NATURAL GAS 3=ELECTRICITY



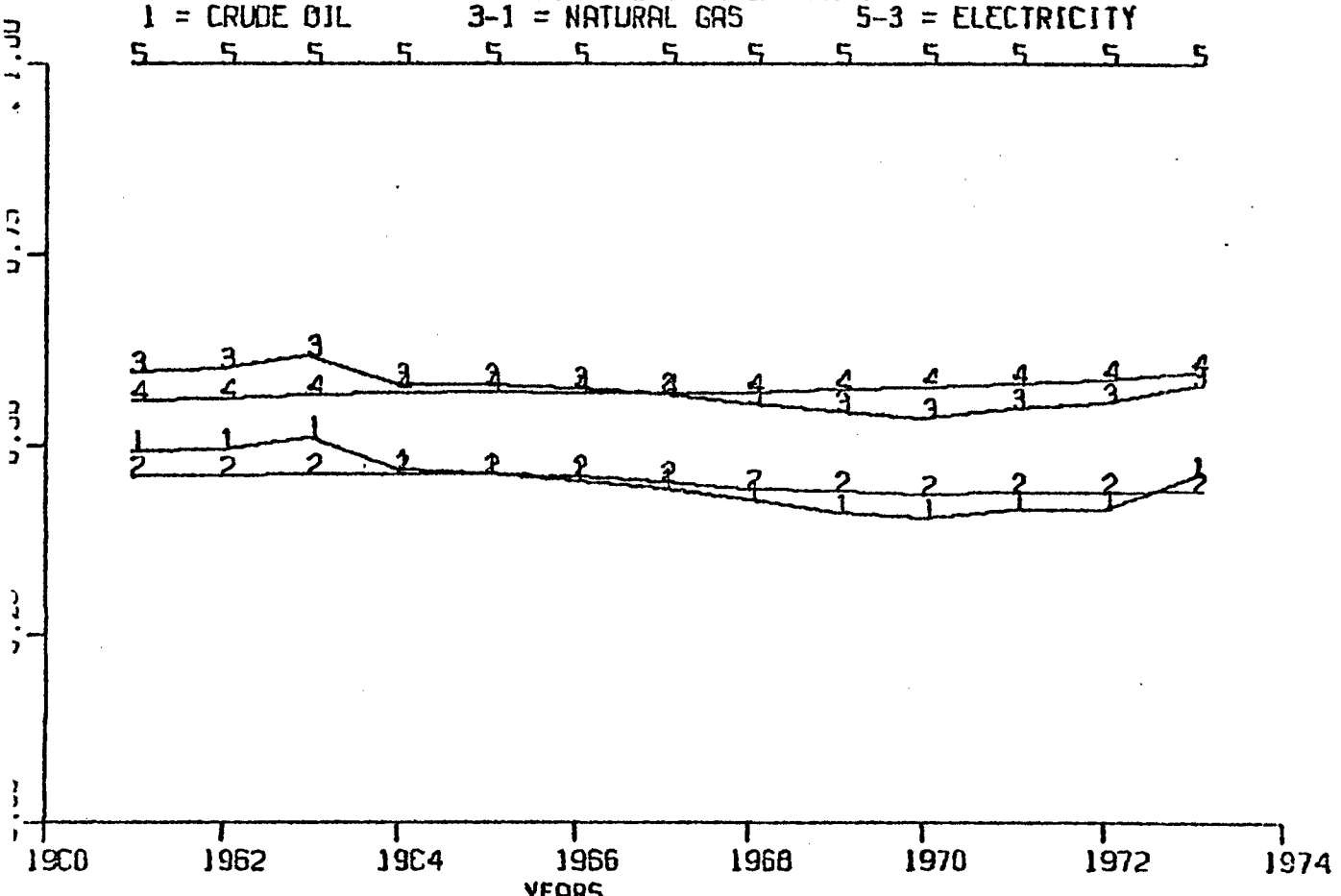
CROSS DEMAND PRICE ELASTICITIES IN ONTARIO
1=XELAS(O,G) 2=XELAS(O,L) 3=XELAS(G,O)
4=XELAS(G,L) 5=XELAS(L,O) 6=XELAS(L,G)



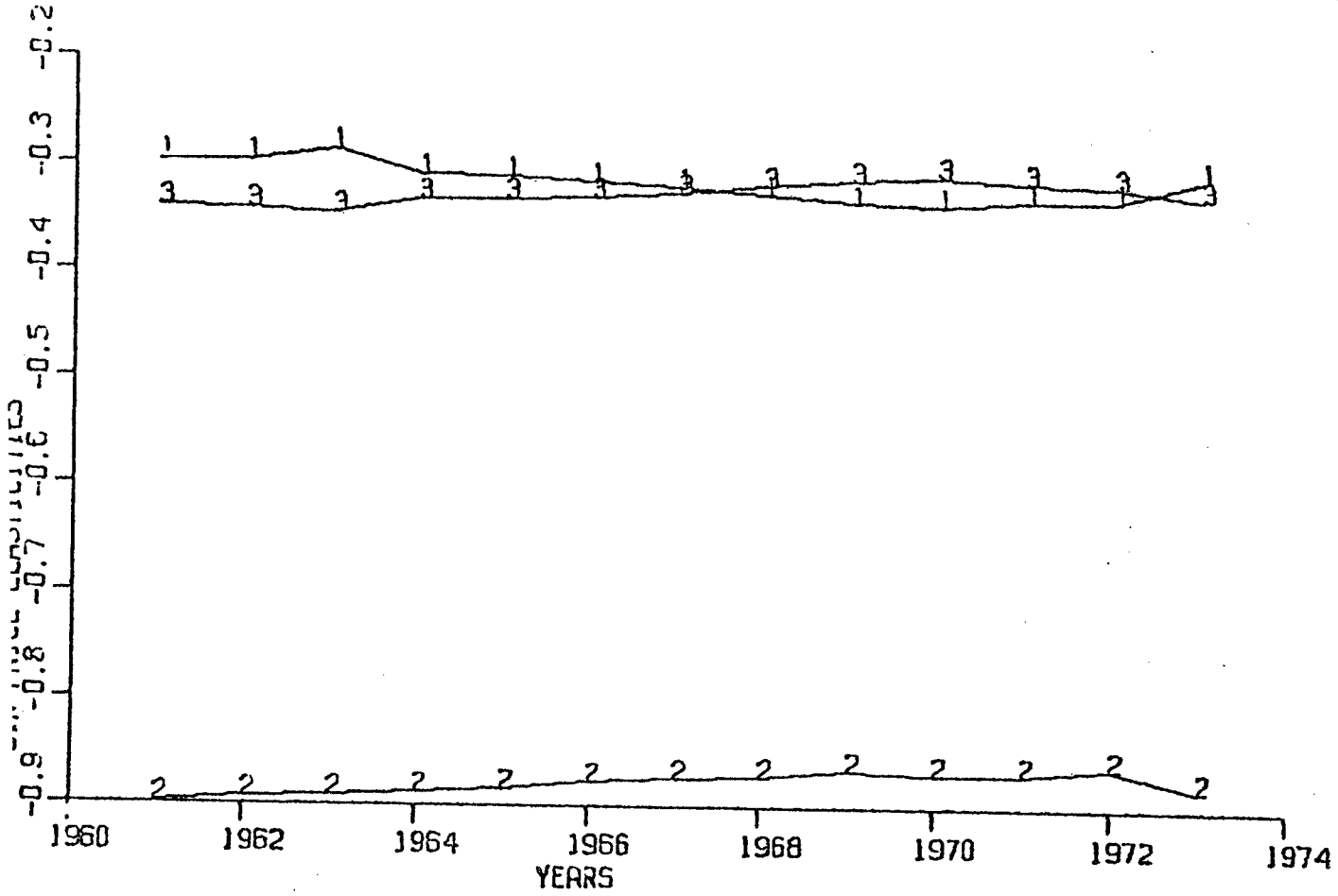
TOTAL EXPENDITURE ON PRIMARY ENERGY IN PRAIRIES
(EXCLUDING ENERGY USED IN GENERATING SECONDARY ELECTRICITY)



ACTUAL AND ESTIMATED FUEL SHARES FOR PRAIRIES
1.3.5 = ACTUAL SHARE 2.4 = ESTIMATED SHARE
1 = CRUDE OIL 3-1 = NATURAL GAS 5-3 = ELECTRICITY



OWN DEMAND PRICE ELASTICITIES IN PRAIRIES
1=CRUDE OIL 2=NATURAL GAS 3=ELECTRICITY



CROSS DEMAND PRICE ELASTICITIES IN PRAIRIES
1=XELAS(O.G) 2=XELAS(O.L) 3=XELAS(G.O)
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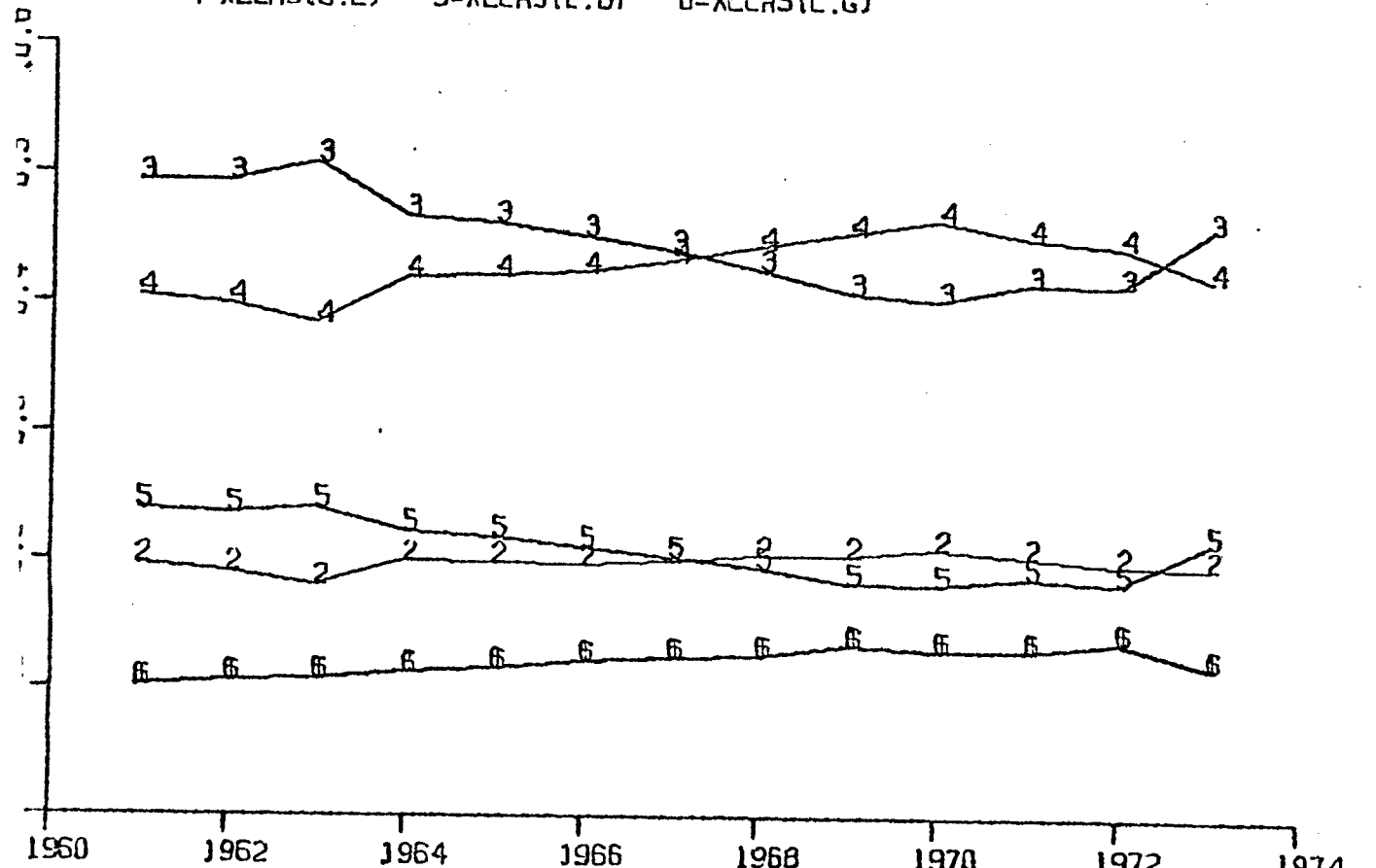
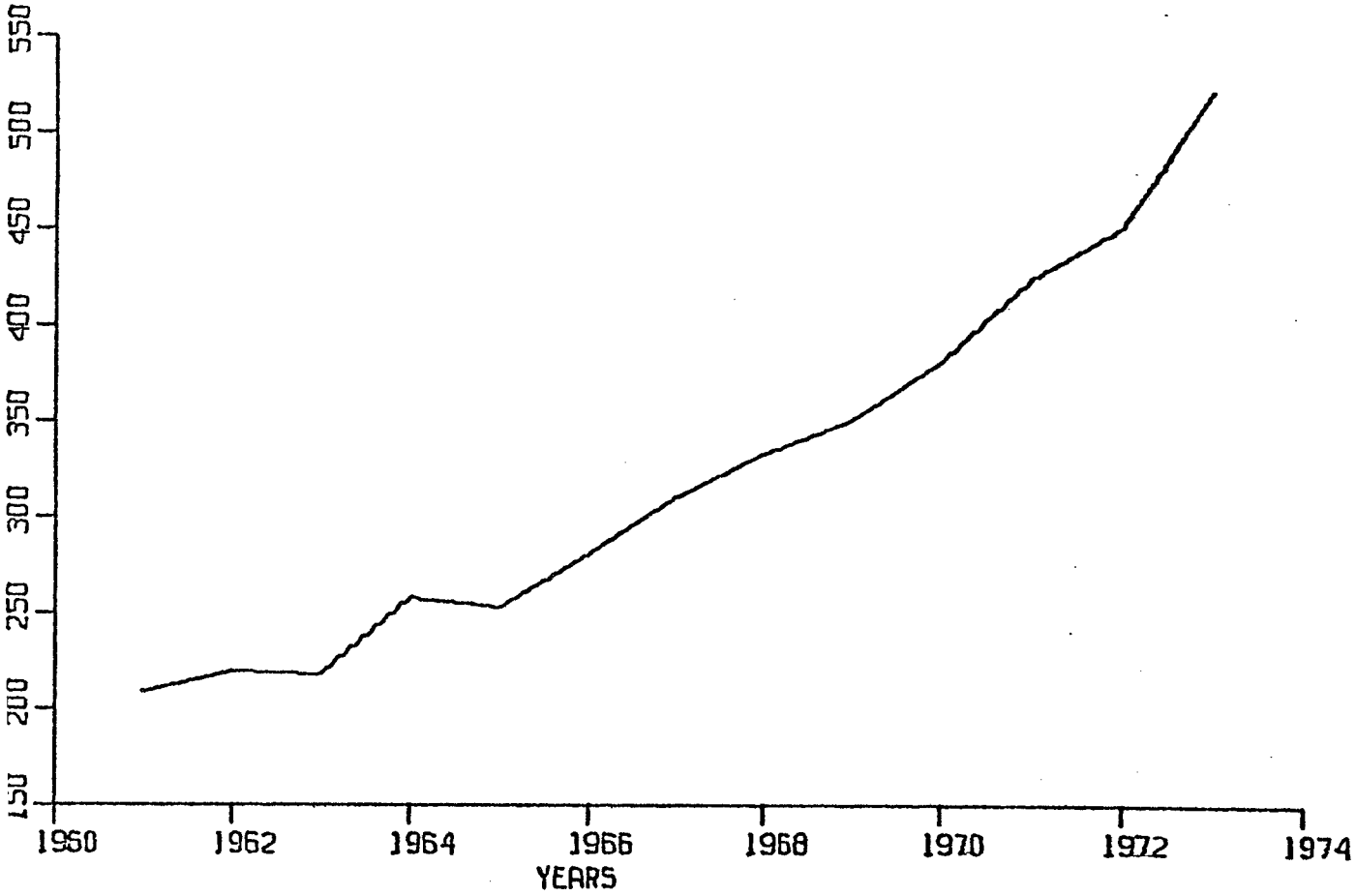
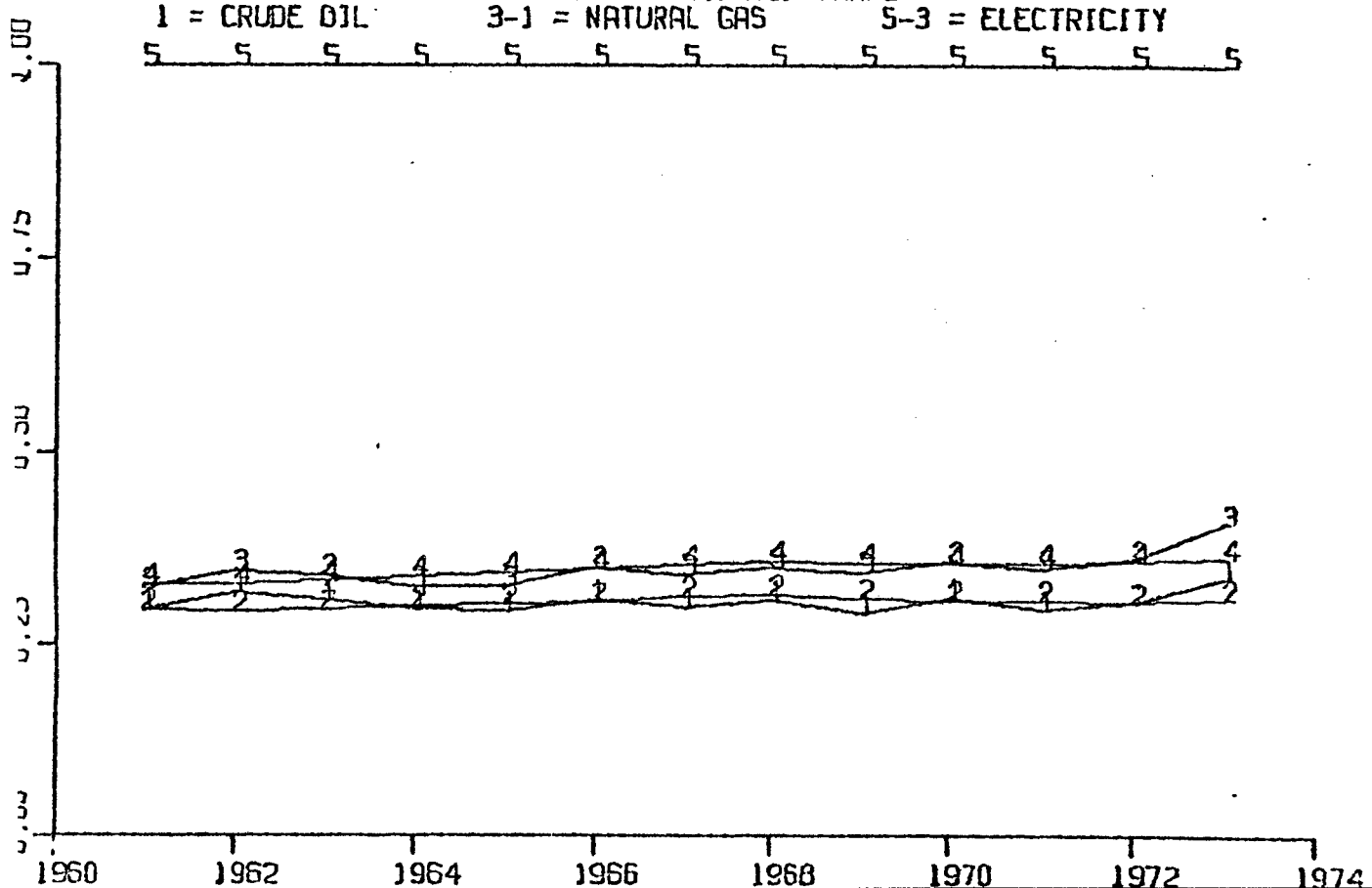


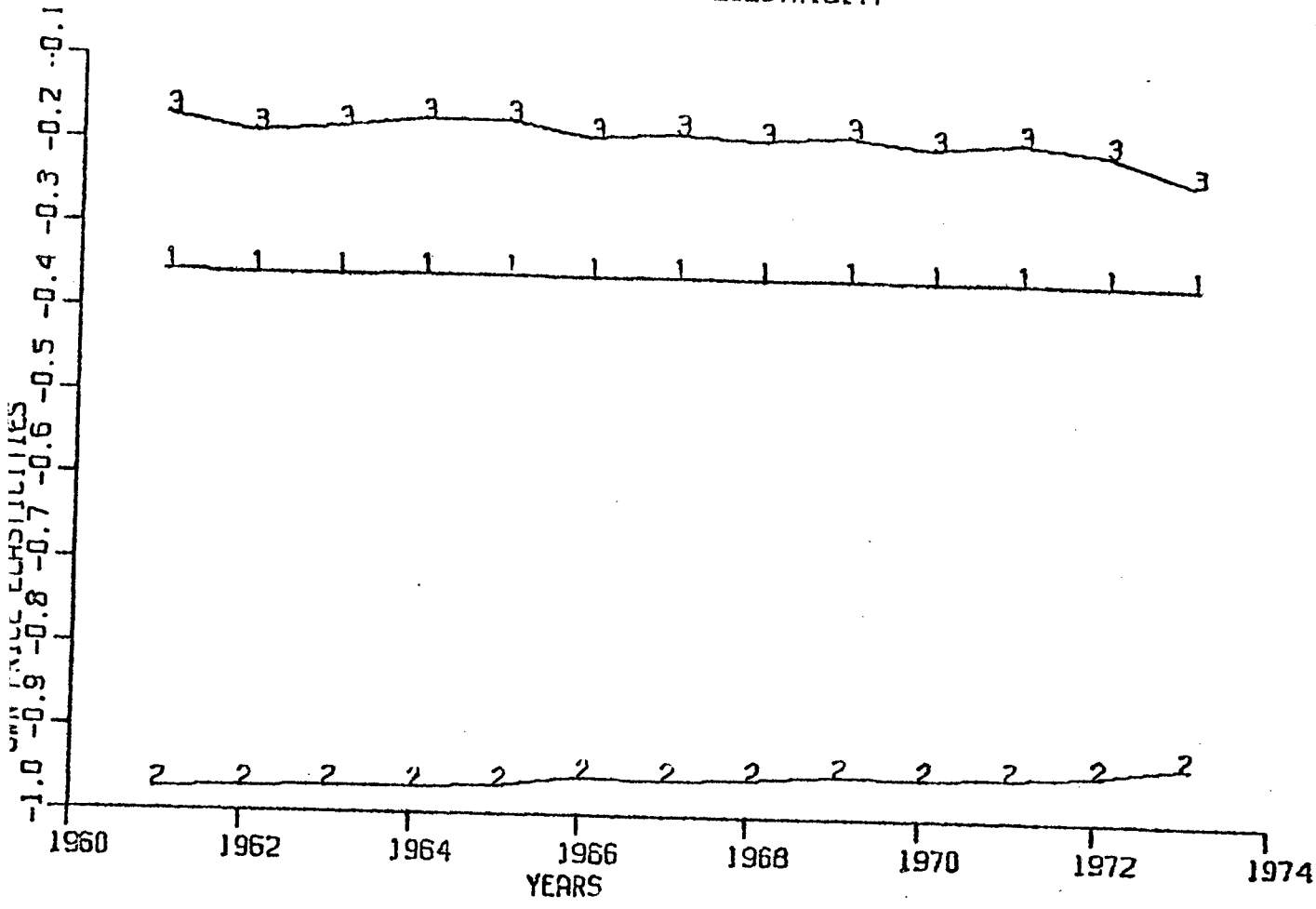
TOTAL EXPENDITURE ON PRIMARY ENERGY IN B.C.
(EXCLUDING ENERGY USED IN GENERATING SECONDARY ELECTRICITY)



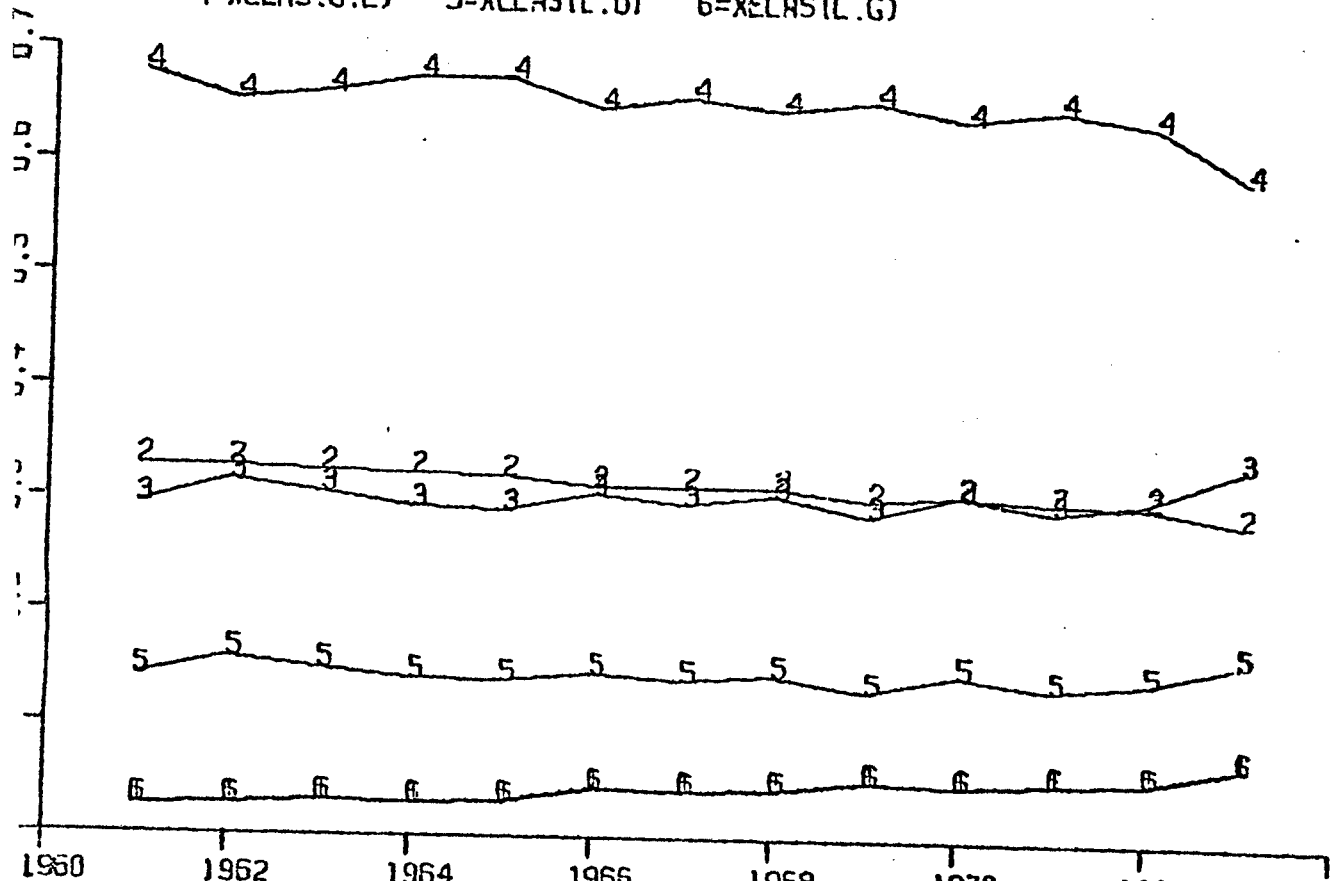
ACTUAL AND ESTIMATED FUEL SHARES FOR B.C.
1,3,5 = ACTUAL SHARE 2,4 = ESTIMATED SHARE
1 = CRUDE OIL 3-1 = NATURAL GAS 5-3 = ELECTRICITY



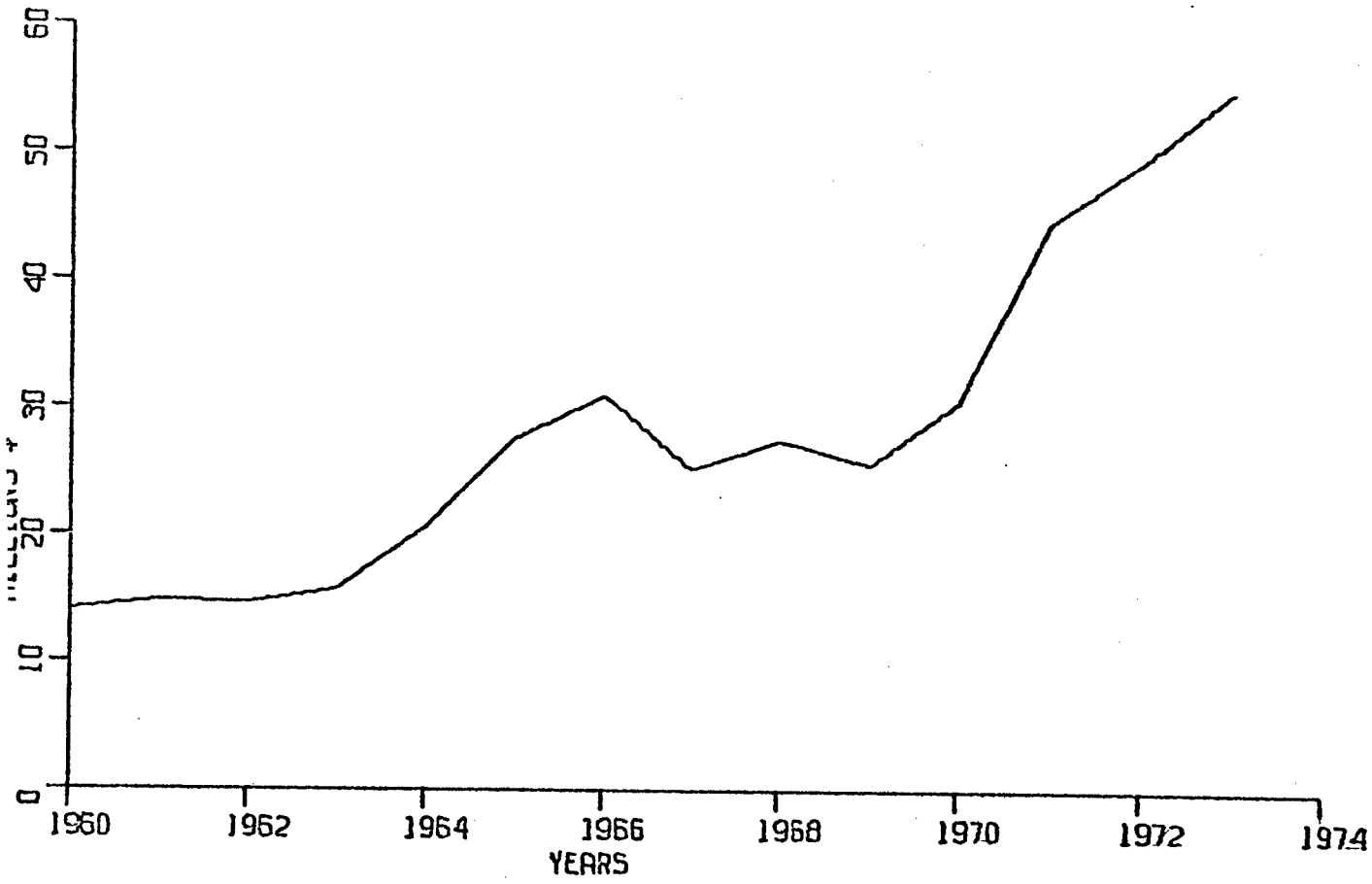
OWN DEMAND PRICE ELASTICITIES IN B.C.
1=CRUDE OIL 2=NATURAL GAS 3=ELECTRICITY



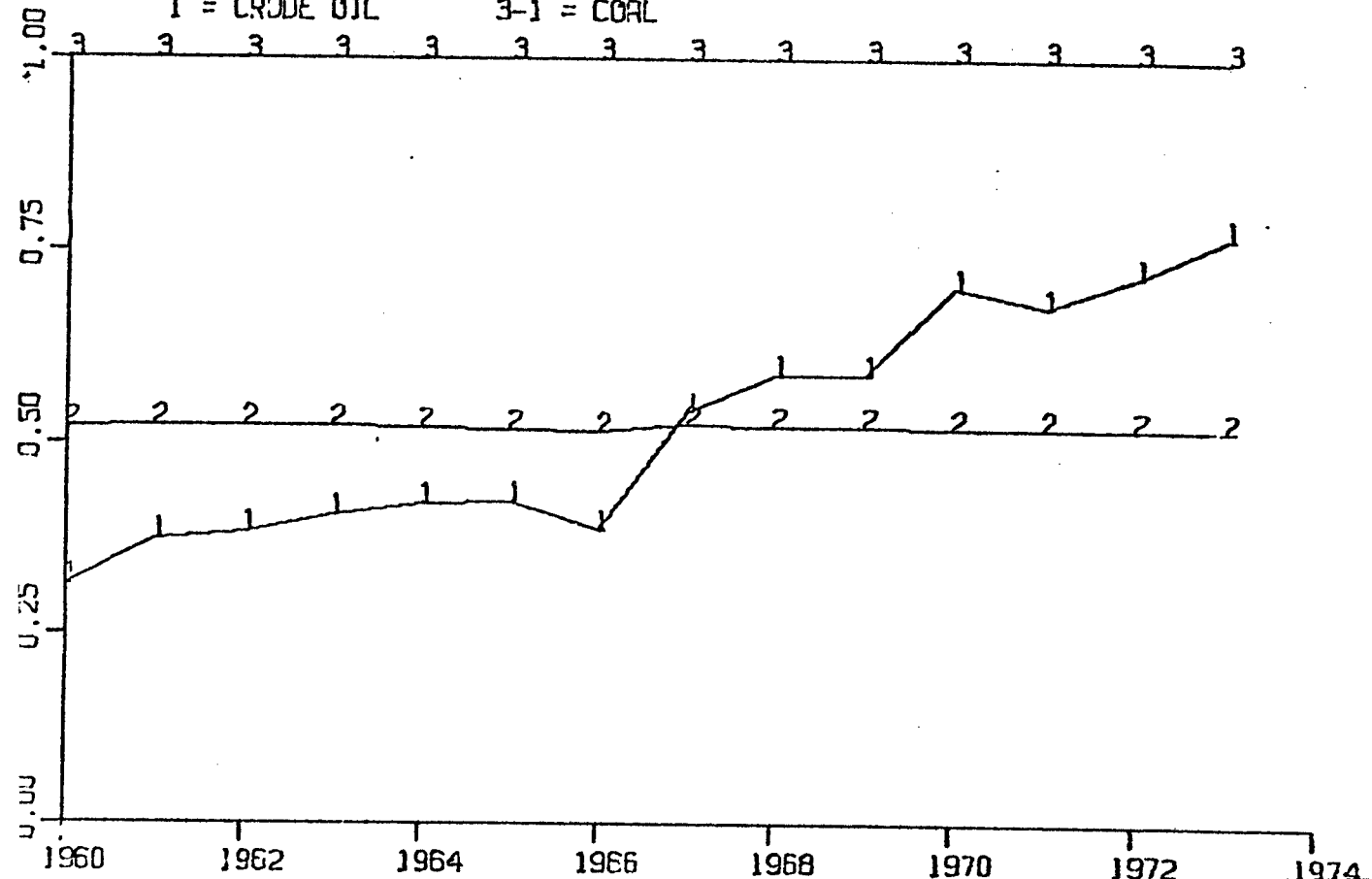
CROSS DEMAND PRICE ELASTICITIES IN B.C.
1=XELAS(O,G) 2=XELAS(O,L) 3=XELAS(G,O)
4=XELAS(G,L) 5=XELAS(L,O) 6=XELAS(L,G)



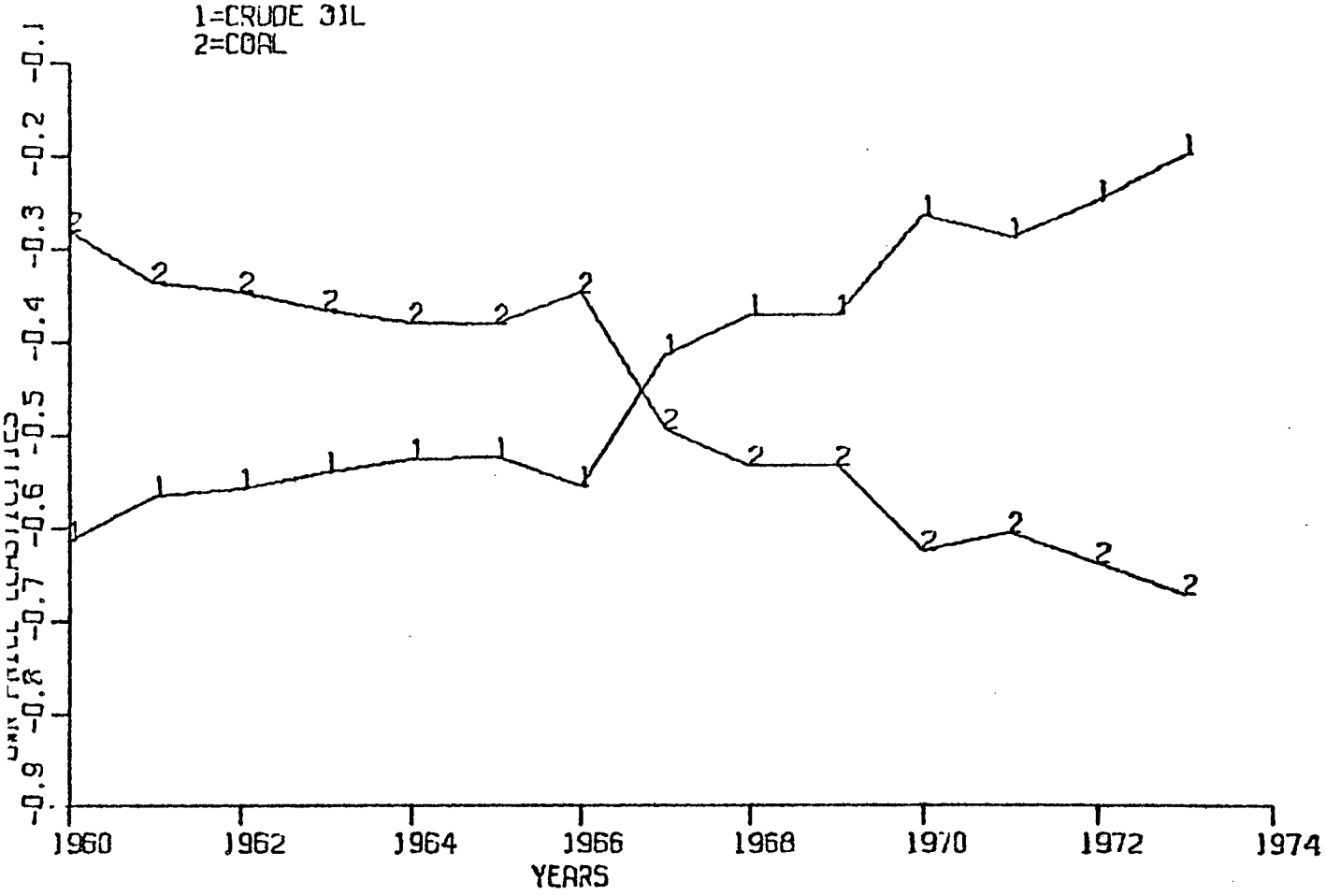
TOTAL EXPENDITURE ON PRIMARY ENERGY FUELS
USED TO GENERATE SECONDARY ELECTRICITY IN ATLANTIC



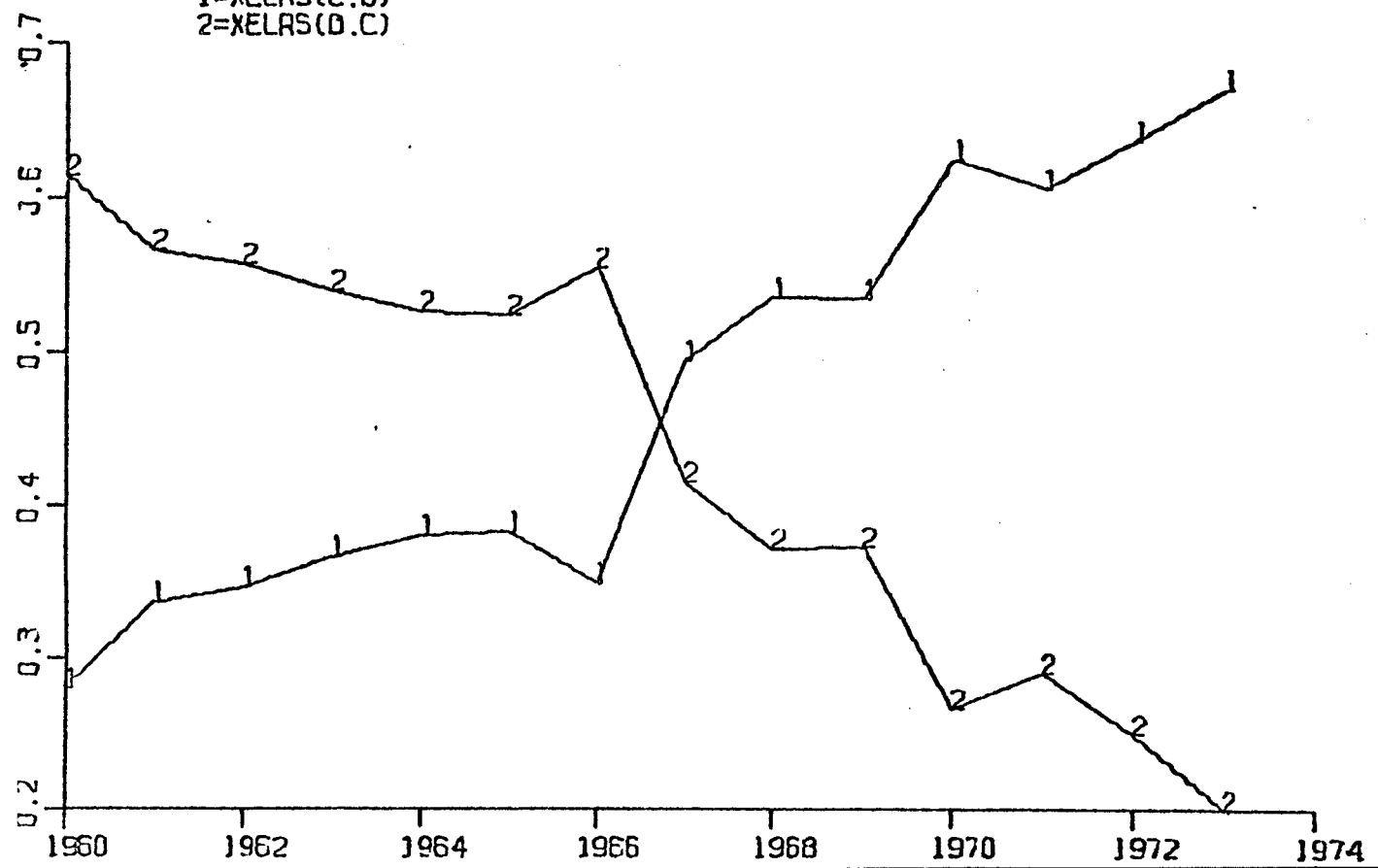
ACTUAL AND ESTIMATED FUEL SHARES FOR GENERATING ELECTRICITY IN ATLANTIC
1.3 = ACTUAL SHARE 2 = ESTIMATED SHARE
1 = CRUDE OIL 3-1 = COAL



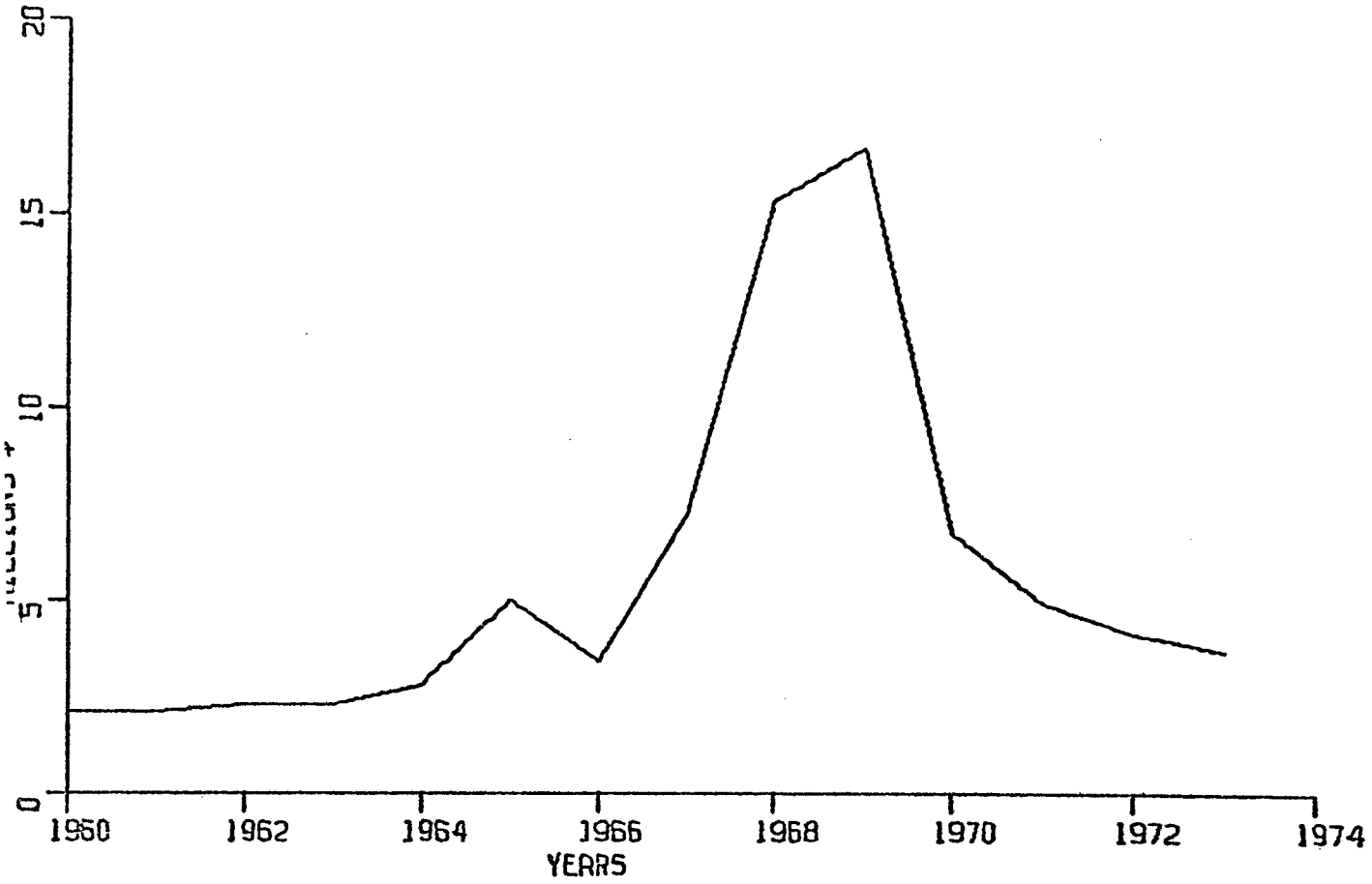
OWN DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN ATLANTIC
1=CRUDE OIL
2=COAL



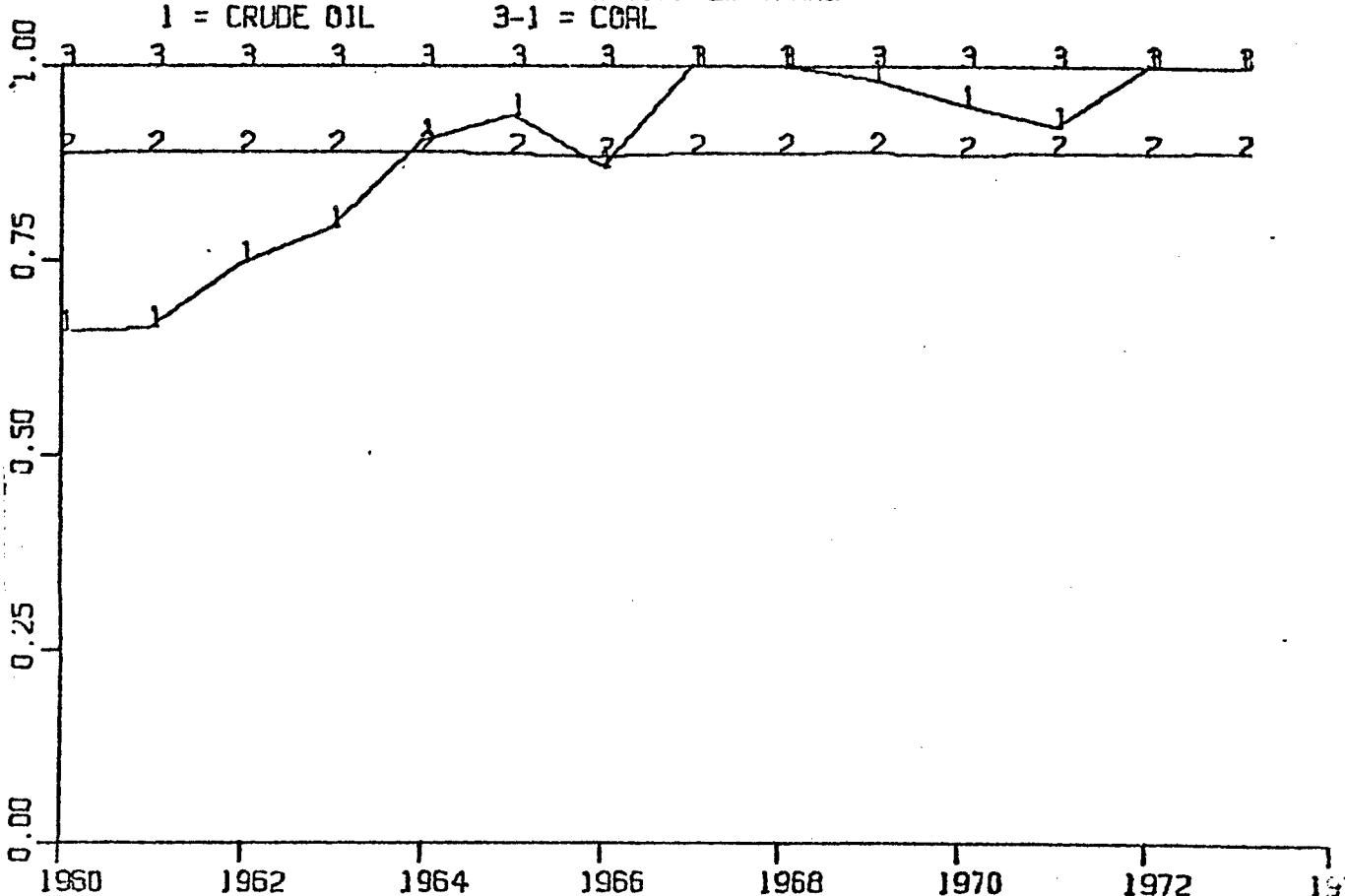
CROSS DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN ATLANTIC
1=XELAS(C,O)
2=XELAS(O,C)



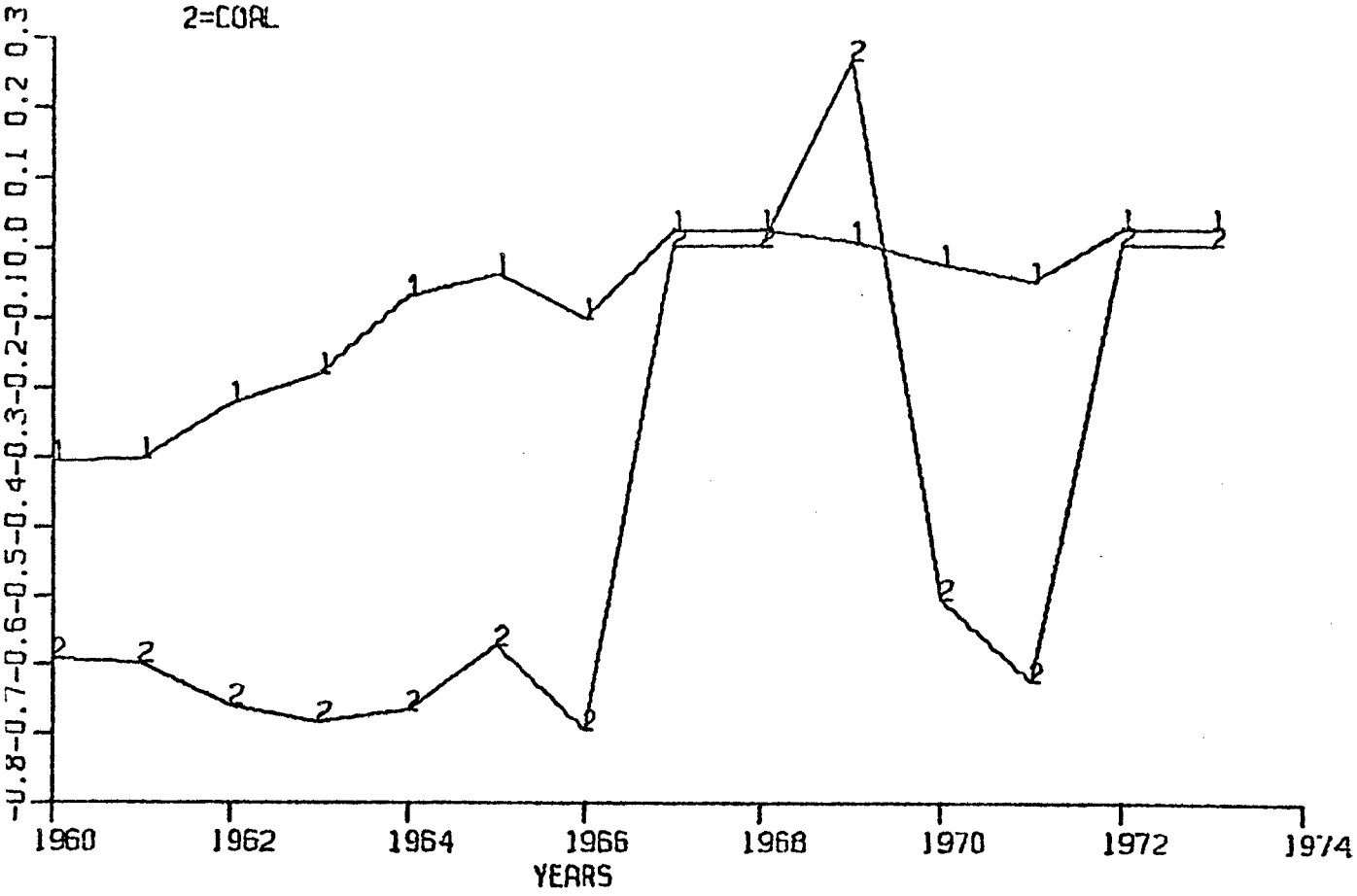
TOTAL EXPENDITURE ON PRIMARY ENERGY FUELS
USED TO GENERATE SECONDARY ELECTRICITY IN QUEBEC



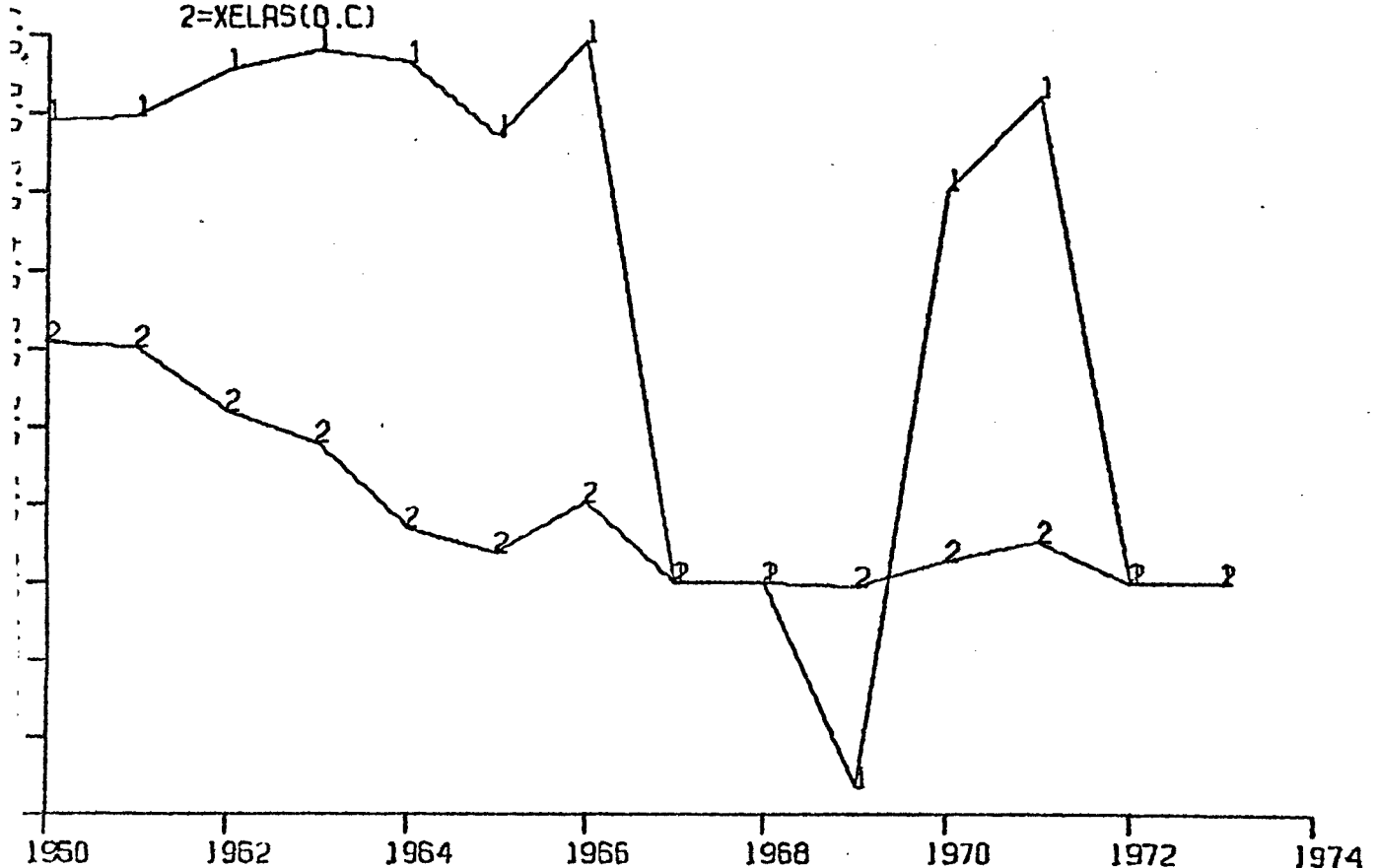
ACTUAL AND ESTIMATED FUEL SHARES FOR GENERATING ELECTRICITY IN QUEBEC
3 = ACTUAL SHARE 2 = ESTIMATED SHARE
1 = CRUDE OIL 3-1 = COAL



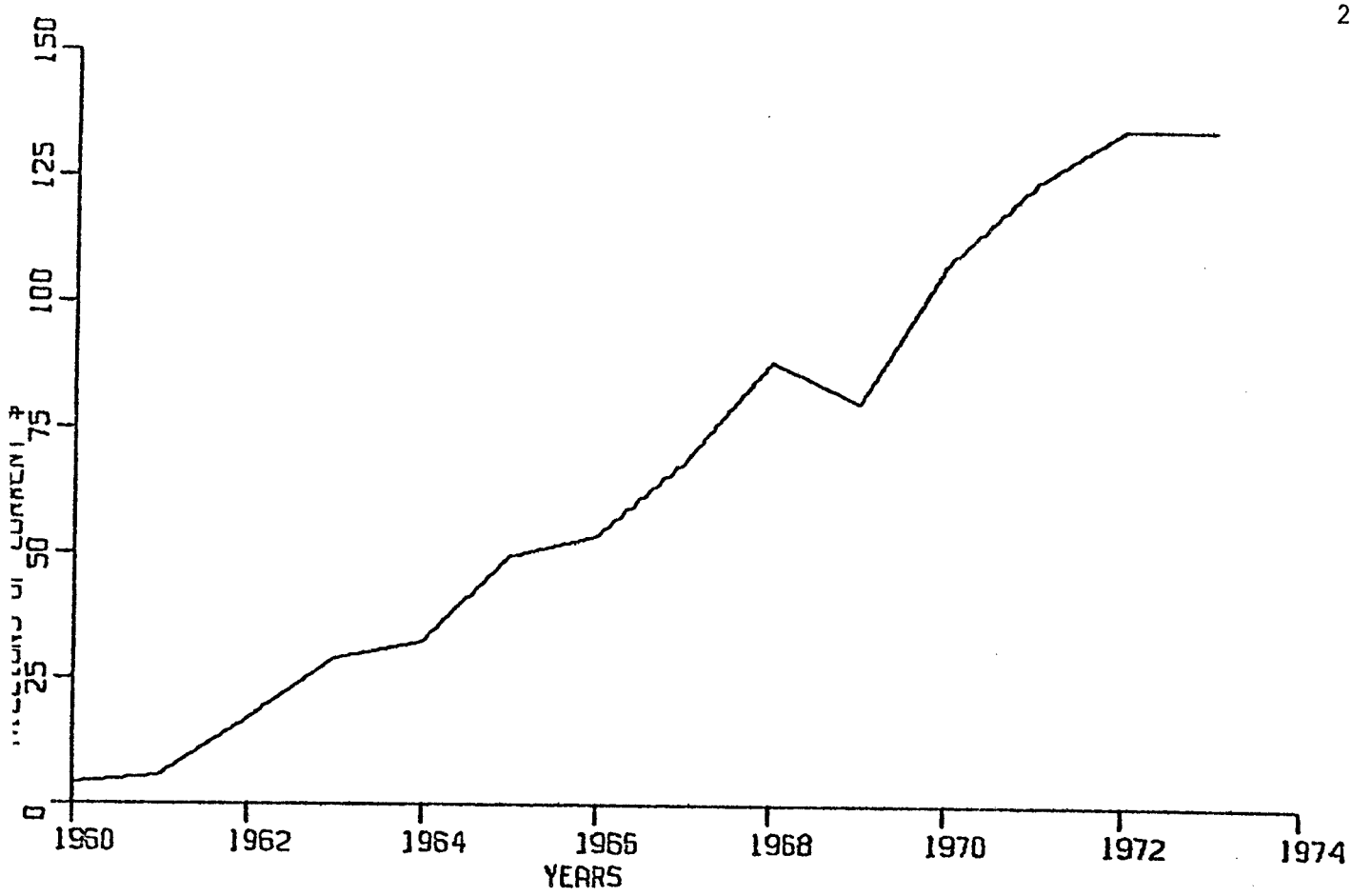
OWN DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN QUEBEC
1=CRUDE OIL
2=COAL



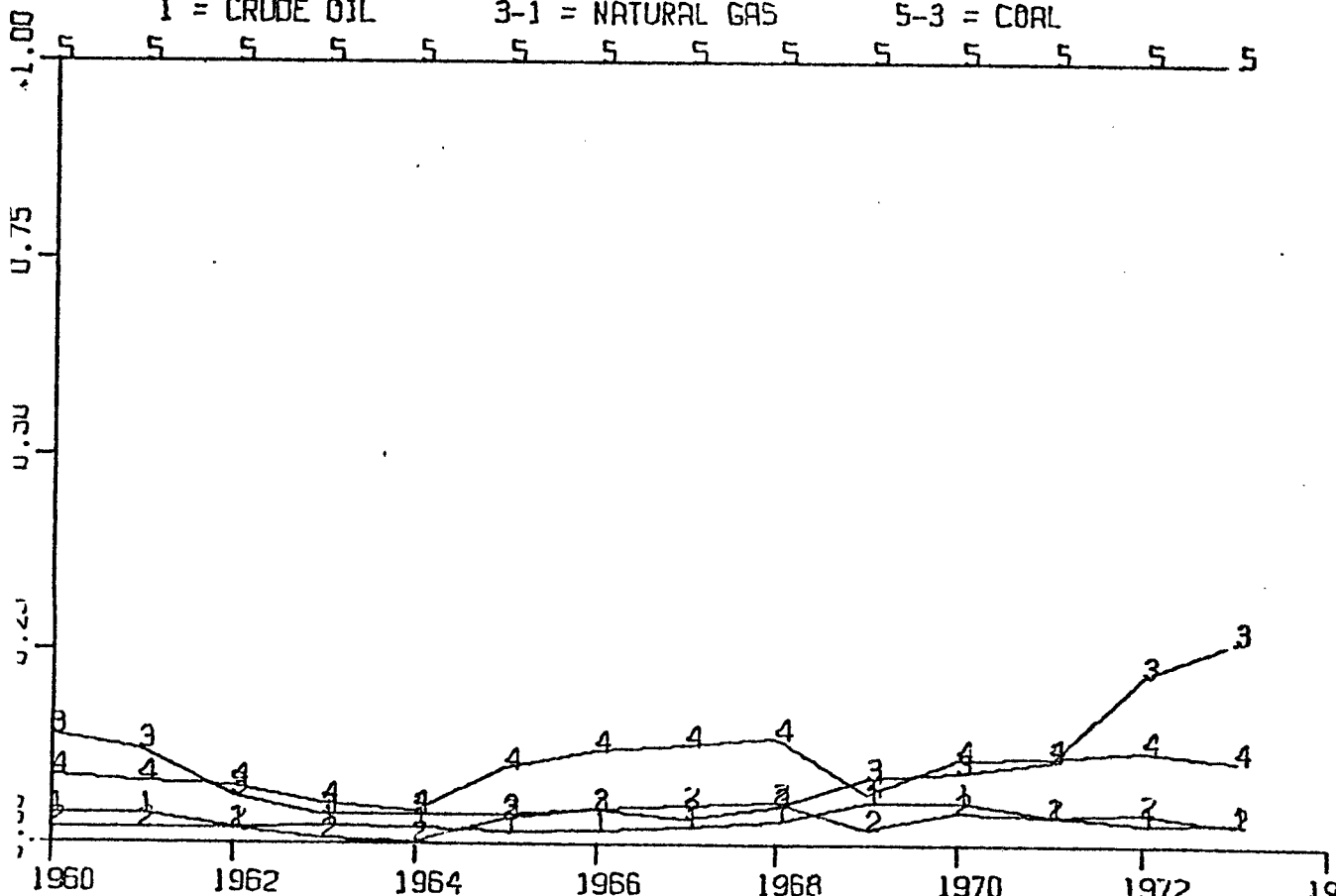
CROSS DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN QUEBEC
1=XELAS(C.O)
2=XELAS(O.C)



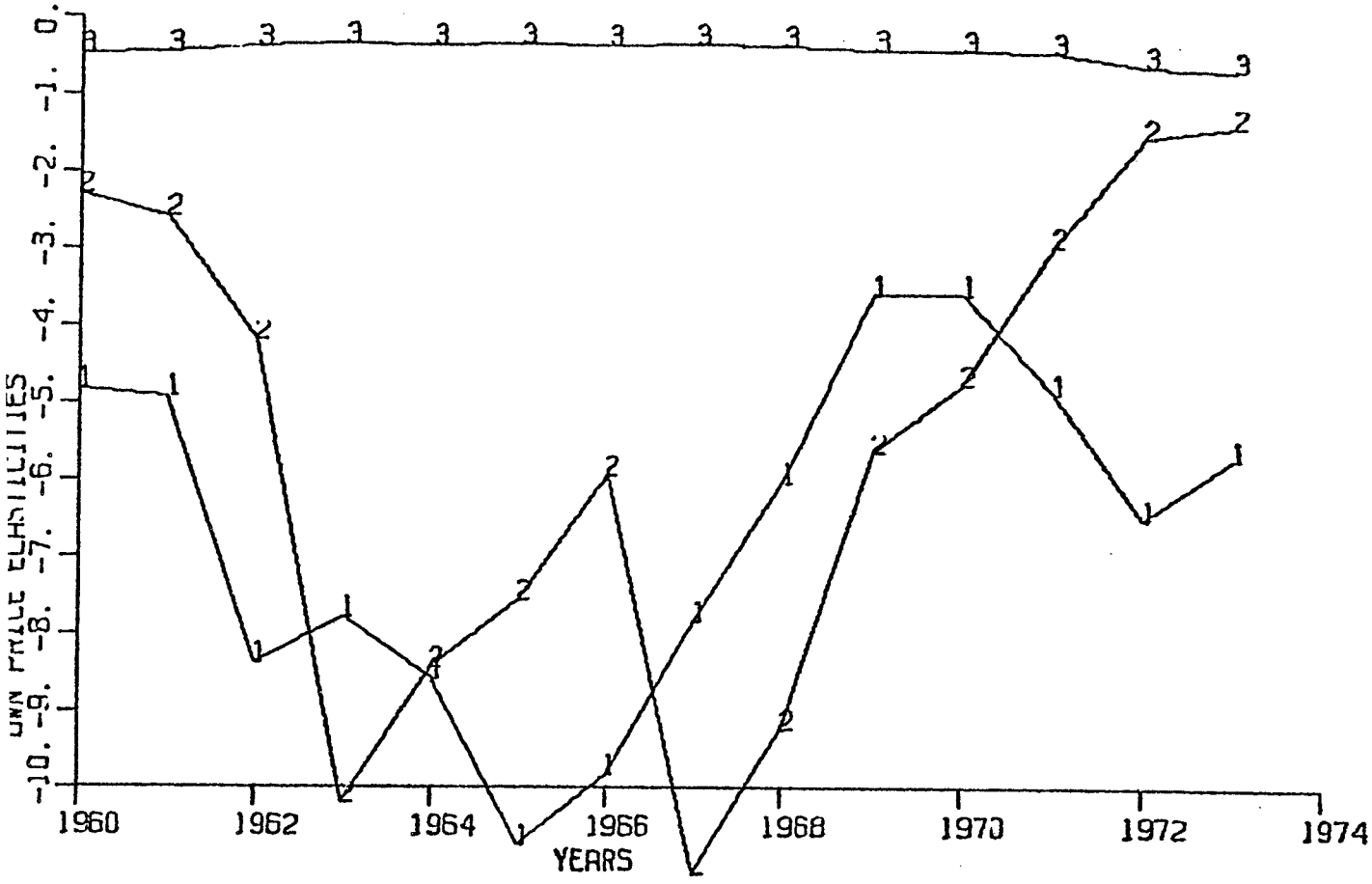
TOTAL EXPENDITURE ON PRIMARY ENERGY FUELS
USED TO GENERATE SECONDARY ELECTRICITY IN ONTARIO



ACTUAL AND ESTIMATED FUEL SHARES FOR GENERATING ELECTRICITY IN ONTARIO
1.3.5 = ACTUAL SHARE 2.4 = ESTIMATED SHARE
1 = CRUDE OIL 3-1 = NATURAL GAS 5-3 = COAL



OWN DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN ONTARIO
1=CRUDE OIL 2=NATURAL GAS 3=COAL



CROSS DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN ONTARIO
1=XELAS(C.O) 2=XELAS(C.G) 3=XELAS(O.C)
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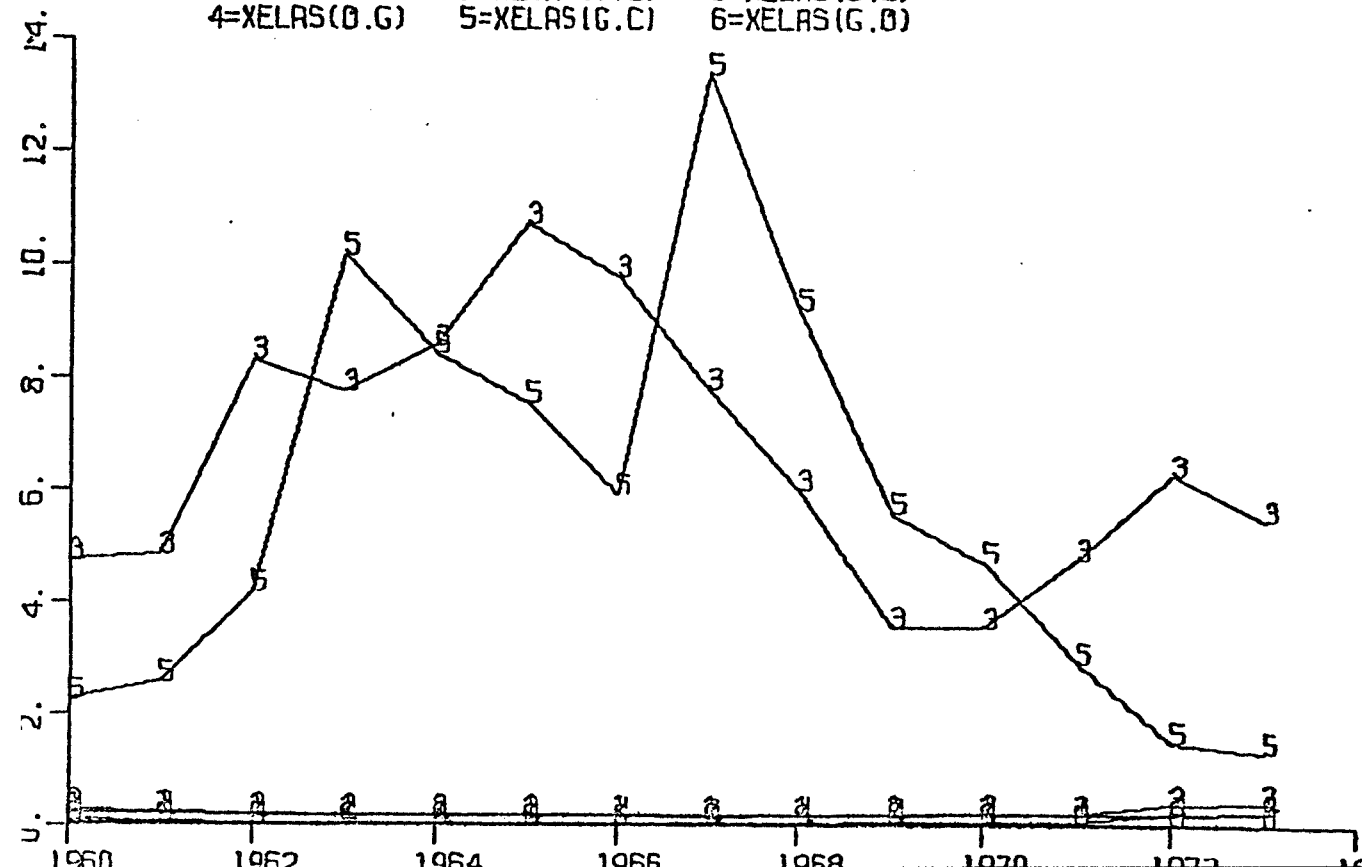
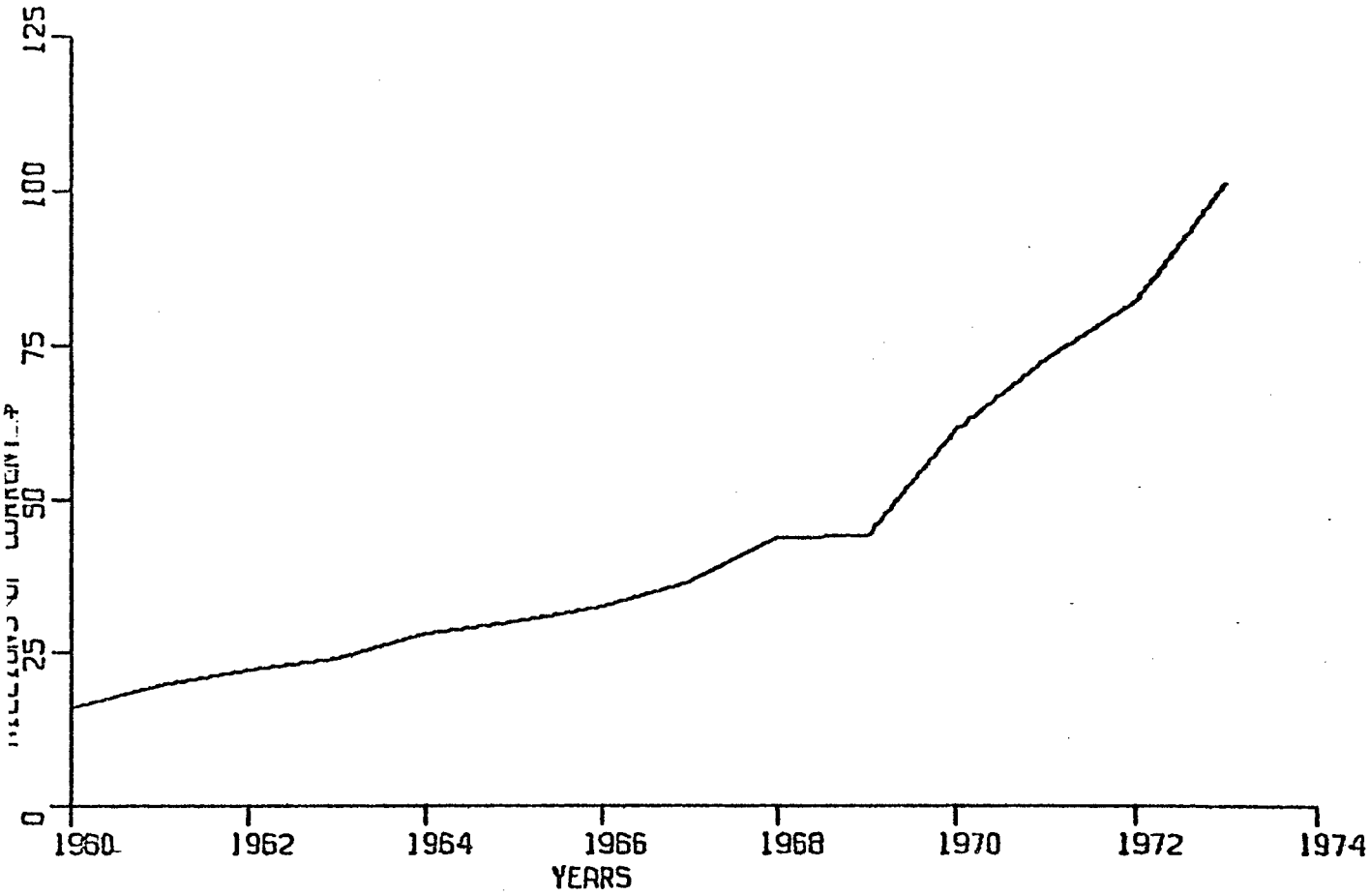


TOTAL EXPENDITURE ON PRIMARY ENERGY FUELS
USED TO GENERATE SECONDARY ELECTRICITY IN PRAIRIES



ACTUAL AND ESTIMATED FUEL SHARES FOR GENERATING ELECTRICITY IN PRAIRIES
1.3.5 = ACTUAL SHARE 2.4 = ESTIMATED SHARE
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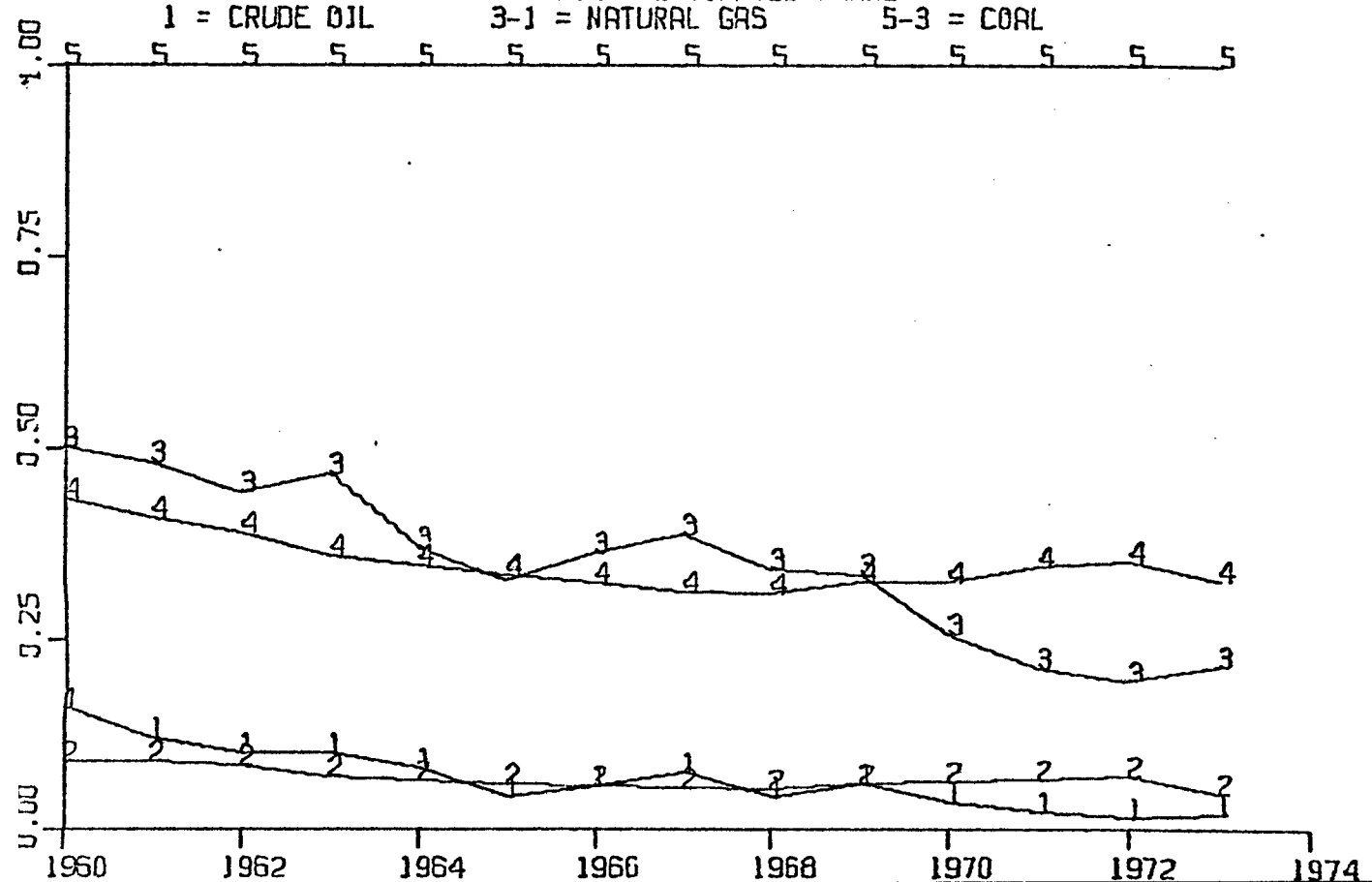
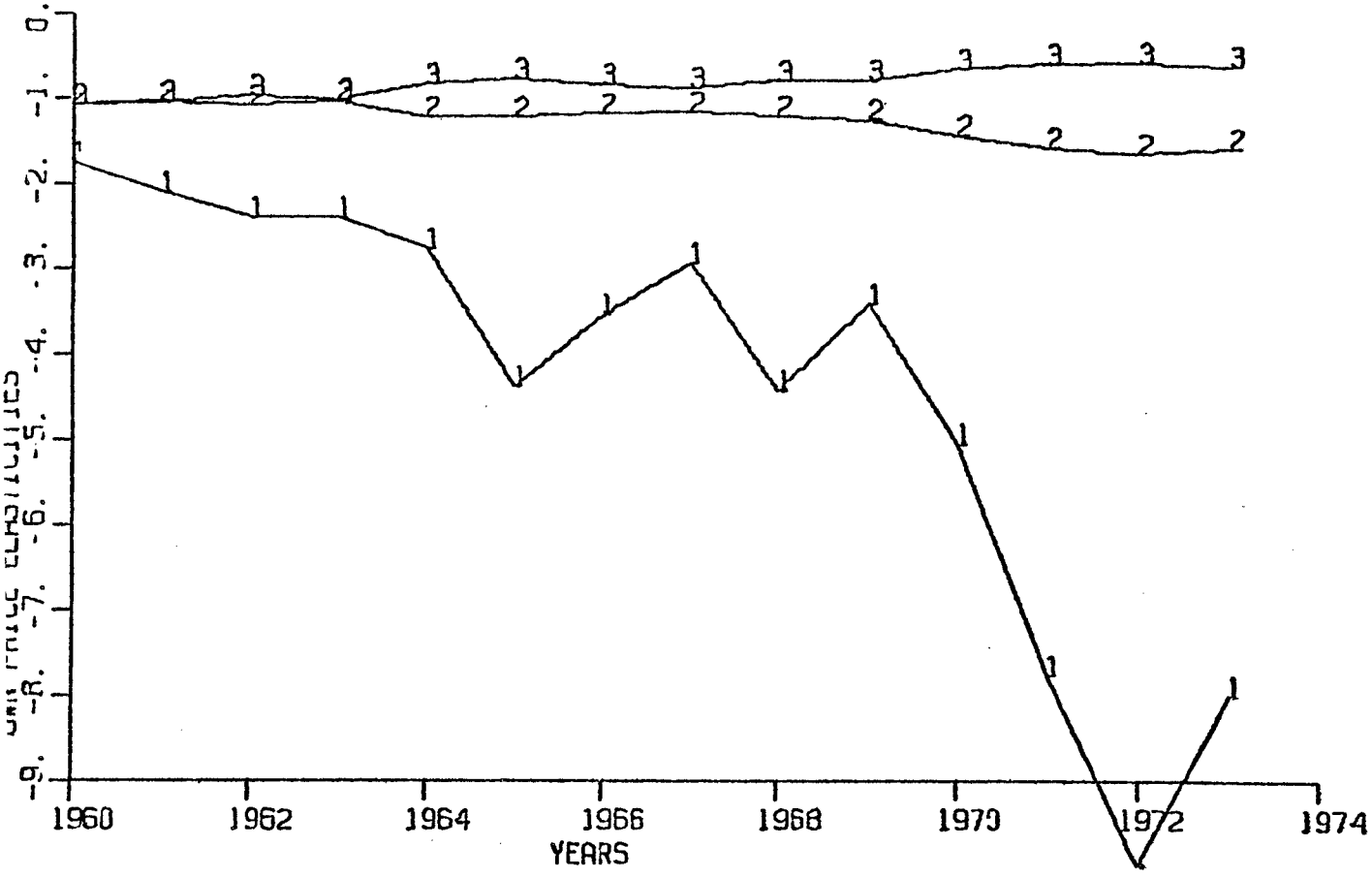
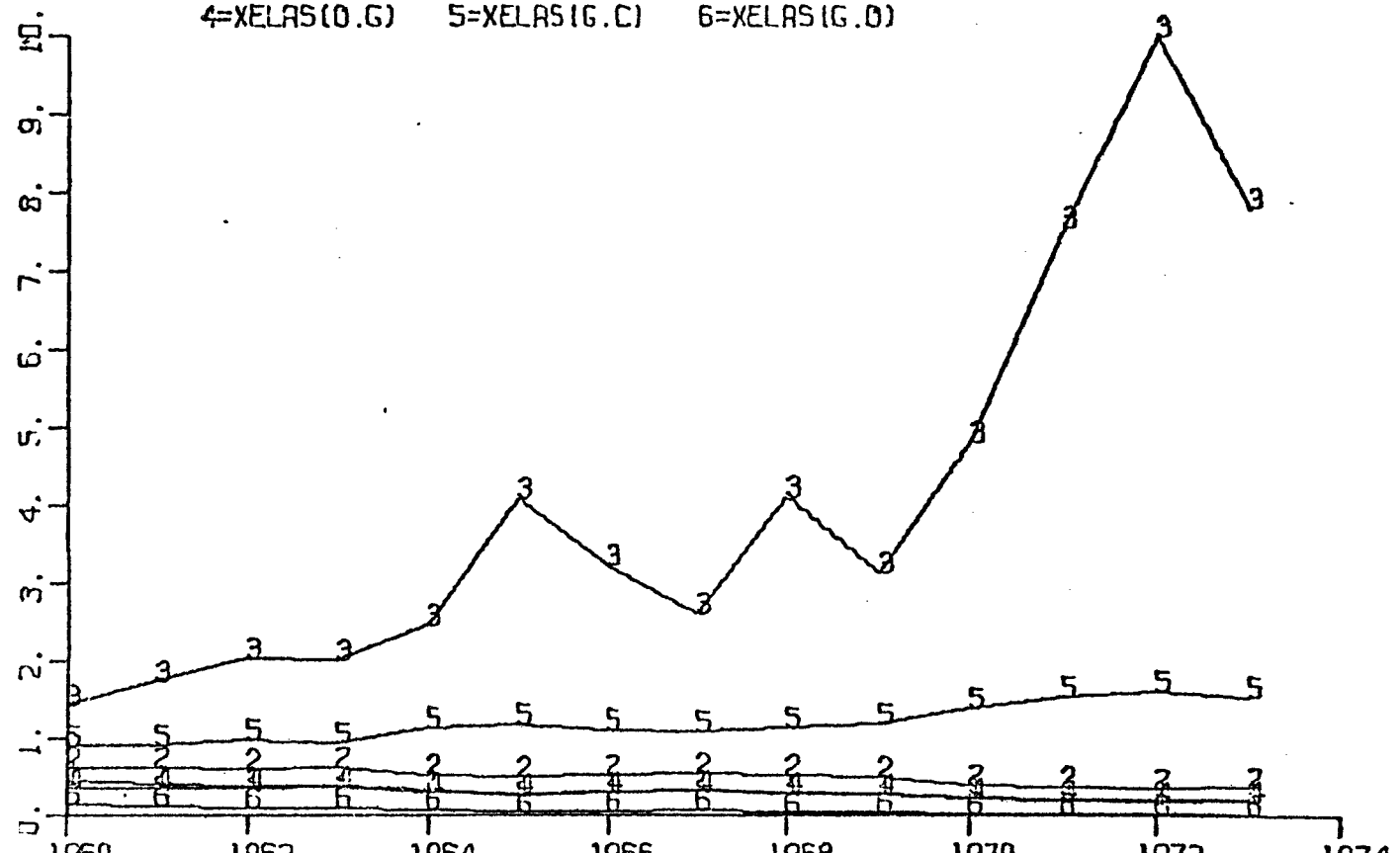


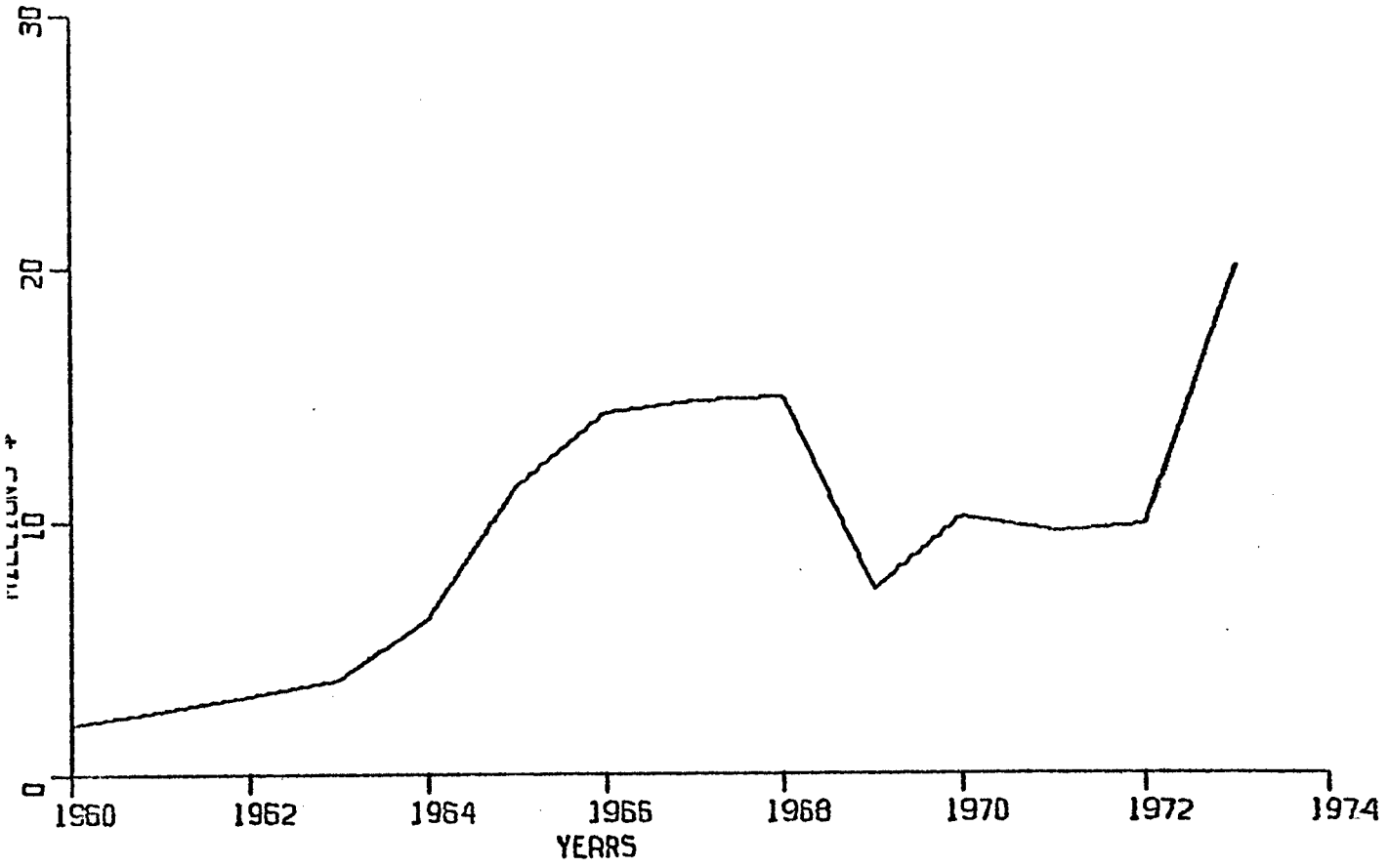
OWN DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN PRAIRIES
1=CRUDE OIL 2=NATURAL GAS 3=COAL



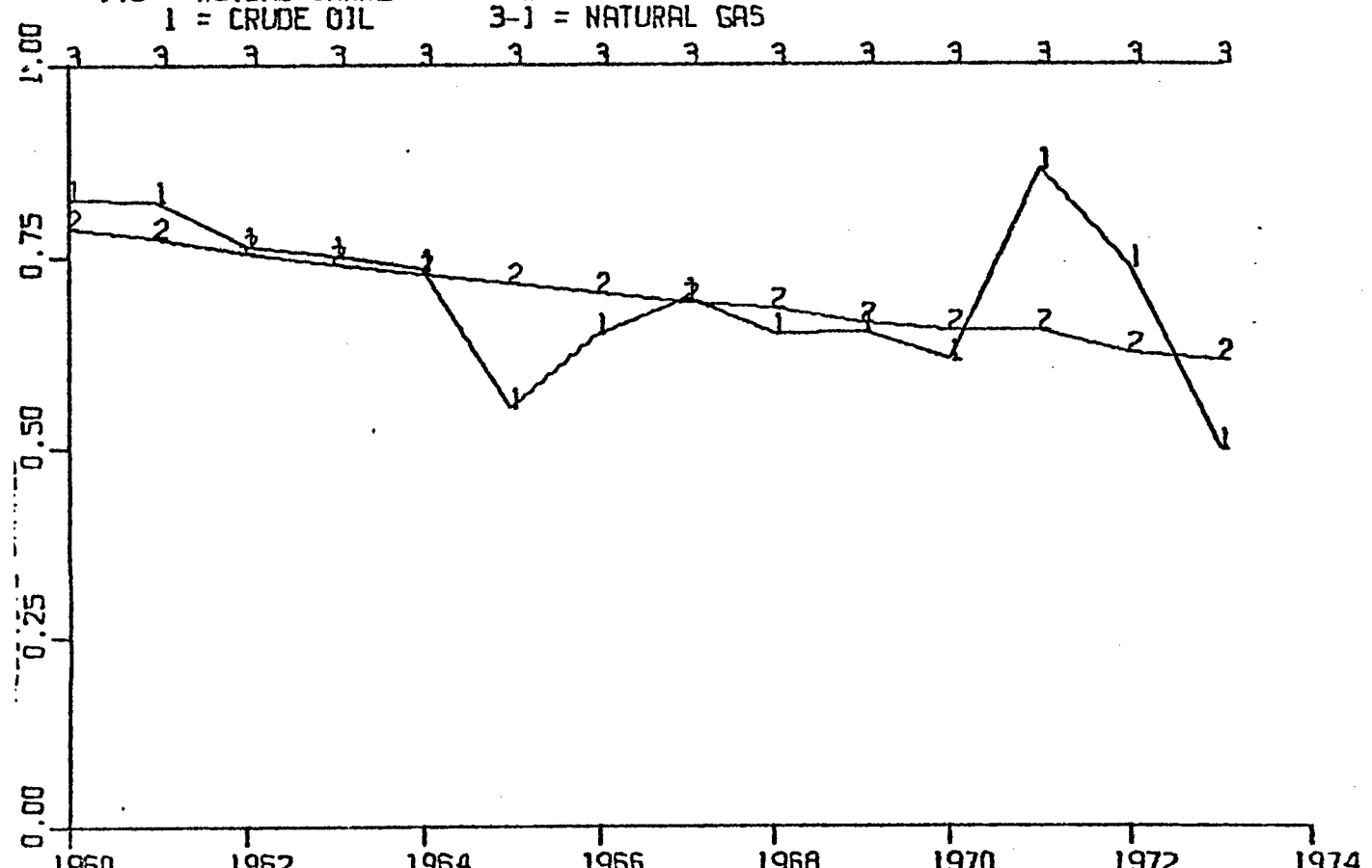
CROSS DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN PRAIRIES
1=XELAS(C.O) 2=XELAS(C.G) 3=XELAS(O.C)
4=XELAS(O.G) 5=XELAS(G.C) 6=XELAS(G.O)



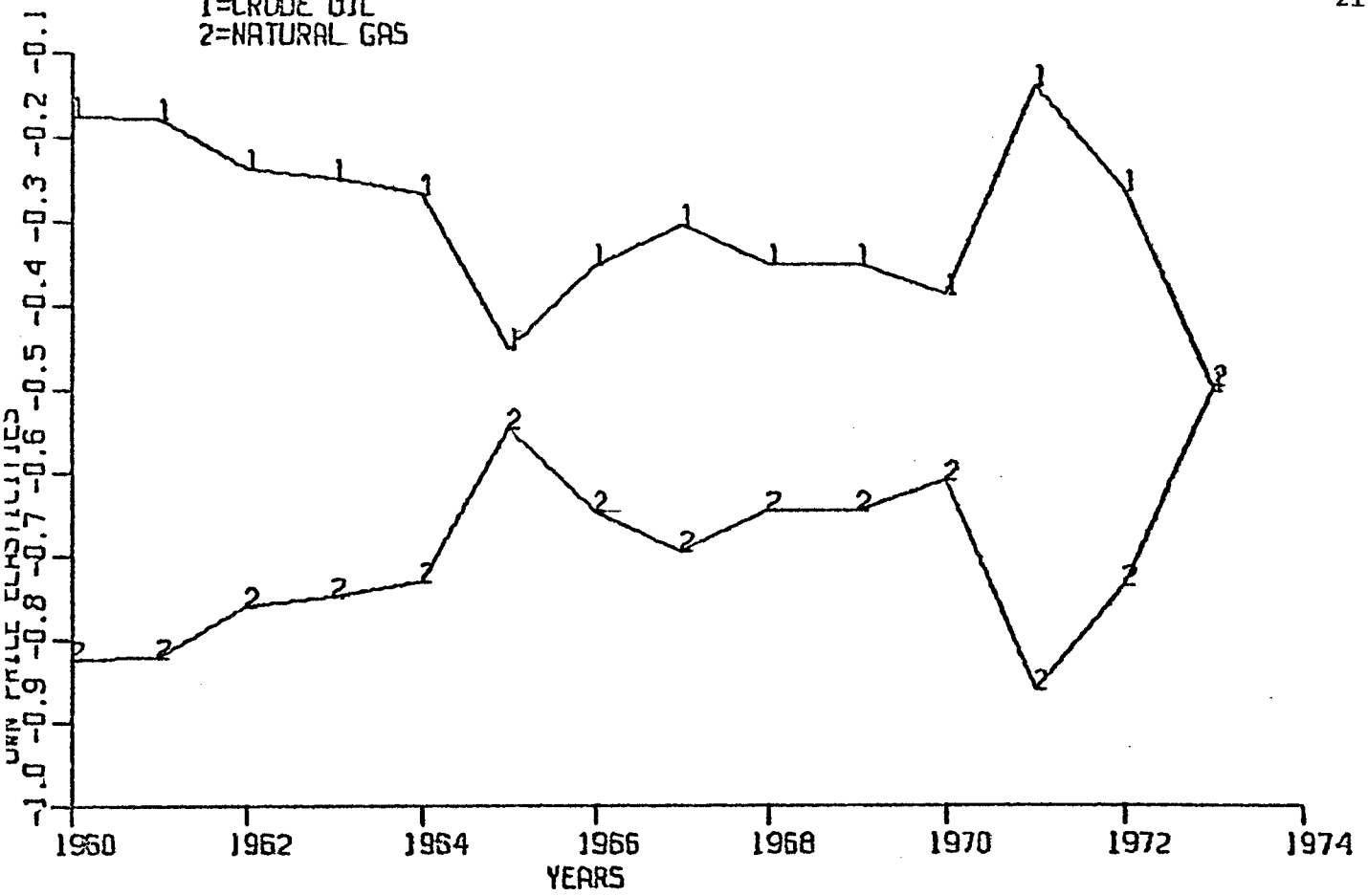
TOTAL EXPENDITURE ON PRIMARY ENERGY FUELS
USED TO GENERATE SECONDARY ELECTRICITY IN B.C.



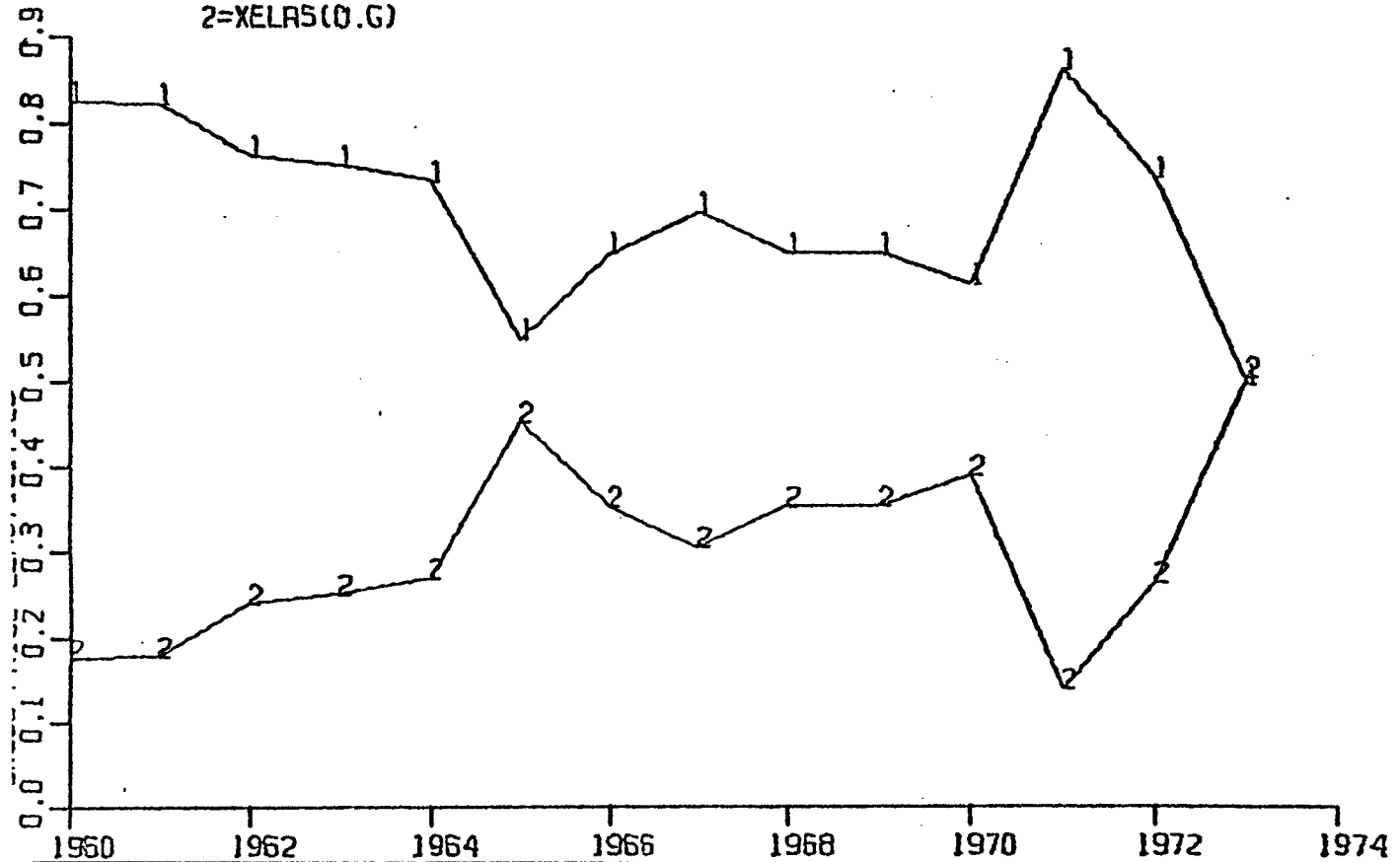
ACTUAL AND ESTIMATED FUEL SHARES FOR GENERATING ELECTRICITY IN B.C.
1.3 = ACTUAL SHARE 2 = ESTIMATED SHARE
1 = CRUDE OIL 3-1 = NATURAL GAS



OWN DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN B.C.
1=CRUDE OIL
2=NATURAL GAS



CROSS DEMAND PRICE ELASTICITIES FOR FUELS
USED IN GENERATING SECONDARY ELECTRICITY IN B.C.
1=XELAS(G,O)
2=XELAS(O,G)



3.C Btu Efficiency Conversion Factors

The Btu conversion factors have been obtained from the introduction to the Statistics Canada document, Detailed Energy Supply and Demand in Canada . For electricity the conversion factor is 3.412 million Btu/'000 kwh; for natural gas the conversion factor is approximately 1.0 million Btu/mcf; for crude oil the conversion factor is 5.803 million Btu/bbl; for coal the conversion factor varies over time and by region because different types of coal have different factors.

Table 1: Btu Conversion Factors For Natural Gas And Coal

	Natural Gas all regions	Coal Atlantic	Quebec	Ontario	Prairies
1958	1.07	24.78	25.39	25.48	16.39
1959	1.07	24.92	25.38	25.59	16.38
1960	1.07	24.86	25.40	25.61	15.50
1961	1.07	25.21	25.37	25.62	15.34
1962	1.06	25.08	25.36	25.60	15.39
1963	1.05	25.11	25.37	25.76	15.49
1964	1.035	25.01	25.39	25.84	15.48
1965	1.02	24.92	25.43	25.81	15.55
1966	1.01	25.23	25.45	25.82	15.48
1967	1.00	25.34	25.41	25.85	15.55
1968	1.00	24.91	25.41	25.94	15.26
1969	1.00	25.19	25.49	25.87	15.20
1970	1.00	25.21	25.49	25.47	14.85
1971	1.00	25.29	25.51	25.23	14.88
1972	1.00	25.05	25.53	25.55	15.03
1973ff[2]	1.00	25.18	25.51	25.42	14.92

The utilization efficiency factors were obtained from a study by F. Gorbet (p.19). These factors are assumed to be constant over time and region. Table 2 contains the original factors for each end-use. Table 3 contains the calculated efficiency factors for each of the primary fuels aggregated over all end uses. This aggregation by primary fuel was done for each region by weighting the efficiency factor in each end-use by the percentage of the fuel used in that end-use. For crude oil it is necessary to aggregate for each region in two stages: the first stage involves weighting the efficiency factors for each of the crude oil products in each of the end-uses by the percentage of the fuel used in that end-use (similar to the other primary fuels); the second stage involves weighting each of the average efficiency factors for the crude oil products by the percentage of the crude oil products (relative to all crude oil products). These average primary fuel efficiency factors vary by region and

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[2] From 1973 forward, we use the average of the factors for 1970,1971, and 1972.

over time because of different fuel shares across regions, and shifts in fuel shares over time.

Table 2: Utilization Efficiency Factors Across All End-use Sectors (proportion)

	res.	com.	ind.	trans.			
				road	rail	air	marine
coal	.50	.65	.87	-	.08	-	.08
LPG	.75	.78	.85	-	-	-	-
still gas	-	-	.85	-	-	-	-
kerosene	.55	.82	.82	-	.55	-	.55
diesel oil	.23	.23	.26	.23	.23	-	.15
light fuel oil	.65	.82	.82	-	.82	-	.10
heavy fuel oil	.80	.80	.87	-	.80	-	.10
motor gasoline	-	-	-	.20	-	-	-
aviation gasoline	-	-	-	-	-	.20	-
aviation turbofuel	-	-	-	-	-	.30	-
natural gas	.75	.78	.85	-	-	-	-
electricity	1.00	1.00	1.00	-	-	-	-

where: res. is used to represent the residential sector,
com. is used to represent the commercial sector,
ind. is used to represent the industrial sector,
trans. is used to represent the transportation sector.

Table 3: Utilization Efficiency Factors for each of the Primary Fuels (proportion)

	Atlantic		Quebec			Ontario		
year	oil	elec	oil	gas	elec	oil	gas	elec
1958	.424	1.0	.498	.768	1.0	.460	.786	1.0
1959	.443	1.0	.493	.776	1.0	.467	.797	1.0
1960	.454	1.0	.487	.807	1.0	.472	.800	1.0
1961	.459	1.0	.488	.822	1.0	.470	.802	1.0
1962	.463	1.0	.493	.817	1.0	.477	.804	1.0
1963	.452	1.0	.496	.817	1.0	.482	.804	1.0
1964	.467	1.0	.511	.819	1.0	.478	.804	1.0
1965	.470	1.0	.518	.813	1.0	.486	.802	1.0
1966	.449	1.0	.529	.813	1.0	.480	.803	1.0
1967	.467	1.0	.536	.812	1.0	.486	.805	1.0
1968	.466	1.0	.539	.814	1.0	.487	.807	1.0
1969	.486	1.0	.542	.815	1.0	.480	.808	1.0
1970	.491	1.0	.546	.812	1.0	.478	.810	1.0
1971	.508	1.0	.540	.815	1.0	.463	.811	1.0
1972[3]	.495	1.0	.543	.814	1.0	.474	.810	1.0

where: oil is used to represent crude oil,
gas is used to represent natural gas,
elec is used to represent electricity.

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[3] The efficiency factor used for 1972 and for all future years is a 3-year average using the data from 1969, 1970 and 1971.

Table 3: Utilization Efficiency Factors For Each Of The Primary Fuels (cont'd)

	Prairies			B.C.		
Year	Oil	Gas	Elec	Oil	Gas	Elec
1958	.374	.795	1.0	.427	.784	1.0
1959	.374	.797	1.0	.439	.791	1.0
1960	.349	.797	1.0	.440	.796	1.0
1961	.343	.797	1.0	.431	.798	1.0
1962	.340	.796	1.0	.430	.798	1.0
1963	.331	.797	1.0	.437	.797	1.0
1964	.327	.797	1.0	.443	.793	1.0
1965	.336	.795	1.0	.430	.790	1.0
1966	.331	.797	1.0	.420	.800	1.0
1967	.327	.798	1.0	.421	.798	1.0
1968	.316	.798	1.0	.423	.798	1.0
1969	.317	.799	1.0	.447	.802	1.0
1970	.310	.798	1.0	.419	.800	1.0
1971	.319	.798	1.0	.411	.804	1.0
1972♦	.315	.798	1.0	.426	.802	1.0

where: oil is used to represent crude oil,
gas is used to represent natural gas,
elec is used to represent electricity.

♦ The efficiency factor used for 1972 and for all future years is a 3-year average using the data from 1969, 1970 and 1971.

3.D Estimated Equations for Energy Supply Use and Losses

Each of the variables in the fuel losses[5] equations are in natural units. The form of each equation is as follows: LOSS F = a*X, where LOSS F is the quantity of regional fuel loss, and X is the regional sale (net of fuel losses) of fuel, or the production of fuel in the case of natural gas in the producing regions. The following tables will summarize the parameter estimates and equation statistics from the losses estimations.

Table 1: Losses Parameters and Equation Statistics for Crude Oil

	Atlantic	Quebec	Ontario	Prairies	B.C.
a	.0486561	.0803773	.0889120	.0985430	.0499854
	(5.324)	(28.29)	(18.003)	(33.763)	(6.522)
rho	.773634	.357458	.386700	-.383094	.469126
	(4.729)	(1.482)	(1.624)	(-1.606)	(2.057)
R^2	.753	.900	.585	.505	.032
dw	2.33	1.75	1.797	1.883	2.188
ser	.663	.992	1.258	1.026	.577
Y	3.096	9.761	9.194	6.522	1.992
nobs	15	15	15	15	15
est. time	1959-73	1959-73	1959-73	1959-73	1959-73
est. proc	Coch-Orcu	Coch-Orcu	Coch-Orcu	Coch-Orcu	Coch-Orcu

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[5] Losses will be used to mean energy supply industry use, and losses and adjustments use.

Table 2: Losses Parameters and Equation Statistics for Natural Gas

	Quebec	Ontario	Prairies	B.C.
a	-.0507479	.0586273	.174397	.281222
	(-2.082)	(3.676)	(17.037)	(11.240)
rho	1.010010	.953488	.791283	-
		(12.251)	(5.012)	
R^2	.5147	.952	.970	.680
dw	2.149	1.234	2.379	.561
ser	.506	3.303	11.724	16.720
Y	.782	24.082	179.242	40.641
nobs	15	15	15	16
est. time	1959-73	1959-73	1959-73	1958-73
est. proc	Coch-Orcu	Coch-Orcu	Coch-Orcu	OLS

Table 3: Losses Parameters and Equation Statistics for Electricity

	Atlantic	Quebec	Ontario	Prairies	B.C.
a	.0883340	.0920821	.0929071	.141550	.0775977
	(38.151)	(51.480)	(13.486)	(65.183)	(26.654)
rho	.297382	.322412	.877308	.415031	-.001802
	(1.206)	(1.319)	(7.080)	(1.767)	(-.00698)
R^2	.968	.949	.945	.992	.888
dw	1.836	2.004	2.658	2.198	1.785
ser	.0616	.258	.257	.0875	.239
Y	.762	4.819	5.258	2.183	1.536
nobs	15	15	15	15	15
est. time	1959-73	1959-73	1959-73	1959-73	1959-73
est. proc	Coch-Orcu	Coch-Orcu	Coch-Orcu	Coch-Orcu	Coch-Orcu

3.E Construction of Energy Quantities and Prices

1. Construction of energy quantities

All of the natural unit energy quantities are obtained from the Statistics Canada document Detailed Energy Supply and Demand in Canada. The data is reported over the time period 1958-1973 for five regions of Canada: Atlantic, Quebec, Ontario, Prairies, and B.C.[6] For each region and each year the following procedure was adopted. The primary energy availability (col. 7) for crude oil , natural gas and electricity was obtained. The primary energy availability includes all aspects of supply: total production, exports, imports, inter-regional transfers, stock changes, and inter-product transfers.

The secondary (thermal generated) energy availability for electricity (col. 21) is then added to the primary energy availability to arrive at total availability of electricity (col. 25). Then the energy supply industry use (col. 26) and the losses and adjustments (col. 35) are subtracted from the previously calculated total available electricity to obtain the net electricity demanded.

The amount of natural gas used to generate thermal electricity (col. 8 plus col. 9) is subtracted from the primary energy availability to arrive at the net primary supply (col. 12). Then the energy supply industry use (col. 26) and the losses and adjustments (col. 35) are subtracted from the previously calculated net primary supply to obtain the net natural gas demanded.

The amount of crude oil products used to generate thermal electricity are subtracted from the primary energy availability to arrive at the net primary supply. The crude oil products are crude oil (col. 8 plus col. 9), diesel fuel oil (col. 22 plus col. 23), light fuel oil (col. 22 plus col. 23), and heavy fuel oil (col. 22 plus col. 23). The quantity of crude oil remaining is then purged of the energy supply industry uses (col. 26) and the losses and adjustments (col. 35) for each of the crude oil products. These crude oil products are crude oil, still gas, motor gasoline, kerosene, diesel fuel oil, light fuel oil, heavy fuel oil, petroleum coke, aviation gasoline, and aviation turbofuel. The remaining quantity is the net crude oil demand.

The quantity of coal used to generate thermal electricity (col. 8 plus col. 9) is used in the auxiliary demand model. The quantities of natural gas and crude oil products which are used to generate thermal electricity are also used in the auxiliary demand model.

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[6] The B.C. region also includes data from Yukon and Northwest Territories.

The quantities of crude oil products, natural gas, and electricity which are absorbed in the energy supply industry and losses and adjustments use are the dependent variables for a set of equations reported in appendix 3.D.

All of the quantities are converted from natural units to output Btu units. The conversion factors are reported in appendix 3.C.

The following tables report by region the natural unit quantities of the energy fuels used for non-thermal demand, the energy fuels used for thermal demand, the energy fuels which are included in the losses and energy supply use demand, the crude oil which is re-exported, and the electricity generated by hydro source and the electricity generated by thermal power plants. All units for quantities are in millions of natural units.

2. Construction of energy prices

The construction of energy prices is complicated by the fact that they must be available for each of the five regions. Transportation tariffs are necessary in most cases to transform, both regionally and inter-regionally, the wellhead prices to market prices. In some cases the market price is calculated as a weighted average of two different sources. For some fuels it was impossible to obtain a time series for the transportation tariff, so that assumptions had to be made in order to generate a time series from a few point estimates. Some regions import the energy fuel from abroad, in which case the landed price (c.i.f.) must be obtained. All values reported in international trade statistics are measured f.o.b. at the point of exit from the exporting country. For the imports of coal into Ontario this valuation presents no problem. Since it is impossible to obtain a time series for tanker rates, the f.o.b. price for crude oil is of no use.

The energy prices will be explained below by energy type by region. The crude oil prices in the Atlantic region must be derived from the average c.i.f. landed price of all crude oil imports, obtained from Statistics Canada publication #45-205, Petroleum Refineries. In order to disentangle the aggregate price, the assumption was made that due to a shorter transportation route, there exists a 10 cent[7] price differential

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[7] The 10 cents/bbl price differential is obtained by assuming that 40% of the Quebec imports are through the Portland to Montreal pipeline at 3.5 cents/bbl, and 60% of Quebec imports are by ship down the St. Lawrence to Montreal for 1000 extra miles at roughly 12.8 cents/bbl. The Portland to Montreal pipeline tariff is available in the C.P.A. Statistical Yearbook up to 1971; the shipping tariff is obtained from Oil Import Question (p.248, Appendix E) which states a shipping cost in 1969 of 23 cents/bbl for a 1800 mile journey from Venezula.

between the Atlantic and Quebec regions, in favour of the Atlantic . The prices for the two regions are calculated as follows:

let p represent the average refinery price for total imports in Quebec and Atlantic;
let p1, x1 represent the price and quantity in Atlantic;
let p2, x2 represent the price and quantity in Quebec;
assume that the quantity weights xi/(x1+x2) will be used in weighting the two regional prices;
then p1*x1/(x1+x2) + p2*x2/(x1+x2) = p, where p2 = p1+.10,
hence p1 = p-.10*(x2/(x1+x2))
and p2 = p1 + .10

The crude oil price in the Ontario market is derived from adding the Interprovincial Pipeline Co. transportation tariff from Edmonton to Port Credit onto the Prairies crude oil wellhead price. The transportation tariff is available from the CPA, Statistical Yearbook for various years up to 1971. Ontario does produce a very small amount of crude oil, and it is possible to obtain the average wellhead price from table 3 of Statistics Canada publication #26-213, Crude Petroleum and Natural Gas Industry . But a weighted price was not constructed because a transportation tariff was not available. Since the amount was so small it is conjectured that its price would have to be competitive with Prairies crude oil; hence a weighted price is unnecessary.

The wellhead price of crude oil in the Prairies is obtained from the marketable production section of table 3 in the Statistics Canada publication #26-213. The transportation tariff of 10 cents/bbl within the Prairie region has been obtained for 1972 from table 2-8, p.25 of the study by Powrie and Gainer.

The wellhead price of crude oil in B.C. is obtained from the same source as the wellhead price in the Prairies. The market price in B.C. is a weighted price of crude oil from the Prairie and B.C. regions. Both of the transportation tariffs are available from the CPA, Statistical Yearbook , for various years up to 1971. The Prairie crude oil is shipped by TransMountain Oil Pipeline Co. from Edmonton to Burnaby; the B.C. crude oil is shipped by Westcoast Petroleum Ltd., (formerly Western Pacific Products and Crude Oil Pipelines Ltd.) from Taylor to Kamloops, then by TransMountain Oil Pipelines Co. from Kamloops to Burnaby.

The city-gate price of natural gas in Quebec is derived from adding a fixed nominal transportation tariff onto the Prairie wellhead price. The transportation tariff is obtained from information in a study by Powrie and Gainer (table 3-7, p.76). They report that in 1973 there existed a 6 cents/mcf transport differential between shipping natural gas to Ontario and Quebec. The city-gate price of natural gas in Ontario is derived from a weighted average of the Ontario wellhead price and the Prairie wellhead price plus a fixed nominal transportation tariff. The transportation tariff of 30 cents/mcf in 1972 to ship natural gas from Alberta fields to Toronto is

obtained from a study by ERCB, Review of Field Pricing of Gas in Alberta, p.2-9. The Ontario wellhead price of natural gas was obtained from the marketable products section of table 3 in Statistics Canada publication #26-213. The production of natural gas in Ontario is very small.

The wellhead price of natural gas in the Prairies is obtained from the marketable production section of table 3 in Statistics Canada publication #26-213. The transportation tariff of 4 cents/mcf in 1973 for the Prairie region is obtained from the Powrie and Gainer study (table 3-7, p.76) by weighting the transportation tariffs in Alberta, Saskatchewan, and Manitoba.

The wellhead price of natural gas in B.C. is obtained from the same source as for the Prairie price. To obtain the transportation tariff within B.C. the average wellhead price was subtracted from the average selling price to B.C. Hydro. On p.37-38 of CPA, Natural Gas Producing Industry in B.C. , the average price paid for natural gas by Westcoast Transmission Co. is reported; and on pp.3-24 and 3-33 of Westcoast Transmission Co., Submission in the Matter of the Energy Act and in the Matter of a Public Hearing on the Matter Concerning the Natural Gas Industry in B.C. , the average selling price to B.C. Hydro is reported. From the BCEC , Report in Matters Concerning the Natural Gas Industry in B.C., p.48, a transportation tariff of 20 cents/mcf is available for 1973.

For each region, the average electricity price obtained from Statistics Canada publication #57-202, Electric Power Statistics Vol 2 , is for the retail market. From 1958-1963 the electricity quantity was obtained from table 4, 'disposal of energy' and electricity revenue obtained from table 6, 'revenue from sale of electricity'. From 1964-1973 both the electricity quantity and revenue are obtained from table 6, 'energy sales by category of service'. To transform the electricity prices from a retail to wholesale (city-gate) market a coefficient is derived by using the average transfer price between Ontario Hydro and Toronto Hydro. The transformation coefficient is .75, which is the average value from 1965-1971 of the ratio of the cost of electricity sold to Toronto over the cost of electricity to final users. This coefficient is assumed to be constant over time and the same across regions.

The wellhead price of coal in the Atlantic region is obtained from table 1C, 'fuels', in the Statistics Canada publication #26-201, General Review of the Mineral Industries . The transportation tariff for bituminous coal (class #238) within the Atlantic region is obtained from various issues of the Canadian Transportation Commission report, Waybill Analysis.

The price of coal in Quebec is a weighted average of coal imported from the U.S. and coal produced in the Atlantic region. The coal transportation tariffs are obtained for 1964 from an EMR report, The Cape Bretton Coal Problem (p.115, Appendix D). It is assumed that U.S. imports come through Ontario and up the St. Lawrence River. The transportation rates are assumed to be

fixed in nominal terms.

The price of coal in Ontario is obtained by adding a transportation tariff to the price of imported U.S. coal. The average f.o.b. coal price (code 261-49) is obtained from Statistics Canada publication #65-203, Imports: Merchandise Trade . The transportation tariff is obtained from the same source as quoted for Quebec.

The f.o.b. mine price of coal in the Prairies is obtained from table 1C, 'fuels', of Statistics Canada publication #26-201. The transportation tariff within the Prairies is obtained from the CTC publication , Waybill Analysis . The coal tariff is a weighted average of bituminous coal (class #238) and lignite coal (class #239). Since the publication has only tariffs for a 'western' region, the assumption was made that the ton-mile tariff is the same for B.C. and Prairies. To obtain an average mileage for the Prairie region, the pre-1969 western mileage was used because the Prairies had a much larger consumption than B.C. From 1970, it was assumed that coal was transported an average of 600 miles at a cost of .7 cents/ton-mile, implying a transport tariff of $4.20/ton.

The following tables contain the regional energy city-gate prices (in natural units) and the actual values used as transportation tariffs among and between regions over the period 1958-1973.

Crude Oil Transport Rates (cents/bbl)

	Edm-P.C.	Edm-Burn	Tay-Kam	Kam-Burn	Port-Mon	Pra-Pra
1958	72	40	-	-	3	10
1959	54	40	-	-	3	10
1960	54	40	-	-	3	10
1961	54	40	-	22	3	10
1962	51	40	66	22	3.5	10
1963	51	40	56	22	3.5	10
1964	51	40	56	22	3.5	10
1965	51	40	56	22	3.5	10
1966	51	40	56	22	3.5	10
1967	51	40	46.5	17.4	3.5	10
1968	51	40	44.2	17.4	3.5	10
1969	51	40	41.5	17.4	3.5	10
1970	51	40	41.5	17.4	3.5	10
1971	51	40	41.5	17.4	3.5	10
1972	51	40	41.5	17.4	3.5	10
1973	51	40	41.5	17.4	3.5	10

where:
Edm-P.C. is the transportation from Edmonton to Port Credit,
Edm-Burn is the transportation from Edmonton to Burnaby,
Tay-Kam is the transportation from Taylor to Kamloops,
Kam-Burn is the transportation from Kamloops to Burnaby,
Port-Mon is the transportation from Portland to Montreal,
Pra-Pra is the transportation within the Prairies.

Natural Gas Transport Rates (cents/mcf)

	Pra-Pra	Pra-Ont	Pra-Que	BC-bord	BC-BC
1958	4	30	36	16	16
1959	4	30	36	15.7	15.7
1960	4	30	36	12.8	12
1961	4	30	36	12.8	12
1962	4	30	36	12.8	12
1963	4	30	36	12.8	12
1964	4	30	36	12.8	12
1965	4	30	36	12.8	12
1966	4	30	36	12.8	12
1967	4	30	36	15	12
1968	4	30	36	14.5	12
1969	4	30	36	14.2	12
1970	4	30	36	14	12
1971	4	30	36	14	12
1972	4	30	36	20	12
1973	4	35	40	20	20

where:
Pra-Pra is the transportation within the Prairies,
Pra-Ont is the transportation from Prairies to Ontario,
Pra-Que is the transportation from Prairies to Quebec,
BC-bord is the transportation from BC to border for exports,
BC-BC is the transportation within BC.

Coal Transport Rates ($/ton)

	Atl-Atl	Atl-Que	US-Que	US-Ont	Pra-Pra
1958	1.76	3.20	4.70	3.50	3.94
1959	1.90	3.20	4.70	3.50	4.31
1960	1.75	3.20	4.70	3.50	4.29
1961	1.72	3.20	4.70	3.50	4.39
1962	1.79	3.20	4.70	3.50	4.35
1963	1.79	3.20	4.70	3.50	4.31
1964	1.80	3.20	4.70	3.50	4.50
1965	1.80	3.20	4.70	3.50	4.50
1966	1.80	3.20	4.70	3.50	4.50
1967	1.80	3.20	4.70	3.50	4.50
1968	1.80	3.20	4.70	3.50	4.50
1969	1.90	3.20	4.70	3.50	4.80
1970	1.61	3.20	4.70	3.50	4.20
1971	2.47	3.20	4.70	3.50	4.20
1972	2.50	3.20	4.70	3.50	4.20
1973	2.50	3.20	4.70	3.50	4.20

where:
Atl-Atl is the transportation within the Atlantic,
Atl-Que is the transportation from Atlantic to Quebec,
US-Que is the transportation from US to Quebec,
US-Ont is the transportation from US to Ontario,
Pra-Pra is the transportation within the Prairies.

The following tables contain the historical quantity and price numbers, in natural units, which were used to estimate the demand system. All of the regional variables have an abreviation for the region appended to the mnemonic variable name. The following code is used:

any variable ending in 'AT' is associated with the Atlantic region,
any variable ending in 'QU' is associated with the Quebec region,
any variable ending in 'ON' is associated with the Ontario region,
any variable ending in 'PR' is associated with the Prairie region,
any variable ending in 'BC' is associated with the B.C. region.

Only the first part of the mnemonic name will be given since the description and units are uniform across region. The mnemonic names and units will be described below:

QO is the quantity of crude oil demanded by (non-thermal) final users, in MMbbl,
QG is the quantity of natural gas demanded by (non-thermal) final users, in Bcf,
QL is the quantity of electricity demanded by (non-thermal) final users, in billion Kwh,
HELEC is the quantity of hydro electricity supplied, in billion Kwh,
SELEC is the quantity of secondary (thermal) electricity supplied, in billion Kwh,
LOSSG is the quantity of losses and energy supply use of natural gas, in Bcf,
LOSSO is the quantity of losses and energy supply use of crude oil, in MMbbl,
LOSSL is the quantity of losses and energy supply use of electricity, in billion Kwh,
REXU is the quantity of crude oil re-exported, in MMbbl,
QCL is the quantity of coal demanded for thermal electricity generation, in MMtons,
QOL is the quantity of crude oil products demanded for thermal electricity generation, in MMbbl,
QGL is the quantity of natural gas demanded for thermal electricity generation, in Bcf,
UGNE is the real gross national expenditure in millions of 1961 $,
PGNE is the price index for gross national expenditure,
TOT is the expenditure on all energy fuels by (non-thermal) final users, in millions $,
GASPM is the natural gas distribution pipeline miles;
PO is the price of crude oil, in $/bbl,
PG is the price of natural gas, in $/Mcf,
PL is the price of electricity, in $/'000 Kwh,
PC is the price of coal, in $/ton,
PEN is a price index for non-thermal energy fuels, 1961=1.0 .

YEAR	QOAT	QOQU	QOON	QOPR	QOBC
1958	13.280	80.639	58.291	47.203	19.844
1959	13.616	89.234	66.863	50.172	21.828
1960	22.732	88.289	68.523	49.371	22.520
1961	26.783	92.151	75.084	49.065	22.887
1962	25.582	94.173	76.825	54.418	25.926
1963	28.753	100.799	86.141	57.461	24.078
1964	32.193	93.559	93.021	57.710	26.874
1965	30.715	93.057	98.979	63.383	25.706
1966	32.279	107.923	103.149	65.502	29.639
1967	31.630	109.623	102.538	66.591	32.181
1968	29.949	121.227	109.938	68.497	35.512
1969	37.013	124.383	116.001	71.343	35.428
1970	37.463	139.717	121.944	72.770	40.070
1971	50.895	151.186	120.933	73.885	40.195
1972	64.869	163.368	126.080	80.336	42.793
1973	76.893	175.469	136.642	86.580	46.881

YEAR	QGQU	QGON	QGPR	QGBC
1958	2.902	50.273	102.497	10.395
1959	5.121	82.218	125.881	18.668
1960	12.177	102.722	137.276	24.050
1961	24.210	123.979	151.560	26.382
1962	22.775	147.258	166.980	28.685
1963	27.161	166.546	174.460	31.096
1964	33.113	192.813	195.442	35.291
1965	31.235	216.772	223.198	36.336
1966	32.485	236.667	241.192	54.354
1967	35.260	277.540	250.800	56.482
1968	44.082	304.773	269.162	63.620
1969	50.718	346.205	311.159	78.936
1970	50.649	397.557	306.182	80.563
1971	55.291	440.602	333.966	95.758
1972	58.148	497.044	375.900	107.725
1973	64.131	513.250	359.875	117.361

YEAR	QLAT	QLQU	QLON	QLPR	QLBC
1958	4.089	34.068	28.315	7.067	11.201
1959	4.378	35.496	31.318	7.904	11.663
1960	4.515	40.614	32.926	8.526	12.802
1961	4.671	40.219	33.958	9.280	12.617
1962	5.111	40.381	35.919	10.077	13.827
1963	5.788	41.048	37.932	11.094	14.556
1964	6.662	45.275	40.990	11.912	16.556
1965	7.629	47.592	44.580	13.188	17.887
1966	8.258	51.544	48.522	14.267	20.173
1967	8.880	53.535	51.534	15.230	21.602
1968	9.932	55.538	55.489	16.932	23.109
1969	10.744	59.394	59.062	19.168	25.052
1970	11.861	64.172	63.431	20.822	24.233
1971	12.729	64.555	66.817	22.609	27.781
1972	14.084	70.104	71.969	25.101	29.433
1973	15.551	75.191	77.143	27.607	31.393

YEAR	HELECAT	HELECQU	HELECON	HELECPR	HELECBC
1958	2.847	36.937	30.809	4.699	11.376
1959	2.981	38.431	34.616	5.095	11.836
1960	2.677	43.679	36.291	5.317	12.765
1961	2.638	43.460	37.060	5.541	12.457
1962	3.190	43.809	35.786	6.079	13.876
1963	3.750	44.454	33.696	6.824	14.467
1964	3.742	49.425	36.138	7.297	15.845
1965	3.789	51.273	37.505	8.554	15.954
1966	3.914	56.051	42.402	9.152	17.297
1967	4.513	57.309	42.810	9.441	19.004
1968	5.516	57.048	43.932	9.311	20.486
1969	6.572	60.682	44.543	11.775	24.588
1970	7.107	68.352	45.686	10.980	23.168
1971	6.262	69.951	46.319	11.798	27.052
1972	7.613	75.740	51.440	13.592	29.643
1973	9.120	81.790	59.326	13.662	29.163

YEAR	SELECAT	SELECQU	SELECON	SELECPR	SELECBC
1958	1.640	0.218	1.240	3.265	0.654
1959	1.827	0.233	0.997	3.872	0.703
1960	2.247	0.324	0.867	4.300	0.837
1961	2.434	0.308	1.216	4.895	0.941
1962	2.408	0.351	4.355	5.265	1.016
1963	2.596	0.379	8.382	5.770	1.192
1964	3.466	0.470	9.397	6.291	1.877
1965	4.439	0.955	11.772	6.440	3.485
1966	4.937	0.541	11.423	7.113	4.125
1967	5.105	1.481	14.024	8.079	4.045
1968	5.313	3.504	17.212	10.125	4.393
1969	5.051	3.808	20.215	9.998	2.289
1970	5.841	1.377	23.803	12.903	3.121
1971	7.523	0.796	26.637	14.019	2.524
1972	7.738	0.549	27.649	15.095	2.498
1973	7.911	0.415	24.956	17.872	5.082

YEAR	LOSSGQU	LOSSGON	LOSSGPR	LOSSGBC
1958	0.686	4.915	102.676	7.443
1959	1.568	4.659	87.289	2.592
1960	1.188	5.581	97.319	3.469
1961	0.593	7.599	110.561	6.304
1962	1.339	8.136	128.948	19.628
1963	1.196	11.975	133.437	27.928
1964	0.877	15.185	161.772	26.419
1965	1.071	21.402	165.980	29.482
1966	1.679	30.733	169.178	37.540
1967	1.101	29.887	168.026	46.970
1968	0.926	31.114	185.786	59.341
1969	0.898	33.857	202.907	78.003
1970	0.606	38.931	247.174	85.780
1971	-0.501	40.516	251.997	76.288
1972	-0.072	42.430	275.531	67.294
1973	-0.740	39.225	302.727	75.780

YEAR	LOSSOAT	LOSSOQU	LOSSCON	LOSSOPR	LOSSOBC
1958	1.515	6.063	5.730	5.318	1.572
1959	1.809	6.354	6.697	5.051	1.726
1960	2.649	6.304	6.765	5.243	2.071
1961	1.942	6.776	7.301	4.752	1.942
1962	2.058	7.761	7.821	6.771	1.506
1963	2.612	8.112	8.753	7.615	1.876
1964	3.012	7.980	9.520	5.491	2.017
1965	2.266	9.410	10.147	6.524	2.070
1966	2.722	8.136	10.108	6.480	2.132
1967	2.850	8.322	9.876	6.393	2.039
1968	3.310	9.946	9.008	6.635	2.006
1969	2.577	12.681	6.786	7.097	1.719
1970	3.629	13.067	10.422	6.272	1.501
1971	5.129	13.127	12.561	9.013	3.084
1972	4.644	13.573	10.359	5.230	1.582
1973	5.231	14.858	11.781	9.264	1.559

YEAR	LOSSLAT	LOSSLQU	LOSSLON	LOSSLPR	LOSSLBC
1958	0.397	3.086	3.734	0.897	0.829
1959	0.429	3.168	4.295	1.062	0.875
1960	0.409	3.388	4.231	1.092	0.800
1961	0.401	3.549	4.319	1.157	0.780
1962	0.488	3.779	4.222	1.266	1.065
1963	0.559	3.784	4.146	1.499	1.103
1964	0.545	4.620	4.545	1.676	1.166
1965	0.598	4.637	4.696	1.806	1.551
1966	0.593	5.048	5.303	1.998	1.249
1967	0.738	5.255	5.301	2.290	1.447
1968	0.898	5.013	5.656	2.504	1.771
1969	0.879	5.097	5.697	2.605	1.825
1970	1.086	5.558	6.057	3.060	2.056
1971	1.056	6.193	6.138	3.208	1.795
1972	1.266	6.185	7.120	3.587	2.708
1973	1.480	7.014	7.140	3.927	2.852

YEAR	REXUAT	REXUQU
1958	0.014	0.180
1959	0.343	0.366
1960	0.157	0.218
1961	0.023	0.000
1962	1.841	0.068
1963	1.656	0.092
1964	0.683	1.041
1965	0.141	0.706
1966	0.241	0.090
1967	0.016	0.160
1968	0.0	0.273
1969	0.0	0.312
1970	0.000	1.596
1971	6.357	3.511
1972	15.419	12.194
1973	18.524	14.715

YEAR	QCLAT	QCLQU	QCLON	QCLPR	QCLBC
1958	0.733	0.055	0.592	0.764	0.028
1959	0.739	0.050	0.478	0.657	0.015
1960	0.857	0.062	0.414	1.033	0.018
1961	0.830	0.060	0.568	1.310	0.020
1962	0.790	0.048	1.780	1.598	0.001
1963	0.826	0.041	3.125	1.703	0.0
1964	1.040	0.022	3.486	2.356	0.0
1965	1.288	0.024	4.383	2.724	0.0
1966	1.327	0.030	4.295	2.816	0.0
1967	1.230	0.0	5.331	3.086	0.0
1968	1.119	0.0	6.611	4.034	0.0
1969	1.031	0.027	7.410	3.918	0.0
1970	0.793	0.027	8.686	5.986	0.0
1971	1.074	0.028	9.562	6.719	0.0
1972	1.057	0.0	8.459	7.350	0.0
1973	0.858	0.0	7.381	8.451	0.0

YEAR	QOLAT	QOLQU	QOLON	QOLPR	QOLBC
1958	0.919	0.296	0.033	0.980	0.464
1959	1.267	0.348	0.031	0.990	0.500
1960	1.701	0.510	0.057	1.086	0.626
1961	2.101	0.512	0.075	0.992	0.781
1962	2.070	0.608	0.122	0.931	0.884
1963	2.365	0.660	0.213	0.945	1.025
1964	3.271	0.919	0.210	0.878	1.604
1965	4.567	1.775	0.250	0.502	2.175
1966	4.854	1.152	0.298	0.716	3.197
1967	5.593	2.844	0.491	1.041	3.567
1968	6.492	5.905	0.860	0.719	3.367
1969	6.066	6.374	1.485	1.012	1.627
1970	9.006	2.584	1.998	0.840	2.112
1971	10.950	1.595	1.431	0.548	2.638
1972	11.996	1.353	1.086	0.448	2.258
1973	12.391	1.039	1.058	0.593	2.649

YEAR	QGLAT	QGLQU	QGLON	QGLPR	QGLBC
1958	0.0	0.0	0.800	31.982	1.154
1959	0.0	0.0	0.964	41.649	1.454
1960	0.0	0.0	1.101	41.650	1.678
1961	0.0	0.0	1.165	44.704	2.135
1962	0.0	0.347	1.770	45.525	3.460
1963	0.0	0.0	1.029	50.072	4.299
1964	0.0	0.053	1.399	44.291	7.451
1965	0.0	0.0	2.400	46.289	22.799
1966	0.0	0.036	3.433	52.164	22.078
1967	0.0	0.029	1.722	58.389	19.592
1968	0.0	0.080	3.349	66.569	22.918
1969	0.0	0.080	5.336	61.548	10.984
1970	0.0	0.079	8.769	66.380	17.145
1971	0.0	0.108	18.912	68.744	5.731
1972	0.0	0.052	56.260	69.845	11.322
1973	0.0	0.081	65.904	87.691	32.594

YEAR	UGNE	PGNE
1958	36101.496	0.963
1959	37478.035	0.983
1960	38553.617	0.995
1961	39649.020	1.000
1962	42369.785	1.013
1963	44549.871	1.032
1964	47547.176	1.057
1965	50723.906	1.091
1966	54238.020	1.140
1967	56039.254	1.185
1968	59328.820	1.223
1969	62475.992	1.278
1970	64057.324	1.336
1971	67796.000	1.378
1972	71757.000	1.441
1973	76344.938	1.569

YEAR	TOTAT	TOTQU	TOTON	TOTPR	TOTBC
1958	87.020	426.474	389.808	204.595	178.204
1959	86.806	437.959	422.055	216.784	192.210
1960	113.414	450.079	444.714	219.906	209.713
1961	128.490	483.065	489.458	237.615	208.848
1962	131.268	496.173	521.023	259.836	219.956
1963	143.731	528.955	582.563	287.748	217.839
1964	165.634	551.146	666.402	318.779	257.740
1965	168.937	562.311	720.078	353.061	252.728
1966	175.161	601.761	768.596	374.616	280.657
1967	178.471	644.345	812.885	390.795	310.946
1968	182.284	739.103	889.611	416.645	332.505
1969	210.845	757.040	971.797	453.514	350.752
1970	218.491	841.377	1073.481	474.978	380.601
1971	281.032	953.529	1174.340	511.539	424.433
1972	348.109	1047.396	1287.270	565.405	450.657
1973	434.634	1217.156	1549.867	673.003	521.561

YEAR	GASPMQU	GASPMCN	GASPMPR	GASPMBC
1958	971.000	8094.898	3658.400	2379.900
1959	1027.400	9144.297	4215.797	2709.300
1960	1115.100	9528.797	4714.000	3028.300
1961	1123.600	10183.898	5022.098	3182.800
1962	1143.900	10864.898	5471.098	3427.500
1963	1203.000	11700.000	5877.000	3647.000
1964	1263.000	12297.000	6198.000	3843.000
1965	1295.000	12700.000	6581.000	4053.000
1966	1361.000	13315.000	6756.000	4264.000
1967	1417.000	13737.000	7652.000	4466.000
1968	1488.000	14497.000	9266.000	4610.000
1969	1572.000	15058.000	10313.000	5004.000
1970	1568.000	15610.000	11304.000	5197.000
1971	1638.000	16080.000	11827.000	5202.000
1972	1693.000	16665.000	12912.000	5864.000
1973	1830.000	16418.000	13749.000	6149.000

YEAR	POAT	POQU	POON	POPR	POBC
1958	2.980	3.080	3.130	2.510	2.810
1959	2.700	2.800	2.820	2.380	2.680
1960	2.600	2.700	2.770	2.330	2.630
1961	2.630	2.730	2.830	2.390	2.690
1962	2.710	2.810	2.770	2.360	2.690
1963	2.680	2.780	2.960	2.550	2.780
1964	2.640	2.740	2.990	2.580	2.820
1965	2.540	2.640	2.990	2.580	2.870
1966	2.460	2.560	3.000	2.590	2.900
1967	2.440	2.540	3.000	2.590	2.880
1968	2.500	2.600	3.010	2.600	2.870
1969	2.470	2.570	3.010	2.600	2.870
1970	2.370	2.470	3.040	2.630	2.940
1971	2.740	2.840	3.290	2.880	3.120
1972	2.940	3.040	3.330	2.920	3.210
1973	3.400	3.500	3.980	3.570	3.750

YEAR	PGQU	PGCN	PGPR	PGBC
1958	0.445	0.382	0.125	0.222
1959	0.446	0.386	0.126	0.223
1960	0.450	0.390	0.130	0.209
1961	0.479	0.416	0.159	0.213
1962	0.486	0.421	0.166	0.215
1963	0.498	0.433	0.178	0.222
1964	0.504	0.440	0.184	0.223
1965	0.504	0.445	0.184	0.225
1966	0.511	0.447	0.191	0.228
1967	0.516	0.453	0.196	0.230
1968	0.517	0.454	0.197	0.230
1969	0.517	0.455	0.197	0.230
1970	0.524	0.461	0.204	0.230
1971	0.522	0.460	0.202	0.231
1972	0.529	0.467	0.209	0.230
1973	0.583	0.533	0.223	0.310

YEAR	PLAT	PLQU	PLON	PLPR	PLBC
1958	11.602	5.190	6.645	10.372	10.725
1959	11.430	5.235	6.442	10.312	11.107
1960	12.030	5.077	6.525	10.207	11.362
1961	12.427	5.467	6.637	10.372	11.227
1962	12.120	5.460	6.855	10.290	10.417
1963	11.520	5.730	6.735	9.930	9.892
1964	12.105	6.142	7.402	11.242	10.515
1965	11.917	6.322	7.350	11.257	9.547
1966	11.595	5.992	7.282	11.137	9.037
1967	11.407	6.495	7.365	11.107	9.502
1968	10.815	7.222	7.575	10.957	9.345
1969	11.115	6.922	7.875	10.785	9.217
1970	10.935	7.320	8.190	10.620	10.080
1971	11.122	7.672	8.587	10.230	9.967
1972	11.175	7.417	8.827	10.050	9.802
1973	11.137	7.522	9.495	10.275	9.855

YEAR	PCAT	PCQU	PCON	PCPR
1958	11.160	11.540	8.830	7.540
1959	11.550	11.560	8.770	8.000
1960	11.330	11.490	8.660	7.650
1961	11.210	11.800	8.840	7.750
1962	11.440	11.950	8.950	7.690
1963	11.330	11.860	8.960	7.570
1964	11.480	11.880	8.960	7.540
1965	12.350	12.960	10.910	7.400
1966	14.310	14.590	11.960	7.340
1967	9.320	11.930	12.420	7.250
1968	10.060	12.590	12.810	7.140
1969	10.150	11.270	9.890	7.440
1970	11.460	12.760	11.320	7.560
1971	13.330	13.180	11.640	8.510
1972	13.070	13.720	12.510	8.970
1973	14.580	14.770	13.490	9.370

YEAR	PENAT	PENQU	PENON	PENPR	PENBC
1958	1.047	1.035	1.054	0.962	0.986
1959	0.976	0.990	0.982	0.931	0.987
1960	0.984	0.961	0.975	0.955	0.995
1961	1.000	1.000	1.000	1.000	1.000
1962	0.999	1.010	1.002	1.000	0.953
1963	0.982	1.023	1.022	1.047	0.925
1964	0.980	1.039	1.079	1.118	0.964
1965	0.952	1.034	1.072	1.107	0.912
1966	0.943	0.977	1.078	1.117	0.891
1967	0.915	1.012	1.083	1.126	0.919
1968	0.896	1.073	1.098	1.137	0.909
1969	0.891	1.045	1.126	1.126	0.886
1970	0.864	1.052	1.157	1.134	0.969
1971	0.917	1.143	1.231	1.141	0.977
1972	0.970	1.157	1.247	1.148	0.968
1973	1.057	1.252	1.404	1.270	1.042

4. Description of Non-frontier Gas and Oil Production

The non-frontier gas and oil production sectors, whose detailed equations may be found in sections 2.B and 2.C of the appendix, are modelled on an annual basis. The coding of these sectors deals primarily with expected costs and benefits of non-frontier production as they accrue to: provincial governments, the federal government, producers, and Canadian and U.S. consumers. Values for production, prices and investment outlays are used to calculate stocks of capital, taxable profits, corporate income taxes and royalties, through the working of the tax and royalty regimes as they apply in each period.

4.A The Construction of Some Series Used

The first set of variables will be those that are common to both models; then the second set, those that are related to the natural gas model; and finally the third set, those that are used in the crude oil model.

The exogenous price index PEXOG is used to represent an underlying inflationary trend in all prices. The index is assumed be 1.0 in 1961. From 1973 to 1975 the actual implicit price index for gross national expenditure was used, as reported in the Canadian Statistical Review. It was assumed that prior to 1973 the rate of growth of PEXOG was a constant annual growth of approximately 3.78%. This growth rate was calculated so that the index would pass through the actual value for 1961 and 1972. For 1976, it is assumed that the growth rate is approximately 8.2% and thereafter is 4%.

The Canadian Petroleum Association, Statistical Yearbook, has compiled the data for imports and exports of crude oil and natural gas[8]. Since the imports of natural gas have been relatively small a separate series is not maintained, but the export series for natural gas is calculated net of the imports. The future flow of natural gas exports has been calculated from the existing export contracts,[9] which are available in the National Energy Board, Annual Report. The quantity of 1975 exports of crude oil has been obtained from the Canadian Statistical Review, and a preliminary estimate of the 1976

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[8] The numbers reported in the Statistical Yearbook are identical to those reported by Statistics Canada.

[9] The construction of future export flows was done by Chris Sanderson, as part of his joint work with John Helliwell on the Mackenzie pipeline model.

exports has been obtained from Oilweek, April 26, 1976. Our best guess about future exports of crude oil has been obtained from a graph on p.46 of the National Energy Board, Canadain Oil: Supply and Requirements. The imports of crude oil are determined endogenously within the model.

The gross additions of new reserves of both marketable natural gas and crude oil have been obtained from the CPA, Statistical Yearbook. For both fuels the reserve figures were used which credit revisions and extensions to the current year, not the year of discovery. This is more desirable from an economic point of view because the development costs incurred in extending the reserve can be calculated in the current year. Also from a simulation point of view it is awkward to have to re-execute an historical simulation each time new reserves data are available.

The gross additions of new reserves of marketable natural gas are obtained in the CPA Statistical Yearbook from column 5 of table 6, historical record of remaining marketable natural gas reserves in Canada. Probable reserves were used from 1963, whereas only proved reserves data were available before 1963. For 1974 the reserves have been taken from several other sources because the CPA included reserves from the Mackenzie Delta. The additions to recoverable reserves (on 1000 Btu basis) of marketable natural gas for Alberta is 5.166 tcf, which has been obtained from the AERCB, Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulpher: Province of Alberta (ERCB 75-18). There has been a net negative gross additions to reserves in BC of .367 tcf, as obtained from the B.C. Dept of Mines and Petroleum Resources 1974 reserves report, Hydrocarbon and By-Products Reserves in B.C.. Hence a gross new additions figure of 4.8 tcf for 1974 is used. The NEB estimates of gross new additions for the future period are used. The estimates are contained in figure 12, p. 33 of NEB, Canadian Natural Gas Supply and Requirements (1975).

The gross additions of new proved reserves of crude oil up to 1974 are obtained in the CPA Statistical Yearbook from cclumn 5 of table 4, historical record of remaining crude oil reserves in Canada. The estimates of gross additions to reserves in the future have been obtained by using the Gulf series (p.26) reported in the NEB report , Canadian Oil: Supply and Requirements (1975).

Within the natural gas model there are three constructed prices and one production flow which are not described elsewhere. The historical export price of Canadian natural gas (PEXPORTG) has been obtained from dividing total revenues by the total quantity. These series are obtained from the Canadian Statistical Review, from 1961. Since the export revenue from natural gas was unavailable as a separate series before 1961, a guess had to be made as to the export price for 1958-1960. The export price for each year from 1958-1960 was assumed to be constant, taking a value computed by averaging the 1961 and 1962 price. The 1976 value for PEXPORTG is the weighted average of

the following per Mcf prices: $1.60 from January to August, $1.80 from September to December, and $1.94 after January 1, 1977. The regulated natural gas price in Toronto (PGASREG) is constructed by adding the transport tariff to the wellhead price. After 1973 the regulated price has been set by the federal government. For 1974 and 1975 the announced regulated prices have been used; and for future years it is assumed that Toronto natural gas prices will be increased until a Btu equivalence is reached with crude oil in 1981. The commodity based opportunity cost of natural gas in the Toronto market, PGAS, is assumed to be equal to the market price until 1973, and then it is assumed to be equal to the Btu equivalent price of offshore crude oil.

The production flow from natural gas reserves connected before 1974, GASMAX73, is obtained from the production variable GASMAX when the natural gas production model is executed using the constraint that no new reserves are discovered and no new reserves are connected after 1973.

Within the crude oil model there is one price and four production variables which are not described elsewhere. The mid-west U.S. price of offshore crude oil, POILUS, is obtained by adding a transportation tariff to the offshore price. Beginning in 1974 POILUS is used to determine the export tax to levy, such that the U.S. consumers of Canadian crude oil will pay the international price. The historical production from the Great Canadian Oil Sands plant , GCOSPRC, is obtained from the CPA, Statistical Yearbook. In the forecast it is assumed that production will continue at 50 Mbbl/d until 1977, and thereafter at 65 Mbbl/d. The production flow of crude oil from wells drilled before 1974, OILPRCLD, is defined as a declining fraction of OILMAX74. The CILPROLD variable is used in the royalty equations. The reason for the declining fraction is that we assume that producers successfully argue that some of the production included in OILMAX74 is extracted using enhanced recovery. The production from the Alberta oil sands, net of GCOSPRO, is included in the variable CPROSUM.[10] The standard forecast is similar to that reported on p.64-65 of the EMR An Energy Strategy for Canada; namely, it is assumed that three Syncrude-sized plants are built, with start-up dates of 1979, 1983 and 1986. The production from all of the oil sands plants is exogenous, and therefore unaffected by any change in demand.

The production flow from crude oil reserves connected before 1974, OILMAX74 , is obtained from a series reported on p.87 of appendix D in the NEB, Canadian Oil: Supply and Requirments. To generate the series past the last year reported, 1994, a constant rate of decline of approximately 12% is used. When the series is used it is necessary to begin the 1974

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[10] The production from the oil sands is obtained from the general oil sands model, which has been developed by Gerry May and John Helliwell.

simulations with a lagged value of OILREXES=0 , and a lagged value of OILRBASE which is the sum of all elements in the OILMAX74 series. The NEB forecast of crude oil producibility from established reserves is used in order to ensure the maximum degree of compatibility. Another reason for using the NEB series is that it has been derived from pool-by-pool data compiled during the NEB 1975 public hearings.

4.B The Construction of Reserve Costs

The reserve cost coefficients are explained within a separate section because they are an important component in the taxation and rent equations. In the description below we will indicate the source for the historical reserve costs, and explain the estimation of the cost coefficients for exploration and development, natural gas processing plants, land acquisition and rentals, and operating expenditures for both the natural gas and crude oil sectors.

I. Exploration and development costs for western Canada

The reserve costs for both natural gas and crude oil were developed in a same manner. The two derived exploration and development cost coefficients for the natural gas model, A(1907) and A(1908), are used in the definition of the two cost variables, RESCOST and GASCOSTM. Similarly the two derived exploration and development cost coefficients for the crude oil model, A(1933) and A(1934), are used in the definition of the two cost variables, OILRCOST and OILCOSTM.

The source for the reserve cost data is the section of the CPA Statistical Yearbook which enumerates the net cash expenditures of the petroleum industry. Unfortunately the expenditure data reported by the Canadian Petroleum Association and by Statistics Canada is aggregated for the petroleum industry as a whole, although the CPA statistics prior to 1968 did report development expenditure data by separate category. In order to obtain a ratio which can be used to split the crude oil and natural gas expenditures a ratio of the development drilling footage for each product to the total development drilling footage is used. The rationale behind this decision is that producers expectations as to the outcome of the development drilling are fairly certain so that the split using the footage of crude oil and natural gas development wells to the total should represent the desired split in expenditure.[11]

The data reported in the Statistical Yearbook are disaggregated into exploration, development, and operating expenditures of the petroleum industry. We choose to aggregate the development and exploration expenditures, after extracting the land acquisition and rental expenditures from the exploration expenditures, and extracting the natural gas plant expenditures from the development expenditures. The land acquisition payments, which are described in part III, are

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[11] The use of this ratio has an obvious drawback: if the intent of the development drilling was to find crude oil (natural gas) but natural gas (crude oil) was found instead then the developer would be expected to develop what was found.

treated separately because they enter separately into the rent equations. The natural gas plant expenditure is subtracted from the aggregate petroleum data because it can be clearly associated with the natural gas expenditures. The natural gas processing plant expenditure is estimated as a separate component, described in part II. The development and exploration expenditure data were aggregated only to simplify the construction of a cost function. Since the depreciation rate for tax purposes is now set differently for development expenses (30%) compared to exploration expenses (100%), and since the lead-time between investment and output is different, we will attempt to disaggregate sometime in the future. The current data include petroleum expenditures for only Western Canada: namely Alberta, Saskatchewan, B.C., and Manitoba. The exploration expenses for the Arctic and offshore regions were not included because the cost function was only to indicate expenditure on non-frontier sources.

The development drilling statistics which were used to pro-ration the expenditures were obtained from the drilling completions table reported in the CPA Statistical Yearbook. Prior to 1968, it was possible to obtain the ratio of expenditures on productive natural gas development wells to the total expenditure on productive development wells. But after 1967 we could only obtain separate crude oil and natural gas data on the number of successful natural gas development wells, and separate crude oil and natural gas data for the footage of development drilling completions. During most of the historical period the percentage of the natural gas development wells to the total number of development wells has only been a few percentage points different than the percentage of natural gas development drilling footage to the total development drilling footage. It is only in the post-1970 period that the ratios differ as the relative depth per well tended to become greater for crude oil. During the pre-1968 period the ratio of the expenditure on productive natural gas development wells to the total expenditure on productive development wells has been higher than the two ratios used in the weighted average. The reason is that the total expenditure includes the expenditure on natural gas plants. Whereas the footage ratio used to split the aggregate expenditures is net of the natural gas plant expenditure. For consistency we have used the footage ratio mentioned above for splitting the aggregate expenditures in all the historical period.

In order to calculate the per-unit reserve cost we used the gross reserve additions data reported in the CPA Statistical Yearbook. The same source was used to construct the data for the discovery variables, reported in appendix 4.A. In order to remove the inflationary trend in the exploration and development costs we deflate the current dollar expenditures by the PGNE deflator reported in the Canadian Statistical Review. Hence we end up with data which represent the per unit constant dollar pro-rated aggregate (exploration and development) expenditure on each fuel for the non-frontier region. The following are the results of the estimations with respect to exploration and

development costs.

1. crude oil:
The form of the estimated equation is as follows:

PEROIL = a + b * OILSUM,

where PEROIL is the ratio of the constant 1961$ pro-rationed expenditure on exploration and development of oil reserves over the gross reserve additions of oil;
OILSUM is the cumulative sum of gross reserve additions of oil.

The parameter estimates for the 1958-1966 period are as follows:

a	.912365	(6.796)	R^2 = .6576
b	-.0000676	(-3.667)	dw = 3.11
			nobs = 9
			estimation period: 1958-1966
			estimation procedure: OLS

The parameter estimates for the 1967-1974 period are as follows:

a	-4.41140	(-2.00)	R^2 = .4786
b	+ .0003934	(2.347)	dw = 1.61
			nobs = 8
			estimation period:1967-1974
			estimation prodedure: OLS

2. natural gas:
The form of the estimated equation is as follows:

PERGASMP = a + b * GASSUM,

where PERGASMP is the ratio of the constant 1961$ pro-rationed expenditure on exploration and development (net of natural gas plants) of natural gas reserves over the gross reserves additions of natural gas;
GASSUM is the cumulative sum of gross reserve additions of natural gas.

The historical data was split into two periods: 1958-1966, and 1967-1974. Within the second period the 1972 observation is dropped because the gross reserve addition in 1972 is very small, leading to very large per unit costs. The parameter estimates for the 1958-1966 period are as follows:

a	3.32951	(.488)	R^2 = .135
b	.162781	(1.045)	dw = 1.88
			nobs = 9
			estimation period: 1958-1966

estimation procedure: OLS.

The parameter estimates for the 1967-1974 period are as follows:

a	-16.6332	(-1.355)	R^2 = .756
b	.637365	(3.940)	dw = 1.49
			nobs = 7
			estimation period: 1961-1971, and 1973-1974
			estimation procedure: OLS

II. Natural gas plant development expenditure for western Canada

The nominal expenditure on natural gas plants, extracted from the CPA Statistical Yearbook, is converted to constant 1961$ using the PGNE deflator. The ratio of the constant 1961$ expenditure on natural gas plants over the incremental demand for natural gas is assumed to be constant. The average value of 443 million 1961$ per tcf over the 1959-1973 period is used. The 1974 value is disregarded because a net decrease in natural gas production occurred. Relating the natural gas plant expenditure to incremental demand is very approximate. The plant expenditures are probably related to the prices of the natural gas by-products, the sourness of the natural gas, and to projected future demand (especially future export commitments).

III. Land acquisition expenditure for western Canada

The expenditure of the petroleum industry on land acquisition and rentals are disaggregated by using the same crude oil-natural gas pro-ration factors discussed in part I. We use the same price deflator as discussed in part I. The production of both natural gas and crude oil are obtained from the CPA Statistical Yearbook.

1. crude oil:

The ratio of the pro-rationed constant 1961$ expenditure on land acquisition and rentals for crude oil over the production of crude oil is assumed to be a linear function of cumulative production. The last actual value of .08 1961$ per barrel is used for the forecast period.

2. natural gas:

The ratio of the pro-rationed constant 1961$ expenditure on land acquisition and rentals for natural gas over the production of natural gas is assumed to be constant. The average value over the 1958-1974 period is 2.5 1961 cents per Mcf.

IV. Operating expenditure for western Canada

In order to pro-ration the operating expenditures reported

in the CPA, Statistical Yearbook it would be desirable to have data on the total number of operating natural gas and crude oil wells. Since this data is unavailable we used a proxy for the number of operating wells by cumulating over the 1958-1974 period the total number of yearly completions of productive wells (exploration and development). The moving cumulative for both the number of productive crude oil and natural gas wells were used to create pro-rationing factors, which were then used to disaggregate the operating expenditure of the petroleum industry into operating expenditure for crude oil and for natural gas. We are implicitly assuming that the cost of operating a natural gas well is identical to the cost of operating a crude oil well. The operating expenditure on natural gas plants was removed from the data to be pro-rationed, but added back into the calculated data for the operating expenditure for natural gas, after pro-rationing. The nominal operating expenditure is converted to constant 1961$ expenditure by using the PGNE deflator. The production of both crude oil and natural gas are obtained from the CPA Statistical Yearbook. The following are the results of the estimations of the operating expenditure.

1. crude oil:

The ratio of the pro-rationed constant 1961$ operating expenditure for crude oil over the wellhead production of crude oil is estimated to be a linear function of the accumulated production. The form of the estimated equation is as follows:

PEROILOP = a + b * OILPROSUM,

where PEROILOP is the ratio of the constant 1961$ pro-rationed operating expenditure over the production;
OILPROSUM is the cumulative sum of the crude oil production.

The parameter estimates are as follows:

a	.449909	(30.677)	R^2 = .8497
b	-.00003303	(-9.207)	dw = 1.38
			nobs = 17
			estimation period: 1958-1974
			estimation prodedure: OLS

For the forecast period it is assumed that the per unit operating expenditure is constant in real terms at the last estimated value (.20 1961$ per barrel).

2. natural gas:

The ratio of the pro-rationed constant 1961$ operating expenditures for natural gas over the wellhead production of marketable natural gas is estimated to be a linear function of the accumulated production. The form of the estimated equation is as follows:

PERGASOP = a + b * GASPROSUM,

where PERGASOP is the ratio of the constant 1961$ pro-rationed operating expenditures over the production of natural gas;
GASPROSUM is the cumulative sum of the natural gas production.

The parameter estimates are as follows:

a	65.4881	(20.116)	R^2 = .1758
b	-.467668	(-1.789)	dw = .711
			nobs = 17
			estimation period : 1958-1974
			estimation procedure: OLS

For the forecast period it is assumed that the per unit operating expenditure is constant in real terms at the last estimated value (5.4 1961 cents per Mcf).

V. Data used to construct the estimation variables

The following tables contain the historical data used to construct the estimation variables. The mnemonic variable names are described below (in order of occurrence in the table):

PGNE is the price deflator for GNE, 1961=1.0;
OILPRO is the production of crude oil, MMbbl/yr;
OILACUM is the accumulated production of crude oil, MMbbl;
GASPRO is the production of natural gas, Tcf/yr;
GASACUM is the accumulated production of natural gas, Tcf;
OILADD is the gross reserve additions of crude oil, MMbbl/yr;
OILSUM is the accumulated reserve additions of oil, MMbbl;
GASADD is the gross reserve additions of natural gas, Tcf/yr;
GASSUM is the accumulated gross reserve additions of natural gas, Tcf;
OILFRA is the expenditure fraction attributed to crude oil;
GASFRA is the expenditure fraction attributed to natural gas;
TOTALE is the total expenditure on exploration and development, millions $;
OILE is the crude oil component of the expenditure on exploration and development, millions $;
GASE is the natural gas component of the expenditure on exploration and development, millions $;
GASPE is the expenditure on natural gas processing plants, millions $;
PEROIL is the per unit (of reserve additions) crude oil component of the constant $ expenditure on exploration and development, millions 1961$/MMbbl;
PERGASMP is the per unit (of reserve additions) natural gas component of the constant $ expenditure on exploration and development, millions 1961$/Tcf;
PERGASP is the per unit (of incremental demand) natural gas constant $ processing plant expenditure, millions 1961$/Tcf;
LANDE is total expenditure on land acquisition, millions $;
OILLE is the crude oil component of the expenditure on land

acquisition, millions $;
GASLE is the natural gas component of the expenditure on land acquisition, millions $;
PEROILL is the per unit (of production) crude oil component of the constant $ expenditure on land acquisition, millions 1961$/MMbbl;
PERGASL is the per unit (of production) natural gas component of the constant $ expenditure on land acquisition, millions 1961$/Tcf;
OILWELL is the number of productive crude oil wells;
GASWELL is the number of productive natural gas wells;
OILWFRA is the expenditure fraction attributed to crude oil;
GASWFRA is expenditure fraction attributed to natural gas;
OPMPE is the total operating expenditure net of natural gas processing plants, millions $;
OPPE is the total operating expenditure on natural gas processing plants, millions $;
OILOPE is the crude oil component of the operating expenditure, millions $;
GASOPE is the natural gas component of the operating expenditure, millions $;
PERGASOP is the per unit (of production) natural gas component of the constant $ operating expenditure, millions 1961$/Tcf;
PEROILOP is the per unit (of production) crude oil component of the constant $ operating expenditure, millions 1961$/MMbbl.

YEAR	PGNE	OILPRO	OILACUM	GASPRO	GASACUM
1958	0.963	166.818	1111.789	0.281	2.782
1959	0.983	187.096	1298.885	0.363	3.145
1960	0.995	194.777	1493.662	0.450	3.595
1961	1.000	229.114	1722.776	0.564	4.160
1962	1.014	261.378	1984.151	0.774	4.934
1963	1.032	280.103	2264.261	0.847	5.781
1964	1.058	300.040	2564.301	0.944	6.725
1965	1.092	319.782	2884.081	1.039	7.764
1966	1.141	349.021	3233.101	1.113	8.877
1967	1.186	380.910	3614.011	1.219	10.096
1968	1.224	406.144	4020.151	1.377	11.473
1969	1.279	438.524	4458.680	1.612	13.086
1970	1.336	492.207	4950.879	1.856	14.942
1971	1.378	523.235	5474.117	2.048	16.990
1972	1.447	602.765	6076.879	2.295	19.285
1973	1.560	698.099	6774.980	2.455	21.740
1974	1.770	656.077	7431.059	2.439	24.179

YEAR	OILADD	OILSUM	GASADD	GASSUM
1958	457.500	4273.297	2.587	27.834
1959	515.000	4788.297	3.359	31.193
1960	372.500	5160.797	4.041	35.234
1961	716.100	5876.898	3.236	38.470
1962	552.000	6428.898	2.518	40.988
1963	657.300	7086.199	3.216	44.204
1964	1567.000	8653.195	8.329	52.533
1965	825.200	9478.398	1.958	54.491
1966	1396.600	10874.996	3.941	58.432
1967	721.300	11596.297	2.897	61.329
1968	584.200	12180.496	4.628	65.957
1969	631.600	12812.098	4.836	70.793
1970	377.200	13189.297	4.600	75.393
1971	254.200	13443.496	3.628	79.021
1972	205.100	13648.598	0.835	79.856
1973	279.700	13928.297	5.108	84.964
1974	98.200	14026.496	4.800	89.764

YEAR	CILFRA	GASFRA	TOTALE	OILE	GASE
1958	0.953	0.047	297.200	283.261	13.939
1959	0.919	0.081	284.300	261.385	22.915
1960	0.920	0.080	310.400	285.692	24.708
1961	0.853	0.147	320.600	273.600	47.000
1962	0.854	0.146	303.500	259.310	44.190
1963	0.907	0.093	329.600	298.980	30.620
1964	0.880	0.120	346.700	305.096	41.604
1965	0.912	0.088	368.600	336.089	32.510
1966	0.850	0.150	381.000	323.850	57.150
1967	0.780	0.220	437.500	341.119	96.381
1968	0.695	0.305	435.900	302.994	132.906
1969	0.672	0.328	458.300	307.794	150.506
1970	0.586	0.414	422.200	247.240	174.960
1971	0.560	0.440	401.400	224.663	176.736
1972	0.624	0.376	489.000	305.282	183.717
1973	0.540	0.460	617.200	333.226	283.974
1974	0.457	0.543	692.800	316.471	376.329

YEAR	GASPE	PEROIL	PERGASMP	PERGASP
1958	40.700	0.643	5.595	375.200
1959	13.600	0.516	6.940	167.986
1960	20.600	0.771	6.145	237.417
1961	61.600	0.382	14.524	539.906
1962	20.700	0.463	17.307	97.284
1963	36.700	0.441	9.226	490.010
1964	42.700	0.184	4.721	416.684
1965	35.400	0.373	15.205	340.340
1966	56.900	0.203	12.709	670.062
1967	107.000	0.399	28.052	857.466
1968	91.000	0.424	23.462	468.252
1969	95.100	0.381	24.333	316.497
1970	170.600	0.491	28.469	523.094
1971	243.900	0.641	35.352	923.631
1972	117.300	1.029	152.053	328.744
1973	67.300	0.764	35.637	269.041
1974	136.400	1.821	44.295	

YEAR	LANDE	OILLE	GASLE	PEROILL	PERGASL
1958	112.600	107.319	5.281	0.668	19.526
1959	137.100	126.050	11.050	0.685	30.951
1960	111.300	102.440	8.859	0.529	19.769
1961	111.600	95.239	16.361	0.416	28.982
1962	112.000	95.693	16.307	0.361	20.769
1963	121.300	110.031	11.269	0.381	12.893
1964	172.600	151.888	20.712	0.478	20.743
1965	252.600	230.321	22.279	0.660	19.636
1966	215.700	183.345	32.355	0.460	25.468
1967	211.700	165.062	46.637	0.365	32.268
1968	220.600	153.339	67.261	0.308	39.894
1969	225.500	151.446	74.054	0.270	35.910
1970	155.300	90.944	64.356	0.138	25.947
1971	169.600	94.925	74.675	0.132	26.459
1972	167.600	104.633	62.967	0.120	18.964
1973	186.400	100.637	85.763	0.092	22.393
1974	208.800	95.380	113.420	0.082	26.274

YEAR	OILWELL	GASWELL	OILWFRA	GASWFRA	OPMPE
1958	1440.000	200.000	0.878	0.122	86.000
1959	1404.000	302.000	0.850	0.150	87.700
1960	1480.000	291.000	0.845	0.155	101.900
1961	1381.000	391.000	0.828	0.172	103.700
1962	1242.000	331.000	0.821	0.179	114.600
1963	1493.000	338.000	0.820	0.180	135.900
1964	1539.000	361.000	0.818	0.182	134.800
1965	1713.000	318.000	0.822	0.178	151.300
1966	1360.000	340.000	0.820	0.180	164.600
1967	1162.000	370.000	0.814	0.186	168.200
1968	1017.000	476.000	0.804	0.196	180.500
1969	1049.000	522.000	0.793	0.207	202.800
1970	811.000	730.000	0.775	0.225	224.400
1971	675.000	835.000	0.754	0.246	258.100
1972	867.000	1157.000	0.728	0.272	290.400
1973	1000.000	1645.000	0.695	0.305	353.300
1974	733.000	1892.000	0.660	0.340	458.600

YEAR	OPPE	OILCPE	GASOPE	PERGASOP	PERCILOP
1958	8.800	75.512	19.288	71.317	0.470
1959	12.300	74.542	25.458	71.305	0.405
1960	11.800	86.108	27.592	61.568	0.444
1961	23.200	85.877	41.023	72.671	0.375
1962	30.900	94.082	51.417	65.485	0.355
1963	32.800	111.435	57.265	65.520	0.385
1964	37.700	110.323	62.177	62.270	0.348
1965	35.300	124.367	62.233	54.849	0.356
1966	40.400	134.913	70.087	55.167	0.339
1967	52.000	136.961	83.239	57.591	0.303
1968	56.600	145.084	92.016	54.577	0.292
1969	61.000	160.896	102.904	49.900	0.287
1970	70.100	173.846	120.654	48.646	0.264
1971	88.900	194.536	152.464	54.021	0.270
1972	109.300	211.409	188.291	56.707	0.242
1973	118.200	245.621	225.879	58.978	0.226
1974	140.800	302.603	296.797	68.754	0.261

4.C The Sources for the Coefficients Used

The first section will describe the sources for the coefficients in the natural gas production model, followed by the sources for the coefficients in the crude oil production model.

The coefficient A(1860) represents the fraction of the natural gas commodity value in the Toronto market. It rises over five years from .85 in 1976 to 1.0 in 1981. This adjustment in the price of natural gas is the same as the NEB price assumption 'b' [35, p.2] and the price assumption stated as government policy on p. 22 in the EMR, An Energy Strategy for Canada: Policies for Self-Reliance. We have used the upper bound (five years) of the federal government range of eliminating the gas price differential in 3 to 5 years.

The coefficient A(1890) is used to represent the annual real after-tax supply price of capital for Canadian business. The value of the coefficient is derived by averaging the annual 1956-1970 values of the RDX2 variable, RHOR (real supply price of capital). The annual real social time preference rate, A(1894), has been set equal to the average real supply price of capital.

The average annual real Canadian tax return on industrial capital, A(1895), has been obtained by taking the 1961-1973 annual average ratio of the RDX2 variables TCA (corporation income tax accruals) over KB$ (replacement value of business capital stock).

The provincial share of corporation income tax, A(1916), is evaluated by using average ratio of the 1965-1973 annual values for the RDX2 variables TCAPM (provincial corporation income tax accruals) over TCA (total corportion income tax accruals). The average provincial share is assumed to represent the federal-provincial split on income from natural gas and crude oil, most of which is generated in Alberta. The federal share is the residual, ie 1-A(1916).

The maximum rate of unearned depletion allowance is set at 33 and 1/3% in the pre-1974 period. From 1974 the maximum rate of earned depletion is set at 25%, as proposed on p.13 in the Budget Speech, November 18, 1974. The depletion rate is the same for both crude oil production and natural gas production.

The historical marginal corporation income tax on natural gas production profits is set at .43. It is assumed that the same rate is applicable to the crude oil production profits. The figure has been calculated and reported on p.178 in Helliwell et al, "Where does Canada's national interest lie?" [77].

The assumed general rate of inflation is represented by

coefficient A(1972). Its value of 4% is approximately the average rate of price inflation in GNE from 1961 to 1973. This rate of inflation is used from 1977 onward.

Since income from an investment in a natural gas pool is spread out over a long period of years, we calculate the discounted cost of capital on a delivery basis, which is coefficient A(1902). The discounted value for each year is weighted by the proportion of total recoverable reserves that are delivered that year. We use the real after-tax supply price of capital, coefficient A(1890), as the discount rate. The conversion of millions of current dollars per tcf to cents/Mcf is obtained by multiplying the discounted natural gas by 0.1. Hence this coefficient converts the capital cost of new reserves from millions of current dollars to cents/Mcf of eventual production.

The royalty rate for non-frontier natural gas, coefficient A(1904) varies over time as the provincial governments have made changes. Before 1974 the average royalty rate, as a percentage of the wellhead price, was 16 and 2/3%. The post-1973 royalty rates are different for old and new natural gas, and different rebate schemes have been introduced between 1974 and 1975. Hence the post-1974 royalty payments are determined endogenously in the model, and described within the taxation section, appendix 4.D.

The proportion of natural gas flow to total recovery, coefficient A(1910), is obtained by converting the standard flow rate of 1 Bcf/d for each 7300 Bcf of recoverable marketable natural gas to a yearly flow of 365 Bcf for each 7300 Bcf.

The value of 114 Tcf used for the total stock of recoverable reserves of non-frontier natural gas, coefficient A(1919), is slightly lower -by 1 Tcf- than the latest estimate by the NEB. In the report Canadian Natural Gas: Supply and Requirements it is stated that for conventional producing areas "the Board [NEB] considers an ultimate potential of 115 Tcf reasonable" [35, p.34].

The CPA production figures for marketable natural gas are used as the historical data for the natural gas model. But the domestic demand which is the major driving variable behind the amount of production in the model, is determined from the demand model which uses historical data from Statistics Canada. In terms of natural gas sales and net exports both of these data sources are identical, but they differ in terms of the losses and adjustments reported. Therefore in order to equate the two series, the amount of losses and adjustment predicted from the Statistics Canada data is reduced by a certain proportion. This proportion is calculated as a 1969-1973 average of the ratio of the difference between the two marketable natural gas production series over the losses and adjustments reported in Statistics Canada. The coefficient A(2136), which has a value of .655,

represents this proportion. [12]

The coefficient A(1901) which represetnts the delivery cost to transport natural gas from the Alberta border to the Toronto market varies over time. The historical values have been explained in appendix 3.E. The value for the wellhead tc Toronto transportation tariff from 1974 is within the tariff range of 45-50 cents/Mcf mentioned on p.22 of the EMR report, An Energy Strategy for Canada: Policies for Self-Reliance.

The transportation tariff from the wellhead to the border for natural gas exports is determined endogenously during the historical period. During the forecast period, we assume that the tariff is 66% of the Alberta border to Toronto transportation tariff. Applying this percentage to the historical Alberta border to Toronto tariff would yield approximately the historical wellhead tc border export tariff. The transportation tariff from the border to the Chicago market is the same as that reported on p.220 in Helliwell et. al., "Where does Canada's national interest lie?" [77]. As with most of our transportation tariffs it is assumed to be constant in nominal terms over the historical period, but grow with the rate of inflation in the forecast period.

The coefficient A(1952) which represents the provincial share of corporation income tax on crude oil production is derived in the same way as coefficient A(1916) which represents the provincial share of natural gas production.

The coefficient A(1935) converts the capital cost of new reserves from millions of dollars to $/bbl of eventual production. This coefficient is calculated using the same method as the corresponding natural gas coefficient A(1902).

The royalty rate for crude oil production, coefficient A(1945), is defined to be .125 before 1962, and .14 from 1962 to 1973. The historical royalty rates were obtained from p.4 of a study by Kalymon and Quirin, "Incentive in the Western Canadian Oil Industry, " September 1974 . The post-1973 royalty payments are determined endogenously within the model because different royalty rates apply to old and new crude oil production, and various rebate schemes came into effect in 1975. The post-1973 royalty equations are described in appednix 4.D.

The coefficient used to represent the maximum crude oil production flow as a proportion of total recoverable reserves, A(1942), has been obtained from the standard pool pattern reported on p.80, Volume II, in An Energy Policy for Canada: Phase 1.

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[12] The relationship between the two data sources can be summarized by the following equation: CPA marketable production = Statistics Canada sales + (1-.655)*Statistics Canada losses + net exports.

The ultimate recoverable reserves of conventional non-frontier crude oil, coefficient A(1937), is obtained from the 1973 Geological Survey of Canada report, the results of which were published on p.89 of Volume I, An Energy Policy for Canada: Phase 1. We aggregated the ultimate recoverable oil for Alberta, Saskatchewan, Manitoba, and B.C. It was impossible to update this estimate with the latest report of the GSC, as published on p.61-64 in the EMR, An Energy Strategy for Canada: Policies for Self-Reliance, beacuse the frontier and non-frontier ultimate recoverable reserve estimates are aggregated.

The throughput of the Sarnia to Montreal pipeline, coefficient A(1941), is set to 250 Mbbl/d after 1976 as reported on p.46, of Canadian Oil: Supply and Requirements. The pipeline flow for the start-up year of 1976 is assumed to be on average 100 Mbbl/d [36, p.44]. The same coefficient is used to represent the pre-1962 penetration of offshore crude oil into Ontario; and the post-1972 penetration of western Canadian crude oil into the Quebec market. The numbers used from 1958 to 1961 are obtained from the import of primary energy supply into Ontario, reported in Statistics Canda, Detailed Energy Supply and Demand in Canada 1958-1969. The number used from 1973 to 1975 are obtained from the annual forecast, p.20 of Oilweek, Vol 27, No.11 (April 26, 1976).

Both the transportation tariff for crude oil from the U.S. east coast to the U.S. mid-west, coefficient A(1938), and the transportation tariff from the Prairies to the U.S. mid-west, coefficient A(1940), have been obtained from the Powrie and Gainer study, table 2-8, p.25.

Within the losses model there is an explicit coefficient used to split the Canadian production of natural gas between B.C. and Prairies. The value of .157 used for B.C. production over total production is the average 1968-1974 value using marketable natural gas production reported on p.22 in CPA, Statistical Yearbook: 1974.

4.D The Description of the Taxation and Royalty System

Since the tax and royalty treatment for non-frontier gas and oil are quite similar, a detailed description of taxation and royalty regulations as they apply to non-frontier gas production will also illustrate the treatment for non-frontier oil production.[13]

The procedure for charging production costs may influence the accuracy of the model's treatment of taxation and royalties. Insofar as our cost treatment allows, the simulation model of the non-frontier natural gas sector incorporates: corporation tax provisions of the November 1974 and June 1975 federal budgets; a two-price system for natural gas, with increases in the border price flowing back to producers in the form of higher field prices, after 1974; royalty calculations as set forth in the Alberta royalty regulations, including Alberta's exploration drilling incentives and selective royalty reductions; and, indemnification for federal taxes paid by producers with respect to royalties (or their deemed equivalent) from British Columbia production.

While most of the equations which define capital stocks, taxable profits, corporate income taxes and royalties are relatively straightforward, some of the more important features of our tax and royalty treatment are reported below:

1. Effective federal corporation tax rates vary with taxation regimes as determined by successive federal budgets; effective provincial tax rates vary with taxation regimes (provincial budgets) and with the relative distribution of natural gas and oil production among the three major producing provinces (Alberta, British Columbia and Saskatchewan). For 1976 and thereafter, the effective federal and provincial corporate tax rates are adjusted to reflect the 'special resource abatement' of the June 1975 federal budget. Our treatment of this abatement provides an illustration of the difficulties encountered in disaggregating the total cost of non-frontier production into its various bookkeeping components. Since we have been unable to distinguish capital cost allowances from interest and depletion expenses, the federal and provincial corporate tax rates have been multiplied by a factor of .65 to take account of charges against taxable income which are not accounted for explicitly. Thus, an effective federal tax rate of 23.4 percent (the 'basic' federal rate, 46%, minus the provincial abatement, 10%, with the result multiplied by .65) has been applied to total taxable income, rather than a rate of 27 percent being applied to gross income minus operating expenses and capital cost allowances and

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[13] This last section describing the taxation and royalty eqations in the post-1973 period was written by Bruce Duncan. Most of this section appears in the Natural Resources Working Paper.

the full 36 percent rate being applied to the balance.

2. After 1974, producers are assumed to receive a weighted field price for gas, with the weighted price in each period equal to the average domestic wellhead price multiplied by the proportion of non-frontier gas production consumed domestically, plus the average export price net of transportation costs to the border multiplied by the proportion of non-frontier gas production sold tc the United States.

3. The earned depletion system replaces the automatic depletion write-off after 1973 in determining the proportion of taxable profits that are subject to corporation tax.

4. Royalties are assumed to be non-deductible for federal corporation tax purposes from January 1, 1974, while remaining deductible for provincial tax purposes. The assumption that the provisions of the November 1974 federal budget, such as the non-deductibilty cf royalties in determining federal ccrporation taxes, are effective from January 1,1974, rather than May 6, 1974, is due to the annual nature of the simulation model.

5. Royalty rates for old and new gas are taken directly from the Alberta Natural Gas Royalty Regulations[14] ; and producers receive a royalty credit equal to .35 and .45 of exploration drilling expenditures in 1974 and thereafter, respectively.[15]

Besides allocating the flows resulting from the accounting framework to the respective parties, the rent equations allocate inter-party transfers. There are two main transfers involved in the non-frontier sectors:

1. A cash transfer is made by the Alberta government to producers, equalling 25 percent of royalties payable, up to a ceiling of one million dollars per producer. The transfer, referred to as a 'selective royalty reduction' under Alberta's incentives programme (ALPIP), is intended to offset, primarily for smaller producers, the effects of the federal taxation cf provincial royalties. About thirty of Alberta's largest producers receive the one million dollar limit[16] and, lacking a distinction between producers of natural gas and producers of oil, we have apportioned the thirty million dollars equally between the two non-frontier sectors. Small Alberta producers, who receive the full 25 percent reduction in royalties payable, account for about 10 percent of non-frontier production of gas and oil.[17]

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[14] A. R. 16/74, as amended by A. R. 19/74 and A. R. 152/75. The effective royalty rates for old and new oil were taken directly from a "Statement by Premier Lougheed re Alberta Petroleum Exploration Plan - December 1974", pg. 4

[15] See a "Statement by Premier Lougheed .." op. cit., pg. 6

[16] Ibid., pg. 4

[17] Alberta Department of Energy and Natural Resources, Fiscal Planning Division, Edmontcn, Alberta

2. The British Columbia government indemnifies producers for that proportion of federal corporation tax which is paid with respect to the non-deductibility of royalties. British Columbia producers account for about 14 percent of gas production from the three western provinces in 1974, 16 percent thereafter, and about 3.2 percent of Western Canada's oil production.[18]

In conclusion, it should be noted that a major shortcoming of the model is that it omits revenues from natural gas by-products. Until the end of 1973, revenue to the sector from by-products was about 20 percent of total revenue from natural gas. We hope to include this aspect of non-frontier production in future versions of our aggregate energy model.

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[18] The proportions were derived from the Canadian Petroleum Association, 1974 Statistical Yearbook, pg. 18-22

5. The Base Case Model Forecast

5.A Assumptions Used to Produce the Base Case Forecast

Most of the assumptions explained in this section will be from the energy demand sector. The forecast assumptions used for variables associated with the natural gas and crude oil production models have been explained either in appendix 4, or else in chapters four and five. The following assumptions have been obtained from many sources. As with all forecasts, a range of uncertainty surrounds the assumed values. Some of the key assumptions will be subjected to a sensitivity analysis.

Actual numbers from the Canadian Statistical Review have been used for PGNE and UGNE until 1975. The gross national expenditure price index, PGNE is assumed to grow at approximately 8% in 1976, 6% in 1977 and 4% thereafter. The rate of growth for the real gross national expenditure is assumed to be 5.4% from 1976 to 1981, and thereafter 4.5%. The assumptions about UGNE growth are a mixture of those reported on p.49 in the EMR, An Energy Strategy for Canada: Policies for Self-Reliance and those reported on p.33 in the NEB, Canadian Oil: Supply and Requirements.

All of the transportation tariffs for coal are assumed to grow at the underlying rate of inflation after 1973. All of the transportation tariffs for crude oil and natural gas are assumed to grow at the underlying rate of inflation after 1974.

The actual values for natural gas distribution pipeline miles for 1974 have been used. The forecasted growth rate for this variable varies across regions. The growth rate in Quebec is assumed to be 8%. This rather high growth rate is used because the NEB has "adopted the view of the Quebec government on the expansion of the market area" [35, p.10], which is for natural gas to "significantly increase its share of total energy consumption from five percent in 1973 to about 20 percent by 1995" [35, p.9]. The growth rate in Ontario and B.C. is assumed to be 4%. In both regions the NEB forecasts an increase in the market share for natural gas during the price phase-in period, and a continuing slight penetration in the residential and commercial markets after a Btu equivalence in price is reached [35, p.5-9]. The growth rate in the Prairie region is assumed to be 3%. It is slightly lower because of the already extensive market penetration of natural gas. In each region the growth rate exponentially declines after 1982.

Due to lack of information, it is assumed that the increases in the retail price of electricity are uniform across regions, except for the 1974-1976 increase in the Atlantic region. The increase in the Atlantic region is assumed to be

greater than in any other region because a larger proportion of the electricity used is generated from thermal fuels. The price increases are slightly modified[19] from those used in the industrial sector of Ontario, reported in Fuss, Hyndman and Waverman, "Residential , Commerical and Industrial Demand for Energy in Canada," [60, p.40]. The retail price of electricity is assumed to grow by 20% (30% in Atlantic) from 1974-1976, by 15% from 1977-1980, and by 4% after 1981.

Again due to lack of information, it is assumed that the increases in the wellhead price of coal (or border price of U.S. coal) is uniform across regions after 1976. The average price increase from 1974-1976 has been obtained from Statistics Canada, Energy Statistics, Volume 11, No.1. Again the price increases are only slightly modified[20] from those used in the industrial sector of Ontario, reported in Fuss, Hyndman and Waverman [60, p.40]. The wellhead or border price of coal is assumed to grow by 36% in Atlantic and U.S., 62% in Prairies and 52% in B.C. from 1974-1976, by 10% from 1977-1980, and by 4% from 1981.

The landed price of offshore crude oil for 1974 and 1975 has to be calculated using the f.o.b. price reported in Statistics Canada, Imports by Commodity (catalogue #65-007, item #264-10). For 1974 the f.o.b. price of crude oil is $9.09/bbl and for 1975, $11.03/bbl.[21] If we assume a transportation tariff of approximately $.90/bbl to land the crude oil in Canada, then the offshore crude oil price becomes $10.00/bbl in 1974 and $12.00/bbl in 1975. The landed offshore crude oil price is assumed to be $13.00/bbl in 1976, as reported on p.49 of EMR, An Energy Strategy for Canada: Policies for Self-Reliance. After 1976 the crude oil price is assumed to increase only with the general rate of inflation (4%). The international crude oil price is converted into Canadian dollars by the foreign exchange rate, PFX, which is assumed to be unity throughout the base case solution.

The per-barrel Prairie wellhead price of crude oil for 1975 is $7.25 (average of $6.50 for 6 months and $8.00 for 6 months), for 1976 is $8.53 (average of $8.00 for 6 months and $9.05 for 6 months). The Prairie wellhead price of crude oil is assumed to increase until by 1980 it is priced competitively with the offshore crude oil. Therefore the following per barrel prices are used: $10.25 in 1977, $11.75 in 1978, and $13.25 in 1979.

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[19] The Fuss et al report assumes increases in the electricity price as follows: 16% from 1971-1975, 14% from 1976-1980, and 6% from 1981-1985.

[20] The Fuss et al report assumes increases in the coal price as follows: 30% from 1971-1975, 14% from 1976-1980, and 5% from 1981-1985.

[21] In 1975, cumulative data was available only to October, so the October price of $11.22 is assumed to hold for November and December.

The Prairie natural gas wellhead price is determined after 1973 by subtracting the Prairie to Toronto transportation tariff from the regulated price in the Toronto market, PGASREG. The construction of PGASREG is described in appendix 4.A. The B.C. natural gas wellhead price is under the control of the B.C. Petroleum Corporation which in turn is influenced by the B.C. provincial government.[22] Therefore we have assumed that the B.C. natural gas wellhead price is independant of the Prairies wellhead price. It is assumed that the B.C. wellhead price increases by 40% in 1976, 20% from 1977-1978, 15% from 1979-1980, and then at 6% therefter. Since it is assumed that the average natural gas price in the Prairies is discounted after 1975 (Crommelin [43, p.15]), the primary price of natural gas is roughly equivalent between B.C. and the Prairies.

The amount of hydro and nuclear electricity generated in each region is an exogenous variable. The growth rates used in the forecast are about 1.5% less than the historical 1969-1972 growth rates. Since the higher relative energy prices in the forecast imply a lower growth in electricity demand, we assume that this lower growth will lead to fewer projects for hydro and nuclear electric generation. The following regional hydro and nuclear electric supply growth rates are assumed: 2% in Atlantic, 4% in Quebec, 2% in Ontario, 2% in Prairies and 3% in B.C. In reality the supply of hydro and nuclear generated electric capacity is an economic decision, but we have not attempted to model the behavioral relationship. The EMR [32, p.68] forecast that for the low growth case hydro and nuclear electrical capacity will grow at close to the historical average of 5.5% per year.

In both the Prairie region and the B.C. region a relatively high percentage of crude oil product use is in the form of deisel fuel, which has a low efficiency factor (see table 2, in appendix 3.C). During the forecast the overall efficiency factor for crude oil was raised so that it was closer to the other regions because the large increases forecast for the crude oil price would have led to a rather large regional divergence of the output Btu price of crude oil. Increasing the efficiency factor for crude oil assumes that either deisel fuel will lose some of its market share or that its relative price will fall.

The model calculated subsidy payments for crude oil were about 2% lower than those reported on p.114-117 in the EMR, An Energy Strategy for Canada: Policies for Self-Reliance, and also lower than the approximate 1974 value (12/15 of the January 1, 1974 to March 31, 1975 value) reported in table 1, appendix NR16, p.20:47 of Minutes of Proceedings and Evidence of the

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[22] The B.C. government approved on November, 1975 an increase in the wellhead price of natural gas in B.C. to $.53/Mcf. But we assume that the domestic price increases will be phased-in over the next few years.

House of Commons, Standing Committee on National Resources and Public Works, Issue no. 20, May 6, 1975. Since we are uncertain as to whether this discrepency arose due to an incorrect world oil price or an incorrect import quantity, a coefficient is added to the per barrel subsidy payment. The value of this coefficient declines from approximately 2% in 1976 to 0 in 1980.

An exogenous series DPETRO is used to represent the post-1973 additions to petrochemical demand for natural gas. We use the NEB forecast of new petrochemical demand reported on p.23, table 5 in NEB, Canadian Natural Gas: Supply and Requirements. Due to lack of alternative information it is assumed that there will be no new petrochemical demand after 1995, the last year in the NEB forecast.

The quantities of re-exported crude oil products from Atlantic and Quebec have been obtained for 1974 from the December 1974 issue of Statistics Canada, Refined Petroleum Products (#45/004). Due to lack of information it was assumed that this quantity of re-exports would remain constant in the future.

All of the estimated equations have the estimation residuals added back until the end of the estimation period (1973). This is done so that during the historical period the simulated value will be equal to the actual value. In some cases this 'add factor' was assumed to remain at its last known value. But in most cases an attempt was made to tune the 1974-1976 simulated values to published preliminary values. The preliminary values for primary energy fuels has been obtained from many sources: namely Statistics Canada, NEB reports on crude oil and natural gas, and the Oilweek magazine. The 'add factors' must be specified for both the total current dollar expenditure equation and for the share equation. In order to adjust a specific regional fuel quantity it is necessary to adjust both equations, which implies some uncertainty as to the proper adjustment mix. All of the add factors are listed at the end of the demand model equations in appendix 2.A.

5.B Results of the Base Case Forecast

The following tables indicate the simulation values for a subset of the model variables. The simulation covers the period from 1974 to 1995. The printout variables, whose description is contained in appendix 1, include both the endogenous and exogenous variables.

DYNAMIC SIMULATION ON 09-15-76

	1 PO.AT	2 TOTSAT	3 QC.AT	4 QL.AT	5 QOL.AT	6 QCL.AT	7 OBTU.AT	8 PO.QU	9 PG.QU	10 TOTSQU
1974	2.265	740.172	220.661	56.647	40.925	17.086	288.090	2.265	1.074	2155.714
1975	2.821	875.153	215.622	48.370	27.211	10.789	275.206	2.821	1.302	2608.233
1976	3.302	1044.622	221.125	43.856	20.069	7.140	276.644	3.302	1.714	3106.047
1977	3.935	1260.190	222.517	46.629	22.998	8.814	281.274	3.935	2.099	3659.687
1978	4.489	1429.132	220.368	46.386	21.353	8.484	279.368	4.489	2.465	4256.066
1979	5.043	1621.913	222.562	45.803	19.339	7.859	281.483	5.043	2.850	4917.477
1980	5.529	1822.538	226.875	45.295	17.765	7.229	285.813	5.529	3.216	5620.102
1981	5.750	1944.103	231.701	46.898	19.379	7.885	292.788	5.750	3.445	6014.250
1982	5.980	2092.177	239.084	48.826	21.563	8.774	302.667	5.980	3.583	6454.309
1983	6.219	2286.943	251.290	51.319	24.751	10.071	317.955	6.219	3.727	7007.387
1984	6.468	2499.036	264.033	53.921	28.073	11.423	333.915	6.468	3.876	7643.691
1985	6.727	2730.219	277.364	56.644	31.547	12.836	350.607	6.727	4.031	8337.680
1986	6.996	2982.788	291.368	59.504	35.201	14.323	368.135	6.996	4.192	9094.285
1987	7.276	3258.722	306.079	62.508	39.045	15.887	386.541	7.276	4.360	9919.551
1988	7.567	3560.182	321.533	65.664	43.088	17.532	405.869	7.567	4.534	10819.809
1989	7.869	3889.525	337.767	68.980	47.340	19.263	426.165	7.869	4.715	11801.836
1990	8.184	4249.340	354.820	72.462	51.812	21.082	447.478	8.184	4.904	12873.094
1991	8.512	4642.438	372.735	76.121	56.515	22.996	469.859	8.512	5.100	14041.641
1992	8.852	5071.902	391.554	79.964	61.460	25.008	493.361	8.852	5.304	15316.332
1993	9.206	5541.102	411.323	84.001	66.658	27.123	518.042	9.206	5.516	16706.762
1994	9.574	6053.699	432.091	88.242	72.122	29.346	543.959	9.574	5.737	18223.484
1995	9.957	6613.719	453.907	92.698	77.863	31.682	571.176	9.957	5.966	19877.910

	11 QC.QU	12 QG.QU	13 QL.QU	14 QOL.QU	15 QCL.QU	16 OBTU.QU	17 PO.ON	18 PG.ON	19 TOTSON	20 QO.ON
1974	555.119	61.412	314.630	56.336	4.908	949.366	2.265	1.012	2226.083	390.389
1975	551.022	73.121	301.895	32.314	2.756	944.971	2.821	1.235	2699.559	390.151
1976	568.086	71.934	290.583	12.713	1.023	950.293	3.302	1.642	3566.815	446.552
1977	559.560	74.036	297.248	23.617	1.996	951.322	3.935	2.026	4246.289	444.746
1978	565.098	77.617	303.295	14.528	1.258	967.308	4.489	2.390	4954.633	450.287
1979	576.034	81.485	307.274	0.063	0.006	986.942	5.043	2.774	5742.785	458.757
1980	594.163	86.263	308.780	0.000	0.000	1012.240	5.529	3.138	6586.656	471.507
1981	604.443	89.783	321.686	0.000	0.000	1039.868	5.750	3.365	7072.051	478.285
1982	617.861	96.325	334.979	0.000	0.000	1074.080	5.980	3.499	7583.027	486.539
1983	641.129	103.638	351.383	0.000	0.000	1122.061	6.219	3.639	8228.426	503.455
1984	669.855	111.258	369.429	0.000	0.000	1177.489	6.468	3.785	8974.852	525.342
1985	700.446	118.790	388.191	0.000	0.000	1235.452	6.727	3.936	9791.188	548.961
1986	732.892	126.295	407.719	6.530	0.576	1296.053	6.996	4.094	10681.078	574.138
1987	767.246	133.840	428.094	14.242	1.256	1359.492	7.276	4.258	11651.520	600.879
1988	803.552	141.484	449.379	22.119	1.950	1425.939	7.567	4.428	12709.953	629.197
1989	841.853	149.282	471.633	30.295	2.671	1495.554	7.869	4.605	13864.367	659.115
1990	882.207	157.284	494.919	38.859	3.427	1568.507	8.184	4.789	15123.543	690.666
1991	924.679	165.534	519.295	47.869	4.221	1644.969	8.512	4.981	16496.930	723.891
1992	969.345	174.071	544.825	57.385	5.060	1725.121	8.852	5.180	17994.996	758.848
1993	1016.287	182.934	571.571	67.453	5.948	1809.146	9.206	5.387	19629.004	795.596
1994	1065.601	192.156	599.598	78.123	6.889	1897.243	9.574	5.603	21411.348	834.206
1995	1117.385	201.769	628.973	89.439	7.887	1989.611	9.957	5.827	23355.473	874.754

	21	22	23	24	25	26	27	28	29	30
	QG.ON	QL.ON	QOL.ON	QGL.ON	QCL.ON	OBTU.ON	PO.PR	PG.PR	TOT$PR	QO.PR
1974	437.520	269.183	0.725	32.977	160.537	1257.792	2.939	0.524	1038.618	172.135
1975	444.862	261.926	1.281	29.047	124.133	1264.067	3.481	0.672	1264.001	181.403
1976	451.958	280.758	3.680	31.003	134.127	1353.081	3.887	0.795	1530.934	198.416
1977	446.211	287.862	1.966	27.172	151.155	1359.584	4.476	0.927	1788.302	199.745
1978	451.814	291.423	1.115	24.594	160.636	1381.521	4.961	1.062	2068.314	205.789
1979	462.116	293.624	0.566	22.487	166.837	1410.013	5.445	1.216	2384.893	213.365
1980	479.889	294.095	0.484	21.042	167.924	1448.828	5.857	1.362	2721.718	222.818
1981	489.501	305.775	0.525	21.580	183.298	1485.031	5.990	1.473	2908.974	228.819
1982	511.792	316.848	0.562	23.109	196.280	1535.108	6.147	1.532	3111.842	234.832
1983	539.681	331.157	0.617	25.361	215.409	1603.019	6.324	1.593	3371.122	244.603
1984	570.548	347.305	0.681	27.995	237.788	1681.070	6.521	1.657	3672.060	256.485
1985	602.129	364.323	0.749	30.782	261.456	1762.803	6.735	1.723	4001.280	269.013
1986	634.470	382.149	0.820	33.703	286.264	1848.042	6.966	1.792	4360.602	282.168
1987	667.777	400.836	0.895	36.767	312.294	1937.068	7.213	1.863	4752.949	295.987
1988	702.225	420.431	0.973	39.984	339.616	2030.134	7.475	1.938	5181.340	310.498
1989	737.970	440.979	1.055	43.361	368.293	2127.475	7.752	2.016	5649.004	325.731
1990	775.156	462.528	1.142	46.903	398.382	2229.337	8.044	2.096	6159.461	341.713
1991	813.914	485.126	1.232	50.620	429.957	2335.958	8.351	2.180	6716.547	358.478
1992	854.376	508.827	1.327	54.522	463.093	2447.599	8.673	2.267	7324.480	376.061
1993	896.661	533.683	1.427	58.613	497.848	2564.510	9.009	2.358	7987.836	394.500
1994	940.895	559.752	1.531	62.907	534.313	2686.965	9.361	2.452	8711.625	413.834
1995	987.193	587.093	1.641	67.409	572.558	2815.237	9.728	2.550	9501.293	434.108

	31	32	33	34	35	36	37	38	39	40
	QG.PR	QL.PR	QOL.PR	QGL.PR	QCL.PR	OBTU.PR	PO.BC	PG.BC	TOT$BC	QO.BC
1974	342.448	97.799	3.440	49.686	82.339	621.037	2.427	0.499	741.731	112.408
1975	330.253	94.669	4.519	45.389	60.094	615.325	2.987	0.567	901.824	115.937
1976	343.734	93.429	6.778	47.618	40.903	644.939	3.456	0.715	1157.042	131.496
1977	350.562	95.118	5.326	44.427	44.036	655.159	4.084	0.815	1360.491	131.153
1978	360.129	96.615	4.709	42.514	46.682	672.657	4.626	0.933	1585.595	134.334
1979	369.231	97.809	4.339	40.589	49.100	690.934	5.168	1.041	1840.471	138.741
1980	383.095	98.320	4.301	39.642	50.493	715.183	5.640	1.163	2123.966	145.203
1981	385.597	102.520	4.525	39.173	53.533	728.324	5.842	1.227	2263.721	147.469
1982	403.996	106.623	4.740	41.034	56.076	757.294	6.055	1.294	2424.943	150.689
1983	426.756	111.779	5.047	43.694	59.712	795.456	6.281	1.365	2632.164	156.633
1984	451.738	117.508	5.401	46.760	63.902	838.541	6.518	1.440	2872.649	164.070
1985	477.114	123.482	5.773	49.978	68.298	882.931	6.768	1.518	3134.701	171.916
1986	502.992	129.699	6.161	53.339	72.891	928.714	7.029	1.602	3420.461	180.191
1987	529.566	136.187	6.568	56.861	77.705	976.149	7.302	1.690	3732.313	188.918
1988	556.997	142.965	6.995	60.555	82.752	1025.446	7.587	1.783	4072.713	198.114
1989	585.419	150.054	7.442	64.429	88.047	1076.789	7.886	1.881	4444.242	207.793
1990	614.957	157.470	7.912	68.494	93.602	1130.349	8.196	1.985	4849.746	217.972
1991	645.721	165.235	8.404	72.757	99.427	1186.291	8.521	2.095	5292.305	228.672
1992	677.822	173.366	8.920	77.227	105.536	1244.780	8.858	2.211	5775.301	239.913
1993	711.361	181.884	9.462	81.913	111.940	1305.977	9.210	2.334	6302.398	251.719
1994	746.438	190.810	10.029	86.828	118.656	1370.044	9.576	2.463	6877.633	264.114
1995	783.148	200.164	10.624	91.980	125.696	1437.140	9.957	2.600	7505.371	277.125

	41	42	43	44	45	46	47	48	49	50
	QG.BC	QL.BC	QOL.BC	QGL.BC	OBTU.BC	TOT$	TEL$	OBTU	QOILEAST	QOILWEST
1974	103.458	120.384	12.394	29.702	343.123	6902.316	454.415	3459.407	272.478	276.757
1975	112.906	118.159	8.657	23.698	354.151	8348.762	430.270	3453.719	261.863	275.930
1976	117.405	123.952	9.827	25.996	380.287	10405.453	483.229	3605.244	263.834	306.402
1977	123.776	126.128	8.512	24.518	388.788	12314.953	597.154	3636.127	264.385	301.198
1978	128.794	127.857	7.442	22.223	399.024	14293.734	640.278	3699.877	263.244	303.250
1979	137.031	129.211	6.326	19.790	413.345	16507.531	655.520	3782.717	264.176	308.112
1980	144.705	130.207	5.158	16.461	428.811	18874.973	706.528	3890.876	271.103	316.605
1981	149.657	134.231	5.173	16.926	440.401	20203.094	788.583	3986.414	276.369	320.621
1982	155.613	138.863	5.412	18.158	454.570	21666.293	876.039	4123.719	283.635	325.865
1983	163.040	145.206	6.362	21.679	474.661	23526.035	1000.236	4313.148	295.907	337.102
1984	171.005	152.465	7.624	26.194	497.713	25662.285	1147.632	4528.727	310.126	351.730
1985	178.733	160.047	8.937	30.787	521.276	27995.063	1311.106	4753.066	325.171	367.517
1986	186.316	167.981	10.316	35.482	545.492	30539.211	1522.072	4986.430	342.384	384.378
1987	193.839	176.298	11.774	40.302	570.498	33315.051	1760.188	5229.746	360.724	402.322
1988	201.365	185.020	13.319	45.262	596.401	36343.992	2023.092	5483.785	380.013	421.360
1989	208.944	194.170	14.956	50.367	623.284	39648.973	2313.822	5749.262	400.310	441.502
1990	216.618	203.767	16.691	55.625	651.230	43255.184	2635.427	6026.898	421.666	462.771
1991	224.422	213.835	18.531	61.045	680.317	47189.859	2991.148	6317.391	444.129	485.194
1992	232.385	224.396	20.479	66.633	710.618	51483.012	3384.534	6621.473	467.753	508.807
1993	240.532	235.476	22.541	72.396	742.207	56167.102	3819.300	6939.875	492.592	533.648
1994	248.883	247.100	24.724	78.340	775.156	61277.789	4299.672	7273.363	518.705	559.766
1995	257.457	259.295	27.032	84.472	809.539	66853.750	4830.086	7622.695	546.151	587.211

	51	52	53	54	55	56	57	58	59	60
	QGAS	QELEC	LOSSGAS	LOILEAST	LOILWEST	GASACUM	RESDISCV	RESBASE	RESCOST	RESEXCES
1974	1307.219	251653.938	506.423	17.896	43.013	24.244	4.800	65.496	2164.406	34.993
1975	1321.824	241799.375	507.033	27.706	49.341	26.751	3.000	65.989	2210.836	36.960
1976	1374.756	244014.750	517.700	28.235	25.767	29.312	3.000	66.428	2281.574	37.740
1977	1439.645	249995.313	531.188	28.041	25.380	31.946	2.500	66.294	2338.590	37.162
1978	1477.022	253686.000	539.779	28.146	25.574	34.624	2.500	66.116	2382.552	37.199
1979	1511.563	256072.750	544.402	28.462	25.999	37.323	2.000	65.417	2392.516	37.125
1980	1597.986	256944.813	562.391	28.997	26.712	40.112	2.000	64.628	2430.208	35.667
1981	1626.016	267030.750	567.899	29.341	27.048	42.926	1.500	63.314	2412.641	34.984
1982	1699.493	277297.313	558.087	29.808	27.477	45.683	1.500	62.056	2385.633	35.922
1983	1792.711	290399.625	576.584	30.609	28.400	48.529	1.000	60.211	2342.632	33.002
1984	1895.635	304990.188	598.025	31.557	29.604	51.478	1.000	58.262	2326.859	29.562
1985	2015.280	320247.750	622.207	32.563	30.906	54.544	0.500	55.696	2283.092	24.911
1986	2121.024	336181.625	630.941	33.628	32.299	57.645	0.500	53.095	2198.779	21.535
1987	2229.414	352849.063	627.503	34.753	33.783	60.719	0.500	50.521	2098.623	19.132
1988	2341.057	370298.563	651.817	35.941	35.358	63.909	0.500	47.831	2032.626	13.785
1989	2456.371	388573.438	664.971	37.193	37.025	67.157	0.500	45.083	1947.671	9.822
1990	2589.029	407721.375	622.023	38.511	38.786	70.168	0.500	42.571	1845.173	10.322
1991	2713.360	427787.063	631.229	39.898	40.642	73.216	0.500	40.024	1740.855	8.885
1992	2842.780	448820.750	647.527	41.356	42.597	76.336	0.500	37.403	1633.061	5.084
1993	2977.564	470871.563	672.053	42.888	44.654	79.572	0.260	34.428	1506.350	0.260
1994	3118.198	493992.188	651.917	44.497	46.816	82.689	0.0	31.311	1369.980	0.0
1995	3268.533	518236.063	627.812	46.188	49.088	85.665	0.0	28.335	1239.757	0.0

	61	62	63	64	65	66	67	68	69	70
	GASCCSTM	CAN.REQ.	EXPORTS	SUM	GASMAXA	DEFICIT	YGASNFT	TCGASNF	PENTCANT	KRENTGAS
1974	33.023	1.482	1.022	2.504	2.504	0.000	372.918	94.514	2021.484	1796.854
1975	29.155	1.497	1.011	2.508	2.508	0.000	1182.368	296.285	5066.566	5572.883
1976	29.954	1.553	1.007	2.561	2.561	0.000	2009.992	410.053	8935.281	10257.398
1977	30.621	1.623	1.011	2.634	2.634	0.000	2750.586	670.375	13278.656	15426.367
1978	31.287	1.663	1.015	2.678	2.678	0.000	3494.158	925.869	18409.281	21435.762
1979	31.820	1.699	1.000	2.699	2.699	0.000	4244.820	1148.175	24347.105	28367.605
1980	32.353	1.792	0.996	2.788	2.788	0.000	4901.418	1315.799	31076.113	36457.395
1981	32.753	1.822	0.993	2.815	2.815	0.000	5288.547	1453.357	38730.613	45762.172
1982	33.152	1.892	0.865	2.757	2.757	0.0	5353.965	1481.388	47335.680	56257.707
1983	33.419	1.992	0.854	2.846	2.846	0.000	5734.965	1593.301	57172.695	68414.250
1984	33.685	2.102	0.847	2.949	2.949	0.000	6160.754	1697.088	68383.438	82471.313
1985	33.819	2.230	0.836	3.066	3.066	0.000	6642.090	1847.343	81173.750	98727.688
1986	33.952	2.339	0.763	3.102	3.102	0.000	6957.711	1980.578	95646.688	117295.188
1987	34.085	2.446	0.628	3.074	3.074	0.0	7125.770	2055.028	111886.563	138313.688
1988	34.218	2.566	0.624	3.190	3.190	0.000	7673.719	2190.824	130276.000	162451.563
1989	34.352	2.686	0.562	3.248	3.248	0.000	8091.973	2338.522	151051.375	189965.875
1990	34.485	2.804	0.208	3.012	3.091	0.0	7678.133	2249.914	174017.313	220443.063
1991	34.618	2.931	0.117	3.048	3.048	0.000	8042.328	2366.518	199903.875	255025.563
1992	34.751	3.066	0.055	3.121	3.121	0.000	8537.668	2521.765	229150.938	294348.000
1993	0.0	3.209	0.047	3.257	3.236	0.058	9210.398	2735.255	262284.938	339170.063
1994	0.0	3.343	0.007	3.350	3.117	0.640	9215.012	2747.460	299383.500	389439.250
1995	0.0	3.485	0.007	3.492	2.976	1.414	9154.398	2733.708	39373.910	51484.055

	71	72	73	74	75	76	77	78	79	80
	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$	OILPRO	OILMAX	OILACUM	CPROSUM	OILRDISC
1974	-3810.972	2472.290	-1110.915	1479.462	2766.981	1803.834	1803.834	7419.266	-0.000	98.234
1975	-4516.094	3692.334	-1151.827	3497.022	4051.446	1545.353	1815.669	7983.316	-0.000	181.000
1976	-4920.020	5467.895	-1076.740	5601.938	5184.332	1420.051	1734.669	8501.633	-0.000	168.000
1977	-4983.320	7612.305	-720.647	7458.418	6059.617	1444.733	1619.669	9028.957	-0.000	156.000
1978	-4835.090	10338.973	-102.893	9212.758	6822.023	1295.887	1489.669	9501.953	-0.000	147.000
1979	-4388.652	13700.152	778.229	10812.301	7465.590	1174.872	1338.669	9930.781	51.500	135.000
1980	-3565.464	17680.145	1900.345	12262.203	8180.168	1108.394	1184.669	10335.344	92.800	129.000
1981	-2474.538	22255.242	3269.977	13737.418	8974.070	1074.578	1074.578	10727.563	108.300	118.000
1982	-1222.046	27385.246	4823.059	15390.109	9881.332	1071.976	1071.976	11118.832	108.300	112.000
1983	443.865	33185.934	6649.688	17241.633	10893.117	1032.702	1048.913	11495.766	170.000	103.000
1984	2632.788	39729.309	8772.215	19315.906	12021.117	1023.048	1023.048	11869.176	216.500	95.000
1985	5444.500	47097.469	11266.102	21639.727	13279.980	982.654	982.654	12227.844	237.200	91.000
1986	8851.719	55336.258	14164.445	24243.117	14699.816	928.954	928.954	12566.910	288.700	82.000
1987	12880.215	64491.391	17466.465	27159.711	16316.090	881.467	881.467	12888.645	340.200	76.000
1988	17903.016	74733.438	21266.504	30427.191	18121.645	842.123	842.123	13196.016	360.900	73.000
1989	23898.172	86187.563	25638.242	34087.766	20154.395	809.115	809.115	13491.340	366.100	69.000
1990	30450.098	98824.063	30458.137	38188.730	22522.348	770.566	770.566	13772.594	376.300	65.000
1991	38118.246	112975.125	35950.684	42783.066	25198.789	711.412	711.412	14032.258	381.500	61.000
1992	47111.848	128862.063	42230.078	47930.133	28214.203	660.872	660.872	14273.473	386.700	56.000
1993	57695.699	146742.438	49441.859	53696.422	31593.980	601.193	601.193	14492.906	386.700	52.000
1994	69634.500	166720.813	57535.195	60156.430	35392.594	548.154	548.154	14692.980	386.700	50.000
1995	9593.078	21834.945	7692.129	7784.336	4579.582	494.341	494.341	14873.414	386.700	50.000

	81	82	83	84	85	86	87	88	89	90
	OILRBASE	OILRCOST	OILCOSTM	OILREXES	OILCAND	OILXTOT	OILIMPT	OILSUM	OILPIPEM	GFSUBO
1974	6398.188	3181.603	6.944	79.889	1671.627	909.200	730.746	1803.834	64.800	1122.245
1975	6015.133	3099.457	4.451	358.215	1684.491	698.000	787.139	1545.353	6.200	1494.108
1976	5664.813	3027.577	4.694	639.711	1710.241	460.000	700.189	1420.051	100.000	1206.912
1977	5293.484	2936.574	4.920	858.224	1695.900	350.000	551.167	1444.733	250.000	670.170
1978	4967.484	2862.497	5.133	1074.615	1699.215	210.000	548.327	1295.887	250.000	422.249
1979	4673.656	2795.503	5.328	1268.061	1717.120	126.000	551.748	1174.872	250.000	183.464
1980	4398.090	2732.176	5.515	1423.562	1762.787	75.600	572.193	1108.394	250.000	0.0
1981	4123.867	2657.423	5.685	1182.468	1790.081	45.360	587.563	1074.578	250.000	0.0
1982	3844.596	2570.536	5.847	379.588	1826.809	27.216	608.749	1071.976	250.000	0.0
1983	3570.660	2474.656	5.996	482.588	1895.937	16.330	644.564	1032.702	250.000	0.0
1984	3292.248	2363.427	6.134	13.377	1980.869	9.798	686.118	1023.048	250.000	0.0
1985	3024.579	2250.558	6.265	0.0	2071.665	5.879	792.689	1045.250	187.405	0.0
1986	2767.511	2131.215	6.384	0.0	2171.749	3.527	892.622	1041.408	137.546	0.0
1987	2521.776	2008.949	6.494	0.0	2278.307	2.116	993.757	1041.725	89.742	0.0
1988	2287.401	1886.722	6.599	0.0	2390.882	1.270	1124.129	1076.651	15.472	0.0
1989	2061.074	1760.920	6.699	0.0	2509.672	0.762	1270.219	1130.695	-71.580	0.0
1990	1844.818	1633.250	6.793	0.0	2634.888	0.457	1423.480	1183.286	-162.721	0.0
1991	1646.153	1510.523	6.882	0.0	2766.747	0.274	1609.109	1244.421	-283.009	0.0
1992	1460.935	1388.789	6.963	0.0	2905.513	0.165	1793.106	1309.159	-398.287	0.0
1993	1293.499	1273.749	7.038	0.0	3051.457	0.099	1998.663	1382.787	-531.595	0.0
1994	1143.423	1167.671	7.110	0.0	3204.887	0.059	2205.093	1460.227	-662.074	0.0
1995	1012.989	1075.338	7.182	0.0	3366.130	0.036	2420.125	1541.620	-797.279	0.0

	91	92	93	94	95	96	97	98	99	100
	TXCIL	YOILNFT	TCOILNF	KROILCAN	KRENTCIL	KROILP$	KROILGP$	KROILGF$	KROILC1$	XBALGO$
1974	1420.351	2832.119	805.114	13390.172	9027.336	-5557.750	13460.320	-771.099	1895.871	1389.890
1975	1210.157	3246.236	1060.853	21321.977	16407.676	-6260.250	17780.969	-419.232	5306.199	1031.751
1976	750.513	3562.243	936.989	29870.875	24640.297	-6663.148	22601.914	-268.723	8970.266	664.236
1977	417.742	4472.492	1192.301	38399.223	33311.430	-6481.254	27539.633	354.032	11899.031	1067.554
1978	177.123	4663.598	1245.187	47406.000	42535.414	-6204.555	33139.707	1103.782	14496.492	589.106
1979	63.155	4816.516	1289.606	57052.332	52479.457	-5825.313	39453.668	2111.508	16739.602	286.256
1980	17.814	5020.543	1348.270	67623.375	63469.121	-5292.070	46574.203	3433.531	18753.473	-121.127
1981	11.116	5042.301	1358.256	79439.438	75788.938	-4650.281	54517.965	4911.684	21009.625	-409.218
1982	6.936	5211.324	1408.415	92764.188	89764.188	-3821.629	63445.199	6603.520	23537.203	-1030.074
1983	4.328	5199.918	1408.383	107655.188	105405.125	-2866.329	73409.000	8493.746	26368.867	-1399.055
1984	2.701	5337.699	1450.310	124418.250	123079.813	-1704.878	84598.188	10645.480	29541.203	-1792.088
1985	1.685	5308.652	1443.149	143159.188	142856.250	-385.758	97098.313	13048.684	33095.191	-2646.400
1986	1.052	5197.004	1414.728	164063.188	164902.813	1069.684	111039.938	15716.648	37076.742	-3713.691
1987	0.656	5106.352	1391.048	187408.375	189518.563	2688.265	126606.813	18686.410	41537.297	-5077.633
1988	0.409	5050.453	1375.695	213516.188	217052.500	4505.004	144010.875	22002.355	46534.480	-6291.055
1989	0.256	5024.117	1369.184	242745.313	247891.500	6555.824	163488.063	25714.961	52132.855	-7932.598
1990	0.159	4952.918	1349.973	275441.438	282388.500	8849.887	185272.250	29861.801	58404.750	-10885.332
1991	0.099	4729.590	1287.680	311911.313	320820.750	11349.676	209582.188	34457.840	65431.191	-13276.820
1992	0.062	4545.629	1237.321	352640.875	363706.688	14096.660	236739.000	39568.219	73302.938	-15704.496
1993	0.039	4275.098	1162.018	398078.250	411489.125	17084.066	267050.438	45233.063	82121.688	-18265.078
1994	0.024	4027.469	1091.881	448806.000	464780.813	20350.148	300905.938	51523.441	92001.375	-21162.582
1995	0.015	3747.103	1011.299	58380.102	60548.723	2762.583	39123.422	6757.594	11905.133	-24158.992

EXOGENOUS ASSUMPTIONS USED TO PRODUCE FORECAST

	1	2	3	4	5	6	7	8	9	10
	UGNE	PGNE	PC.CFF	PCW.PR	PGW.PR	PGW.BC	PLR.AT	PLR.QU	PLR.ON	PLR.PR
1974	78924.000	1.770	10.000	5.720	0.378	0.200	19.305	12.036	15.192	16.440
1975	79081.813	1.950	12.000	7.250	0.513	0.255	25.096	14.443	18.230	19.728
1976	83352.188	2.110	13.000	8.530	0.803	0.357	32.625	17.332	21.876	23.674
1977	87853.188	2.237	13.520	10.250	1.093	0.428	37.519	19.932	25.158	27.225
1978	92597.250	2.326	14.061	11.750	1.366	0.514	43.147	22.921	28.932	31.308
1979	97597.438	2.419	14.623	13.250	1.654	0.591	49.619	26.359	33.271	36.004
1980	102867.688	2.516	15.208	14.563	1.925	0.680	57.062	30.313	38.262	41.405
1981	108422.500	2.616	15.816	15.145	2.084	0.721	59.344	31.526	39.792	43.061
1982	113301.375	2.721	16.449	15.751	2.168	0.764	61.718	32.787	41.384	44.784
1983	118399.813	2.830	17.107	16.381	2.254	0.810	64.187	34.098	43.039	46.575
1984	123727.688	2.943	17.791	17.036	2.344	0.858	66.754	35.462	44.761	48.438
1985	129295.313	3.061	18.503	17.718	2.438	0.910	69.424	36.881	46.551	50.376
1986	135113.438	3.183	19.243	18.426	2.536	0.964	72.201	38.356	48.414	52.391
1987	141193.375	3.311	20.013	19.163	2.637	1.022	75.089	39.890	50.350	54.486
1988	147546.938	3.443	20.813	19.930	2.743	1.084	78.093	41.486	52.364	56.666
1989	154186.375	3.581	21.646	20.727	2.852	1.149	81.217	43.145	54.459	58.932
1990	161124.625	3.724	22.512	21.556	2.966	1.218	84.465	44.871	56.637	61.290
1991	168375.063	3.873	23.412	22.418	3.085	1.291	87.844	46.666	58.902	63.741
1992	175951.750	4.028	24.349	23.315	3.208	1.368	91.358	48.533	61.259	66.291
1993	183869.375	4.189	25.323	24.248	3.337	1.450	95.012	50.474	63.709	68.942
1994	192143.313	4.356	26.335	25.218	3.470	1.537	98.813	52.493	66.257	71.700
1995	200789.563	4.531	27.389	26.226	3.609	1.629	102.765	54.592	68.907	74.568

	11	12	13	14	15	16	17	18	19	20
	PLR.BC	PCW.AT	PCW.PR	PCW.BC	PC.US	QHL.AT	QHL.QU	QHL.ON	QHL.PR	QHL.BC
1974	15.768	16.429	8.375	18.058	13.586	35.654	310.785	209.473	54.952	109.607
1975	18.922	22.343	13.568	27.448	18.477	36.367	310.785	213.662	56.051	112.895
1976	22.706	30.387	21.980	41.720	25.129	37.094	310.785	217.935	57.171	116.282
1977	26.112	33.425	24.178	45.892	27.642	37.836	310.785	222.294	58.315	119.770
1978	30.029	36.768	26.596	50.481	30.406	38.593	323.217	226.739	59.481	123.363
1979	34.533	40.445	29.256	55.529	33.447	39.365	336.145	231.274	60.671	127.064
1980	39.713	44.489	32.181	61.082	36.792	40.152	349.591	235.899	61.884	130.876
1981	41.301	46.269	33.469	63.526	38.263	40.955	363.574	240.617	63.122	134.802
1982	42.953	48.119	34.807	66.067	39.794	41.774	378.117	245.430	64.384	138.846
1983	44.671	50.044	36.200	68.709	41.386	42.609	393.241	250.338	65.672	143.012
1984	46.458	52.046	37.648	71.458	43.041	43.462	408.971	255.345	66.985	147.302
1985	48.316	54.128	39.154	74.316	44.763	44.331	425.330	260.451	68.325	151.721
1986	50.249	56.293	40.720	77.289	46.553	45.217	442.343	265.660	69.691	156.273
1987	52.259	58.544	42.348	80.380	48.415	46.122	460.036	270.973	71.085	160.961
1988	54.349	60.886	44.042	83.595	50.352	47.044	478.438	276.392	72.507	165.789
1989	56.523	63.322	45.804	86.939	52.366	47.985	497.575	281.920	73.957	170.763
1990	58.784	65.854	47.636	90.417	54.461	48.945	517.478	287.558	75.436	175.886
1991	61.136	68.489	49.542	94.033	56.639	49.923	538.177	293.309	76.945	181.162
1992	63.581	71.228	51.523	97.795	58.905	50.922	559.704	299.175	78.483	186.597
1993	66.124	74.077	53.584	101.706	61.261	51.940	582.092	305.158	80.053	192.195
1994	68.769	77.040	55.728	105.775	63.711	52.979	605.375	311.261	81.654	197.961
1995	71.520	80.122	57.957	110.006	66.260	54.039	629.590	317.486	83.287	203.900

	21	22	23	24	25	26	27	28	29	30
	GPM.QU	GPM.ON	GPM.PR	GPM.BC	DPETRO	QOILREAT	QOILREQU	PFX	PEXOG	PGAS
1974	1718.000	17022.000	14960.000	5558.000	1.300	27.552	4.272	1.000	1.770	172.325
1975	1855.440	17702.879	15408.793	5780.316	12.700	27.552	4.272	1.000	1.950	206.790
1976	2003.875	18410.992	15871.051	6011.527	28.200	27.552	4.272	1.000	2.110	224.022
1977	2164.184	19147.430	16347.176	6251.984	91.100	27.552	4.272	1.000	2.194	232.983
1978	2337.319	19913.324	16837.586	6502.063	106.900	27.552	4.272	1.000	2.282	242.302
1979	2524.304	20709.855	17342.707	6762.145	109.900	27.552	4.272	1.000	2.373	251.994
1980	2726.248	21538.246	17862.980	7032.629	148.300	27.552	4.272	1.000	2.468	262.074
1981	2944.347	22184.387	18398.863	7313.934	150.200	27.552	4.272	1.000	2.567	272.557
1982	3179.895	22683.512	18950.824	7606.488	152.200	27.552	4.272	1.000	2.670	283.459
1983	3370.687	23066.277	19377.199	7834.680	154.300	27.552	4.272	1.000	2.777	294.797
1984	3522.364	23358.207	19704.176	8010.949	156.500	27.552	4.272	1.000	2.888	306.589
1985	3641.242	23579.918	19953.555	8146.125	174.000	27.552	4.272	1.000	3.003	318.852
1986	3733.411	23747.762	20142.949	8249.223	175.800	27.552	4.272	1.000	3.123	331.606
1987	3804.285	23874.543	20286.328	8327.523	177.700	27.552	4.272	1.000	3.248	344.870
1988	3858.448	23970.145	20394.629	8386.797	179.700	27.552	4.272	1.000	3.378	358.665
1989	3899.650	24042.129	20476.297	8431.570	181.700	27.552	4.272	1.000	3.513	373.011
1990	3930.882	24096.262	20537.789	8465.332	196.900	27.552	4.272	1.000	3.654	387.932
1991	3954.491	24136.957	20584.031	8490.754	199.200	27.552	4.272	1.000	3.800	403.449
1992	3972.303	24167.523	20618.793	8509.871	201.600	27.552	4.272	1.000	3.952	419.586
1993	3985.721	24190.477	20644.902	8524.242	204.000	27.552	4.272	1.000	4.110	436.370
1994	3995.820	24207.707	20664.512	8535.035	206.500	27.552	4.272	1.000	4.274	453.824
1995	4003.411	24220.633	20679.230	8543.141	212.600	27.552	4.272	1.000	4.445	471.977

	31	32	33	34	35	36	37	38
	PGASREG	PEXPORTG	GASMAX73	POILUS	GCOSPRO	OILMAX74	OILPROLD	EXCAPGAS
1974	82.000	52.000	6.613	10.624	46.247	1802.000	1802.000	0.0
1975	100.000	123.340	6.482	12.687	50.000	1812.000	1793.880	0.0
1976	133.027	166.670	6.323	13.744	50.000	1731.000	1696.553	0.0
1977	164.140	194.000	6.102	14.294	50.000	1616.000	1568.003	0.0
1978	193.618	223.100	5.885	14.865	65.000	1486.000	1427.445	0.0
1979	224.686	251.994	5.660	15.460	65.000	1335.000	1269.571	0.0
1980	254.212	262.074	5.430	16.078	65.000	1181.000	1111.888	0.0
1981	272.557	272.557	5.203	16.722	65.000	1035.000	964.687	0.0
1982	283.459	283.459	4.968	17.390	65.000	905.000	835.083	0.058
1983	294.797	294.797	4.674	18.086	65.000	791.000	722.592	0.0
1984	306.589	306.589	4.348	18.809	65.000	693.000	626.736	0.0
1985	318.852	318.852	3.963	19.562	65.000	609.000	545.260	0.0
1986	331.606	331.606	3.530	20.344	65.000	537.000	475.988	0.0
1987	344.870	344.870	3.056	21.158	65.000	474.000	415.945	0.028
1988	358.665	358.665	2.574	22.004	65.000	420.000	364.873	0.0
1989	373.011	373.011	2.158	22.885	65.000	373.000	320.801	0.0
1990	387.931	387.932	1.781	23.800	65.000	332.000	282.684	0.236
1991	403.448	403.449	1.488	24.752	65.000	297.000	250.354	0.200
1992	419.586	419.586	1.239	25.742	65.000	266.000	221.980	0.127
1993	436.370	436.370	1.027	26.772	65.000	238.000	196.628	0.012
1994	453.824	453.824	0.852	27.842	65.000	214.000	175.032	0.131
1995	471.977	471.977	0.697	28.956	65.000	186.000	150.609	0.272

6. The Sensitivity and Policy Experiments

6.A Description of Sensitivity and Policy Experiments

In this section we will explain in detail the modifications made to the model in order to generate the results reported in the next section. First the modifications used to generate the six sensitivity experiments will be explained; and then the adjustments used to generate the eight policy experiments will be outlined. All of the adjustments are relative to the values used to generate the control solution.

In general, the first three sensitivity experiments involve different assumptions about the growth of real GNE, the next two experiments involve different assumptions about the price of offshore crude oil, and the last experiment involves adjusting the efficiency conversion factors for oil and gas. The first experiment assumes that in the post-1975 period the rate of growth of UGNE is 4.5%. The second and third experiments assume that the post-1981 growth of UGNE is 3.6% per year, and 5.2% per year respectively. The fourth experiment assumes that the post-1980 price of offshore crude oil remains at its nominal 1980 level. The fifth experiment assumes that the post-1981 nominal price of offshore crude oil grows at 10% per annum. The last experiment assumes that the efficiency factors for oil and gas in the non-thermal markets increase by .5% per annum.

In general, the first two policy experiments involve modifying the price of natural gas and crude oil; the next four experiments involve altering the export flow of natural gas and crude oil; the last two experiments invclve changing the Sarnia-Montreal pipeline flow. The first policy experiment reduces by 15% the wellhead price of natural gas in B.C. and sets the coefficient A(1860), which adjusts the Toronto regulated price, to .85. This later effect binds only after 1976. The second policy experiment reduces by 15% the wellhead price of crude oil in the Prairie region. The third policy experiment reduces the export flow of natural gas by 10%; and the fourth policy experiment increases the export flow of natural gas by 10%. The fifth policy experiment increases the export flow of crude oil by 250 Mbbl/d, and sets the Sarnia-Montreal pipeline eastward flow (coefficient A(1941)) to zero after 1976. The sixth policy experiment reduces the export flow of crude oil to zero after 1975, and increases the Sarnia-Montreal pipeline flow to 350 Mbbl/d after 1976. The seventh policy experiment reduces to zero the eastward flow through the Sarnia-Montreal pipeline, and the last policy experiment increases to 350 Mbbl/d the eastward flow through the Sarnia-Montreal pipeline after 1976.

6.B Results of the Sensitivity and Policy Experiments

All of the variables in the following tables are reported in both 'shock minus control' format and 'percentage shock minus control' format. The 'shock' results are generated from the experiment, and the 'control' results are those reported in appendix 5.B. The percentage results are reported because in most instances they express quite well the relative size of the shock. However, I find the percentage results misleading in the case of the following variables: OILPIPEM, GFSUBO, TXOIL, and XBALGO$. Arbitrarily, the percentage result was set to 0.0 when the control result was zero, as is the case for GFSUBO after 1980.

Only a selected subset of the model variables are displayed in the following tables. The regional prices and quantities of crude oil, natural gas and electricity are reported for Ontario only. The Ontario region was chosen partly because it is the largest energy region in Canada, and because significant quantities of all fuels are used. The other variables attempt to portray the Canadian demand for and expenditure on energy fuels, the production of and taxable income from oil and gas, the Sarnia-Montreal pipeline flow and oil imports, the federal government subsidy payments and oil export tax receipts, the current account balance for oil and gas, and the rents accruing to the participants in gas and oil production. All of the rents are reported as a net present value, as of the end of 1976.

	PO.CN	PG.ON	PL.CN	QO.ON	OG.ON	OL.CN	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	-4.129	-4.179	-2.596	-96.547	-21.163	-12.557	-7.713
1977	0.0	0.0	0.0	-8.189	-8.216	-5.300	-227.496	-41.202	-24.893	-15.733
1978	0.0	0.0	0.0	-12.378	-12.420	-8.011	-394.215	-62.466	-37.652	-23.837
1979	0.0	0.0	0.0	-16.738	-16.860	-10.713	-604.172	-64.874	-51.200	-31.930
1980	0.0	0.0	0.0	-21.403	-21.784	-13.350	-859.457	-83.223	-66.152	-39.862
1981	0.0	0.0	0.0	-25.933	-26.541	-16.579	-1098.813	-101.210	-80.171	-49.483
1982	0.0	0.0	0.0	-26.381	-27.750	-17.180	-1178.426	-103.461	-83.526	-51.386
1983	0.0	0.0	0.0	-27.298	-29.262	-17.956	-1279.590	-107.409	-87.595	-53.814
1984	0.0	0.0	0.0	-28.485	-30.936	-18.832	-1395.801	-112.197	-92.060	-56.518
1985	0.0	0.0	0.0	-29.766	-32.649	-19.754	-1522.684	-117.305	-96.606	-59.346
1986	0.0	0.0	0.0	-31.131	-34.402	-20.721	-1661.059	-129.256	-101.242	-62.298
1987	0.0	0.0	0.0	-32.580	-36.208	-21.734	-1812.043	-142.707	-105.996	-65.387
1988	0.0	0.0	0.0	-34.116	-38.076	-22.796	-1976.805	-156.647	-110.898	-68.621
1989	0.0	0.0	0.0	-35.737	-40.013	-23.910	-2156.551	-171.216	-115.965	-72.006
1990	0.0	0.0	0.0	-37.449	-42.030	-25.079	-2352.742	-186.515	-121.221	-75.556
1991	0.0	0.0	0.0	-39.250	-44.132	-26.304	-2566.770	-202.609	-126.681	-79.275
1992	0.0	0.0	0.0	-41.146	-46.326	-27.590	-2800.305	-212.945	-132.363	-83.173
1993	0.0	0.0	0.0	-43.139	-48.618	-28.937	-3055.098	-222.131	-138.286	-87.259
1994	0.0	0.0	0.0	-45.232	-51.017	-30.351	-3333.105	-231.984	-144.464	-91.545
1995	0.0	0.0	0.0	-47.431	-53.527	-31.833	-3636.387	-242.428	-150.910	-96.037

	OBTU	GASPRO	YGASNFT	CILPRC	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGO$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	-31.368	-0.045	-8.734	-8.781	-22.326	0.0	-10.212	-15.714	0.0	48.458
1977	-62.860	-0.091	-26.593	-17.118	-53.664	0.0	-19.905	-21.079	0.0	98.229
1978	-95.349	-0.136	-52.875	-25.693	-93.484	0.0	-30.121	-20.290	0.0	154.588
1979	-129.215	-0.185	-90.531	-34.629	-143.344	0.0	-29.903	-8.764	0.0	159.607
1980	-165.231	-0.240	-139.797	-44.318	-202.566	0.0	-38.222	0.0	0.0	212.168
1981	-201.990	-0.290	-184.336	-53.587	-253.793	0.0	-46.524	0.0	0.0	268.583
1982	-208.868	-0.302	-200.094	-54.418	-267.133	0.0	-47.707	0.0	0.0	286.427
1983	-218.551	-0.317	-217.938	-56.203	-285.754	0.0	-49.687	0.0	0.0	310.247
1984	-229.637	-0.333	-237.840	-58.543	-308.578	0.0	-51.980	0.0	0.0	337.551
1985	-241.168	-0.350	-259.227	-51.577	-281.293	9.505	-63.910	0.0	0.0	431.625
1986	-253.164	-0.367	-282.449	12.874	75.121	76.673	-137.229	0.0	0.0	963.863
1987	-265.676	-0.384	-308.184	12.874	78.523	79.575	-147.077	0.0	0.0	1074.344
1988	-278.742	-0.402	-334.160	12.874	82.051	82.658	-157.340	0.0	0.0	1195.289
1989	-292.398	-0.420	-363.043	12.874	85.648	85.921	-168.100	0.0	0.0	1328.113
1990	-306.688	-0.439	-396.078	23.646	160.254	100.143	-190.193	0.0	0.0	1562.770
1991	-321.648	-0.459	-431.160	27.583	193.492	107.716	-206.045	0.0	0.0	1760.742
1992	-337.305	-0.480	-469.750	30.929	224.719	114.893	-218.310	0.0	0.0	1940.168
1993	-353.707	-0.441	-449.168	45.625	341.133	133.620	-241.463	0.0	0.0	2231.773
1994	-370.898	0.059	66.887	38.781	301.859	131.015	-243.618	0.0	0.0	2341.762
1995	-388.906	0.086	99.555	32.964	266.970	129.650	-247.308	0.0	0.0	2472.324

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-853.156	-1549.285	-886.789	-277.402	-308.516	-76.586	0.0

	KRCILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-618.586	-923.742	-388.675	-286.156	-138.086	-110.777

SENSITIVITY EXPERIMENT 1: THE POST-1975 GROWTH IN REAL GNE IS SET TO 4.5% PER YEAR
VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	PO.CN	PG.ON	PL.CN	QO.ON	QG.ON	QL.ON	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	-0.925	-0.925	-0.925	-0.928	-1.307	-1.152	-0.926
1977	0.0	0.0	0.0	-1.841	-1.841	-1.841	-1.847	-2.543	-2.282	-1.845
1978	0.0	0.0	0.0	-2.749	-2.749	-2.749	-2.758	-3.844	-3.399	-2.754
1979	0.0	0.0	0.0	-3.648	-3.648	-3.648	-3.660	-3.956	-4.520	-3.655
1980	0.0	0.0	0.0	-4.539	-4.539	-4.539	-4.553	-4.929	-5.649	-4.547
1981	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-5.883	-6.725	-5.431
1982	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-5.874	-6.682	-5.431
1983	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-5.857	-6.617	-5.431
1984	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-5.839	-6.550	-5.431
1985	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-5.822	-6.491	-5.431
1986	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-6.098	-6.438	-5.431
1987	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-6.395	-6.389	-5.431
1988	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-6.668	-6.345	-5.431
1989	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-6.922	-6.303	-5.431
1990	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-7.163	-6.265	-5.431
1991	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-7.392	-6.228	-5.431
1992	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-7.380	-6.194	-5.431
1993	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-7.314	-6.161	-5.431
1994	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-7.258	-6.131	-5.431
1995	0.0	0.0	0.0	-5.422	-5.422	-5.422	-5.439	-7.207	-6.101	-5.431

	OBTU	GASPRO	YGASNFT	CILPRC	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGO$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	-0.870	-0.644	-0.435	-0.618	-0.627	0.0	-1.459	-1.302	0.0	7.295
1977	-1.729	-1.255	-0.967	-1.185	-1.200	0.0	-3.611	-3.145	0.0	9.201
1978	-2.577	-1.855	-1.513	-1.983	-2.005	0.0	-5.493	-4.805	0.0	26.241
1979	-3.416	-2.502	-2.133	-2.947	-2.976	0.0	-5.420	-4.777	0.0	55.757
1980	-4.247	-3.141	-2.852	-3.998	-4.035	0.0	-6.680	0.0	0.0	-175.161
1981	-5.067	-3.760	-3.486	-4.987	-5.033	0.0	-7.918	0.0	0.0	-65.633
1982	-5.065	-4.000	-3.737	-5.076	-5.126	0.0	-7.837	0.0	0.0	-27.806
1983	-5.067	-4.064	-3.800	-5.442	-5.495	0.0	-7.709	0.0	0.0	-22.175
1984	-5.071	-4.124	-3.861	-5.722	-5.781	0.0	-7.576	0.0	0.0	-18.836
1985	-5.074	-4.163	-3.903	-5.249	-5.299	5.072	-8.062	0.0	0.0	-16.310
1986	-5.077	-4.314	-4.060	1.386	1.445	55.744	-15.374	0.0	0.0	-25.954
1987	-5.080	-4.558	-4.325	1.460	1.538	88.672	-14.800	0.0	0.0	-21.158
1988	-5.083	-4.596	-4.355	1.529	1.625	534.251	-13.997	0.0	0.0	-19.000
1989	-5.086	-4.721	-4.486	1.591	1.705	-120.035	-13.234	0.0	0.0	-16.742
1990	-5.089	-5.323	-5.159	3.069	3.236	-61.543	-13.361	0.0	0.0	-14.357
1991	-5.091	-5.496	-5.361	3.877	4.091	-38.061	-12.805	0.0	0.0	-13.262
1992	-5.094	-5.612	-5.502	4.680	4.944	-28.847	-12.175	0.0	0.0	-12.354
1993	-5.097	-4.975	-4.877	7.589	7.980	-25.136	-12.081	0.0	0.0	-12.219
1994	-5.099	0.692	0.726	7.075	7.495	-19.789	-11.048	0.0	0.0	-11.066
1995	-5.102	1.056	1.088	6.668	7.125	-16.262	-10.219	0.0	0.0	-10.234

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-2.167	-3.009	-9.244	-1.270	-4.011	-0.984	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$

CONSUMPTION EXPENDITURE BY THE POST-1981 GROWTH IN REAL GNE IS SET TO 3.6% PER YEAR
VALUES ARE SHOCK - CONTROL

	PC.CN	PG.ON	PL.CN	QC.CN	QG.ON	QL.CN	TOT$	OBTU.O	OBTU.G	OBTU.I
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	-4.538	-4.773	-2.955	-202.703	-17.778	-14.316	-8.838
1983	0.0	0.0	0.0	-9.347	-10.020	-6.148	-438.172	-36.755	-29.924	-18.427
1984	0.0	0.0	0.0	-14.563	-15.816	-9.627	-713.613	-57.337	-46.998	-28.895
1985	0.0	0.0	0.0	-20.195	-22.151	-13.403	-1033.113	-79.570	-65.491	-40.265
1986	0.0	0.0	0.0	-26.279	-29.040	-17.491	-1402.195	-110.119	-85.434	-52.589
1987	0.0	0.0	0.0	-32.851	-36.508	-21.914	-1827.074	-143.773	-106.878	-65.929
1988	0.0	0.0	0.0	-39.946	-44.583	-26.692	-2314.598	-179.650	-129.890	-80.347
1989	0.0	0.0	0.0	-47.603	-53.298	-31.849	-2872.469	-218.029	-154.550	-95.912
1990	0.0	0.0	0.0	-55.858	-62.691	-37.407	-3509.117	-259.137	-180.941	-112.694
1991	0.0	0.0	0.0	-64.750	-72.802	-43.393	-4234.039	-303.192	-209.167	-130.772
1992	0.0	0.0	0.0	-74.323	-83.678	-49.835	-5057.801	-350.416	-239.336	-150.229
1993	0.0	0.0	0.0	-84.614	-95.362	-56.758	-5991.824	-401.011	-271.552	-171.145
1994	0.0	0.0	0.0	-95.674	-107.910	-64.197	-7049.332	-455.218	-305.951	-193.621
1995	0.0	0.0	0.0	-107.547	-121.371	-72.180	-8244.344	-513.255	-342.648	-217.745

	OBTU	GASPRO	YGASNFT	OILPRC	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBAIGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	-35.927	-0.052	-35.086	-9.353	-46.023	0.0	-8.204	0.0	0.0	49.255
1983	-74.836	-0.108	-74.563	-19.234	-98.098	0.0	-17.012	0.0	0.0	106.223
1984	-117.402	-0.170	-120.758	-29.920	-158.328	0.0	-26.573	0.0	0.0	172.563
1985	-163.629	-0.237	-174.777	-20.263	-111.156	21.172	-58.084	0.0	0.0	392.277
1986	-213.707	-0.309	-237.012	0.829	4.781	54.682	-106.358	0.0	0.0	747.031
1987	-267.879	-0.387	-310.691	0.829	5.105	68.084	-136.080	0.0	0.0	994.016
1988	-326.375	-0.470	-388.887	0.829	5.434	82.544	-167.914	0.0	0.0	1275.621
1989	-389.469	-0.560	-480.641	0.829	5.766	98.142	-202.083	0.0	0.0	1596.605
1990	-457.434	-0.656	-589.922	0.829	6.090	114.948	-238.774	0.0	0.0	1961.953
1991	-530.578	-0.761	-715.680	3.635	25.586	135.853	-280.984	0.0	0.0	2401.125
1992	-609.234	-0.868	-851.555	6.020	43.504	157.718	-325.680	0.0	0.0	2894.398
1993	-693.730	-0.923	-944.809	11.444	84.961	184.084	-376.506	0.0	0.0	3479.945
1994	-784.453	-0.425	-443.715	9.728	75.160	204.870	-423.497	0.0	0.0	4070.836
1995	-881.746	0.0	16.508	8.269	66.453	227.564	-474.250	0.0	0.0	4741.039

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-643.465	-1211.324	-723.391	-237.539	-250.414	0.0	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-99.227	-152.461	-67.749	-49.926	-34.734	0.0

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	PO.ON	PG.ON	PL.CN	QO.ON	QG.CN	QL.CN	TOT$	OBTU.O	OBTU.G	OBTU.I
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	-0.933	-0.933	-0.933	-0.936	-1.009	-1.145	-0.934
1983	0.0	0.0	0.0	-1.857	-1.857	-1.857	-1.862	-2.004	-2.260	-1.860
1984	0.0	0.0	0.0	-2.772	-2.772	-2.772	-2.781	-2.984	-3.344	-2.777
1985	0.0	-0.0	0.0	-3.679	-3.679	-3.679	-3.690	-3.949	-4.400	-3.685
1986	0.0	0.0	0.0	-4.577	-4.577	-4.577	-4.591	-5.195	-5.433	-4.585
1987	0.0	0.0	0.0	-5.467	-5.467	-5.467	-5.484	-6.443	-6.442	-5.476
1988	0.0	0.0	0.0	-6.349	-6.349	-6.349	-6.369	-7.647	-7.431	-6.359
1989	0.0	0.0	0.0	-7.222	-7.222	-7.222	-7.245	-8.815	-8.400	-7.234
1990	0.0	0.0	0.0	-8.088	-8.088	-8.088	-8.113	-9.952	-9.351	-8.101
1991	0.0	0.0	0.0	-8.945	-8.945	-8.945	-8.972	-11.061	-10.283	-8.959
1992	0.0	0.0	0.0	-9.794	-9.794	-9.794	-9.824	-12.145	-11.199	-9.810
1993	0.0	0.0	0.0	-10.635	-10.635	-10.635	-10.668	-13.204	-12.099	-10.653
1994	0.0	0.0	0.0	-11.469	-11.469	-11.469	-11.504	-14.242	-12.984	-11.487
1995	0.0	0.0	0.0	-12.295	-12.295	-12.294	-12.332	-15.258	-13.853	-12.314

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	-0.871	-0.686	-0.655	-0.873	-0.883	0.0	-1.348	0.0	0.0	-4.782
1983	-1.735	-1.389	-1.300	-1.862	-1.887	0.0	-2.639	0.0	0.0	-7.592
1984	-2.592	-2.105	-1.960	-2.925	-2.966	0.0	-3.873	0.0	0.0	-9.629
1985	-3.443	-2.822	-2.631	-2.062	-2.094	11.297	-7.327	0.0	0.0	-14.823
1986	-4.286	-3.640	-3.406	0.089	0.092	39.755	-11.915	0.0	0.0	-20.116
1987	-5.122	-4.596	-4.360	0.094	0.100	75.867	-13.694	0.0	0.0	-19.576
1988	-5.952	-5.383	-5.068	0.098	0.108	533.519	-14.937	0.0	0.0	-20.277
1989	-6.774	-6.292	-5.940	0.102	0.115	-137.107	-15.909	0.0	0.0	-20.127
1990	-7.590	-7.946	-7.683	0.108	0.123	-70.641	-16.774	0.0	0.0	-18.024
1991	-8.399	-9.118	-8.899	0.511	0.541	-48.003	-17.462	0.0	0.0	-18.085
1992	-9.201	-10.151	-9.974	0.911	0.957	-39.599	-18.163	0.0	0.0	-18.430
1993	-9.996	-10.415	-10.258	1.904	1.987	-34.629	-18.838	0.0	0.0	-19.052
1994	-10.785	-4.972	-4.815	1.775	1.866	-30.944	-19.205	0.0	0.0	-19.236
1995	-11.567	0.0	0.180	1.673	1.773	-28.543	-19.596	0.0	0.0	-19.624

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-1.634	-2.353	-7.541	-1.088	-3.255	0.0	0.0

	KRCILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-0.170	-0.252	-2.452	-0.128	-0.514	0.0

VALUES ARE SHOCK - CONTROL

	PC.CN	PG.ON	PL.ON	QO.ON	QG.CN	QL.CN	TCT$	OBTU.O	OBTU.G	OBTU.I
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	3.532	3.716	2.300	157.785	13.834	11.134	6.880
1983	0.0	0.0	0.0	7.335	7.863	4.825	343.867	28.830	23.444	14.461
1984	0.0	0.0	0.0	11.523	12.515	7.618	564.730	52.613	37.112	22.866
1985	0.0	0.0	0.0	16.113	17.674	10.693	824.395	83.647	52.127	32.128
1986	0.0	0.0	0.0	21.143	23.365	14.073	1128.297	110.159	68.552	42.314
1987	0.0	0.0	0.0	26.650	29.617	17.778	1482.434	137.951	86.455	53.489
1988	0.0	0.0	0.0	32.676	36.468	21.834	1893.695	168.372	105.924	65.730
1989	0.0	0.0	0.0	39.262	43.959	26.268	2369.680	201.552	127.061	79.116
1990	0.0	0.0	0.0	46.453	52.136	31.109	2919.055	237.692	149.977	93.734
1991	0.0	0.0	0.0	54.296	61.049	36.387	3551.449	277.001	174.794	109.676
1992	0.0	0.0	0.0	62.838	70.749	42.135	4277.617	319.703	201.639	127.037
1993	0.0	0.0	0.0	72.136	81.299	48.388	5109.914	366.059	230.668	145.932
1994	0.0	0.0	0.0	82.240	92.757	55.183	6061.648	416.320	262.017	166.466
1995	0.0	0.0	0.0	93.214	105.195	62.561	7148.375	470.781	295.864	188.765

	CBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	27.965	0.040	27.289	7.279	35.816	0.0	6.386	0.0	0.0	-38.344
1983	58.734	0.085	58.012	15.089	77.004	0.0	13.349	0.0	0.0	-83.349
1984	92.906	0.134	95.301	8.086	42.820	-15.578	40.593	0.0	0.0	-263.605
1985	130.566	0.189	138.953	2.518	13.797	-30.525	71.065	0.0	0.0	-479.945
1986	171.965	0.248	189.828	1.180	6.641	-42.124	95.570	0.0	0.0	-671.258
1987	217.344	0.313	250.715	1.180	6.836	-53.348	120.254	0.0	0.0	-878.414
1988	267.016	0.382	314.758	1.180	7.027	-65.620	147.269	0.0	0.0	-1118.781
1989	321.277	0.460	393.594	1.180	7.246	-79.026	176.759	0.0	0.0	-1396.527
1990	380.492	0.543	487.379	1.180	7.469	-93.659	208.909	0.0	0.0	-1716.563
1991	445.012	0.633	593.172	-1.004	-7.211	-111.797	246.107	0.0	0.0	-2103.086
1992	515.230	0.629	614.125	-2.860	-20.652	-131.025	286.039	0.0	0.0	-2542.102
1993	591.578	0.0	-15.238	-2.832	-21.273	-149.902	327.394	0.0	0.0	-3026.016
1994	674.488	0.0	-14.641	-2.407	-18.886	-170.019	371.885	0.0	0.0	-3574.723
1995	764.469	0.0	-14.109	-2.046	-16.793	-191.964	420.243	0.0	0.0	-4201.137

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGF$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	416.293	789.055	474.855	154.973	159.223	0.0	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	57.734	88.162	38.787	29.297	20.098	0.0

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	PO.ON	PG.ON	PL.CN	QO.ON	QG.ON	QL.CN	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	0.726	0.726	0.726	0.728	0.785	0.891	0.727
1983	0.0	0.0	0.0	1.457	1.457	1.457	1.462	1.572	1.771	1.459
1984	0.0	0.0	0.0	2.194	2.193	2.194	2.201	2.738	2.641	2.197
1985	0.0	0.0	0.0	2.935	2.935	2.935	2.945	4.152	3.502	2.940
1986	0.0	0.0	0.0	3.683	3.683	3.683	3.695	5.197	4.359	3.689
1987	0.0	0.0	0.0	4.435	4.435	4.435	4.450	6.182	5.211	4.443
1988	0.0	0.0	0.0	5.193	5.193	5.193	5.210	7.167	6.060	5.202
1989	0.0	0.0	0.0	5.957	5.957	5.957	5.977	8.149	6.906	5.967
1990	0.0	0.0	0.0	6.726	6.726	6.726	6.748	9.129	7.751	6.738
1991	0.0	0.0	0.0	7.501	7.501	7.501	7.526	10.106	8.594	7.514
1992	0.0	0.0	0.0	8.281	8.281	8.281	8.309	11.080	9.435	8.296
1993	0.0	0.0	0.0	9.067	9.067	9.067	9.098	12.053	10.277	9.083
1994	0.0	0.0	0.0	9.858	9.858	9.858	9.892	13.025	11.119	9.876
1995	0.0	0.0	0.0	10.656	10.656	10.656	10.693	13.995	11.962	10.675

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XRALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.678	0.533	0.510	0.679	0.687	0.0	1.049	0.0	0.0	3.722
1983	1.362	1.088	1.012	1.461	1.481	0.0	2.071	0.0	0.0	5.957
1984	2.051	1.663	1.547	0.790	0.802	-6.231	5.916	0.0	0.0	14.709
1985	2.747	2.247	2.092	0.256	0.260	-16.288	8.965	0.0	0.0	18.136
1986	3.449	2.921	2.728	0.127	0.128	-30.626	10.707	0.0	0.0	18.075
1987	4.156	3.714	3.518	0.134	0.134	-59.446	12.101	0.0	0.0	17.300
1988	4.869	4.371	4.102	0.140	0.139	-424.129	13.101	0.0	0.0	17.784
1989	5.588	5.174	4.864	0.146	0.144	110.402	13.916	0.0	0.0	17.605
1990	6.313	6.587	6.348	0.153	0.151	57.558	14.676	0.0	0.0	15.769
1991	7.044	7.579	7.376	-0.141	-0.152	39.503	15.295	0.0	0.0	15.840
1992	7.781	7.361	7.193	-0.433	-0.454	32.897	15.952	0.0	0.0	16.187
1993	8.524	0.0	-0.165	-0.471	-0.498	28.199	16.381	0.0	0.0	16.567
1994	9.273	0.0	-0.159	-0.439	-0.469	25.680	16.865	0.0	0.0	16.892
1995	10.029	0.0	-0.154	-0.414	-0.448	24.077	17.365	0.0	0.0	17.390

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	1.057	1.533	4.950	0.710	2.070	0.0	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	0.099	0.146	1.404	0.075	0.297	0.0

VALUES ARE SHOCK - CONTROL

	PO.CN	PG.ON	PL.CN	QO.CN	QG.ON	QL.CN	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	-0.221	-0.129	0.0	8.189	9.220	-5.704	-385.746	31.852	20.655	-15.406
1982	-0.451	-0.264	0.0	16.307	20.905	-9.770	-766.348	66.460	48.984	-26.187
1983	-0.690	-0.404	0.0	24.746	35.790	-12.185	-1148.129	106.383	87.515	-32.156
1984	-0.939	-0.550	0.0	33.903	53.576	-13.879	-1563.777	151.504	135.484	-36.138
1985	-1.198	-0.701	0.0	43.927	73.630	-15.721	-2038.109	202.059	191.074	-40.432
1986	-1.467	-0.858	0.0	54.863	96.067	-17.739	-2580.367	251.827	254.859	-45.143
1987	-1.747	-1.022	0.0	66.777	121.054	-19.958	-3200.094	306.622	327.631	-50.356
1988	-2.038	-1.192	0.0	79.743	148.795	-22.395	-3907.086	368.009	410.378	-56.128
1989	-2.340	-1.370	0.0	93.839	179.519	-25.069	-4711.859	436.457	504.278	-62.507
1990	-2.655	-1.554	0.0	109.147	213.486	-27.998	-5626.082	512.538	610.684	-69.543
1991	-2.983	-1.745	0.0	125.749	250.978	-31.200	-6662.684	596.875	731.134	-77.290
1992	-3.323	-1.945	0.0	143.728	292.298	-34.698	-7836.137	690.152	867.379	-85.809
1993	-3.677	-2.152	0.0	163.177	337.789	-38.512	-9162.305	793.114	1021.443	-95.161
1994	-4.045	-2.367	0.0	184.184	387.810	-42.666	-10659.047	906.556	1195.621	-105.420
1995	-4.428	-2.591	0.0	206.846	442.755	-47.185	-12346.043	1039.264	1392.568	-116.658

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GPSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	36.607	0.076	-249.941	18.689	-154.066	0.0	14.044	0.0	0.000	-61.641
1982	84.840	0.179	-483.926	37.293	-318.848	0.0	30.097	0.0	0.000	-88.649
1983	148.512	0.320	-750.676	56.877	-464.813	0.0	49.409	0.0	-0.000	-118.320
1984	225.230	0.494	-1042.422	7.218	-933.219	-71.228	142.568	0.0	-0.000	-530.659
1985	311.906	0.697	-1372.844	8.011	-1147.641	-94.350	190.201	0.0	-0.000	-584.147
1986	409.023	0.929	-1683.676	6.673	-1340.394	-122.081	241.576	0.0	-0.000	-561.985
1987	517.344	1.193	-1957.250	6.673	-1518.771	-151.131	296.564	0.0	-0.000	-426.973
1988	637.895	1.494	-2382.191	6.673	-1696.553	-183.059	357.538	0.0	-0.000	-290.309
1989	771.867	1.277	-3030.152	6.673	-1875.586	-218.115	424.955	0.0	-0.000	0.422
1990	920.582	1.563	-3107.602	1.067	-2051.227	-262.158	504.926	0.0	-0.000	728.797
1991	1085.535	1.150	-3839.273	-3.673	-2145.898	-308.984	591.539	0.0	-0.000	1368.836
1992	1268.352	0.629	-4689.680	-8.740	-2239.313	-360.060	686.577	0.0	-0.000	2084.320
1993	1470.883	0.000	-5681.035	-7.830	-2250.071	-409.375	784.374	0.0	-0.000	2941.469
1994	1695.176	0.000	-6015.656	-6.656	-2252.283	-462.944	891.313	0.0	-0.000	3994.004
1995	1943.531	0.000	-6284.902	-5.657	-2220.034	-521.527	1012.914	0.0	-0.000	5121.625

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-5464.141	-8925.898	-4409.891	-2349.211	-2166.781	-0.008	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-3559.195	-5264.234	-2172.094	-1858.051	-1234.145	0.0

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	PO.CN	PG.CN	PL.CN	QO.CN	QG.CN	QL.CN	TCT$	OBTU.O	OBTU.G	OBTU.L
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	-3.846	-3.846	0.0	1.712	1.884	-1.866	-1.909	1.852	1.732	-1.691
1982	-7.544	-7.544	0.0	3.352	4.085	-3.083	-3.537	3.773	3.919	-2.768
1983	-11.100	-11.100	0.0	4.915	6.632	-3.679	-4.880	5.801	6.611	-3.245
1984	-14.519	-14.519	0.0	6.454	9.390	-3.996	-6.094	7.884	9.640	-3.473
1985	-17.807	-17.807	0.0	8.002	12.228	-4.315	-7.280	10.029	12.838	-3.700
1986	-20.968	-20.968	0.0	9.556	15.141	-4.642	-8.449	11.880	16.206	-3.936
1987	-24.008	-24.008	0.0	11.113	18.128	-4.979	-9.606	13.740	19.749	-4.183
1988	-26.931	-26.931	0.0	12.674	21.189	-5.327	-10.750	15.664	23.479	-4.442
1989	-29.741	-29.741	0.0	14.237	24.326	-5.685	-11.884	17.646	27.410	-4.715
1990	-32.443	-32.443	0.0	15.803	27.541	-6.053	-13.007	19.684	31.559	-4.999
1991	-35.042	-35.042	0.0	17.371	30.836	-6.431	-14.119	21.776	35.945	-5.295
1992	-37.540	-37.540	0.0	18.940	34.212	-6.819	-15.221	23.920	40.588	-5.603
1993	-39.942	-39.942	0.0	20.510	37.672	-7.216	-16.313	26.115	45.511	-5.923
1994	-42.252	-42.252	0.0	22.079	41.217	-7.622	-17.395	28.362	50.738	-6.254
1995	-44.473	-44.473	0.0	23.646	44.850	-8.037	-18.467	30.895	56.301	-6.597

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.918	0.983	-4.726	1.739	-3.055	0.0	2.390	0.0	0.000	15.063
1982	2.057	2.364	-9.039	3.479	-6.118	0.0	4.944	0.0	0.000	8.606
1983	3.443	4.104	-13.089	5.508	-8.939	0.0	7.665	0.0	-0.000	8.457
1984	4.973	6.121	-16.920	0.705	-17.484	-28.491	20.779	0.0	-0.001	29.611
1985	6.562	8.295	-20.669	0.815	-21.618	-50.346	23.994	0.0	-0.001	22.073
1986	8.203	10.928	-24.199	0.718	-25.792	-88.756	27.064	0.0	-0.003	15.133
1987	9.892	14.168	-27.467	0.757	-29.743	-168.406	29.843	0.0	-0.001	8.409
1988	11.632	17.091	-31.044	0.792	-33.592	-1183.189	31.806	0.0	-0.001	4.615
1989	13.425	14.352	-37.446	0.825	-37.332	304.714	33.455	0.0	-0.001	-0.005
1990	15.275	18.941	-40.473	0.138	-41.414	161.109	35.471	0.0	-0.003	-6.695
1991	17.183	13.770	-47.738	-0.516	-45.372	109.178	36.762	0.0	-0.001	-10.310
1992	19.155	7.361	-54.929	-1.322	-49.263	90.402	38.290	0.0	-0.000	-13.272
1993	21.195	0.000	-61.681	-1.302	-52.632	77.009	39.245	0.0	-0.001	-16.104
1994	23.307	0.000	-65.281	-1.214	-55.923	69.923	40.421	0.0	-0.001	-18.873
1995	25.497	0.000	-68.654	-1.144	-59.247	65.413	41.854	0.0	-0.000	-21.200

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-13.878	-17.337	-45.969	-10.759	-28.169	-0.000	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-6.097	-8.694	-78.625	-4.749	-18.263	0.0

SENSITIVITY EXPERIMENT 3: THE NUMBERS THESE CHOSEN UNDER THE MEDIUM

VALUES ARE SHOCK - CONTROL

	PO.CN	PG.ON	PL.CN	QO.ON	QG.CN	QL.CN	TOT$	OBTU.O	OBTU.G	OBTU.I
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.345	0.202	0.0	-11.932	-13.781	8.443	592.102	-46.955	-30.969	22.751
1983	0.738	0.432	0.0	-23.882	-30.928	14.427	1200.563	-95.959	-71.594	38.397
1984	1.185	0.694	0.0	-36.117	-51.554	17.681	1827.891	-132.190	-121.881	46.088
1985	1.692	-0.990	0.0	-49.090	-74.507	19.715	2525.289	-185.641	-178.122	50.343
1986	2.265	1.325	0.0	-63.098	-98.986	21.750	3337.332	-251.118	-237.799	54.361
1987	2.911	1.703	0.0	-78.207	-124.991	23.790	4283.473	-323.153	-300.770	58.191
1988	3.639	2.129	0.0	-94.467	-152.535	25.844	5385.293	-400.744	-366.965	61.873
1989	4.456	2.608	0.0	-111.946	-181.659	27.907	6665.746	-484.187	-436.440	65.381
1990	5.374	3.145	0.0	-130.715	-212.426	29.965	8150.063	-573.777	-509.312	68.662
1991	6.403	3.747	0.0	-150.844	-244.904	32.004	9866.980	-669.797	-585.718	71.658
1992	7.554	4.420	0.0	-172.409	-279.174	34.006	11848.926	-772.546	-665.830	74.303
1993	8.840	5.173	0.0	-195.482	-315.318	35.952	14132.773	-882.321	-749.809	76.525
1994	10.276	6.014	0.0	-220.143	-353.428	37.821	16760.398	-999.438	-837.849	78.243
1995	11.879	6.951	0.0	-246.470	-393.596	39.586	19779.188	-1124.221	-930.137	79.368

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GPSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	-53.463	-0.114	367.098	-27.218	227.977	0.0	-20.690	0.0	0.000	71.420
1983	-122.512	-0.264	778.234	-54.518	447.141	0.0	-37.590	0.0	0.0	95.805
1984	-209.125	-0.450	1242.867	-82.459	683.324	0.0	-58.961	0.0	0.0	123.979
1985	-307.063	-0.650	1788.730	-52.841	1289.762	59.169	-143.373	0.0	0.0	545.635
1986	-412.219	-0.867	2321.176	-31.409	1862.438	112.454	-228.102	0.0	0.0	918.118
1987	-524.547	-1.096	2804.250	-17.834	2419.375	160.258	-310.539	0.0	0.0	1144.084
1988	-644.105	-1.339	3539.270	7.262	3148.164	222.033	-409.579	0.0	0.0	1582.340
1989	-771.211	-1.590	4251.945	0.132	3622.969	254.153	-481.758	0.0	0.0	1469.305
1990	-906.281	-1.855	4260.453	0.132	4161.133	296.113	-566.718	0.0	0.0	566.289
1991	-1049.773	-2.132	4865.465	8.298	4685.395	349.086	-665.771	0.0	0.0	-18.395
1992	-1202.168	-2.425	5607.176	15.238	5238.027	403.829	-769.824	0.0	0.0	-721.359
1993	-1363.969	-2.671	6722.488	29.196	5812.266	468.725	-887.405	0.0	0.0	-1460.973
1994	-1535.723	-2.366	8440.082	24.465	6097.785	518.222	-993.121	0.0	0.0	-2921.875
1995	-1717.973	-1.874	10821.551	22.904	6353.352	574.334	-1109.143	0.0	0.0	-4505.020

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	7281.402	11605.996	5509.035	3300.277	2796.613	0.008	0.0

	KRCILCAN	KRENTCIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	6287.984	9341.902	3890.382	3262.223	2189.328	0.0

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	PO.ON	PG.ON	PL.ON	QO.ON	QG.ON	QL.ON	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	5.769	5.769	0.0	-2.452	-2.693	2.665	2.733	-2.666	-2.477	2.405
1983	11.871	11.871	0.0	-4.744	-5.731	4.357	5.103	-4.687	-5.406	3.875
1984	18.325	18.325	0.0	-6.875	-9.036	5.091	7.123	-6.879	-8.672	4.429
1985	25.152	25.152	0.0	-8.942	-12.374	5.411	9.020	-9.214	-11.968	4.607
1986	32.372	32.372	0.0	-10.990	-15.601	5.691	10.928	-11.846	-15.121	4.739
1987	40.009	40.009	0.0	-13.015	-18.718	5.935	12.857	-14.481	-18.130	4.833
1988	48.086	48.086	0.0	-15.014	-21.722	6.147	14.818	-17.057	-20.995	4.897
1989	56.629	56.630	0.0	-16.984	-24.616	6.328	16.812	-19.576	-23.722	4.931
1990	65.666	65.666	0.0	-18.926	-27.404	6.479	18.842	-22.036	-26.321	4.936
1991	75.223	75.223	0.0	-20.838	-30.090	6.597	20.909	-24.436	-28.796	4.909
1992	85.332	85.332	0.0	-22.720	-32.676	6.683	23.015	-26.775	-31.157	4.852
1993	96.024	96.024	0.0	-24.571	-35.166	6.737	25.162	-29.053	-33.408	4.763
1994	107.333	107.334	0.0	-26.389	-37.563	6.757	27.351	-31.268	-35.556	4.642
1995	119.295	119.295	0.0	-28.176	-39.870	6.743	29.586	-33.420	-37.605	4.489

	OBTU	GASPRO	YGASNFT	OILPRC	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	-1.296	-1.505	6.857	-2.539	4.375	0.0	-3.399	0.0	0.002	-6.933
1983	-2.840	-3.380	13.570	-5.279	8.599	0.0	-5.832	0.0	0.0	-6.848
1984	-4.618	-5.570	20.174	-8.060	12.802	0.0	-8.593	0.0	0.0	-6.918
1985	-6.460	-7.738	26.930	-5.377	24.295	31.573	-18.087	0.0	0.0	-20.618
1986	-8.267	-10.205	33.361	-3.381	35.837	81.757	-25.554	0.0	0.0	-24.723
1987	-10.030	-13.019	39.354	-2.023	47.380	178.577	-31.249	0.0	0.0	-22.532
1988	-11.746	-15.320	46.122	0.862	62.334	1435.091	-36.435	0.0	0.0	-25.152
1989	-13.414	-17.869	52.545	0.016	72.112	-355.060	-37.927	0.0	0.0	-18.522
1990	-15.037	-22.485	55.488	0.017	84.014	-181.976	-39.812	0.0	0.0	-5.202
1991	-16.617	-25.537	60.498	1.166	99.066	-123.348	-41.375	0.0	0.0	0.139
1992	-18.156	-28.363	65.676	2.306	115.232	-101.392	-42.932	0.0	0.0	4.593
1993	-19.654	-30.125	72.988	4.856	135.956	-88.173	-44.400	0.0	0.0	7.999
1994	-21.114	-27.703	91.591	4.463	151.405	-78.273	-45.038	0.0	0.0	13.807
1995	-22.538	-22.976	118.211	4.633	169.554	-72.037	-45.830	0.0	0.0	18.647

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGF$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	18.493	22.543	57.427	15.115	36.357	0.000	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	10.771	15.429	140.824	8.338	32.398	0.0

VALUES ARE SHOCK - CONTROL

	PO.ON	PG.ON	PL.ON	QO.ON	QG.ON	QL.ON	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	-0.011	-0.005	0.0	0.842	1.077	-0.600	-15.855	2.094	1.927	-1.644
1975	-0.028	-0.012	0.0	1.610	2.319	-0.951	-35.926	4.488	4.546	-2.506
1976	-0.049	-0.024	0.0	2.743	3.741	-1.234	-63.000	7.535	7.868	-3.051
1977	-0.078	-0.040	0.0	3.695	5.197	-1.364	-91.488	10.927	11.790	-3.268
1978	-0.111	-0.059	0.0	4.648	6.761	-1.485	-125.836	14.019	16.015	-3.470
1979	-0.149	-0.082	0.0	5.620	8.429	-1.619	-168.543	20.069	20.560	-3.732
1980	-0.190	-0.108	0.0	6.625	10.300	-1.774	-219.836	23.720	25.575	-4.073
1981	-0.225	-0.132	0.0	7.706	12.239	-1.926	-259.230	27.532	30.664	-4.390
1982	-0.262	-0.154	0.0	8.779	14.548	-2.120	-305.281	31.430	36.804	-4.804
1983	-0.303	-0.177	0.0	10.029	17.161	-2.350	-362.066	35.957	43.771	-5.304
1984	-0.345	-0.202	0.0	11.448	20.068	-2.599	-428.340	41.000	51.517	-5.850
1985	-0.391	-0.229	0.0	13.002	23.228	-2.862	-503.164	46.481	59.914	-6.430
1986	-0.439	-0.257	0.0	14.692	26.647	-3.141	-587.684	45.880	68.978	-7.048
1987	-0.491	-0.287	0.0	16.526	30.339	-3.441	-683.254	51.982	78.752	-7.714
1988	-0.545	-0.319	0.0	18.512	34.324	-3.764	-791.180	58.510	89.279	-8.430
1989	-0.603	-0.353	0.0	20.659	38.621	-4.111	-912.953	65.488	100.610	-9.201
1990	-0.665	-0.389	0.0	22.979	43.254	-4.485	-1050.250	72.985	112.803	-10.031
1991	-0.731	-0.428	0.0	25.482	48.248	-4.885	-1204.781	81.056	125.925	-10.921
1992	-0.800	-0.468	0.0	28.180	53.626	-5.316	-1378.664	89.740	140.034	-11.878
1993	-0.874	-0.511	0.0	31.086	59.418	-5.777	-1574.027	99.089	155.200	-12.904
1994	-0.952	-0.557	0.0	34.213	65.653	-6.272	-1793.410	109.144	171.500	-14.005
1995	-1.035	-0.605	0.0	37.575	72.359	-6.803	-2039.492	119.961	189.009	-15.184

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	4.323	-0.010	-0.449	-2.124	-3.508	0.0	-2.666	-3.673	0.0	9.732
1975	9.481	-0.018	-1.757	-4.288	-9.141	0.0	-4.959	-8.495	0.0	21.720
1976	16.021	-0.025	-4.861	-7.049	-17.919	0.0	-7.351	-11.311	0.0	34.881
1977	22.979	-0.030	-8.687	-8.908	-27.918	0.0	-9.025	-9.557	0.0	44.535
1978	30.283	-0.035	-13.458	-10.956	-39.844	0.0	-10.999	-7.409	0.0	56.449
1979	37.964	-0.040	-19.703	-13.129	-54.316	0.0	-11.594	-3.421	0.0	61.885
1980	46.259	-0.047	-27.395	-15.556	-71.059	0.0	-13.859	0.0	0.0	76.932
1981	54.776	-0.052	-32.922	-17.578	-83.199	0.0	-15.939	0.0	0.0	92.019
1982	64.414	-0.059	-39.082	-19.778	-97.031	0.0	-18.249	0.0	0.0	109.566
1983	75.438	-0.067	-46.234	-22.427	-113.992	0.0	-21.042	0.0	0.0	131.391
1984	87.711	-0.077	-54.578	-25.417	-133.992	0.0	-24.159	0.0	0.0	156.887
1985	101.047	-0.086	-63.922	13.820	76.523	42.433	-69.950	0.0	0.0	472.414
1986	115.461	-0.097	-74.441	12.820	73.879	44.857	-79.583	0.0	0.0	558.973
1987	131.012	-0.108	-86.699	13.107	76.516	48.817	-87.628	0.0	0.0	640.094
1988	147.785	-0.120	-99.336	13.352	83.109	53.003	-96.254	0.0	0.0	731.227
1989	165.859	-0.132	-114.059	13.559	87.703	57.444	-105.517	0.0	0.0	833.664
1990	185.320	-0.146	-131.457	17.908	119.777	66.334	-119.623	0.0	0.0	982.914
1991	206.277	-0.160	-150.605	18.092	125.516	71.386	-130.292	0.0	0.0	1113.398
1992	228.820	-0.176	-172.480	1.902	15.637	60.418	-125.373	0.0	0.0	1114.219
1993	253.074	-0.132	-134.180	1.215	11.027	65.325	-136.780	0.0	0.0	1264.219
1994	279.137	0.018	23.078	1.033	9.916	71.135	-149.575	0.0	0.0	1437.781
1995	307.156	0.022	28.617	0.878	8.959	77.399	-163.333	0.0	0.0	1632.824

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-244.668	-429.492	-235.445	-73.973	-80.840	-39.242	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-212.617	-303.340	-115.443	-86.699	-14.078	-87.020

SENSITIVITY EXPERIMENT 6: THE EFFICIENCY FACTORS FOR OIL AND GAS ARE INCREASED BY 1 PERCENT

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	PC.CN	PG.CN	PL.CN	QC.CN	QG.CN	QL.CN	TOT$	OBTU.C	OBTU.G	OBTU.L
1974	-0.497	-0.497	0.0	0.216	0.246	-0.223	-0.230	0.134	0.182	-0.191
1975	-0.992	-0.992	0.0	0.413	0.521	-0.363	-0.430	0.294	0.429	-0.304
1976	-1.485	-1.485	0.0	0.614	0.828	-0.440	-0.605	0.465	0.722	-0.366
1977	-1.975	-1.975	0.0	0.831	1.165	-0.474	-0.743	0.674	1.081	-0.383
1978	-2.462	-2.463	0.0	1.032	1.496	-0.509	-0.880	0.863	1.446	-0.401
1979	-2.948	-2.948	0.0	1.225	1.824	-0.551	-1.021	1.224	1.815	-0.427
1980	-3.430	-3.430	0.0	1.405	2.146	-0.603	-1.165	1.405	2.184	-0.465
1981	-3.911	-3.911	0.0	1.611	2.500	-0.630	-1.283	1.600	2.572	-0.482
1982	-4.389	-4.389	0.0	1.804	2.842	-0.669	-1.409	1.784	2.944	-0.508
1983	-4.864	-4.864	0.0	1.992	3.180	-0.710	-1.539	1.961	3.306	-0.535
1984	-5.338	-5.338	0.0	2.179	3.517	-0.748	-1.669	2.134	3.665	-0.562
1985	-5.808	-5.808	0.0	2.368	3.858	-0.785	-1.797	2.307	4.026	-0.588
1986	-6.277	-6.277	0.0	2.559	4.200	-0.822	-1.924	2.164	4.386	-0.614
1987	-6.743	-6.743	0.0	2.750	4.543	-0.859	-2.051	2.329	4.747	-0.641
1988	-7.207	-7.207	0.0	2.942	4.888	-0.895	-2.177	2.490	5.108	-0.667
1989	-7.669	-7.669	0.0	3.134	5.233	-0.932	-2.303	2.648	5.469	-0.694
1990	-8.128	-8.128	0.0	3.327	5.580	-0.970	-2.428	2.803	5.829	-0.721
1991	-8.585	-8.585	0.0	3.520	5.928	-1.007	-2.553	2.957	6.191	-0.748
1992	-9.040	-9.040	0.0	3.713	6.277	-1.045	-2.678	3.110	6.553	-0.776
1993	-9.492	-9.492	0.0	3.907	6.627	-1.082	-2.802	3.263	6.915	-0.803
1994	-9.942	-9.942	0.0	4.101	6.978	-1.121	-2.927	3.415	7.278	-0.831
1995	-10.390	-10.390	0.0	4.296	7.330	-1.159	-3.051	3.566	7.642	-0.859

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBAIGC$
1974	0.125	-0.147	-0.120	-0.118	-0.124	0.0	-0.365	-0.327	0.0	0.700
1975	0.275	-0.267	-0.149	-0.277	-0.282	0.0	-0.630	-0.569	0.0	2.105
1976	0.444	-0.357	-0.242	-0.496	-0.503	0.0	-1.050	-0.937	0.0	5.251
1977	0.632	-0.409	-0.316	-0.617	-0.624	0.0	-1.637	-1.426	0.0	4.172
1978	0.818	-0.471	-0.385	-0.845	-0.854	0.0	-2.006	-1.755	0.0	9.582
1979	1.004	-0.544	-0.464	-1.117	-1.128	0.0	-2.101	-1.865	0.0	21.619
1980	1.189	-0.615	-0.559	-1.403	-1.415	0.0	-2.422	0.0	0.0	-63.513
1981	1.374	-0.671	-0.623	-1.636	-1.650	0.0	-2.713	0.0	0.0	-22.486
1982	1.562	-0.780	-0.730	-1.845	-1.862	0.0	-2.998	0.0	0.0	-10.637
1983	1.749	-0.863	-0.806	-2.172	-2.192	0.0	-3.265	0.0	0.0	-9.391
1984	1.937	-0.947	-0.886	-2.484	-2.510	0.0	-3.521	0.0	0.0	-8.754
1985	2.126	-1.028	-0.962	1.406	1.441	22.643	-8.824	0.0	0.0	-17.851
1986	2.316	-1.139	-1.070	1.380	1.422	32.612	-8.916	0.0	0.0	-15.052
1987	2.505	-1.282	-1.217	1.487	1.538	54.397	-8.818	0.0	0.0	-12.606
1988	2.695	-1.371	-1.294	1.585	1.646	342.583	-8.563	0.0	0.0	-11.623
1989	2.885	-1.489	-1.410	1.676	1.746	-80.251	-8.307	0.0	0.0	-10.509
1990	3.075	-1.770	-1.712	2.324	2.418	-40.766	-8.404	0.0	0.0	-9.030
1991	3.265	-1.921	-1.873	2.543	2.654	-25.224	-8.097	0.0	0.0	-8.386
1992	3.456	-2.059	-2.020	0.288	0.344	-15.169	-6.992	0.0	0.0	-7.095
1993	3.647	-1.493	-1.457	0.202	0.258	-12.288	-6.844	0.0	0.0	-6.922
1994	3.838	0.212	0.250	0.188	0.245	-10.744	-6.783	0.0	0.0	-6.794
1995	4.029	0.275	0.313	0.178	0.239	-9.708	-6.749	0.0	0.0	-6.759

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-0.621	-0.834	-2.454	-0.339	-1.051	-0.504	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-0.364	-0.501	-4.179	-0.222	-0.208	-0.731

VALUES ARE SHOCK - CONTROL

	PO.ON	PG.ON	PL.ON	OO.ON	OG.ON	OL.CN	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	0.0	0.0	0.0	0.0	0.0	0.0	-2.656	-0.654	9.744	-0.431
1975	0.0	0.0	0.0	0.0	0.0	0.0	-3.461	-0.697	11.312	-0.454
1976	0.0	0.0	0.0	0.0	0.0	0.0	-4.152	-0.710	13.614	-0.445
1977	0.0	-0.069	0.0	-2.532	13.119	-1.639	-43.000	-5.662	50.906	-2.962
1978	0.0	-0.158	0.0	-4.690	26.854	-3.036	-86.762	-9.996	88.070	-5.128
1979	0.0	-0.266	0.0	-6.617	41.559	-4.235	-136.082	-12.176	126.333	-6.991
1980	0.0	-0.388	0.0	-8.684	57.663	-5.416	-196.500	-15.738	167.286	-8.825
1981	0.0	-0.505	0.0	-10.436	73.817	-6.672	-247.273	-18.775	209.046	-10.758
1982	0.0	-0.525	0.0	-9.823	78.160	-6.397	-247.000	-17.882	221.520	-10.423
1983	0.0	-0.546	0.0	-9.694	83.012	-6.376	-256.891	-17.794	236.210	-10.469
1984	0.0	-0.568	0.0	-9.998	87.910	-6.610	-277.520	-18.425	251.541	-10.893
1985	0.0	-0.590	0.0	-10.489	92.724	-6.961	-304.059	-19.358	266.776	-11.489
1986	0.0	-0.614	0.0	-11.001	97.663	-7.322	-332.680	-24.239	282.361	-12.096
1987	0.0	-0.639	0.0	-11.538	102.759	-7.697	-363.676	-25.208	298.403	-12.722
1988	0.0	-0.664	0.0	-12.100	108.035	-8.085	-397.266	-26.333	314.977	-13.368
1989	0.0	-0.691	0.0	-12.691	113.513	-8.491	-433.777	-27.543	332.160	-14.040
1990	0.0	-0.718	0.0	-13.311	119.217	-8.914	-473.477	-28.820	350.019	-14.739
1991	0.0	-0.747	0.0	-13.959	125.167	-9.355	-516.637	-30.161	368.622	-15.466
1992	0.0	-0.777	0.0	-14.641	131.379	-9.817	-563.660	-31.571	388.018	-16.227
1993	0.0	-0.808	0.0	-15.355	137.874	-10.300	-614.848	-33.049	408.269	-17.020
1994	0.0	-0.840	0.0	-16.105	144.669	-10.807	-670.645	-34.599	429.431	-17.850
1995	0.0	-0.874	0.0	-16.892	151.783	-11.337	-731.438	-36.223	451.557	-18.719

	OBTU	GASPRO	YGASNET	OILPRC	YOILNET	OILPIPEM	OILIMPT	GPSUBO	TXOIL	XBALGO$
1974	7.155	0.035	1.564	-0.598	-0.986	0.0	0.0	0.0	0.0	0.0
1975	8.990	0.041	3.942	-0.639	-1.362	0.0	0.000	0.0	0.0	-0.001
1976	10.711	0.049	9.574	-0.655	-1.666	0.0	-0.000	0.0	0.0	0.001
1977	37.010	0.185	-40.247	-4.822	-15.117	0.0	-0.961	-1.021	0.0	4.741
1978	64.728	0.321	-102.840	-8.264	-30.074	0.0	-1.879	-1.273	0.0	9.646
1979	94.723	0.461	-176.897	-11.249	-46.578	0.0	-1.807	-0.537	0.0	9.647
1980	127.484	0.611	-278.941	-14.452	-66.082	0.0	-2.392	0.0	0.0	13.277
1981	160.012	0.762	-375.770	-17.085	-80.961	0.0	-2.948	0.0	0.0	17.017
1982	172.090	0.808	-396.082	-16.129	-79.215	0.0	-2.870	0.0	0.0	17.232
1983	184.520	0.862	-429.316	-15.947	-81.105	0.0	-2.900	0.0	0.0	18.106
1984	196.219	0.917	-468.375	-16.440	-86.688	0.0	-3.033	0.0	0.0	19.695
1985	207.297	0.973	-518.313	25.180	138.672	42.399	-45.607	0.0	0.0	308.016
1986	218.563	1.029	-560.629	22.998	131.559	41.031	-46.567	0.0	0.0	327.070
1987	230.094	1.087	-601.023	21.910	130.160	40.797	-46.496	0.0	0.0	339.641
1988	241.961	1.146	-657.004	20.614	127.176	40.398	-46.329	0.0	0.0	351.953
1989	254.219	1.210	-709.895	19.141	122.691	39.869	-46.056	0.0	0.0	363.879
1990	266.926	1.275	-757.875	27.107	179.883	48.827	-55.289	0.0	0.0	454.293
1991	280.141	1.133	-967.977	24.374	167.816	47.130	-53.880	0.0	0.0	460.430
1992	293.891	0.588	-1509.660	7.241	52.680	31.089	-38.146	0.0	0.0	339.008
1993	308.234	-0.084	-2185.563	5.753	43.410	30.745	-38.122	0.0	0.0	352.352
1994	323.203	-0.140	-2263.070	4.890	38.121	31.083	-38.795	0.0	0.0	372.918
1995	338.859	-0.211	-2312.500	4.157	33.249	31.611	-39.673	0.0	0.0	396.609

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	4766.996	3799.168	-1232.902	-1439.527	-951.086	7422.590	0.0

	KRCILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-14.336	-17.723	-4.276	1.949	1.766	-17.133

POLICY EXPERIMENT 1: THE REGULATED TORONTO PRICE AND THE BC WELLHEAD PRICE OF NATURAL GAS ARE REDUCED BY 15%
VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	PO.ON	PG.ON	PL.ON	QO.ON	QG.ON	QL.ON	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	0.0	0.0	0.0	0.0	0.0	0.0	-0.038	-0.042	0.922	-0.050
1975	0.0	0.0	0.0	0.0	0.0	0.0	-0.041	-0.046	1.068	-0.055
1976	0.0	0.0	0.0	0.0	0.0	0.0	-0.040	-0.044	1.249	-0.053
1977	0.0	-3.409	0.0	-0.569	2.940	-0.569	-0.349	-0.349	4.667	-0.347
1978	0.0	-6.593	0.0	-1.042	5.944	-1.042	-0.607	-0.615	7.951	-0.592
1979	0.0	-9.574	0.0	-1.442	8.993	-1.442	-0.824	-0.742	11.153	-0.800
1980	0.0	-12.371	0.0	-1.842	12.016	-1.842	-1.041	-0.932	14.285	-1.007
1981	0.0	-15.000	0.0	-2.182	15.080	-2.182	-1.224	-1.091	17.534	-1.181
1982	0.0	-15.000	0.0	-2.019	15.272	-2.019	-1.140	-1.015	17.721	-1.102
1983	0.0	-15.000	0.0	-1.926	15.382	-1.926	-1.092	-0.970	17.843	-1.057
1984	0.0	-15.000	0.0	-1.903	15.408	-1.903	-1.081	-0.959	17.897	-1.047
1985	0.0	-15.000	0.0	-1.911	15.399	-1.911	-1.086	-0.961	17.925	-1.051
1986	0.0	-15.000	0.0	-1.916	15.393	-1.916	-1.089	-1.143	17.955	-1.055
1987	0.0	-15.000	0.0	-1.920	15.388	-1.920	-1.092	-1.130	17.987	-1.057
1988	0.0	-15.000	0.0	-1.923	15.385	-1.923	-1.093	-1.121	18.021	-1.058
1989	0.0	-15.000	0.0	-1.925	15.382	-1.925	-1.094	-1.114	18.054	-1.059
1990	0.0	-15.000	0.0	-1.927	15.380	-1.927	-1.095	-1.107	18.089	-1.059
1991	0.0	-15.000	0.0	-1.928	15.378	-1.928	-1.095	-1.100	18.123	-1.060
1992	0.0	-15.000	0.0	-1.929	15.377	-1.929	-1.095	-1.094	18.157	-1.060
1993	0.0	-15.000	0.0	-1.930	15.376	-1.930	-1.095	-1.088	18.190	-1.059
1994	0.0	-15.000	0.0	-1.931	15.376	-1.931	-1.094	-1.082	18.224	-1.059
1995	0.0	-15.000	0.0	-1.931	15.375	-1.931	-1.094	-1.077	18.256	-1.059

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGO$
1974	0.207	0.512	0.419	-0.033	-0.035	0.0	0.0	0.0	0.0	0.0
1975	0.260	0.598	0.333	-0.041	-0.042	0.0	0.000	0.0	0.0	-0.000
1976	0.297	0.704	0.476	-0.046	-0.047	0.0	-0.000	0.0	0.0	0.000
1977	1.018	2.569	-1.463	-0.334	-0.338	0.0	-0.174	-0.152	0.0	0.444
1978	1.749	4.375	-2.943	-0.638	-0.645	0.0	-0.343	-0.301	0.0	1.637
1979	2.504	6.230	-4.167	-0.957	-0.967	0.0	-0.328	-0.293	0.0	3.370
1980	3.276	7.992	-5.691	-1.304	-1.316	0.0	-0.418	0.0	0.0	-10.961
1981	4.014	9.881	-7.105	-1.590	-1.606	0.0	-0.502	0.0	0.0	-4.158
1982	4.173	10.702	-7.398	-1.505	-1.520	0.0	-0.471	0.0	0.0	-1.673
1983	4.278	11.053	-7.486	-1.544	-1.560	0.0	-0.450	0.0	0.0	-1.294
1984	4.333	11.356	-7.603	-1.607	-1.624	0.0	-0.442	0.0	0.0	-1.099
1985	4.361	11.581	-7.803	2.562	2.612	22.624	-5.754	0.0	0.0	-11.639
1986	4.383	12.113	-8.058	2.476	2.531	29.831	-5.217	0.0	0.0	-8.807
1987	4.400	12.910	-8.435	2.486	2.549	45.460	-4.679	0.0	0.0	-6.689
1988	4.412	13.112	-8.562	2.448	2.518	261.112	-4.121	0.0	0.0	-5.595
1989	4.422	13.598	-8.773	2.366	2.442	-55.698	-3.626	0.0	0.0	-4.587
1990	4.429	15.450	-9.871	3.518	3.632	-30.007	-3.884	0.0	0.0	-4.173
1991	4.434	13.573	-12.036	3.426	3.548	-16.653	-3.348	0.0	0.0	-3.468
1992	4.438	6.872	-17.682	1.096	1.159	-7.806	-2.127	0.0	0.0	-2.159
1993	4.441	-0.944	-23.729	0.957	1.015	-5.784	-1.907	0.0	0.0	-1.929
1994	4.444	-1.643	-24.559	0.892	0.947	-4.695	-1.759	0.0	0.0	-1.762
1995	4.445	-2.585	-25.261	0.841	0.887	-3.965	-1.639	0.0	0.0	-1.642

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	12.107	7.379	-12.852	-6.593	-12.364	95.353	0.0

	KROILCAN	KPENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-0.025	-0.029	-0.155	0.005	0.026	-0.144

VALUES ARE SHOCK - CONTROL

	PO.ON	PG.ON	PL.ON	QO.ON	QG.ON	QL.CN	TOT$	OBTU.O	OBTU.G	OBTU.I
1974	-0.312	0.0	0.0	35.970	-21.960	-11.371	-389.844	100.586	-63.046	-39.857
1975	-0.395	0.0	0.0	33.350	-19.697	-5.454	-421.063	112.129	-53.402	-20.143
1976	-0.465	0.0	0.0	35.512	-18.076	-1.243	-466.422	130.421	-45.242	-6.243
1977	-0.559	0.0	0.0	35.495	-16.574	0.837	-510.492	140.796	-39.836	-0.249
1978	-0.641	0.0	0.0	36.218	-16.569	1.112	-581.922	142.140	-39.671	0.460
1979	-0.723	0.0	0.0	36.923	-16.867	1.251	-670.512	146.827	-40.631	0.569
1980	-0.794	0.0	0.0	37.760	-17.447	1.302	-767.574	150.141	-42.453	0.317
1981	-0.826	0.0	0.0	38.203	-17.478	1.510	-807.824	153.781	-42.424	0.700
1982	-0.859	0.0	0.0	38.854	-17.967	1.716	-854.164	158.167	-43.686	1.050
1983	-0.893	0.0	0.0	40.119	-18.831	1.849	-923.246	165.074	-45.896	1.171
1984	-0.929	0.0	0.0	41.758	-19.888	1.951	-1006.387	173.240	-48.577	1.197
1985	-0.966	0.0	0.0	43.559	-20.966	2.061	-1096.742	182.010	-51.270	1.250
1986	-1.005	0.0	0.0	45.507	-22.061	2.181	-1194.984	185.446	-53.978	1.326
1987	-1.045	0.0	0.0	47.590	-23.192	2.305	-1302.313	196.831	-56.752	1.407
1988	-1.087	0.0	0.0	49.804	-24.367	2.432	-1419.637	208.472	-59.618	1.488
1989	-1.130	0.0	0.0	52.149	-25.590	2.561	-1547.852	220.650	-62.589	1.569
1990	-1.176	0.0	0.0	54.627	-26.866	2.694	-1687.914	233.436	-65.674	1.651
1991	-1.223	0.0	0.0	57.240	-28.198	2.833	-1840.875	246.872	-68.886	1.735
1992	-1.271	0.0	0.0	59.993	-29.592	2.976	-2007.922	260.996	-72.238	1.821
1993	-1.322	0.0	0.0	62.890	-31.050	3.126	-2190.223	275.843	-75.735	1.911
1994	-1.375	0.0	0.0	65.935	-32.577	3.282	-2389.250	291.452	-79.389	2.004
1995	-1.430	0.0	0.0	69.133	-34.177	3.444	-2606.441	307.867	-83.212	2.101

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	32.789	-0.229	-11.315	7.989	-554.207	-73.909	113.387	322.596	284.734	-413.862
1975	52.035	-0.195	-19.353	74.607	-483.861	0.0	48.749	449.675	277.063	-213.520
1976	75.624	-0.166	-32.158	77.894	-501.378	0.0	57.510	512.419	214.828	-272.885
1977	87.100	-0.146	-43.109	77.086	-612.239	0.0	64.169	491.552	196.416	-316.663
1978	90.802	-0.146	-56.783	78.261	-599.258	0.0	64.566	527.416	135.095	-331.366
1979	92.890	-0.149	-73.191	79.410	-581.367	0.0	66.857	570.011	91.405	-356.847
1980	94.591	-0.156	-91.016	80.996	-578.504	0.0	68.389	618.474	60.276	-379.624
1981	97.690	-0.156	-99.273	82.087	-571.000	0.0	70.196	658.691	37.612	-405.244
1982	100.113	-0.160	-106.426	17.894	-854.195	-65.710	138.097	706.852	23.470	-829.121
1983	103.512	-0.168	-116.129	0.341	-928.008	-86.191	161.798	772.886	14.645	-1010.274
1984	107.449	-0.178	-127.512	-70.710	-1266.394	-160.996	240.253	849.257	9.139	-1560.164
1985	111.914	-0.188	-139.703	-97.845	-1399.638	-192.240	275.405	933.284	5.702	-1859.971
1986	116.863	-0.198	-152.844	-100.655	-1413.250	-199.485	283.557	1026.041	3.558	-1991.625
1987	122.203	-0.208	-167.449	-101.906	-1424.469	-205.481	294.751	1133.274	2.220	-2153.066
1988	127.914	-0.219	-182.156	-102.969	-1442.132	-211.591	306.139	1250.785	1.386	-2325.703
1989	133.980	-0.230	-198.602	-103.874	-1465.318	-217.840	317.895	1379.725	0.865	-2511.609
1990	140.422	-0.241	-217.449	-111.179	-1515.377	-230.801	336.628	1521.226	0.539	-2765.992
1991	147.234	-0.253	-237.414	-104.889	-1464.754	-230.479	342.366	1676.464	0.337	-2925.668
1992	154.426	-0.265	-259.930	-102.632	-1442.383	-234.514	352.770	1846.733	0.210	-3135.152
1993	162.008	-0.218	-221.449	-87.639	-1327.338	-226.142	351.091	2033.439	0.131	-3245.043
1994	169.984	0.102	116.188	-74.493	-1221.764	-219.961	351.948	2238.131	0.082	-3383.074
1995	178.383	0.110	129.422	-63.319	-1116.363	-216.108	355.498	2462.479	0.051	-3553.887

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KPNFGF$	KRENTC1$	KRENTC2$
1976PV	-841.445	-1290.457	-571.992	-178.090	-198.594	6656.484	0.0

	KROILCAN	KRENTCIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	3068.650	455.727	-3328.641	-3589.512	-9233.313	16607.145

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	PO.CN	PG.ON	PL.CN	QC.CN	QG.ON	QL.ON	TOT$	OBTU.O	OBTU.G	OBTU.L
1974	-13.772	0.0	0.0	9.214	-5.019	-4.224	-5.648	6.429	-5.963	-4.642
1975	-14.014	0.0	0.0	8.548	-4.428	-2.082	-5.043	7.338	-5.041	-2.441
1976	-14.089	0.0	0.0	7.952	-4.000	-0.443	-4.482	8.057	-4.152	-0.750
1977	-14.205	0.0	0.0	7.981	-3.714	0.291	-4.145	8.690	-3.652	-0.029
1978	-14.275	0.0	0.0	8.043	-3.667	0.382	-4.071	8.747	-3.581	0.053
1979	-14.329	0.0	0.0	8.049	-3.650	0.426	-4.062	8.952	-3.587	0.065
1980	-14.363	0.0	0.0	8.008	-3.636	0.443	-4.067	8.893	-3.625	0.036
1981	-14.363	0.0	0.0	7.987	-3.571	0.494	-3.999	8.939	-3.558	0.077
1982	-14.363	0.0	0.0	7.986	-3.511	0.542	-3.942	8.980	-3.495	0.111
1983	-14.363	0.0	0.0	7.969	-3.489	0.558	-3.924	9.001	-3.467	0.118
1984	-14.363	0.0	0.0	7.949	-3.486	0.562	-3.922	9.016	-3.456	0.115
1985	-14.363	0.0	0.0	7.935	-3.482	0.566	-3.918	9.034	-3.445	0.114
1986	-14.363	0.0	0.0	7.926	-3.477	0.571	-3.913	8.748	-3.432	0.116
1987	-14.363	0.0	0.0	7.920	-3.473	0.575	-3.909	8.820	-3.421	0.117
1988	-14.363	0.0	0.0	7.916	-3.470	0.578	-3.906	8.873	-3.411	0.118
1989	-14.363	0.0	0.0	7.912	-3.468	0.581	-3.904	8.921	-3.402	0.118
1990	-14.363	0.0	0.0	7.909	-3.466	0.583	-3.902	8.965	-3.394	0.119
1991	-14.363	0.0	0.0	7.907	-3.465	0.584	-3.901	9.007	-3.387	0.119
1992	-14.363	0.0	0.0	7.906	-3.464	0.585	-3.900	9.046	-3.380	0.119
1993	-14.363	0.0	0.0	7.905	-3.463	0.586	-3.899	9.083	-3.374	0.119
1994	-14.363	0.0	0.0	7.904	-3.462	0.586	-3.899	9.118	-3.369	0.119
1995	-14.363	0.0	0.0	7.903	-3.462	0.587	-3.899	9.152	-3.364	0.119

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGO$
1974	0.948	-3.332	-3.034	0.443	-19.569	-114.057	15.517	28.746	20.047	-29.777
1975	1.507	-2.838	-1.637	4.828	-14.905	0.0	6.193	30.097	22.895	-20.695
1976	2.098	-2.359	-1.600	5.485	-14.075	0.0	8.213	42.457	28.624	-41.082
1977	2.395	-2.027	-1.567	5.336	-13.689	0.0	11.642	73.347	47.018	-29.662
1978	2.454	-1.986	-1.625	6.039	-12.850	0.0	11.775	124.906	76.272	-56.249
1979	2.456	-2.017	-1.724	6.759	-12.070	0.0	12.117	310.693	144.732	-124.660
1980	2.431	-2.040	-1.857	7.307	-11.523	0.0	11.952	0.0	338.366	313.409
1981	2.451	-2.020	-1.877	7.639	-11.324	0.0	11.947	0.0	338.362	99.029
1982	2.428	-2.123	-1.988	1.669	-16.391	-26.284	22.685	0.0	338.366	80.491
1983	2.400	-2.161	-2.025	0.033	-17.847	-34.476	25.102	0.0	338.359	72.211
1984	2.373	-2.207	-2.070	-6.912	-23.725	-64.398	35.016	0.0	338.358	87.058
1985	2.355	-2.241	-2.103	-9.957	-26.365	-102.580	34.743	0.0	338.356	70.283
1986	2.344	-2.332	-2.197	-10.835	-27.194	-145.031	31.767	0.0	338.353	53.629
1987	2.337	-2.473	-2.350	-11.561	-27.896	-228.969	29.660	0.0	338.359	42.403
1988	2.333	-2.503	-2.374	-12.227	-28.554	-1367.599	27.233	0.0	338.361	36.968
1989	2.330	-2.581	-2.454	-12.838	-29.166	304.329	25.027	0.0	338.362	31.662
1990	2.330	-2.921	-2.832	-14.428	-30.596	141.839	23.648	0.0	338.355	25.410
1991	2.331	-3.025	-2.952	-14.744	-30.970	81.439	21.277	0.0	338.360	22.036
1992	2.332	-3.103	-3.045	-15.530	-31.731	58.881	19.674	0.0	338.363	19.963
1993	2.334	-2.456	-2.404	-14.578	-31.048	42.540	17.566	0.0	339.356	17.766
1994	2.337	1.200	1.261	-13.590	-30.336	33.223	15.961	0.0	338.359	15.986
1995	2.340	1.355	1.414	-12.809	-29.793	27.106	14.689	0.0	338.360	14.710

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-2.137	-2.507	-5.963	-0.816	-2.582	85.511	0.0

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	5.256	0.753	-120.490	-9.175	-136.636	139.496

VALUES ARE SHOCK - CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	-0.299	-15.246	0.0	0.0	0.0	0.0	0.0	0.0	-53.144
1975	0.0	-0.298	-75.300	0.0	0.0	0.0	0.0	0.0	0.0	-124.699
1976	0.0	-0.296	-114.295	0.0	0.0	0.0	0.0	0.0	0.0	-167.904
1977	0.0	-0.297	-141.435	0.0	0.0	0.0	0.0	0.0	0.0	-196.143
1978	0.0	-0.298	-170.801	0.0	0.0	0.0	0.0	0.0	0.0	-226.378
1979	0.0	-0.293	-196.749	0.0	0.0	0.0	0.0	0.0	0.0	-252.018
1980	0.0	-0.292	-205.016	0.0	0.0	0.0	0.0	0.0	0.0	-261.144
1981	0.0	-0.291	-213.055	0.0	0.0	0.0	0.0	0.0	0.0	-270.595
1982	0.0	-0.254	-192.574	0.0	0.0	0.0	0.0	0.0	0.0	-245.207
1983	0.0	-0.251	-198.465	0.0	0.0	0.0	0.0	0.0	0.0	-251.787
1984	0.0	-0.248	-204.277	0.0	0.0	0.0	0.0	0.0	0.0	-259.620
1985	0.0	-0.245	-209.473	0.0	0.0	0.0	0.0	0.0	0.0	-266.512
1986	0.0	-0.224	-198.965	0.0	0.0	0.0	0.0	0.0	0.0	-252.966
1987	0.0	-0.184	-169.855	0.0	0.0	0.0	0.0	0.0	0.0	-216.512
1988	0.0	-0.185	-177.668	0.0	0.0	0.0	0.0	0.0	0.0	-223.859
1989	0.0	-0.165	-165.488	0.0	0.0	0.0	0.0	0.0	0.0	-209.672
1990	0.0	-0.061	-62.316	0.0	0.0	0.0	0.0	0.0	0.0	-80.707
1991	0.0	-0.035	-35.695	0.0	0.0	0.0	0.0	0.0	0.0	-47.121
1992	0.0	-0.016	-15.863	0.0	0.0	0.0	0.0	0.0	0.0	-22.969
1993	0.0	0.048	39.656	0.0	0.0	0.0	0.0	0.0	0.0	-20.707
1994	0.0	0.181	187.551	0.0	0.0	0.0	0.0	0.0	0.0	-3.313
1995	0.0	0.198	214.184	0.0	0.0	0.0	0.0	0.0	0.0	-3.445

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-909.770	-1809.102	-835.145	-361.426	-332.555	-36.313	-243.746

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	-4.355	-4.088	0.0	0.0	0.0	0.0	0.0	0.0	-3.824
1975	0.0	-4.338	-6.369	0.0	0.0	0.0	0.0	0.0	0.0	-12.086
1976	0.0	-4.215	-5.686	0.0	0.0	0.0	0.0	0.0	0.0	-25.278
1977	0.0	-4.110	-5.142	0.0	0.0	0.0	0.0	0.0	0.0	-18.373
1978	0.0	-4.057	-4.888	0.0	0.0	0.0	0.0	0.0	0.0	-38.427
1979	0.0	-3.966	-4.635	0.0	0.0	0.0	0.0	0.0	0.0	-88.040
1980	0.0	-3.826	-4.183	0.0	0.0	0.0	0.0	0.0	0.0	215.595
1981	0.0	-3.776	-4.029	0.0	0.0	0.0	0.0	0.0	0.0	66.125
1982	0.0	-3.359	-3.597	0.0	0.0	0.0	0.0	0.0	0.0	23.805
1983	0.0	-3.213	-3.461	0.0	0.0	0.0	0.0	0.0	0.0	17.997
1984	0.0	-3.074	-3.316	0.0	0.0	0.0	0.0	0.0	0.0	14.487
1985	0.0	-2.919	-3.154	0.0	0.0	0.0	0.0	0.0	0.0	10.071
1986	0.0	-2.633	-2.860	0.0	0.0	0.0	0.0	0.0	0.0	6.812
1987	0.0	-2.189	-2.384	0.0	0.0	0.0	0.0	0.0	0.0	4.264
1988	0.0	-2.112	-2.315	0.0	0.0	0.0	0.0	0.0	0.0	3.558
1989	0.0	-1.853	-2.045	0.0	0.0	0.0	0.0	0.0	0.0	2.643
1990	0.0	-0.740	-0.812	0.0	0.0	0.0	0.0	0.0	0.0	0.741
1991	0.0	-0.413	-0.444	0.0	0.0	0.0	0.0	0.0	0.0	0.355
1992	0.0	-0.184	-0.186	0.0	0.0	0.0	0.0	0.0	0.0	0.146
1993	0.0	0.539	0.431	0.0	0.0	0.0	0.0	0.0	0.0	0.113
1994	0.0	2.120	2.035	0.0	0.0	0.0	0.0	0.0	0.0	0.016
1995	0.0	2.425	2.340	0.0	0.0	0.0	0.0	0.0	0.0	0.014

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	-2.311	-3.514	-8.706	-1.655	-4.323	-0.466	-5.322

VALUES ARE SHOCK - CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.299	13.198	0.0	0.0	0.0	0.0	0.0	0.0	53.140
1975	0.0	0.297	73.186	0.0	0.0	0.0	0.0	0.0	0.0	124.703
1976	0.0	0.295	114.031	0.0	0.0	0.0	0.0	0.0	0.0	167.901
1977	0.0	0.297	141.309	0.0	0.0	0.0	0.0	0.0	0.0	196.141
1978	0.0	0.298	170.675	0.0	0.0	0.0	0.0	0.0	0.0	226.379
1979	0.0	0.293	196.645	0.0	0.0	0.0	0.0	0.0	0.0	252.019
1980	0.0	0.292	204.922	0.0	0.0	0.0	0.0	0.0	0.0	261.140
1981	0.0	0.291	212.977	0.0	0.0	0.0	0.0	0.0	0.0	270.591
1982	0.0	0.254	192.516	0.0	0.0	0.0	0.0	0.0	0.0	245.204
1983	0.0	0.251	198.551	0.001	0.004	0.0	-0.000	0.0	0.0	251.786
1984	0.0	0.248	204.332	0.0	0.0	0.0	0.0	0.0	0.0	259.618
1985	0.0	0.245	209.555	0.001	0.004	0.001	-0.001	0.0	0.0	266.519
1986	0.0	0.224	199.125	0.000	-0.004	0.000	-0.000	0.0	0.0	252.964
1987	0.0	0.184	169.957	0.000	0.004	0.000	-0.000	0.0	0.0	216.504
1988	0.0	0.183	176.805	0.000	0.004	0.000	-0.000	0.0	0.0	223.859
1989	0.0	0.165	165.934	0.000	0.0	0.000	-0.000	0.0	0.0	209.664
1990	0.0	0.061	62.762	0.000	0.0	0.000	-0.000	0.0	0.0	80.711
1991	0.0	0.035	36.203	0.000	0.004	0.000	-0.000	0.0	0.0	47.125
1992	0.0	0.016	16.387	0.000	0.0	0.000	-0.000	0.0	0.0	22.973
1993	0.0	-0.165	-171.477	0.0	0.0	0.0	0.0	0.0	0.0	20.707
1994	0.0	-0.184	-200.742	0.0	0.0	0.0	0.0	0.0	0.0	3.313
1995	0.0	-0.201	-226.836	0.0	-0.000	0.0	0.0	0.0	0.0	3.445

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	881.008	1764.773	815.289	349.875	320.273	35.563	243.762

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGO$
1974	0.0	4.356	3.539	0.0	0.0	0.0	0.0	0.0	0.0	3.823
1975	0.0	4.316	6.190	0.0	0.0	0.0	0.0	0.0	0.0	12.087
1976	0.0	4.212	5.673	0.0	0.0	0.0	0.0	0.0	0.0	25.277
1977	0.0	4.110	5.137	0.0	0.0	0.0	0.0	0.0	0.0	18.373
1978	0.0	4.057	4.885	0.0	0.0	0.0	0.0	0.0	0.0	38.428
1979	0.0	3.966	4.633	0.0	0.0	0.0	0.0	0.0	0.0	88.040
1980	0.0	3.826	4.181	0.0	0.0	0.0	0.0	0.0	0.0	-215.592
1981	0.0	3.776	4.027	0.0	0.0	0.0	0.0	0.0	0.0	-66.124
1982	0.0	3.359	3.596	0.0	0.0	0.0	0.0	0.0	0.0	-23.805
1983	0.0	3.214	3.462	0.000	0.000	0.0	-0.000	0.0	0.0	-17.997
1984	0.0	3.075	3.317	0.0	0.0	0.0	0.0	0.0	0.0	-14.487
1985	0.0	2.919	3.155	0.000	0.000	0.000	-0.000	0.0	0.0	-10.071
1986	0.0	2.633	2.862	0.000	-0.000	0.000	-0.000	0.0	0.0	-6.812
1987	0.0	2.187	2.385	0.000	0.000	0.000	-0.000	0.0	0.0	-4.264
1988	0.0	2.095	2.304	0.000	0.000	0.002	-0.000	0.0	0.0	-3.558
1989	0.0	1.853	2.051	0.000	0.0	-0.000	-0.000	0.0	0.0	-2.643
1990	0.0	0.740	0.817	0.000	0.0	-0.000	-0.000	0.0	0.0	-0.741
1991	0.0	0.414	0.450	0.000	0.000	-0.000	-0.000	0.0	0.0	-0.355
1992	0.0	0.184	0.192	0.000	0.0	-0.000	-0.000	0.0	0.0	-0.146
1993	0.0	-1.864	-1.862	0.0	0.0	0.0	0.0	0.0	0.0	-0.113
1994	0.0	-2.160	-2.178	0.0	0.0	0.0	0.0	0.0	0.0	-0.016
1995	0.0	-2.461	-2.478	0.0	-0.000	0.0	0.0	0.0	0.0	-0.014

	RENTCANT	KRENTGAS	KRENTNF$	KRNFGP$	KRNFGF$	KRENTC1$	KRENTC2$
1976PV	2.238	3.428	8.499	1.602	4.164	0.457	5.323

POLICY EXPERIMENT 5: THE EFFECTS OF CRUDE OIL AND [illegible]

VALUES ARE SHOCK - CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	7.989	13.202	-242.011	242.011	0.0	390.550	86.101
1975	0.0	0.0	0.0	250.000	534.221	0.0	0.0	0.0	433.437	1157.734
1976	0.0	0.0	0.0	150.000	381.949	-100.000	100.000	154.761	407.887	779.627
1977	0.0	0.0	0.0	0.0	-0.340	-250.000	250.000	267.065	298.387	70.596
1978	0.0	0.0	0.0	0.0	-0.902	-250.000	250.000	170.685	210.860	73.421
1979	0.0	0.0	0.0	0.0	-1.422	-250.000	250.000	76.356	125.307	76.357
1980	0.0	0.0	0.0	0.0	-1.965	-250.000	250.000	0.0	58.908	79.408
1981	0.0	0.0	0.0	0.0	-2.488	-250.000	250.000	0.0	61.265	82.589
1982	0.0	0.0	0.0	0.0	-3.082	-250.000	250.000	0.0	63.715	85.890
1983	0.0	0.0	0.0	0.0	-3.645	-250.000	250.000	0.0	66.265	89.325
1984	0.0	0.0	0.0	0.0	-4.215	-250.000	250.000	0.0	68.916	92.896
1985	0.0	0.0	0.0	-37.221	-208.988	-287.221	287.221	0.0	71.673	-154.760
1986	0.0	0.0	0.0	-36.402	-212.398	-286.402	286.402	0.0	74.540	-155.196
1987	0.0	0.0	0.0	-37.653	-227.926	-287.653	287.653	0.0	77.520	-170.551
1988	0.0	0.0	0.0	-38.716	-243.172	-288.716	288.716	0.0	80.621	-185.445
1989	0.0	0.0	0.0	-39.620	-258.234	-289.620	289.620	0.0	83.845	-200.004
1990	0.0	0.0	0.0	-35.595	-241.574	-285.595	285.595	0.0	87.201	-174.922
1991	0.0	0.0	0.0	-36.967	-259.566	-286.967	286.967	0.0	90.688	-193.648
1992	0.0	0.0	0.0	-38.133	-277.160	-288.133	288.133	0.0	94.315	-211.758
1993	0.0	0.0	0.0	-31.726	-240.019	-281.726	281.726	0.0	98.089	-161.008
1994	0.0	0.0	0.0	-26.967	-212.194	-276.967	276.967	0.0	102.011	-121.703
1995	0.0	0.0	0.0	-22.922	-187.276	-272.922	272.922	0.0	106.092	-86.137

	KROILCAN	KRENTCIL	KROILP$	KROILGP$	KRCILGP$	KROILC1$
1976PV	1947.445	2156.223	265.997	253.531	2095.609	-458.883

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.443	0.466	-373.474	33.118	0.0	27.497	6.195
1975	0.0	0.0	0.0	16.178	16.457	0.0	0.0	0.0	35.817	112.211
1976	0.0	0.0	0.0	10.563	10.722	-100.000	14.282	12.823	54.348	117.372
1977	0.0	0.0	0.0	0.0	-0.008	-100.000	45.358	39.850	71.429	6.613
1978	0.0	0.0	0.0	0.0	-0.019	-100.000	45.593	40.423	119.048	12.463
1979	0.0	0.0	0.0	0.0	-0.030	-100.000	45.311	41.619	198.413	26.675
1980	0.0	0.0	0.0	0.0	-0.039	-100.000	43.692	0.0	330.688	-65.558
1981	0.0	0.0	0.0	0.0	-0.049	-100.000	42.549	0.0	551.146	-20.182
1982	0.0	0.0	0.0	0.0	-0.059	-100.000	41.068	0.0	918.577	-8.338
1983	0.0	0.0	0.0	0.0	-0.070	-100.000	38.786	0.0	1530.962	-6.385
1984	0.0	0.0	0.0	0.0	-0.079	-100.000	36.437	0.0	2551.604	-5.184
1985	0.0	0.0	0.0	-3.788	-3.937	-153.263	36.234	0.0	4252.676	5.848
1986	0.0	0.0	0.0	-3.919	-4.087	-208.222	32.085	0.0	7087.801	4.179
1987	0.0	0.0	0.0	-4.272	-4.464	-320.534	28.946	0.0	11813.000	3.359
1988	0.0	0.0	0.0	-4.597	-4.815	-1866.094	25.684	0.0	19688.355	2.948
1989	0.0	0.0	0.0	-4.897	-5.140	404.608	22.801	0.0	32813.922	2.521
1990	0.0	0.0	0.0	-4.619	-4.877	175.512	20.063	0.0	54689.867	1.607
1991	0.0	0.0	0.0	-5.196	-5.488	101.399	17.834	0.0	91149.875	1.459
1992	0.0	0.0	0.0	-5.770	-6.097	72.343	16.069	0.0	151916.375	1.348
1993	0.0	0.0	0.0	-5.277	-5.614	52.996	14.096	0.0	253194.125	0.982
1994	0.0	0.0	0.0	-4.920	-5.269	41.833	12.560	0.0	421990.313	0.575
1995	0.0	0.0	0.0	-4.637	-4.998	34.232	11.277	0.0	703317.125	0.357

	KROILCAN	KRENTCIL	KROILP$	KROILGP$	KRCILGP$	KROILC1$
1976PV	3.336	3.561	9.629	0.648	31.011	-3.854

POLICY EXPERIMENT 6: THE POST-1975 EXPORTS OF CRUDE OIL ARE SET TO ZERO AND THE SARNIA-MONTREAL PIPELINE FLOW IS SET TO 350 MBBL/D

VALUES ARE SHOCK - CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	-460.000	-1164.560	0.0	0.0	0.0	-750.513	-2307.602
1977	0.0	0.0	0.0	-250.000	-781.882	100.000	-100.000	-106.826	-417.742	-1332.535
1978	0.0	0.0	0.0	-110.000	-399.117	100.000	-100.000	-68.274	-177.123	-626.214
1979	0.0	0.0	0.0	-26.000	-105.949	100.000	-100.000	-30.543	-63.155	-177.258
1980	0.0	0.0	0.0	24.400	114.449	100.000	-100.000	0.0	-17.814	111.430
1981	0.0	0.0	0.0	54.640	263.160	100.000	-100.000	0.0	-11.116	300.453
1982	0.0	0.0	0.0	72.784	363.383	100.000	-100.000	0.0	-6.936	427.640
1983	0.0	0.0	0.0	83.671	433.309	100.000	-100.000	0.0	-4.328	516.611
1984	0.0	0.0	0.0	64.460	348.566	74.257	-74.257	0.0	-2.701	414.950
1985	0.0	0.0	0.0	67.988	381.527	73.866	-73.866	0.0	-1.685	456.893
1986	0.0	0.0	0.0	66.650	388.398	70.177	-70.177	0.0	-1.052	466.715
1987	0.0	0.0	0.0	66.650	403.148	68.767	-68.767	0.0	-0.656	485.973
1988	0.0	0.0	0.0	66.650	418.477	67.920	-67.920	0.0	-0.409	505.785
1989	0.0	0.0	0.0	66.650	434.469	67.412	-67.412	0.0	-0.256	526.234
1990	0.0	0.0	0.0	50.258	342.543	50.715	-50.715	0.0	-0.159	412.746
1991	0.0	0.0	0.0	47.274	334.277	47.548	-47.548	0.0	-0.099	403.844
1992	0.0	0.0	0.0	35.386	261.828	35.550	-35.550	0.0	-0.062	314.398
1993	0.0	0.0	0.0	29.677	228.578	29.775	-29.775	0.0	-0.039	274.238
1994	0.0	0.0	0.0	25.225	202.097	25.284	-25.284	0.0	-0.024	242.441
1995	0.0	0.0	0.0	21.441	178.323	21.477	-21.477	0.0	-0.015	214.324

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-1927.320	-2283.309	-453.443	-340.531	-1474.211	-15.090

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	-32.393	-32.692	0.0	0.0	0.0	-100.000	-347.406
1977	0.0	0.0	0.0	-17.304	-17.482	40.000	-18.143	-15.940	-100.000	-124.821
1978	0.0	0.0	0.0	-8.488	-8.558	40.000	-18.237	-16.169	-100.000	-106.299
1979	0.0	0.0	0.0	-2.213	-2.200	40.000	-18.124	-16.648	-100.000	-61.923
1980	0.0	0.0	0.0	2.201	2.280	40.000	-17.477	0.0	-100.000	-91.995
1981	0.0	0.0	0.0	5.085	5.219	40.000	-17.019	0.0	-100.000	-73.421
1982	0.0	0.0	0.0	6.790	6.973	40.000	-16.427	0.0	-100.000	-41.515
1983	0.0	0.0	0.0	8.102	8.333	40.000	-15.514	0.0	-100.000	-36.926
1984	0.0	0.0	0.0	6.301	6.530	29.703	-10.823	0.0	-100.000	-23.155
1985	0.0	0.0	0.0	6.919	7.187	39.415	-9.318	0.0	-100.000	-17.265
1986	0.0	0.0	0.0	7.175	7.474	51.021	-7.862	0.0	-100.000	-12.567
1987	0.0	0.0	0.0	7.561	7.895	76.627	-6.920	0.0	-100.000	-9.571
1988	0.0	0.0	0.0	7.915	8.286	438.997	-6.042	0.0	-100.000	-8.040
1989	0.0	0.0	0.0	8.237	8.648	-94.177	-5.307	0.0	-100.000	-6.634
1990	0.0	0.0	0.0	6.522	6.916	-31.167	-3.563	0.0	-100.000	-3.792
1991	0.0	0.0	0.0	6.645	7.068	-16.801	-2.955	0.0	-100.000	-3.042
1992	0.0	0.0	0.0	5.354	5.760	-8.926	-1.983	0.0	-100.000	-2.002
1993	0.0	0.0	0.0	4.936	5.347	-5.601	-1.490	0.0	-100.000	-1.501
1994	0.0	0.0	0.0	4.602	5.018	-3.819	-1.147	0.0	-100.000	-1.146
1995	0.0	0.0	0.0	4.337	4.759	-2.694	-0.887	0.0	-100.000	-0.887

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-3.301	-3.771	-16.414	-0.870	-21.816	-0.127

VALUES ARE SHOCK - CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	-100.000	-254.032	-100.000	100.000	154.761	0.0	-474.500
1977	0.0	0.0	0.0	-250.000	-782.103	-250.000	250.000	267.065	0.0	-1233.700
1978	0.0	0.0	0.0	-250.000	-907.630	-250.000	250.000	170.685	0.0	-1283.045
1979	0.0	0.0	0.0	-250.000	-1032.368	-250.000	250.000	76.356	0.0	-1334.366
1980	0.0	0.0	0.0	-250.000	-1139.474	-250.000	250.000	0.0	0.0	-1387.743
1981	0.0	0.0	0.0	-250.000	-1179.932	-250.000	250.000	0.0	0.0	-1443.252
1982	0.0	0.0	0.0	-250.000	-1222.101	-250.000	250.000	0.0	0.0	-1500.981
1983	0.0	0.0	0.0	-250.000	-1264.901	-250.000	250.000	0.0	0.0	-1561.021
1984	0.0	0.0	0.0	-250.000	-1310.124	-250.000	250.000	0.0	0.0	-1623.461
1985	0.0	0.0	0.0	-187.405	-1014.008	-187.405	187.405	0.0	0.0	-1265.652
1986	0.0	0.0	0.0	-137.546	-766.488	-137.546	137.546	0.0	0.0	-966.082
1987	-0.004	0.000	0.039	-89.742	-511.277	-89.742	89.742	0.0	0.0	-655.535
1988	0.0	0.000	0.0	-15.470	-74.273	-15.472	15.472	0.0	0.0	-117.535
1989	0.0	0.000	0.004	71.580	477.695	71.580	-71.580	0.0	0.0	565.535
1990	0.0	0.0	0.0	115.808	790.043	115.808	-115.808	0.0	0.0	951.566
1991	0.0	0.0	0.0	156.377	1099.844	156.377	-156.377	0.0	0.0	1336.309
1992	0.0	0.0	0.0	187.490	1364.602	187.490	-187.490	0.0	0.0	1666.266
1993	0.0	0.0	0.004	206.642	1558.762	206.642	-206.642	0.0	0.0	1909.934
1994	0.0	0.0	0.0	217.292	1700.547	217.292	-217.292	0.0	0.0	2088.703
1995	0.0	0.0	0.0	217.016	1762.890	217.016	-217.016	0.0	0.0	2169.492

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-4611.629	-6756.469	-2732.317	-2047.336	-2027.238	50.395

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GFSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	-7.042	-7.131	-100.000	14.282	12.823	0.0	-71.435
1977	0.0	0.0	0.0	-17.304	-17.487	-100.000	45.358	39.850	0.0	-115.563
1978	0.0	0.0	0.0	-19.292	-19.462	-100.000	45.593	40.423	0.0	-217.795
1979	0.0	0.0	0.0	-21.279	-21.434	-100.000	45.311	41.619	0.0	-466.144
1980	0.0	0.0	0.0	-22.555	-22.696	-100.000	43.692	0.0	0.0	1145.691
1981	0.0	0.0	0.0	-23.265	-23.401	-100.000	42.549	0.0	0.0	352.685
1982	0.0	0.0	0.0	-23.321	-23.451	-100.000	41.068	0.0	0.0	145.716
1983	0.0	0.0	0.0	-24.208	-24.325	-100.000	38.786	0.0	0.0	111.577
1984	0.0	0.0	0.0	-24.437	-24.545	-100.000	36.437	0.0	0.0	90.590
1985	0.0	0.0	0.0	-19.071	-19.101	-100.000	23.642	0.0	0.0	47.825
1986	0.0	0.0	0.0	-14.807	-14.749	-100.000	15.409	0.0	0.0	26.014
1987	-0.000	0.001	0.001	-10.181	-10.013	-100.000	9.031	0.0	0.0	12.910
1988	0.0	0.000	0.0	-1.837	-1.471	-100.000	1.376	0.0	0.0	1.868
1989	0.0	0.000	0.000	8.847	9.508	-100.000	-5.635	0.0	0.0	-7.129
1990	0.0	0.0	0.0	15.029	15.951	-71.170	-8.136	0.0	0.0	-8.742
1991	0.0	0.0	0.0	21.981	23.255	-55.255	-9.718	0.0	0.0	-10.065
1992	0.0	0.0	0.0	28.370	30.020	-47.074	-10.456	0.0	0.0	-10.610
1993	0.0	0.0	0.000	34.372	36.461	-38.872	-10.339	0.0	0.0	-10.457
1994	0.0	0.0	0.0	39.641	42.224	-32.820	-9.854	0.0	0.0	-9.870
1995	0.0	0.0	0.0	43.900	47.047	-27.220	-8.967	0.0	0.0	-8.980

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	-7.899	-11.159	-98.904	-5.233	-29.999	0.423

POLICY EXPERIMENT 8: THE SASKIA-MONTREAL TILLERS TAX IS SET TO 35% ABOVE

VALUES ARE SHOCK - CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GPSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	100.000	313.832	100.000	-100.000	-106.826	0.0	493.480
1978	0.0	0.0	0.0	100.000	364.320	100.000	-100.000	-68.274	0.0	513.219
1979	0.0	0.0	0.0	100.000	414.473	100.000	-100.000	-30.543	0.0	533.748
1980	0.0	0.0	0.0	100.000	457.566	100.000	-100.000	0.0	0.0	555.098
1981	0.0	0.0	0.0	100.000	474.031	100.000	-100.000	0.0	0.0	577.302
1982	0.0	0.0	0.0	100.000	491.270	100.000	-100.000	0.0	0.0	600.393
1983	0.0	0.0	0.0	74.595	378.816	74.595	-74.595	0.0	0.0	465.781
1984	0.0	0.0	0.0	6.215	29.848	6.215	-6.215	0.0	0.0	40.359
1985	0.0	0.0	0.0	-19.189	-109.605	-19.189	19.189	0.0	0.0	-129.594
1986	0.0	0.0	0.0	-20.527	-122.203	-20.527	20.527	0.0	0.0	-144.176
1987	0.0	0.0	0.0	-20.527	-127.590	-20.527	20.527	0.0	0.0	-149.941
1988	0.0	0.0	0.0	-20.527	-133.223	-20.527	20.527	0.0	0.0	-155.941
1989	0.0	0.0	0.0	-27.644	-184.102	-27.644	27.644	0.0	0.0	-218.414
1990	0.0	0.0	0.0	-49.459	-335.043	-49.459	49.459	0.0	0.0	-406.395
1991	0.0	0.0	0.0	-52.237	-366.801	-52.237	52.237	0.0	0.0	-446.387
1992	0.0	0.0	0.0	-57.878	-420.445	-57.878	57.878	0.0	0.0	-514.375
1993	0.0	0.0	0.0	-49.598	-375.401	-49.598	49.598	0.0	0.0	-458.418
1994	0.0	0.0	0.0	-42.158	-332.755	-42.158	42.158	0.0	0.0	-405.242
1995	0.0	0.0	0.0	-35.834	-294.969	-35.834	35.834	0.0	0.0	-358.230

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	1252.863	1835.934	742.749	547.391	560.871	-15.090

VALUES ARE 100*(SHOCK - CONTROL)/CONTROL

	OBTU	GASPRO	YGASNFT	OILPRO	YOILNFT	OILPIPEM	OILIMPT	GPSUBO	TXOIL	XBALGC$
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	6.922	7.017	40.000	-18.143	-15.940	0.0	46.225
1978	0.0	0.0	0.0	7.717	7.812	40.000	-18.237	-16.169	0.0	87.118
1979	0.0	0.0	0.0	8.512	8.605	40.000	-18.124	-16.648	0.0	186.458
1980	0.0	0.0	0.0	9.022	9.114	40.000	-17.477	0.0	0.0	-458.277
1981	0.0	0.0	0.0	9.306	9.401	40.000	-17.019	0.0	0.0	-141.074
1982	0.0	0.0	0.0	9.329	9.427	40.000	-16.427	0.0	0.0	-58.286
1983	0.0	0.0	0.0	7.223	7.285	29.838	-11.573	0.0	0.0	-33.292
1984	0.0	0.0	0.0	0.607	0.559	2.486	-0.906	0.0	0.0	-2.252
1985	0.0	0.0	0.0	-1.953	-2.065	-10.239	2.421	0.0	0.0	4.897
1986	0.0	0.0	0.0	-2.210	-2.351	-14.924	2.300	0.0	0.0	3.882
1987	0.0	0.0	0.0	-2.329	-2.499	-22.873	2.066	0.0	0.0	2.953
1988	0.0	0.0	0.0	-2.438	-2.638	-132.674	1.826	0.0	0.0	2.479
1989	0.0	0.0	0.0	-3.417	-3.664	38.620	2.176	0.0	0.0	2.753
1990	0.0	0.0	0.0	-6.419	-6.765	30.395	3.475	0.0	0.0	3.733
1991	0.0	0.0	0.0	-7.343	-7.755	18.458	3.246	0.0	0.0	3.362
1992	0.0	0.0	0.0	-8.758	-9.249	14.532	3.228	0.0	0.0	3.275
1993	0.0	0.0	0.0	-8.250	-8.781	9.330	2.482	0.0	0.0	2.510
1994	0.0	0.0	0.0	-7.691	-8.262	6.368	1.912	0.0	0.0	1.915
1995	0.0	0.0	0.0	-7.249	-7.872	4.495	1.481	0.0	0.0	1.483

	KROILCAN	KRENTOIL	KROILP$	KROILGP$	KROILGF$	KROILC1$
1976PV	2.146	3.032	26.886	1.399	8.300	-0.127