The Power Generation Sector's Demand for Fossil Fuels: A Quantitative Assessment on the Viability of Carbon Fees for the Reduction of Greenhouse Gas Emissions.

By

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Abstract

The demand for fossil fuels by Ontario's conventional steam power generation sector is examined. It is hypothesised that the enactment of a carbon fee policy will induce a change in the relative prices of the three fuels used in this sector (coal, natural gas and heavy fuel oil). This would lead to substantial interfuel substitution and greenhouse gas abatement. The demand share equations for the three fuels are derived from the translog functional form and set in a simulation model to estimate the value of a carbon fee necessary, to reduce carbon dioxide emissions in compliance with the Kyoto Protocol. Results suggest that a fuel specific carbon fee policy would be successful in achieving the desired emissions reduction at a negligible net cost to society.

Résumé

La demande pour le carburant dans le secteur de l'énergie vapeur classique est examinée en Ontario. L'hypothèse est formulée par laquelle l'adoption d'une taxe sur le carbone provoquera un changement de prix-relatif au niveau des trois carburants utilisés dans ce secteur (charbon, gas naturel et mazout lourd). Ceci mènera à une importante substitution parmi les carburants et une réduction des gaz à effet de serre. Les équations des parts de demande pour chacun des carburants sont derivées de la forme fonctionelle « translog », et apposées dans un modèle de simulation pour estimer la valeur d'une taxe sur le carbone nécessaire pour réduire les émissions de dioxide de carbone en accord avec le traité de Kyoto. Les résultats démontrent qu'une taxe sur le carbone spécifique au carburant réussira à atteindre les réductions d'émissions désirées à un coût négligeable à la société.

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Chapter 1: Introduction

Background

In the 1960s, there was a global concern about the cooling trend that was occurring on the Earth's climate. Some even thought that the world was headed into another ice age. During the 80s and 90s, however, these concerns have experienced a complete reversal and the focus is now on a more substantiated warming trend. Scientists from all walks of life have devoted a great deal of attention to climate change with hopes at unveiling the nature of our climate and how people might be influencing it. It now seems to be widely accepted that the "culprit" is anthropogenic Greenhouse gas, hereinafter referred to as GHG. These include nitrous oxide (N_2O), methane (CH_4), but mainly carbon dioxide (CO_2), which stems from the burning of fossil fuels to satisfy our ever-increasing demand for energy, as well as a few long lasting industrial gases such as hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6).

To understand the effect that greenhouse gases like CO_2 have on our climate, we need not look further than, what meteorologists term, the world radiation budget. It is clear that the vast majority of all energy on Earth comes from the sun. In fact, the surface of the globe receives an average of 240 Watts per square meter (Wm^{-2}). This is enough energy to warm our planet to a maximum mean temperature of -18°c, which is insufficient to support life as we know it[1]. Our planet, on the other hand, radiates energy at about 420 Wm^{-2} which translates into a temperature of +15°c. This extra 33°c comes from the radiant energy emitted from earth that bounces off the greenhouse gases in the atmosphere and back to earth forming a sort of tropospheric blanket. The problem is that by burning fossil fuels to generate energy, CO_2, a potent GHG is emitted, effectively thickening the blanket that surrounds us and hence, warming our climate. Using Antarctic ice samples for the last 160,000 years, researchers have found that there is a positive correlation between atmospheric concentrations of CO_2 and global average temperature.

As it stands today, combustion of fossil fuels world wide releases 6 Gigatons (Gts) of CO_2 annually[2]. The majority coming from the industrialised nations. The oceans and biosphere reabsorb a portion of this through the process of photosynthesis in the natural carbon cycle. However, these two carbon sinks are unable to eliminate all anthropogenic carbon dioxide, leaving the balance to accumulate in the atmosphere every year.

In December 1997, representatives of 169 nations met to formalise the first legally binding international treaty to combat climate change known as the Kyoto Protocol. This was the first step to a global commitment to the reduction of GHG.

[1] Lin, Charles. *The Atmosphere and Climate Change*. Kendal/Hunt, Iowa, 1994.
[2] Intergovernmental Panel on Climate Change. 1999. IPCC First order draft of the Third Assessment Report, New York: World Meteorological Organization and the United Nations Environment Program (November).

The following year, they concluded a follow-up meeting in Buenos Aires where they set a two year deadline for the adoption of operational policies to effectively meet their reduction goals. Although much was accomplished with these first two conferences, policy makers are now left with the gruelling decision of how to attain a significant cut in emissions.

Canada and the Kyoto Protocol.

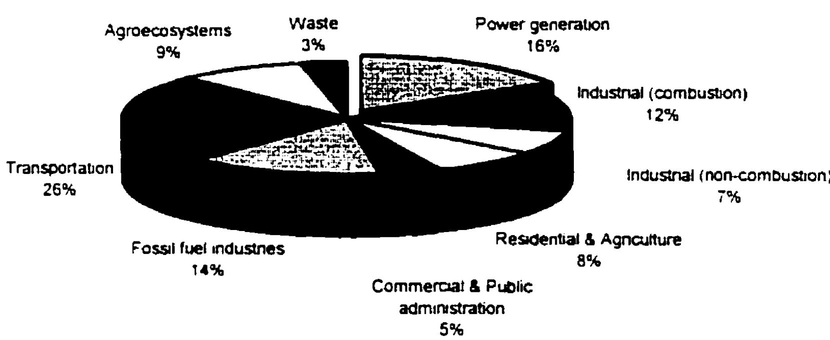
The 1992 United Nations Framework Convention on Climate Change (FCCC), requires Annex I Parties (developed countries and countries whose economies are undergoing transition to a market economy) to take actions aimed at returning net emissions of CO_2 and other greenhouse gases to 1990 levels by the year 2000. It is now evident that none of these countries took any steps to meet that target. The Third Conference of the Parties to the FCCC in Kyoto, Japan, in December 1997 established binding emission reduction targets beyond the year 2000 for Annex I Parties. By the end of 2012, and for developed countries overall, annual GHG emissions for the previous five years must be 5.2% lower than 1990 levels.

Canada's target is a 6% reduction in aggregate emissions below 1990 levels. This is a formidable task considering that in 1995, CO_2 emissions from fossil fuel use were already 9% higher than those of the base year 1990, and continue to increase at an average annual rate of 1.5%. As a result, the problem of abatement is compounded with each passing year. Although CO_2 is but one of the GHG covered by the Kyoto protocol, it is by far the most abundant.

Who is producing the CO_2 in Canada?

Figure 1.1 below, depicts the sectoral dissaggregation of Canada's CO_2 equivalent emissions[3]. It becomes evident that there are mainly three sectors responsible for the bulk of emissions: transportation, power generation and industry. Any mitigation of CO_2 in Canada will almost certainly involve these sectors, but before delving into them, some of the other higher emitting sectors warrant a brief mention.

Figure 1.1: GHG emissions by sector, 1997
Megatonnes of CO2 Equivalent



Source National Climate Change Process Natural Resources Canada. December, 1999

[3] CO_2 equivalent are calculated using the concept of global warming potential (IPCC. 1992). Because some greenhouse gases have a longer life span and are much more effective insulators than CO_2, this is taken into account by assigning Global Warming Potential (GWP) values to each of them. For example: methane has a GWP of 11 and Nitrous oxide has a GWP cf 270. This means that emissions of 1 tonne of methane is equivalent to 11 tonnes of CO_2 emissions.

At 8%, the residential and agricultural sectors remain important contributors to Canada's emissions. Home heating is the main contributor to the residential sector. Although this source is certainly very visible, there are, however, literally millions of emitters. If emissions are to be reduced from this sector, some sort of homogeneous policy might be feasible, but will most certainly be exceedingly difficult to monitor.

The agriculture sector on its own is a negligible contributor to CO_2, but is the main contributor of other greenhouse gases such as methane and carbon monoxide (CO). When you consider the CO_2 equivalent of these gases, the importance of the agriculture sector becomes much more evident. In 1990 for example, agriculture's share of CO_2 emissions were 9,525 kilotonnes, 973 kilotonnes of methane, and 610 kilotonnes of carbon monoxide. Considering that the latter two are much more potent greenhouse gases, the CO_2 equivalent emissions from the agriculture sector jumps up to 24,663 kilotonnes, which ranks this industry as the 4th single biggest contributor next to transportation, power generation, and primary metal production[4].

The transport sector represents all forms of private, public, and commercial transportation, whether it be by air, sea, rail, or land. Any strategy designed to curtail emissions from this sector incites the idea of producing more fuel economic vehicles and using them more efficiently. This has been the case

[4] Smith, Robert. "Canadian Greenhouse Gas Emissions An Input –Output Study". *Environmental Perspectives*. Statistics Canada. Ottawa. Catalogue no. 11-528E (1993): 9-18.

since the oil crisis in the 1970's. Vehicles can now travel further distances while burning less fuel. Yet despite these advancements, CO_2 emissions continue to increase due to the sheer growth in this sector. It would seem that any fuel efficiency gains, which successfully decrease pollutants in transportation, are nullified by the unrelenting expansion of demand.

On the up side, there has been a lot of research into alternative sources of fuel. One of the more prominent areas has been with hydrogen fuel cells which can successfully compete with the internal combustion engine to power vehicles. This technology is encouraging but is a long way from widespread use in the economy and hence, is unlikely to contribute to Canada's Kyoto commitments.

Canada is fortunate enough to possess one of the greatest fresh water supplies suitable for hydropower in the world. Coupled with the fact that the population density is not a constraining factor, it is no wonder that hydro represents the majority of electricity generation. Yet, even though fossil fuel sources only supply 18% of electricity, they are still responsible for more than 100 million tonnes of CO_2 emissions per year. The dominant fuel in this sector is coal as it contains high energy potential for its low relative cost. Unfortunately, of the three main types of fossil fuels (coal, oil and natural gas) available for electricity generation, coal produces considerably more CO_2 per unit of energy generated than its substitutes. It stands to reason then, that fossil fuel fired plants could cut their emissions by switching to cleaner fuels. In any case, considering Canada's long term hydro electric potential, and the room today for CO_2 efficiency gains within the fossil fuel power plants, the prospects are encouraging for significant emissions reduction in this sector.

The industrial sector is characterised by a large number of non-homogeneous emitters, which will, in all likelihood, pose the greatest challenge to the inception of a market-based policy. This sector has the widest classification, composed of all manufacturing industries, including forestry, construction and mining, but excluding the fossil fuel industry. Scale of production and the relative importance of the energy input are both determinants of a plant's propensity to choose the type technology necessary to power its needs. In turn, this investment decision will play a crucial role in the plant's ability to switch from higher emission fuels to those that are more environmentally benign in response to an abatement policy[5].

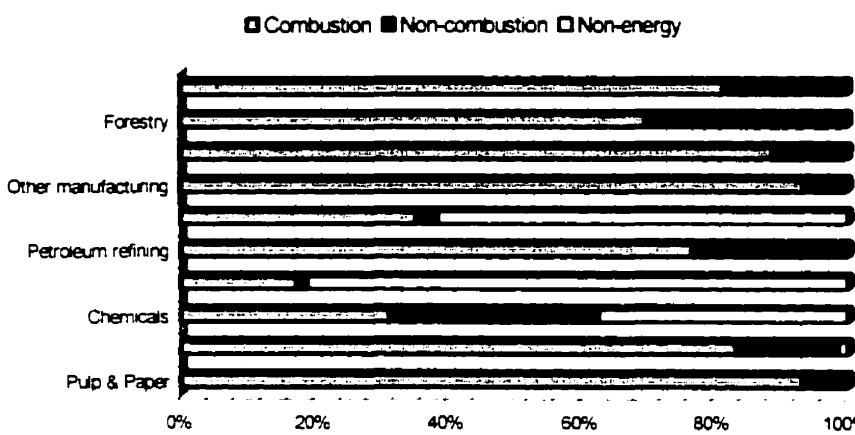
A further hindrance to the design of a uniform policy to curb emissions in the industrial sector is the vicissitude of sources of greenhouse gases. Unlike other sectors where emissions are produced in large part by burning fossil fuels, a significant portion of industrial emissions stem from processes other than combustion. In 1997 for example, industry emitted 127 megatonnes of greenhouse gases, two thirds of which originated from direct combustion for energy[6]. The remaining third are comprised of emissions from various non-

[5] Doms, M.E., March 1993, *Inter fuel substitution and energy technology heterogeneity in U.S. manufacturing.* Discussion Paper CES 93-5, Center for Economic Studies, U. S.
[6] See National Climate Change Process (1999).

energy related industrial processes such as the release of CO_2 in cement production.

Figure 1.2 illustrates the heterogeneity of GHG sources in the industrial process. As expected, combustion forms the majority of emissions but non-combustion, as well as non-energy sources remain significant. More importantly however, the divergence between industries will further complicate the implementation of a sound economic policy to curb emissions from this sector. Nevertheless,

Figure 1.2: Sources of Industrial Emissions, 1997



	Pulp & Paper	Iron & Steel	Chemicals	Smelting & Refining	Petroleum refining	Cement	Other manufacturing	Mining	Forestry	Construction
Non-energy	0	0.2	10.8	9.8	0	5.7	0	0	0	0
Non-combustion	0.8	2.3	9	0.2	4.3	0.3	1.4	0.7	0.3	0.2
Combustion	11.4	12.7	9.1	2.1	14.4	3.3	20.7	5.8	0.7	0.9

Source: National Climate Change Process. Natural Resources Canada. December, 1999

industry's sheer importance as the second largest contributor to Canada's GHG emissions warrants a closer look at some of the policy measures able to assuage this fate.

How will Canada lower its CO_2 emissions?

The problem of CO_2 emissions from the combustion of fossil fuels is, in essence, an energy problem. As is the case with any country, Canada needs energy to sustain economic activity. When this energy is derived from fossil fuels, CO_2 is released and left to accumulate in the atmosphere. The problem is intensified over time as economies grow, putting greater pressures on energy demand[7]. This link between emissions and economic growth is the main source of today's reluctance for the adoption of a CO_2 abatement policy.

However, the Kyoto Protocol does not set out to eliminate emissions, but merely to curb them. Hence, if a policy were designed to persuade fossil fuel consumers to use less carbon intense fuels, CO_2 abatement could be achieved without having to sacrifice energy or economic prosperity. This is the case for carbon taxes or tradable emission permits, so it stands to reason that the policy momentum is swinging in their favour. They would both be effective in achieving emission reduction goals, but at a fraction of the cost of traditional policy measures of command and control[8]. The reason for their recent popularity is that they make use of market mechanisms to efficiently reduce pollution. The idea of using market mechanisms to control externalities originally appeared in the writings of Pigou in 1932[9]. Coase (1960) later reinforced the concept of the

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[7] Kaya, Y. "Impact of Carbon Dioxide Emission control on GNP Growth: Interpretation of Proposed Scenarios." *IPCC Response Strategies Working Group Memorandum*. (1989).

[8] See Randall, A (1987): 358-370, Jorgenson, D.W. (1993) and Pearce, D.W. and R.K. Turner (1990): 85-119.

[9] Pigou, A.C. *The Economics of Welfare*. 4th edition. London. MacMillan & Co. (1932).

market mechanisms' ability to overcome externalities when property rights are well defined and parties can participate in unfettered negotiations. Since their writings, there has been growing support for these ideas, and in recent years, market instruments have become evermore present in policy planning.

The effectiveness of establishing either a carbon tax or an emissions market will be examined. For the purposes here, either economic tool, whether it be a $50 per tonne tax or a permit of the same value, are assumed to reach the same goal. The focus is not on determining which is more appropriate for Canada, but on the result. For this reason both policies are lumped together and are termed "carbon fee".

Carbon fees accomplish their tasks by effectively raising the price of fossil fuels, which would presumably lower their quantity demanded and in turn, lower CO_2 emissions. Perhaps more importantly though, a carbon fee changes the price relative to substitute fuels in accordance to each fuel's carbon content. And so, if natural gas releases less CO_2 than oil or coal for the same amount of energy generated, then the price of natural gas would rise less than that of its substitutes. It would be fair to deduce that high-energy consumers of fossil fuels would begin switching from oil and coal to the less carbon intense, relatively cheaper natural gas. This would go a long way to curtailing emissions in Canada.

In light of Canada's interest in cutting GHG emissions and the expected outcome of a carbon fee policy, it is imperative to ascertain just how much of a carbon fee would be needed to accomplish Kyoto's abatement goal. The solution comes from knowing the shape of the demand curves for the different fossil fuels of varying carbon intensity. Estimating demand for individual fuels would put us in a position to quantify the responsiveness to relative price changes. A lump-sum carbon fee would induce a measurable, disproportionate increase in prices for which the ensuing changes in quantity demanded for each fuel could then be ascertained. Since CO_2 emissions are directly related to the amounts and types of fuels burned, the demand model is easily extended to forecast abatement. An econometric model will thus be constructed to:

1. estimate demand for individual fuels,
2. determine the degree of substitutability between them in response to relative price changes and,
3. to quantify the carbon fee that will be needed to induce the desired abatement.

Policy context

In order to accomplish this task, there are a few issues that need to be addressed. As of yet, there has been no decision made in Canada on how to implement a carbon fee policy. Whether the 6% target would be applied evenly across all sectors or whether some of the higher emitting sectors would be singled out to shoulder the burden is unknown. In any case, the assumption made here is the former.

Furthermore, the industrial structure and the relative importance of energy differ significantly between sectors. It thus becomes problematic to estimate the value of a unilateral carbon fee imposed on all sectors. The scope of the present thesis will hence be limited to power generation, the single largest industrial emitter of CO_2. However, Canada's provinces and territories have vast differences in the technology employed to generate electricity. Quebec, for instance, relies almost entirely on hydro while Ontario employs nuclear, hydro and conventional steam technologies in concert. This heterogeneity is consistent throughout the provinces and so it would be unrealistic to assume that the electric power industry's demand for fuel would be the same across Canada. This necessitates a province specific focus and Ontario was chosen for its sheer CO_2 reduction potential. All to say that if Canada is to reduce its emissions, it might best be served by independent, provincial carbon fee policies. This will require the collaboration of both federal and provincial authorities.

Questions to be addressed.

For the most part, the signatory nations to the Kyoto Protocol recognise the repercussions of greenhouse gases on our climate. Yet, despite their acquiescence, there has been little action taken to quell the rising emissions rate.

There are several reasons that might explain their reluctance. First, because GHG emissions are so directly related to the Gross Domestic Product, it is often believed that in order to decrease emissions, output would have to decrease as well. Second, with technology such as fuel cells and photovoltaics, all sectors of the economy can feasibly replace fossil fuels with a more environmentally benign energy, but at a perversely high cost. Third, when the benefits to avoiding anthropogenic GHG induced climate change only occur in the distant future while the costs would have to be incurred today, it is often deemed "uneconomical" to take any action to curb emissions at even a slight positive discount rate. Research undertaken for this thesis will attempt to demonstrate that substantial abatement can be achieved without a drastic drop in output, or by incurring an exorbitant cost.

There are several different types of fossil fuels being used today for electricity generation. Some emit more CO_2 than others. If the power generation sector can be encouraged to use those with lower emissions, this would go a long way to attaining the Kyoto target. Furthermore, this abatement method would presumably be affordable since conventional steam facilities can often accommodate different types of energy inputs. This premise thus raises the following question: How much of a carbon fee would be needed to induce Ontario's conventional steam facilities to switch to cleaner energy and hence lower CO_2 emissions sufficiently to comply with the Kyoto Protocol?

Due to the advances in econometrics and the development of the translog cost function as one the first non-restrictive tools to model the production process with more than two factor-inputs, it is a relatively painless task to answer this question. Several different types of energy inputs (coal, oil and gas) can now be included with capital and labour in the modelling process to produce a more accurate representation of the structure of production. Using the translog modelling framework, a set of demand equations can be estimated to provide a measure for the degree of substitutability of one fuel input for another in the production process, thus raising a second question: What is the substitutability of the various fuel inputs?

Given that the intensity of CO_2 emissions remains constant with the type of fuel burned, having a measure for the substitutability of energy inputs also provides us with a measure for the substitutability of emissions. In other words, the demand equations drawn from the translog procedure can provide a means to estimate the carbon fee needed to alter the relative price of fossil fuels enough to entice the use of cleaner energy and attain the Kyoto target. In the end, the price of fossil fuels will increase disproportionately and the magnitude of the increase will dictate how costly a carbon fee policy will be. This gives rise to the final question to be addressed: What would be the cost of using a carbon fee policy as a means to satisfy the Ontario power generation sector's Kyoto commitments?

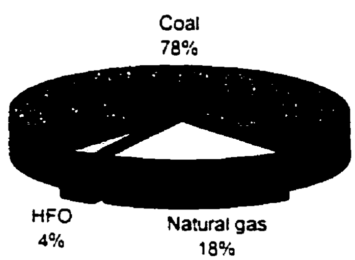
Problem Statement.

Canada will, sooner or later, need to lower its greenhouse gas emissions. Carbon fees are being considered as a possible instrument to achieve this objective. However, if carbon fees need to be very large to only modestly deter emissions, imposing them might impair the economy. It becomes of interest then, to ascertain just how large a carbon fee would need to be in order to attain a set abatement goal. This research will develop a mechanism to estimate the size of the carbon fee required in a particular sector, to achieve the GHG reduction target under the auspices of the Kyoto Protocol.

Chapter 2: Literature Review

The Kyoto Protocol set the CO_2 emissions reduction target that Canada has to have maintained by the year 2012. Short of a unilateral sacrifice by consumers and producers to abate their energy needs, the federal and provincial authorities will have to establish a policy in order to induce the reduction sought. This policy will most likely be a carbon fee. The question is, how high would it have to be to successfully abate Canada's emissions in compliance with the Kyoto Protocol?

Figure 2.1
Electricity generation CO_2 emissions, Ontario 1998



Ontario's fossil fuel fired electric utilities rely heavily on imported bituminous coal, Canadian bituminous coal and lignite for its steam turbines. In recent years though, natural gas and heavy fuel oil (HFO) have made an upsurge and together, represent 22% of this sector's fuel inputs (Figure 2.1). Considering that these three types of coal emit substantially more CO_2 per unit of electricity generated than other substitutes, it isn't hard to imagine the environmental benefits from switching to alternate fuels.

There have been a number of studies that examine interfuel substitution and the role that price plays on this behaviour for producers and consumers alike. The translog cost function approach to modelling energy demand has been widely used ever since Christensen, Jorgenson and Lau (1973) first demonstrated that estimation of non-restrictive substitution characteristics for production structures containing many inputs was possible. Prior to their groundbreaking work, analysis of the production function with more than two factor inputs required the imposition of constraints that were too restrictive[10].

Several studies thereafter examined the role of energy in the structure of production. Fuss (1977) was the very first to employ the translog cost function methodology to modelling energy demand in Canadian manufacturing and his paper remains very well cited to this day. Using time series data, Fuss took a close look at the own and cross-price elasticities for six different energy inputs (E) in production (coal, liquid petroleum, fuel oil, natural gas, electricity and motor gasoline), and for labour (L), capital (K), and materials (M). The assumption of weak seperability in the E, L, K, M aggregates allows the modelling to proceed in two stages: First, the elasticities are estimated for the energy inputs alone to determine the degree of interfuel substitution. At this step, an aggregate energy price index is calculated for the six fuels and is used as an instrumental variable in the second stage, where, in turn, the elasticities are estimated for energy,

[10] McFadden, D.L., 1963, "Constant elasticity of subscription production functions", *Review of Economic Studies* 30, April, 73-77

labour, capital and materials. Their sign will indicate whether pairs of inputs are complements or substitutes. In this pioneering study, Fuss makes several observations:

1. All own-price elasticity estimates are negative. This result is consistent with the postulates of cost-minimising factor demand theory.
2. The cross-price elasticity estimates indicate that there would appear to be substantial scope for interfuel substitution, and substitutability between energy and non-energy inputs. Complementarity did exist, however, between energy and materials, and energy and capital.

Pindyck (1979) conducted a similar study by pooling time series, cross-sectional data for ten industrialised countries. By pooling the data, the author was able to obtain a sample large enough to provide low variance estimates of long-run elasticities. Regional dummy variables had to be included here to allow the intercept parameters to vary across countries and to test the capability of pooling the data from countries that have largely different fuel prices.

All in all, the methodology employed here was very similar to that of Fuss's study with only slight differences in the variables chosen. The goal was to determine long-run elasticity estimates to see whether they would differ from the short-run estimates from previous studies, as energy demand theory would indicate. There is a certain lag that a manufacturer faces in order to alter their machinery to accommodate a different fuel mix and so it is presumed that long-run elasticities would be higher in absolute value than those in the short run. Pindyck's results seem to support that conclusion whereby the own-price elasticity of aggregate energy demand appears to be significantly larger than had previously been thought. Furthermore, energy and capital appear to be substitutes rather than complements in the long-run. Once again, the cross-price elasticity estimates are significant and large, and so there is considerable room for interfuel substitution.

Caloghirou et al. make use of the translog approach to model industrial energy demand in the Greek economy using time series data spanning the years 1980 to 1991. Although the focus here was not on interfuel substitution, the authors make several observations, which support many of Pindyck's conclusions. With the exception of electricity, other energy sources show rather significant substitution with capital while remaining complements with labour.

Where others have simply estimated elasticities to show the relationship between different factors of production, Caloghirou et al. extend their conclusions with a multinomial logit model that allows them to make dynamic short term predictions of the changes in the structure of production for Greek industry. Their results show that manufacturing will substitute away from fossil fuel based energy to electricity.

Bopp and Costello (1989) use the standard translog cost function approach to analyse the choice of interfuel substitution at fossil fuel electric utilities in the US. However, where most make use of this modelling framework to examine the substitutability of energy, labour and capital in the production process, here the focus is on the substitutability of the three main fossil fuels (oil, coal and natural gas) in the generation of electricity. They therefore, assume labour and capital are fixed and interfuel substitution will occur regardless of these two inputs.

The authors estimate the short-run own and cross-price elasticities of industrial demand on national and regional scales using time series and cross sectional data. They draw similar conclusions to those of other studies whereby a fair degree of substitution occurs between fuels. They do enhance the understanding of energy demand in the industrial process by disaggregating the model into regional sub-models and make a case that these regional models provide more robust elasticity estimates.

Estrada and Fugleberg (1989) analyse the own-price elasticities of natural gas and the cross-price elasticities between gas and other fuels in France and West Germany. In so doing, they measured the demand for natural gas and the degree of interfuel substitution in these two countries. Once again, the translog methodology was adopted using time series and cross sectional data for both countries. The authors were attempting to construct a model that would determine changes in market penetration of energy sources for both the residential and industrial sectors. Their underlying hypothesis was that the long-run changes in composition of energy demand was directly associated with changes in the relative fuel prices, as well as infrastructural changes in the economy.

They acknowledge that the short-run price elasticity of energy demand was well known and small (-0.2), but they set out to test if long-run elasticity was higher due to the ability of consumers and producers to change their energy equipment over time. They confirm the results obtained by Pindyck (1989) whereby estimates of elasticity were considerably higher in the long run. Interfuel elasticity estimates were found to be significant but not as high as expected. They attribute this short fall to the oil price shock of the 1970s included in their time series when prices soared so high for all fuels that it triggered the substitution from energy to other factors of production.

Doms (1993) enriches the understanding of fuel choice at the plant level by determining the factors that influence the plant's decision on what type of energy technology to invest in. Doms brings to light the fact that there is significant variation in energy prices in the United States and sets up a linear logit model, using cross-sectional data to test the response by plants in their adoption of energy technologies.

The author first demonstrates that there are several factors that influence the plant's energy choice decision such as energy intensity and scale of production. In any case, the results clearly establish the relationship between prices and type of technology employed. Firms are willing to invest in technologies that can accommodate several different fuel inputs when their price-energy ratio is comparable, but when one price reaches either extreme, firms tend to become locked-in to one energy input.

Doms's conclusions are interesting as they contradict the assumptions made by others where interfuel substitution would occur mainly in the long-run but, as the case is made here, depending on size and location of the plant, fuel switching can occur much more readily. This study supports Bopp and Costello's (1989) findings where regionally disaggregated energy choice sub-models yielded more telling elasticity estimates than one general model.

Elkhafif (1992) estimated industrial energy demand for the province of Ontario using a linear logit, two-stage interfuel substitution approach. As the author explains, this functional form was chosen over the translog methodology to ensure non-negative estimates of expenditure shares[11]. If this condition is violated, then the quasi-concavity assumption might not hold and positive own-price elasticity estimates would arise.

[11] Christensen and Caves (1980) demonstrate that when input prices fall outside a certain range, the translog specification cannot maintain the theoretical conditions of production.

Although the linear logit specification was employed, the objectives of the paper was to obtain estimates for the own and cross-price elasticities in order to enhance policy maker's understanding of the structure of production. The results were comparable to those of Pindyck and Fuss with one important distinction. Two simulations were run to calculate the demand elasticities in response to price shocks: the first including an endogenous energy variable and in the other, energy was held constant. Elkhafif found that the elasticity estimates were larger in the first case than in the second and concludes that, although capital stock adjustments will occur in response to aggregate energy price changes, none will take place due to interfuel substitution.

Smith et al. (1995) make use of a linear logit specification to estimate the demand for coal, oil and gas in eight OECD countries. Much like previous studies, the authors build a system of expenditure share equations for each of the fossil fuels but extend their use beyond elasticity analysis to simulate the effects of an international carbon/energy tax regime on CO_2 emissions.

The authors compared emissions reduction in the year 2030 from baseline in response to an *ad valorem* tax, an energy tax and a carbon tax and conclude that the latter would be more cost effective in reaching its goals. Energy output was not held constant in their simulation and the bulk of emissions reduction was predicted to come from a drop in fossil fuel consumption and not interfuel substitution.

Overall their results are suspect. OLS was used to estimate the demand share equations when most studies of this nature employ a more reliable methodology to solve the system of equations that have simultaneous characteristics. The individual elasticities were not computed, but the coefficients on the prices for the three fuels were in line with expectations except for natural gas in Canada, which does not seem to have any effect on the demand for either fuel. Finally, their elasticity estimate for the total energy aggregate was found to be considerably lower than commonly accepted.

One of the distinguishing features of the translog cost function is its linear parameters, which facilitates estimation of its input share equations. It is this linearity that can cause the predictions of the expenditure shares to be negative when input prices fall outside a certain range. When this phenomenon is suspected to occur, Lutton and LeBlanc (1984) propound the use of the linear logit functional form, which, by design, assures expenditure share values between zero and one. By comparing the two methods in simulation, the authors conclude that neither are difficult to estimate but the logit specification exhibited more flexibility since the shares were confined to the zero-one interval and is thus more suitable for general application.

Through empirical testing, Moody (1996) conducts a similar comparison between the forecasting abilities of the translog and linear logit functional forms. Although similar conclusions are drawn here as in Lutton and LeBlanc (1984), the author reports some of the potential drawbacks of the logit approach. First, the logit system is an ad hoc characterisation of cost shares lacking the theoretical basis of the translog function. Second, symmetry restrictions are not guaranteed during simulation when input prices are set beyond the range of the sample data.

Given the precedent set by previous energy demand models, the choice functional form for the purposes of this study will be the translog cost function. Its primary drawback is its potential to produce estimates of negative expenditure shares, which cannot occur in actuality. But if this happenstance is not suspected, the translog cost function remains an efficient and consistent method for estimating input demand. Recall that the goal here is to analyse the demand response on individual fuels when a carbon fee induces a change in their relative prices. If the producers of electricity truly exhibit cost minimising behaviour, then a downward shift in the share of coal away from the 100% barrier would be expected. Similarly, the shares of natural gas and HFO would presumable rise away from 0%. In this case then, sacrificing the symmetry restriction by employing the logit function is unwarranted.

Chapter 3: The Translog Function

Prior to the 1970s, empirical studies on the structure of production were confined to analysing the trade-off between two inputs, labour and capital. The functional form used in these studies assumed constant elasticity of substitution (CES) which proved to be excessively restrictive to extend to accommodate more than two factors of production. It wasn't until the breakthrough work of Christensen, Jorgenson and Lau (1973), who presented a fundamental deduction of the generalised translog functional form, that allowed for the non-restrictive estimation of substitution possibilities with several factors of production. Their novel approach inspired numerous studies on production incorporating labour and capital inputs, several differing energy inputs, and raw materials[12]. In this chapter, the generalised translog function will first be presented in context with the present energy study, followed by its applicability to estimating the substitutability between utility fuel components.

The advantage of the translog function is that instead of using the production function with its optimisation conditions, the producer's behaviour is assessed by the indirect cost functions. Then, by using the duality between cost and output,

[12] See Berndt and Christensen (1973), Berndt and Wood (1975), Fuss (1977), Pindyck (1979), Estrada and Fugleberg (1989) and Bopp and Costello (1990).

the optimal levels for different inputs can be obtained from the cost function through differentiation.

The translog functional form requires certain assumptions about the structure of production. The production function is assumed to be weakly separable in its major categories of capital, labour, materials and energy. In other words, the marginal rate of substitution between individual fuels is independent of the quantities of capital, labour and materials. Furthermore, the capital, labour and energy inputs are assumed to be homothetic in their components and thus, the energy aggregate is homothetic in individual fuel inputs. This is a necessary and sufficient condition for the underlying two-stage optimising process, where the components within each aggregate are optimised, then the optimal mix of all aggregates is discerned. This condition allows for the construction of an energy sub-model to measure interfuel substitution. It follows that the production function can be written as:

$$Q = f[K, L, e(E_1, \ldots, E_n), M] \tag{1}$$

Where Q is output, and *e* is a homothetic function for the *n* number of energy inputs. The assumptions above allow for the remaining inputs, namely, capital, labour and materials to be broken down into their own sub-models as well, but for the present analysis, the emphasis is on energy.

Given cost-minimising behaviour by firms, if prices and output are exogenously determined, then the duality between cost and production will permit the representation of the production function above by the following cost function:

$$C = g[P_K, P_L, P_e(P_1, \ldots P_n), P_M, Q] \tag{2}$$

Where C is total cost, P_e is a function that aggregates the price of energy[13], and P_i are factor prices for $i = K, L, E, M$.

As stated above, the generalised modelling process involves two stages. The first stage is the derivation of energy demand from the energy sub-model:

$$P_e(P_1, \ldots P_n)$$

Consider an economic agent who has the option to choose between *n* fuel types. Since P_e represents the aggregate price index of energy, it is also the cost per unit of energy to the optimising agent. A translog cost function is a second-order approximation of an arbitrary cost function, and has the form:

$$\ln P_e = \ln \beta_0 + \sum_i \beta_i \ln P_i + \tfrac{1}{2} \sum_i \sum_j \beta i_j \ln P_i \ln P_j \tag{3}$$

[13] The aggregator function P_e would not be a simple weighted average unless the cost of switching from fuel to fuel is zero. In such a case, the fuels would be perfect substitutes.

From Shephard's lemma (1953), the derived demand functions in terms of shares in the cost of the energy aggregate, are found by differentiating the cost function with respect to prices. The energy demand share equations are hence given by:

$$S_i = \beta_i + \sum_j \beta_{ij} \ln P_j, \qquad \textit{for } i, j = 1 \ldots n \qquad (4)$$

where $S_i = \partial \ln P_e \ \partial \ln P_i$. Since the shares in the system of demand equations in (4) must add to 1, only n – 1 of the share equations need be estimated. It should be noted though that the cost function must be linear homogeneous and its underlying production function must be well behaved. Given these conditions, the following parameter restrictions become necessary:

$$\sum_i \beta_i = 1$$
$$\sum_i \beta i_j = \sum_j \beta i_j = 0$$
$$\beta_{ij} = \beta_{ji}, \forall i \neq j$$

Determining the coefficients in the system of demand equations above completes the first stage in the elasticity estimation procedure. Recall that the aim in this stage was the derivation of demand for the energy aggregate. Similar sub-models could be constructed for the other aggregates as well, with the exception of materials[14], but as stipulated earlier, the focus here is on energy.

The second stage involves estimating the demand for all production inputs. The production function, which best represents this case could then be written as follows:

$$Q = f(K, L, E, M) \tag{5}$$

Where gross output is a function of the capital, labour, energy and materials inputs. As was the case with the energy sub-model, the duality between cost and production permits us to portray the production function by its corresponding cost function:

$$C = g[P_K, P_L, P_E, P_M, Q] \tag{6}$$

Which, in turn, can be approximated by a translog function of the form:

$$\begin{aligned}\ln C = \ln \alpha_0 + \sum_i \alpha_i \ln P_i + \alpha_Q \ln Q + \tfrac{1}{2} \sum_i \sum_j \gamma_{ij} \ln P_i \ln P_j + \\ \sum_i \gamma_{iQ} \ln Q \ln P_i + \tfrac{1}{2} \gamma_{QQ} (\ln Q)^2\end{aligned} \tag{7}$$

[14] As Pindyck (1979) p.46, indicates, the materials category is too heterogeneous to derive a meaningful demand share equation.

where C is the total cost and Q is output. There are a few distinctions with the translog cost function used in equation (7) from the one used in (3). First, the inclusion of the Q variable in the second-stage case forced the annexation of additional terms to the arbitrary cost function. Second, the cost here encompasses the prices and quantities of all production inputs rather than the cost of one input in the energy sub-model. These differences might seem superfluous but their understanding is crucial to produce precise coefficients.

Similar to the energy sub-model, the demand functions for aggregate inputs are derived by differentiating the cost function with respect to individual prices to obtain the following system:

$$S_i = \alpha_i + \sum_j \gamma_{ij} \ln P_j + \gamma_{iQ} \ln Q \qquad (8)$$

where $i, j = K, L, E, M$ and $S_i = \partial \ln C / \partial \ln P_i$. As in equation (4), the sum of the shares must equal unity $(\sum Si = 1)$, and the demand system must respect neo-classical production theory. Together, these conditions impose equivalent parameter restrictions[15]:

[15] Christensen et al. (1973) describe the derivation of these restrictions. They can be classified as: Cournot aggregation ($\Sigma_j \gamma_{ij} = 0$), Engel aggregation ($\Sigma_i \gamma_{iQ} = 0$) and Slutsky symmetry ($\gamma_{ij} = \gamma_{ji}$).

$$\sum_i \alpha_i = 1.$$
$$\sum_i \gamma_{ij} = \sum_j \gamma_{ij} = 0.$$
$$\sum_i \gamma_{iQ} = 0.$$
$$\gamma_{ij} = \gamma_{ji}, \forall i \neq j$$

Estimating the coefficients in equation (8) completes the generalised two-stage translog cost modelling procedure. The balance of this section turns to the details of the procedure, the derivation of own and cross-price elasticities and the precise model parameters that will be employed in context of the present study.

The first step in the modelling procedure is to estimate the energy sub-model in equation (4) subject to its constraints. This would yield information as to the structure of interfuel substitution and provide a framework for assessing each energy type's share given an arbitrary set of relative prices. The coefficients obtained would then be substituted into equation (3) to draw an estimate of the aggregate price index for energy $P_{\dot{e}}$, which will serve as an instrumental variable in the second stage.

The second step is to estimate the parameters in equation (8) by replacing the price of energy with its instrumental variable $P_{\dot{e}}$. The coefficients obtained would not only provide information on the structure of interfuel substitution but on the relationship that exists between energy and non-energy inputs in the production process as well. It then becomes possible, through simple parameter manipulation, to estimate the changes in quantities demanded for individual fuels and estimate the own and cross-price elasticities for all inputs.

One of the benefits of the translog cost function is its ease in which the price elasticities can be obtained to measure the substitutability between different factors of production. This elasticity measures the percentage change in the quantity demanded of one factor resulting from a 1 percent change in the price of another. Two factor inputs are said to be substitutes if the elasticity estimate is positive and complements if negative. As Pindyck (1979) points out however, there are several different elasticity estimates obtainable from the translog cost function[16], but the most pertinent measures of price responsiveness here are the partial price ε_{ii} and cross-price ε_{ij} elasticities derived from the following expressions:

$$\varepsilon_{ij} = (\gamma_{ij} + S_i S_j)/S_i, \qquad i \neq j \tag{9}$$

$$\varepsilon_{ii} = (\gamma_{ii} + S_i(S_i - 1))/S_i$$

These are termed partial elasticities as they account for the substitution effect between factors of production but assumes that total input demand remains constant regardless of relative price changes. When applied to analysing the effects of a carbon fee, these elasticities will measure interfuel substitution in response to relative price changes, but assumes the total consumption of energy

[16] Pindyck (1979): pp 51-53.

is constant. At first glance, this assumption might seem unrealistic but for reasons that will become clear later, it supports this paper's underlying premise that significant CO_2 cuts can be achieved without having to seriously dislodge the energy infrastructure.

Before introducing the exact model specifications, it might be useful to recapitulate the objective of this study. CO_2 emissions are generally being accepted as the leading cause of the rise in global average temperature. Carbon fees seem to be the most likely method of abatement. Once applied, the price ratios between fuels will change and it is presumed that producers will alter their energy mix to less carbon intense fuels. In the end, greenhouse gas emissions will fall, but to what extent? This study seeks to answer this question by quantifying the degree of substitutability between fuels. The most suitable way to accomplish this task is with the translog cost function, which employs the duality between cost and production to produce a system of demand share equations for individual fuels. This is a well established methodology for analysing interfuel substitution, and because carbon emissions are relatively fixed by type of fuel burned, it is easily extended for CO_2 abatement analysis.

Earlier uses of the translog functional form have been to examine the relationship between pairs of factor inputs in the production process. Where most were concerned with determining the complementarity or substitutability of energy and capital, and energy and labour, the emphasis here is on the substitutability of the three main energy types (Coal, oil, and natural gas). It is the position of this paper that interfuel substitution can, and will occur in response to relative energy price changes without a discernible effect to capital and labour, and so their role will not be considered. It stands to reason that in an inconstant fossil fuel market, firms can make adjustments in their energy mix without a significant impediment to production. At least two studies on Canadian manufacturing lend support to this premise. Fuss (1977) conducted an elaborate analysis of Canada's manufacturing sector, and included capital, labour and materials, and six different energy inputs using a two-stage model. Fuss showed strong evidence that substantial interfuel substitution would occur in Canadian industry, but there was very little substitution between energy and non-energy inputs. More recently, Elkhafif (1992) examined Ontario's manufacturing sector using a similar procedure, and concluded that when the level of energy consumed is held constant, capital adjustments will occur in response to changes in total demand for energy, but not due to interfuel substitution. Ultimately, the only variables that should thus be considered here are the three energy types. It is hoped that their interactions will provide invaluable information on the substitutability of CO_2 intense fuels for those that are more environmentally benign.

One final note, since the aim here is to isolate the substitution effects of energy due to changes in relative prices of fuel while ignoring its impact on capital and labour, some of the assumptions made earlier in the generalised modelling procedure can be relaxed. In particular, the assumption of homotheticity becomes unnecessary when the only inputs being considered are the energy inputs[17]. Furthermore, since the roles of capital and labour are not being considered, the modelling procedure is reduced to a single stage. Thus, the functional form adopted, allows for non-homotheticity and variable returns to scale and is written as:

$$S_i = a_i + \sum_j b_{ij} \ln P_j + b_{iQ} \ln Q \qquad (10)$$

where

S_i	*Budget share of fuel i*
i, j	*Coal, oil, and gas*
P_j	*Price of fuel j, $i \neq j$*
Q	*Output*
a_i	*Constant term*
$b_{i,Q}$	*Parameters to be estimated measuring sensitivity*

and $S_i = \partial \ln C / \partial \ln P_i$, represents the change in the cost of energy with respect to the change in the price of fuel i. Equation (10) is the standard framework to analyse energy demand, but to fashion the model for the particulars of this study and improve the overall efficiency of the coefficients, additional explanatory variables will be added:

$$S_i = a_i + \sum_j b_{ij} \ln P_j + b_{iQ} \ln Q + d_i S_{it} + \sum_k g_{ik} \ln Z_k \qquad (11)$$

---

[17] The structure of production is homothetic if $\gamma_{iQ} = 0$ for all $i = K, L, E, M$ from equation (7).

where

S_{it}	*Budget share of fuel i in time period t,*
Z_k	*A set of exogenous variables of interest,*
d_i, g_{ik}	*Parameters to be estimated.*

As in equation (8), the demand shares must respect the adding-up criterion $(\sum Si = 1)$, and are subject to the same restrictions:

$$\sum_i a_i = 1.$$
$$\sum_i b_{ij} = \sum_j b_{ij} = 0.$$
$$\sum_i b_{ik} = 0.$$
$$b_{ij} = b_{ji}, \forall i \neq j$$

Finally, the partial own and cross price elasticities are calculated as follows:

$$\varepsilon_{ij} = (b_{ij} + S_iS_j)/S_i, \qquad i \neq j \tag{11}$$
$$\varepsilon_{ii} = (b_{ii} + S_i(S_i - 1))/S_i$$

A set carbon fee will provoke a one time disproportionate increase in the price of fossil fuels. On the whole, profit-maximising producers will react by substituting their higher emission fuels for an energy source that is cleaner and relatively cheaper. With data on Ontario's power generation industry, the above translog procedure will attempt to model this substitution by predicting where the quantity demanded for individual fuels will settle in response to a one time carbon fee induced price increase. In the end, it becomes a simple matter to make a quantitative assessment of the ensuing drop in GHG emissions.

Chapter 4: The Structure

Overview of Ontario's power generating sector

The electric power industry in Canada almost exclusively relies on three means to produce electricity: hydro, nuclear and fossil fuel driven conventional steam. Each of these methods has its own socio-environmental externality but climate changing GHG emissions associated with burning fossil fuels is at the top of the list of environmental concerns today. Conventional steam facilities are responsible for all of this sector's annual GHG emissions, entirely composed of CO_2, and will no-doubtedly need to make certain modifications if Canada is to meet its abatement commitments.

Canada is endowed with abundant water resources which explains its uncommon reliance on hydro electricity. It would be feasible to permanently displace conventional steam technology and replace it with more renewable energy, but presumably at a significant cost. As is hoped to be demonstrated here, it might be possible for Canada to meet, and even exceed its short to medium term abatement goals without abandoning the well established conventional steam infrastructure, and perhaps not incur a prohibitively high cost.

The state of Canada's conventional steam power generation is complex. The provinces Eastward of Quebec will rely on coal and heavy fuel oil (HFO) during peak load seasons with natural gas altogether absent in their fuel mix[18]. Conversely, in the provinces Westward of Ontario, the emphasis seems to be on coal and natural gas with HFO only playing a minute role for power generation. Quebec itself, with its massive James Bay installations, has only a very small natural gas based capacity. The province of Ontario, on the other hand, will make significant use of all three types of fossil fuels to meet its ever-increasing demand for electricity. It follows then that a study aimed at analysing interfuel substitution in Canada's power generation sector would best be served by a province specific focus. In other words, due to the heterogeneous structure of conventional steam power generation, efficient estimates of fossil fuel demand will necessitate a region specific analysis[19].

Ontario's conventional steam power generation sector was chosen as the subject of this study for its dynamic involvement of all three types of fuels and for its sheer CO_2 abatement potential. As is the case with other provinces, and even other countries, coal will account for the bulk of the fuel utilised in Ontario's mixed fuel portfolio. Considering that the CO_2 emission factors from burning coal are at the upper end of the scale at 88 tonnes per terajoule (t/Tj), and those of natural gas stand at 49 t/Tj[20], it isn't hard to imagine the environmental benefits of substituting away from coal. It stands to reason that altering the fuel in

[18] See table 2 of Statistics Canada's Electric Power Generating Stations, 1998 – Catalogue no. 57-206-XPB.
[19] Bopp and Costello (1990) affirm the premise that regional models were more revealing of the underlying economics of the fuel choice problem faced by electric utilities in the United States.
[20] Smith, Robert. (1995) "Canadian Carbon Dioxide Emissions". *Environmental Perspectives*. Statistics Canada Catalogue no. 11-528E, No. 2: 77-88

conventional steam burners will go a long way to cutting emissions, and at a more palatable cost to society.

Up until April 1999, Ontario Hydro was the crown-corporation governing power generation in Ontario. In the process of deregulation, this responsibility has since shifted to a separate provincially owned company named Ontario Power Generation. Despite the name change, this new corporate identity maintains the same diversity of technologies to meet the province's electricity demand, comprised of steam nuclear, hydro and fossil fuel powered conventional steam. Two thirds of the province's energy needs will be met with their baseline hydrologic and nuclear capacity while the remaining third belongs to conventional steam which was responsible for more than 26 million tonnes of CO_2 emissions in 1990.

Conventional steam power generation is the process of burning, either coal, natural gas or HFO to turn liquid water into vapour to drive a generator and produce electricity. Historically, Ontario hydro has made considerable use of all three fuels. Due to the volatile nature of fuel prices though, electricity generating costs will operate under the Merit Order Dispatch system (MOD) where Ontario Hydro and now, Ontario Power Generation, ranks each fuel's operating cost and makes a choice of what fuel to utilise given prevailing market conditions[21]. So, for instance, if the relative price of HFO is low for a given period of time, Ontario

[21] Grenier, Serge. Unit head, energy section, Statistics Canada, Ottawa. Interview July, 2000.

Power generation will rank the HFO burning facilities above others. This is analogous of a cost minimising process where fuels can be substituted for one-another in response to relative price changes.

However, because conventional steam burners cannot accommodate perfect substitution of fossil fuels, the power generation sector, guided by the MOD system, is not poised to make immediate fuel mix adjustments in response to the day to day spot price. Instead, this industry will make its decisions based on the trend of relative fuel prices. This is suggestive of a longer-term relationship between prices and the expenditure share of individual fuels. A matter that further lends itself to this premise is the nature of natural gas based electricity. It is wholly generated by independent producers and purchased on a contractual basis. Ontario Power Generation is hence committed to acquire a predetermined amount of natural gas based electricity for an inflexible period of time.

Given the industrial structure described above, the power generation sector's fuel switching, cost minimising behaviour, which is hoped to be captured in this study's translog procedure, is best suited for long-run analysis. This is consistent with prior studies of this nature[22].

[22] See Pindyck(1979), Estrada and Fugleberg(1989) and Elkhafif(1992).

Methodology

The translog specification involves a system of equations that are simultaneous in nature. Simultaneity results in a cross-equation correlation of the disturbance terms and hence independent OLS estimation of single equations yields biased and inconsistent parameter estimators. It becomes necessary then, to rely on a more sophisticated estimation method which can account for the close conceptual relationship between parameters across equations. The Seemingly Unrelated Regression (SUR) model has become common practice when estimating a system of related equations. The SUR method involves generalised least square estimation and improves the overall efficiency of the model by accounting for the cross-equation correlation of the error terms and for the situation where some of the explanatory variables across equations are identical, as is the case in the present analysis.

In effect, the SUR procedure uses single equation OLS to derive an estimate of the error covariance matrix and once obtained, performs generalised least square estimation. During this process, estimates of the error covariance matrix can be updated and the Zellner procedure iterated until sequential changes in both the covariance matrix and the estimated parameters between iterations become negligible. This is termed the iterative Zellner-efficient estimator (IZEF) and is the choice methodology in the present context, to ensure that the parameter estimates are invariant to the exclusion of one of the equations under the conditions of the adding-up criterion ($\Sigma Si = 1$). When the error term is normally distributed, the IZEF procedure is equivalent to maximum likelihood estimates in multivariate regression models[23].

The Data

The data consists of a time series of quarterly observations on Ontario's electric power industry spanning the years 1981 through 1999. In the years prior to 1981, the techniques used to compile the statistics were different[24] and therefore, less compatible with the present statistics so their inclusion here might unnecessarily introduce a bias to the estimation procedure.

The translog model of energy demand describes the breakdown of electric utility production costs into expenditures on individual fuels and from chapter 3, takes on the following form:

$$S_i = a_i + \sum_j b_{ij} \ln P_j + b_{iQ} \ln Q + d_i S_{it} + \sum_k g_{ik} \ln Z_k \qquad \text{for i, j = coal, nat. gas and HFO}$$

Where S_i is the expenditure share of fuel i, P_j are the prices of each fuel, Q the output, S_{it} Lagged dependent, and Z_k a set of exogenous variables of interest. These variables will be represented in this study as follows:

Scoal	= expenditure share of coal,
Sgas	= expenditure share of natural gas,
Shfo	= expenditure share of HFO.

[23] Berndt, E.R., B.H. Hall, R.E. Hall and J.A Hausman, (1974) Estimation and inference in nonlinear structural models, Annals of Economic and Social Measurement 3, October, pp: 653-666.
[24] Sannes, Greg. Energy section, Statistics Canada. Ottawa. Interview July, 2000.

All shares are expressed as a percentage of the total fuel cost faced by Ontario hydro's conventional steam capacity and must hence add to unity.

lnPcoal3	= price of coal,
lnPgas3	= price of natural gas,
lnPhfo3	= price of HFO.

Prices are natural logarithm transformations of the original prices expressed in dollars per terajoule (Tj). They are lagged by three years to account for the long term input adjustments in response to relative price changes.

lnQ	= output produced by conventional steam facilities.
Scoal3	= equation 1's dependent variable lagged by three years,
Sgas3	= equation 2's dependent variable lagged by three years,

The lagged dependent variables were included to account for the momentum in demand for a particular fuel and for potential serial correlation in the error. Their inclusion basically states that part of today's expenditure share level is related to last period's level and ideally, should only be lagged by one quarter[25]. Unfortunately, since one of this study's main purposes is to set up a simulation model, the lag had to be consistent with the price lags. Otherwise, the predictions would be limited to quarter by quarter estimates and hence during

[25] A set of dependent variables with sequential lags could not be added to the model either. As above, this would impair the model's forecasting ability, which is the primary objective of this analysis. However, as is explained in detail in chapter 5, since the dependent variable, lagged by three years, adequately controls for serial correlation, the bias introduced by excluding other lags is negligible. Bopp and Costello (1990) lend support for this premise.

simulation, the error would be compounded with each additional projection and so longer term forecasts would essentially yield meaningless results. This approach increases the ease and reliability in the forecasting procedure which more than offsets the possible loss of efficiency associated with a longer lagged dependent.

And finally, the notation for the variables which comprise Z_k are:

lnH	=	output produced by hydro facilities,
lnN	=	output produced by nuclear facilities,
d1 to d4	=	dummy variables for quarters 1 through 4 respectively.

All output data are in logarithmic form for Ontario's electric power industry and are expressed in terajoules.

All data were obtained from various energy Statistics Canada publications and through CANSIM, their online time series service. The data collected for Ontario's electric power sector is described in detail in the remainder of this section.

Fuel prices.

For confidentiality reasons, quarterly industrial fuel prices are not directly observable and had to be tabulated from two independent sources. CANSIM matrices 1879 and 1876 yield 1992 constant dollar price indexes for coal, natural gas and HFO under the labels P1003, P1005 and P3324 respectively. These series are part of the industrial product price index series, which represent the change in input costs for industrial activity[26]. These indexes on their own, are indicative of the incremental price changes for each fuel, but provide very little information as to the real price of one fuel in relation to another. Fortunately, total expenditures on each fuel and their quantities consumed by Ontario's conventional steam facilities are obtainable from Statistics Canada's Electric Power publication from which the implicit prices can be drawn[27]. This is an annual publication and so the derived implicit prices in the 1992 edition represent the average cost for each of that year's fuel input. By multiplying the implicit prices by each fuel's corresponding price index with the same base year, yields a good proxy for the quarterly prices paid by Ontario hydro for individual fuels.

In so doing however, compatibility issues arose that will be elucidated here. Ontario's conventional steam facilities make use of at least three different types of coal: Canadian bituminous, imported bituminous and lignite, each having very different energy potential (see table 4.1). Since the price data sought are expressed in dollars per Tj and hence encompass an energy element, a simple division of the total cost of coal by total consumption in natural units might not be reflective of its true price. Instead, taking the cost per Tj of each type of coal and weighing it by its consumption share would render a more apt aggregated

[26] See Statistics Canada, Industry Price Indexes – Catalogue no. 62-011-XPB for an explanation for the methods used to derive the price indexes.
[27] Statistics Canada, Electric Power Statistics – Catalogue no. 57-202-XPB, table 6, 1992.

measurement for the implicit price of coal. In the time period covered in this study, the consumption proportions for Canadian bituminous, imported bituminous and lignite coal remained relatively fixed which afforded the applicability of the same weights to each observation. And so the weighted cost of coal, and the cost of natural gas and HFO are well suited scalars for the price index vectors to produce a data set for the implicit price of the three fuels.

Table 4.1: Ontario's implicit prices of fuel

Consumption by electric

		Consumption	unit	Cost .000 $	cost $/unit
Coal	Can Bit.	2808745	Mg	$ 245,674	$ 87.47
	Imp. Bit.	6486656	Mg	$ 351,653	$ 54.21
	Lignite	923896	Mg	$ 31,010	$ 33.56
HFO		218849	kl	$ 36,818	$ 168.23
Nat. Gas		665034	.000 m3	$ 48,669	$ 73.18

Energy

		kilojoules	per	Consumpt. Tjs	cost $/Tj
Coal	Can. Bit.	25707	kg	$ 72,204	$ 3,402.48
	Imp. Bit.	30110	kg	$ 195,313	$ 1,800.46
	Lignite	16121	kg	$ 14,894	$ 2,082.03
HFO		41437	litre	$ 9,068	**$ 4,060.01**
Nat. Gas		37717	m3	$ 25,083	**$ 1,940.31**

Weighted cost of Coal

		Consumpt.	Share	cost $/Tj	**weighted cost**
Coal	Can. Bit.	2808745	27%	$ 3,402.48	
1992	Imp. Bit.	6486656	63%	$ 1,800.46	**$ 2,266.22**
	Lignite	923896	9%	$ 2,082.03	
	Total	10219297	100%		

Source: Statistics catalogue number 57-202, table 6, 1992

Expenditure Shares.

Much like prices, a quarterly frequency of data for expenditure shares on fuel is unobservable, but the total quantity of coal, natural gas and HFO transferred to electricity in Ontario are found in CANSIM matrices 7976 and 7977 under the labels D387269, D387270 and D387070 respectively. Once obtained, it becomes a simple matter of converting the quantity information into cost by multiplying each quarter's observation by its respective price. The expenditure shares are hence calculated by dividing the cost of each fuel by the sum total of the three.

Output.

Observations for the output by conventional steam, hydro and nuclear facilities are directly observable and found in a series labelled D371911, D371910 and D371912 respectively.

Chapter 5: Empirical results

Section 1: diagnostics.

Before delving into the details of the model and interpreting the coefficients, it might be informative to take a closer look at some of the diagnostics employed. The standard approach is to test for a relationship between regressors, for a dependence in the error terms, and for an non-stochastic error. If any of these symptoms were firmly entrenched in the model, it would certainly cast doubt to its overall credibility. The tests for multicolinearity, autocorrelation and heteroscedasticity will hence be presented in this section.

Multicolinearity

Due to the structure of the translog model, correlation between the independent variables is to be expected. The simultaneous nature of the demand share equations states that demand for individual fuels is not only dependent on its price, but on the prices of other fuel inputs as well. And as fuels are substitutable, it stands to reason then that there must be a certain degree of interaction between the prices themselves, which would introduce a multicolinear element to the model.

A common diagnostic for multicolinearity is given by the matrix of correlations between pairs of independent variables which, in this case, does not reveal a high degree of correlation (Appendix 1). However, this test does not clarify the relations that might exist between one regressor and a combination of other regressors. A more telling test would be to calculate the multiple correlation coefficients of each independent with the other independents to obtain a measure of the goodness of fit under each circumstance. If any of these approaches the model R^2, then there would be a clear indication of a substantial multicollinearity problem. Although these test results suggest that the independents are interrelated, the degree of correlation does not warrant serious concern.

In any case, the presence of correlated explanatory variables does not affect the model's estimated coefficients, but serves only to inflate the standard errors of the correlated coefficients[28]. This, in turn, deflates the t-statistics which might lead to the erroneous expulsion of variables that are believed to be insignificant. If, however, most of the variables are significant and the insignificant ones are not dropped from the model, there are no consequences to the presence of multicolinearity.

[28] Kennedy, Peter. (1998) A Guide to Econometrics. 4th edition, the MIT Press, Cambridge, MA.

Autocorrelation.

Since the model relies on a time-series data set, it would be prudent to check for the presence of serial correlation in the disturbance term. The lagged dependent variables were introduced in both estimated equations to account for the inertia in demand for individual fuels from one quarter to the next. As was explained, the lag on the dependent variable had to be consistent with the price lags to facilitate the forecasting procedure. However, with this extensive lag on the dependent, it might lose its effectiveness to adequately control for the correlation between the error term in time period t and those in previous periods. This potential problem will be examined below.

Due to the disposition of the translog model and the presence of a lagged dependent, the standard Durbin-Watson test statistics will be meaningless[29]. Determining the presence of serial correlation will hence necessitate a different approach. As such, figures A2.1 and A2.2 in Appendix 2 are graphs for the residuals plotted against time where, in this case, the time element is represented by the sequentially ordered observation number. For both share equations, there are no visible patterns in the error throughout time. This would indicate that there is no discernible correlation in the disturbance term. The next step would be to correlate the residual with the residual at incremental lags to numerically identify any potential problems. In all cases, there was less than a 30% correlation between any pair of residuals for both share equations. This

[29] Pindyck, R. and D. Rubinfeld. (1991) Econometric Models and Economic Forecasts. 3rd edition. McGraw Hill. p.147.

lends further support to the conclusion reached above. Regression performed on the same residuals is more telling of the nature of the error's serial relationship. For the natural gas share equation, the coefficient's t-statistics and the model's adjusted R^2 both confirm that very little autocorrelation exists. However, in the coal share equation, there seems to be a stronger relationship between the error in time period t to the error lagged by one period, but the model's R^2 of 6% suggests that there is insufficient cause for concern. In the end, these fundamental tests provide strong evidence that the model will not be seriously affected by serial correlation and so more exhaustive diagnostics are unwarranted.

It becomes of interest then, to run the same series of tests on a model which purposely excludes the lagged dependent, but otherwise contains the exact same set of variables. Under these conditions, graphical and numerical diagnostics in Appendix 2 tell a completely different story. Figures A2.3 and A2.4 illustrate a much more visible pattern in the error for both share equations. The correlation matrix and regression analysis confirm a significantly higher residual dependence between periods. This is compelling evidence for the presence of serial correlation when the lagged dependent is excluded. Although it should be acknowledged that this is not a formal test for the validity of the lagged dependent variable, it certainly builds a strong case for its inclusion in the model.

Heteroscedasticity and normality.

One of the main criteria for a credible regression model, whether it be OLS or IZEF, is a normally distributed error term with constant variance. If these assumptions are violated, it would cast, at least, some doubt on the validity of the model or suggest the possibility of omitted variables. The first step would then be to assess the normality of the residual's distribution. The histograms in figures A3.1 and A3.2 in Appendix 3 provide the first clues that this assumption has been satisfied. The tests for kurtosis and skewness on the errors for both expenditure share equations do not allow the rejection of the null hypothesis of normality in both cases which confirms the conclusion drawn above.

The next step would be to examine the assumption of constant variance in the error term. The presence of heteroscedasticity would not lead to inconsistent , or biased estimates of the coefficients and hence, would not affect the forecasting ability of the model, but it would lead to inefficient standard errors. The residuals to fitted values plot seen in figures A3.3 and A3.4 are perhaps, the most commonly used graphical diagnostic tools to expose potential transgressions with both assumptions. The two plots, however, reveal an unusual occurrence. There seems to be a linear relationship between the residual and the fit toward either extremity of the predicted expenditure shares. Under normal circumstance, this would be alarming, but given the history of fuel use by Ontario's conventional steam sector, and the limitations of the translog model, this is an expected outcome. As explained in Chapter 2, the translog modelling procedure produces an accurate representation of expenditure shares given price fluctuations within a certain range. Beyond this range, the model begins to predict negative share values for some inputs, and greater than 100% shares for others when, in actuality, an expenditure share is expressed as a percentage and can only lie between zero and one. Since the residuals are generated by the difference between the fitted share and the observed share, and since the value of the fitted share does not abide by the same restrictions, this results in what seems to be a linear relationship between the residuals and the fit. This phenomenon is more readily visible on the observed share to fitted share plots in figures A3.5 and A3.6. Coal, for instance, has traditionally been the dominant fuel in conventional steam facilities, and its share can be seen to approach 100%. In reality, this is the obvious ceiling but the predicted shares come close to a fictitious value of 105%. Presumably, market conditions favoured using coal over other fuels which explains the complete commitment to this fuel. But as relative prices continued to change to further enhance coal's attractiveness, its expenditure share equation begins to predict coal use beyond a natural boundary. Conversely, since the shares in the model are restricted to add to unity, if one of them takes on a value of 105%, then at least one other has to be negative. This is the case for the shares of natural gas, which is exhibiting the same symptoms, but at 0% and below. In the end, it is these natural boundaries that are causing the perfectly "inelastic" relationships between the fits and the observations which is inevitably carried-over to the residual to fit diagram. On the up side, figures A3.3 and A3.4's oneway scatter plots, and boxplots in the margins indicate that the residuals are symmetrically distributed around zero, consistent with normality, that there is no clear evidence of outliers and that there is no intrinsic heteroscedasticity marked by the apparent randomness in the error.

At this point, it might be of interest to test the assumption of homoscedasticity. An integer variable was hence added to the data set to evenly divide the error terms into two groups. A "Lower" and "Upper" notation was attached to the observations 13 through 43 and 45 through 75 respectively. The new variable named "Test" will serve to perform a oneway analysis of variance between the two groups of errors for each equation and results can be seen in Appendix 3. The ANOVA's output table produces Bartlett's test of equal variance which clearly does not allow the rejection of the null hypothesis for both equations which confirms the assumption of homoscedasticity.

Section 2: results.

In the previous chapters, it was hypothesised that conventional steam electric utilities remain responsive to relative fuel price changes and will substitute one fuel input for another in order to minimise production costs. The translog model, which attempts to capture this behaviour was estimated with symmetry ($b_{ij} = b_{ji}$)

and homogeneity ($\Sigma_j b_{ij} = 0$) constraints imposed, and the results are summarised in this section.

As explained earlier, the adding-up criteria ($\Sigma Si=1$) forces the exclusion of one of the equations from the three equation system and so the expenditure shares for coal and natural gas were arbitrarily chosen to produce the estimated coefficients. Judging from the summary statistics in table 5.1, the model seems to perform quite well. The F-test, based on the sums of squares, evaluates

Table 5.1

Equation	Obs	Parms	RMSE	"R-sq"	F-Stat	P
Scoal	63	10	.0381603	0.8632	45.96794	0.0000
Sgas	63	10	.0299639	0.9068	66.73928	0.0000
Scoal		*Coef.*	*Std. Err.*	*t*	*P>t*	
	lnpcoal3	-.4637473	.0478014	-9.702	0.000	
	lnpgas3	.3452303	.0423428	8.153	0.000	
	lnphfo3	.118517	.0274482	4.318	0.000	
	lnC	.0594691	.0195448	3.043	0.003	
	lnH	.1584507	.0727104	2.179	0.032	
	lnN	-.0651973	.0322319	-2.023	0.046	
	d2	.0041467	.0169608	0.244	0.807	
	d3	.0345431	.0206565	1.672	0.097	
	d4	-.0132888	.0146606	-0.906	0.367	
	Scoal3	.3742945	.0682795	5.482	0.000	
	Constant	-1.064713	1.121547	-0.949	0.345	
Sgas						
	lnpcoal3	.3452303	.0423428	8.153	0.000	
	lnpgas3	-.3260577	.0482199	-6.762	0.000	
	lnphfo3	-.0191726	.0229269	-0.836	0.405	
	lnC	-.1317919	.0155958	-8.450	0.000	
	lnH	-.060013	.0577368	-1.039	0.301	
	lnN	.0505918	.025121	2.014	0.047	
	d2	-.055285	.0135243	-4.088	0.000	
	d3	-.074097	0162262	-4.566	0.000	
	d4	-.0175541	.0116181	-1.511	0.134	
	Sgas3	.5851193	.0559645	10.455	0.000	
	Constant	1.476262	.8848784	1.668	0.098	

Breusch-Pagan test of independence: chi2(1) = 12.761, Pr = 0.0004 the null hypothesis that the coefficients on all independent variables in the model are all equal to zero. The F Statistic of 45.96 and 66.74 for each equation with 10 and 52 degrees of freedom, leads to the rejection of the null. Consequently, the respective R^2 of .86 and .91 would confirm a good fit for the variables chosen and lend credence to the model's forecasting ability. Finally, the Breusch-Pagan test of independence confirms the simultaneous nature of the expenditure share equations and substantiates the appropriateness of the IZEF methodology[30]. On the whole, the model yielded results for both share equations that were consistent with expectations. First and foremost, all but one the coefficients for the lagged price variables ($\ln p_i 3$) coincided with the anticipated interfuel substitution behaviour. This is readily apparent by their signs, magnitudes and significance tests. However, the coefficient for the price of HFO variable turned-up insignificant in the natural gas share equation. Moreover, its negative sign is suggestive of a slight complementarity between HFO and natural gas rather than substitutability. At peak load capacity, when the demand for electricity is highest, Ontario Power Generation will meet this short-term demand with its HFO and natural gas facilities[31]. Under these circumstances, the importance of minimising fuel is outweighed by the immediate necessity to extend the power generation capacity. The expenditure shares for both fuels will hence climb together, giving the appearance of complementarity. In any case, there would seem to be two

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[30] Berndt, E. R. (1991) The Practice of Econometrics: Classic and Contemporary. Addison-Wesley Publishing Co. p 463.
[31] Grenier, Serge. Unit head, energy section, Statistics Canada, Ottawa. Interview July, (2000).

forces influencing the relationship of HFO and natural gas. In normal times, they will act as substitutable inputs, but during peak loads, there apparent complementarity prevails. These two forces will serve to increase the standard error for the price of HFO coefficient in the natural gas share equation, which would explain its non-significant t statistic.

Second, the coefficients for the production of conventional steam electricity (lnQ) are significant in both equations. Recall from chapter 3, that if $b_{iQ} = 0$ the underlying production structure is homothetic. The significant coefficients then, despite their opposing signs, would confirm non-homotheticity in Ontario's conventional steam sector. The opposing signs merely suggest that when output from conventional steam facilities increases, coal fired plants are responsible for the increase which inevitably causes the share of natural gas to fall.

Third, the lagged dependent variables are significant and positive in both share equations. A direct interpretation of these coefficients would state that part of today's demand share of each fuel can be explained by past demand. Although this is undoubtedly true, causality between periods should not be inferred. Rather, the inflexibility of the power generation sector's infrastructure will restrict the demand for each fuel in both periods. Ontario Power Generation will have some latitude on what types of fuels to use to generate power, but coal burners which, very often, cannot accommodate any type of fuel, remain prevalent. Short of additional investments, this establishes a floor for coal's expenditure share and a ceiling for the shares of other fuels. Fuel purchase commitments will in-turn be affected by this rigidity, which accounts for the significance of the dependent variables lagged by three years.

Finally, even though the remaining variables have no direct bearing on the objective of this study and serve mainly to enhance the quality of the model, a brief mention of their interpretation might be of interest. The quarterly dummies are indicative of a fair degree of seasonal variation with natural gas and only slight variation with coal. This stands to reason since coal seems to be more of a staple fuel input than natural gas or HFO. The coefficient for nuclear energy in the coal share equation is negative which suggests that there is a trade-off between nuclear energy and coal based energy. Perhaps due to a cost minimisation process or due the recent loss of output from the shutdown of some of Ontario's reactors is being offset by an increase in coal fired generation. In any event, for the same reasons as before, this negative relationship in the coal share equation should induce a positive relationship between the same variables in the gas share equation, which is indubitably the case.

In the previous section, the diagnostics informed us that there were no serious problems with the data or the model and that, for the most part, the coefficients would be efficient so as to produce reliable t statistics. Yet even though it is evident in table 5.1 in this section that some of the coefficients are clearly insignificant, none of them will be discarded from the model in order to prevent undue bias on the remaining coefficients. All variables then, will be employed in the simulation procedure and the results thereof can be seen in the following chapter.

Chapter 6: Simulation

Section 1: price elasticities

Since its inception, the translog model has traditionally been used to analyse the demand sensitivity for individual production inputs, when prices change for those inputs and for that of its close substitutes. In other words, the objective of previous studies of this nature was to generate estimates of the own and cross-price elasticities of demand for industrial inputs in one sector, or an aggregation of sectors[32].

The methodology is the same here, but the focus differs whereby the expenditure share equations will be used to forecast demand for individual fuels. Nevertheless, it becomes of interest to derive the own and cross-price elasticity estimates for Ontario's conventional steam sector's fuel inputs.

The partial elasticities were estimated using equation (11) in chapter 3. They are aptly named as they only account for the substitution between fuels under the constraint that total energy demand by Ontario's fossil fuel fired facilities remains

[32] See Fuss (1977), Pindyck (1979), Estrada and Fugleberg (1989), and Bopp and Costello (1990) among others.

constant. It should be noted, however, that since the translog model allows elasticities to vary along the demand curves for each fuel, there are different elasticities for each observation's price combination in the data set. The estimates presented in table 6.1 were tabulated at the mean value for 1998's observations. This is the most recent complete year available and is deemed to be representative of Ontario Power Generations' behaviour.

Table 6.1

Price elasticities, energy constant for Ontario's conventional steam sector.

	Coal	Gas	HFO
Coal	-0.92	0.71	0.21
Gas	2.22	-2.19	-0.03
HFO	3.09	-0.15	-2.94

To interpret this table, the reader should look at the elasticities row by row. Ex: the effect of a change in the price of coal on the three fuels can be seen in the first row.

At first glance, there are a couple of facts that can be deduced. First, all of the own price elasticities are negative, which is consistent with factor demand theory. Second, the own and cross-price elasticities are indicative of substantial interfuel substitution[33]. Since these three fuels are the only inputs being considered for conventional steam power generation, closer inspection of the elasticities reveals a number of interesting characteristics:

[33] As Fuss (1977) points out, this dominant substitution effect assures concavity.

The elasticities in each row of table 6.1 sum to zero. Because energy is assumed to remain fixed, regardless of price changes, any decrease in the quantities demanded of one fuel will be exactly offset by a net increase in the quantity demanded of the other two (and vice-versa).

If the price of coal should increase, the resulting loss in the quantity demanded for coal will be replaced by an increase in the quantity demanded for both natural gas and HFO. This is not the case for a change in the price of the other two fuels. According to the elasticities in the natural gas and HFO rows, there seems to be almost complete substitutability between coal and natural gas, and coal and HFO, but practically no interaction between natural gas and HFO. In fact, as proposed in the previous chapter these latter two fuels seem to be complementing one another to a small degree.

There have been at least two other studies aimed at estimating the elasticities in Canadian manufacturing. Fuss (1977) analysed the substitutability of six different sources of energy available to Ontario's industrial sector. The elasticities he derived for coal, natural gas and fuel oil can be seen in table 6.2. Similarly, Pindyck (1979) included total Canadian manufacturing in his ten-country study and the pertinent results are summarised in table 6.3. It should be noted though, that neither of these two studies elasticities are directly comparable to those in the present analysis. For one, the scope of their research was much broader. But perhaps, more importantly though, electricity was included as an alternative to fossil fuels which is certainly the case in the private industrial sector. The manufacturers are thus faced with a more dynamic input cost-minimisation problem than the electric power industry, which is unquestionably reflected in the elasticities.

Table 6.2

Price elasticities: energy constant for total industrial product in Ontario.

	Coal	Gas	Fuel oil
Coal	**-1.41**	**0.71**	**0.30**
Gas	**0.85**	**-1.21**	**0.20**
Fuel oil	**0.32**	**0.17**	**-1.22**

Source: compiled from Fuss (1977), p 105

Table 6.3

Price elasticities: energy constant for total industrial product in Ontario.

	Solid	Gas	Liquid
Solid	**-1.80**	**1.17**	**0.91**
Gas	**1.35**	**-0.33**	**-0.53**
Liquid	**0.41**	**-0.21**	**-0.81**

Source: compiled from Pindyck (1979), p.194

Despite the differences between the present study and the former two, there are some qualitative aspects appropriate for discussion. As is clearly visible in tables 6.2 and 6.3, the demand for coal was generally more responsive to its price changes in the industrial sector, while the demand for liquid petroleum and natural gas was less responsive. This behaviour is consistent with the structure of the conventional steam sector where, unlike the private sector, coal remains the dominant fuel and the ensuing commitment to capital solely designed to accommodate it, would hinder its substitution relative to other fuels.

There is one final noteworthy observation: much like the present study, Pindyck finds a high degree of interfuel substitution in Canadian manufacturing, but with a slight complementary relationship between fuel oil and natural gas. Fuss, on the other hand, concludes that the cross-price elasticities for the three fuels in question are all positive and are hence purely substitutable. This may be due to differences in the scope and construction of the models.

Section 2: simulation

The model

The objective of this thesis is to estimate the demand for the three fuel inputs in the conventional steam sector. In so doing, the response to carbon fee induced price changes can be gauged to make some well educated predictions for short-run GHG abatement.

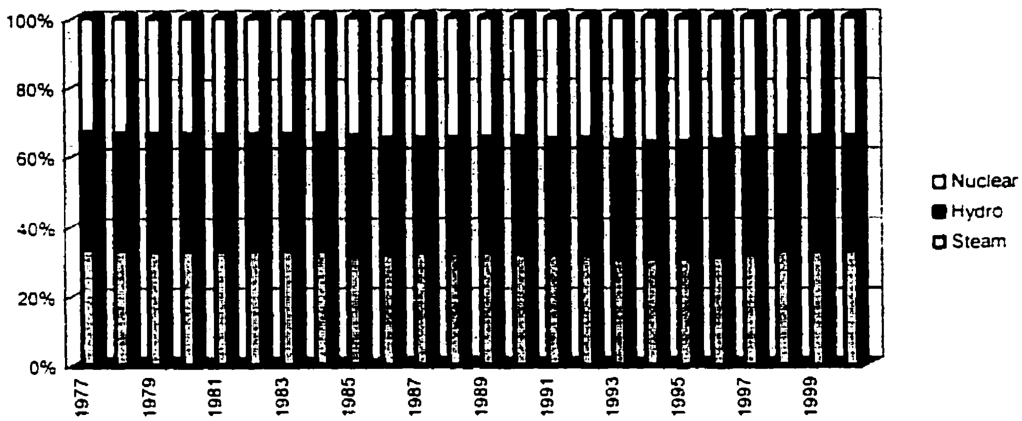
In the previous chapter, table 5.1 enumerated the coefficients obtained by the regression procedure. They can now be fitted into a set of expenditure share equations to forecast the changes in demand in response to an increase in fuel input prices (see table 6.4). Recall that HFO's share equation was not directly estimated in order to preserve the adding-up criterion ($\Sigma\ Si = 1$). Its price coefficients, however, were subsequently derived using the homogeneity and symmetry restrictions. It should be noted though, that HFO's price coefficients, included in table 6.4, were merely obtained to complete the own and cross-price elasticities table from the previous section, but otherwise, serve no purpose in making expenditure share predictions.

Table 6.4: expenditure share equations

	Coefficients:									Predicted	Actual
Equation	constant	lnPcoal3	lnPgas3	lnPhfo3	lnQ	lnH	lnN	Scoal3	Sgas3	Σ Si = 1	Si 1999
Scoal	-1.142941	-0.4637473	0.3452303	0.118517	0.059469	0.158451	-0.065197	0.3743		76%	76%
Sgas	1.551617	0.3452303	-0.326058	-0.0191726	-0.131792	-0.060013	0.050592		0.585119	19%	18%
Shfo	0.5913244	0.118517	-0.019173	-0.099344						5%	6%
Sum	1	0	0	0						100%	100%
Latest observation 1999:		7.828427	7.798273	8.629814	10.58841	10.20390	11.02045	0.7708	0.157553		
Exponents:		$2,510 98	$2,436 39	$5,596 04							

Before assessing the effects of imposing a carbon fee on Ontario's conventional steam sector, it might be useful to first predict where the demand for fuel will stabilise, given today's market conditions. The latest observations in the data set will hence serve as the parameters to complete the model. Because the industry's structure imposes a three year time lag to fully adjust to fuel prices, 1999's observations will yield predictions for 2002's expenditure shares for coal and natural gas, while HFO's share is educed from the difference between 100% and the shares of the other two (table 6.4). However, in order for the share predictions to be meaningful, the proportion of conventional steam, hydro and nuclear power, are assumed to be fixed. In other words, the lnQ, lnH and lnN variables will remain constant throughout the forecasting period. Given the relative inflexibility of the power generating infrastructure, and Ontario Hydro's past behaviour as illustrated in figure 6.1, this would not seem to be an unrealistic assumption.

Figure 6.1
Sources of power generation in Ontario



The model predicts shares for coal, natural gas, and HFO of 76%, 19% and 5% respectively. Considering that 1999's actual shares were almost identical to these, there will be little interfuel substitution at prevailing market conditions.

The Carbon fee.

As stipulated in chapter 1, carbon fees disproportionately raise the prices of various fossil fuels provoking their consumers to both, lower the quantity demanded of all fuels, and switch to those with lower CO_2 emissions. To get a handle on how carbon fees will affect the prices of fuel, the concept of CO_2 emission factors must first be introduced. Since carbon dioxide emissions are relatively constant to the type of fuel burned, emission factors measure the quantity of CO_2 produced per unit of energy. Smith (1995) estimated the CO_2

emission factors for the various fuels used in industrial processes in Canada, and the ones relevant here, can be seen in Table 6.5[34].

Table 6.5: effects of a carbon fee on CO_2 emissions

Carbon Fee **$10.00** $/t. of CO2

	CO2 Emission Factors t/Tj	PΔ $/Tj	Prices $/Tj	PΔ %	Predictions 2002: Shares (With carbon fee) Σ Si = 1	Shares (With carbon fee) dollars	Output in Terajoules NO C. fee	Output in Terajoules With C. fee	Output in Terajoules QtyΔ Tj	CO_2 Emissions in tonnes NO C. fee	CO_2 Emissions in tonnes With C. fee
Coal	88.2	$882.00	$3,392.98	35.13%	70%	901,637,860	296,503	265,737	-10%	26,151,550	23,437,963
Nat. Gas	49.68	$496.80	$2,933.19	20.39%	23%	296,134,816	75,772	100,960	33%	3,764,334	5,015,691
HFO	74	$740.00	$6,336.04	13.22%	7%	95,275,720	9,459	15,037	59%	699,979	1,112,746
					$\lambda = 0.43651$	1,293,048,396	381,734	381,734	0%	30,615,863	29,566,401

Gross cost increase: $ 310,993,611
Cost increase net of revenue: $ 15,329,603.03

Percent change in CO_2 from current levels: **-3%**

Revenue (,000s): $295,664

So, for instance, if a consumer of coal now faces a $10 /tonne carbon fee, the price of coal will increase by $882 /Tj, assuming the consumers bear the total brunt of the price increase[35]. Similarly, the price of natural gas and HFO would increase as well, but in accordance to their respective emission factors.

In keeping with the example, the effects of the price increase can be traced through with the expenditure share equations. By inputting the new prices into the model, the share of coal would drop down to 70%, while the shares of natural gas and HFO would increase to 23% and 7% respectively. If the total energy generated by the conventional steam sector is to remain constant, the fuel price increase would automatically drive up the industry's input costs. Hence, the total

[34] The conventional steam sector uses 3 types of coal for combustion, all having slightly different emission factors. Much like the calculation of coal's price in chapter 4, a series of weights have to be placed on each type of coal to produce an aggregated measure.

[35] This assumption does not necessarily imply a perfectly elastic supply curve for fossil fuels. A carbon fee policy could easily be engineered so as to impose the complete burden of its price influences on the buyers. The fact that Ontario Power Generation is a publicly owned monopoly would only serve to ease the engineering of such a policy.

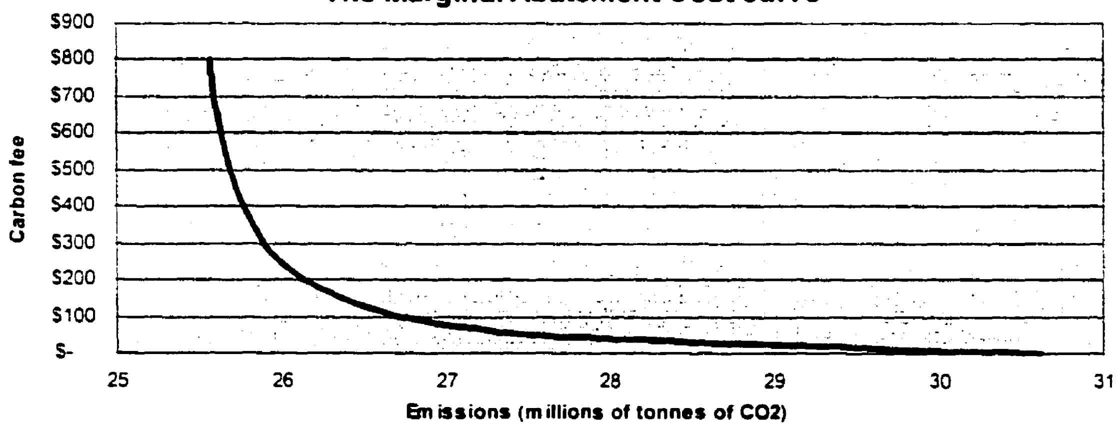
fuel costs in 1998 were just over 982 million dollars. With a $10/tonne carbon fee, total expenditures would have to rise to over 1.293 billion dollars, a 32% increase (see Appendix 4 for details of the calculation).

In all likelihood though, total output by conventional steam facilities would decrease as the relative cost of alternative energy sources goes down. But for the purpose of illustrating the interfuel substitution effect, total output is held constant. Once total expenditures on fuel are known, it becomes a simple matter of breaking it down into dollar value expenditures on each fuel given the predicted percentile shares. From there, dividing through by prices yields the quantity consumed of each fuel in natural units, which translates easily into predicted CO_2 emissions. The demand share equations predict that a one time $10/tonne carbon fee, levied on the consumers of the three fuels in Ontario's conventional steam sector, would abate CO_2 emissions by 3% from the baseline scenario.

There is one final element that should be considered before assessing the true cost of a carbon abatement policy. Carbon fees will generate revenue which will largely offset the higher expenditures associated with a fuel price increase. In the case of a carbon tax, revenues generated are directly proportional to total CO_2 emissions. For an emission permit policy, the initial auction of the pollution certificates would serve to generate revenue as well. Under cost-minimising behaviour, the proceeds from either economic policy should be equivalent[36], and to the benefit of the public sector. Furthermore, from society's perspective, regardless of how the revenue is allocated, for the most part, it counterbalances the higher input costs faced by the fuels' consumers. The difference between the two can be viewed as the net cost to society for imposing a set carbon abatement policy. As elicited from table 6.5, a $10/tonne carbon fee would result in a net cost increase of over 15 million dollars

With the existing framework of the expenditure share model, it might be revealing to forecast emissions at incremental changes of the carbon fee. By then plotting the predicted emissions response to increasing carbon fees, an ad hoc curve could be derived analogous to the marginal abatement cost curve (MAC). Figure 6.2 illustrates the negative relationship that exists between carbon fees

Figure 6.2
The Marginal Abatement Cost curve



[36] Randall, Alan. Resource Economics An Economic Approach to Natural Resource and Environmental Policy. 2nd edition. John Wiley and Sons. (1987): p366

and CO_2 emissions in Ontario's conventional steam sector. The most prevalent feature of this curve is its curvilinear shape[37]. This is consistent with environmental economic theory whereby abatement incentives are subject to diminishing marginal returns[38]. This product of industrial consumer behaviour suggests both that, ceteris paribus, there is an optimal abatement level and a limit to a carbon fee's effectiveness.

The Kyoto target.

The Kyoto Protocol prescribes a 6% overall reduction in greenhouse gases for Canada below 1990 levels. This may be an ambitious target as the conventional steam sector, congruent with other sectors, has steadily increased their emissions over the last decade. As of 1990, total annual CO_2 emissions by Ontario's power generating sector stood at 26,184,945 tonnes (table 6.6). By applying the same convention that Kyoto decrees on Canada to this sector, the emissions goal would be in the order of 24,618,848 tonnes. It is evident, though, from figure 6.2, that a carbon fee alone cannot induce sufficient fuel substitution to achieve the objective, barring any significant capital adjustments. Concessions will need to be made elsewhere.

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[37] One of the main advantages of the translog methodology is its flexibility, as constant elasticity of substitution is not assumed. Thus, during simulation, when expenditure shares for each fuel adjust for simulated price changes, the cross-price elasticity estimates react accordingly. It is the non-constant elasticity estimates that induce the more realistic curvilinear shape of the abatement cost curve.
[38] Hartman, Raymond S., David Wheeler and Manjula Singh. "The cost of air pollution abatement" *Applied Economics*. Volume 29 (1997): pp 759-774.

Table 6.6: the Kyoto

	Year 1990	
	Quantity Tj	Emissions tonnes
Coal	285,683	25,197,241
Gas	5	248
HFO	13,344	987,456
Total	299,032	26,184,945
Kyoto target		24,613,848

If Ontario Power Generation is to cut its emissions to a level equivalent to that mandated by the Kyoto Protocol, reducing total output from its conventional steam facilities could be a solution. By running the model again, but this time allowing output to decrease by 10%, the expenditure share equations predict that a $68/tonne carbon fee would be required to sufficiently stimulate interfuel substitution so as to reach the abatement objective (table 6.7). This comes at a direct net cost of just over 52 million dollars. The resulting CO_2 emissions would be 20% below current levels, the gains stemming equally from the substitution effect and the drop in output. It should be noted however, that the capacities of nuclear or hydro facilities would need to be extended to compensate for the loss in output from conventional steam, unless consumers are willing to tolerate a subsequent increase in the electricity rates, or be persuaded to conserve.

Table 6.7: effects of a carbon fee and output on CO_2 emissions

Carbon Fee: **$68.00** $/t. of CO2

	CO2 Emission Factors tonnes/Tj	$P\Delta$ $/Tj	Prices $/Tj	$P\Delta$ %	Predictions 2002: Shares $\Sigma Si = 1$	dollars	Output in Terajoules: NO C. fee	With C. fee	Qty Δ Tj	CO_2 Emissions in tonnes: NO C. fee	With C. fee
Coal	88.2	$5,997.60	$8,508.58	238.86%	58%	1,516,383,731	296,503	178,218	-40%	26,151,550	15,718,851
Nat. Gas	49.68	$3,378.24	$5,814.63	138.66%	32%	833,127,115	75,772	143,281	89%	3,764,334	7,118,209
HFO	74	$5,032.00	$10,628.04	89.92%	10%	255,436,205	9,459	24,034	154%	699,979	1,778,530
					λ = 0.9388	2,604,947,050	381,734	345,534	-10%	30,615,863	24,615,589

Gross cost increase: $ 1,726,166,014
Cost increase net of tax revenue: 52,305,946.64

Percent change in CO_2 from current levels: -20%

Revenue (,000s): $1,673,860

At the onset of this study, it was hypothesised that significant abatement could be achieved simply by changing the relative prices of fossil fuels and hence altering the fuel mix so that the total energy was maintained but with lower emissions. This would be ideal, as it would satisfy environmental pressures by taking the first steps to thwarting climate change, as well as the economic pressures by keeping costs low. The expenditure share equation models the demand for the three fossil fuels and simulation indicates that substantial interfuel substitution would occur in response to a carbon fee, but not enough to achieve the set target. It is natural to infer from this that, under these particular circumstances, a typical carbon fee cannot provoke a sufficient change in the relative prices.

Of the three fuels being considered here, natural gas is the "cleanest" in terms of CO_2 emissions and thus, a relative increase in its utilisation, holds the greatest potential to curtailing emissions in the near future. It follows then, that if a carbon fee policy were to be applied to coal and HFO, while exempting natural gas, the relative prices would change even further, enhancing the interfuel substitution effect. Simulation was hence carried-out under this scenario and the results can be seen in table 6.8. As anticipated, the model predicts a much greater contribution of natural gas in the generation of electricity. Now, the conventional steam sector's cost minimising behaviour would prescribe a \$27/tonne fuel specific carbon fee in order to attain the Kyoto target. Furthermore, output by this sector would not need to be reduced and the net cost of the policy would be much more marketable. In effect, this policy indirectly subsidises natural gas, but considering the options, it would be the optimal and least cost method for this sector to attain the desired CO_2 emissions goal.

Table 6.8: effects of a coal and HFO specific carbon fee.

Carbon Fee: **$27.00** $/t. of CO2

CO2 Emission Factors tonnes/Tj	PΔ $/Tj	Prices $/Tj	PΔ %	Shares (With carbon fee) Σ Si = 1	dollars	Output in Terajoules NO C. fee	With C. fee	QtyΔ Tj	CO_2 Emissions in tonnes NO C. fee	With C. fee
				Predictions 2002						
88.2	$2,381.40	$4,892.38	94.84%	48%	656,707,883	296,503	134,231	-55%	26,151,550	11,839,161
49.68	$0.00	$2,436.39	0.00%	41%	558,430,660	75,772	229,204	202%	3,764,334	11,386,858
74	$1,998.00	$7,594.04	35.70%	10%	138,960,996	9,459	18,299	93%	699,979	1,354,104
			λ =	1.84386	$ 1,354,099,539	381,734	381,734	0%	30,615,863	24,580,123

Gross cost increase:$ 372,044,754

Cost increase net of revenue$ 15,826,596

Kyoto target: 24,613,848

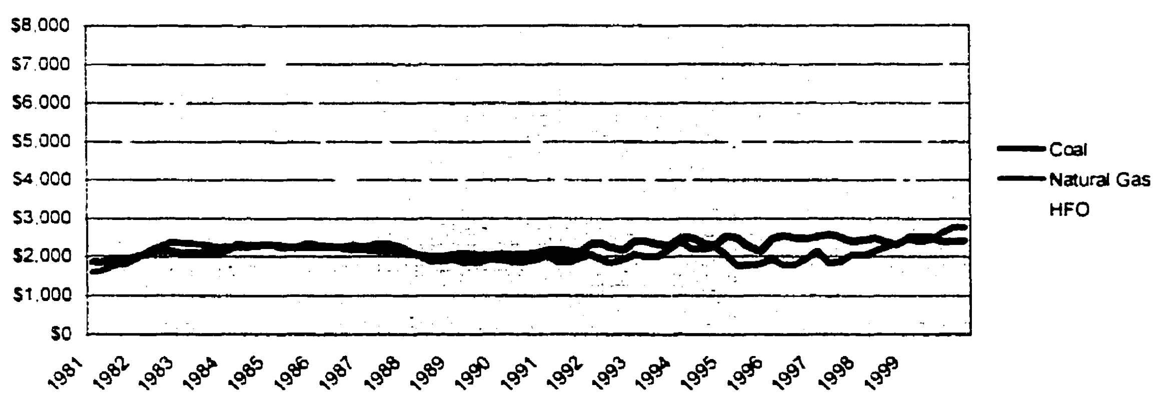
Percent change in CO_2 from current levels: **-20%**

Revenue (,000s): $356.218

Before concluding this section, there are a couple of important features of the model that should be addressed. First, in table 6.8, the expenditure share equations predict that coal's share would drop to 48%. This would involve the reduction in output from existing coal-fired facilities. Perhaps more importantly though, the model predicts that natural gas's share would rise to 41% and electrical output would triple from current levels. At present, natural gas facilities do not have the capacity to meet this potential demand and so the province would need to invest in new facilities. Presumably though, these facilities would share a similar cost structure with existing natural gas facilities. This study's estimated coefficients would hence remain applicable for rendering predictions in the absence of cost data from "unbuilt" natural gas electric facilities. Second, the expenditure share equations attempt to make long term predictions for the demand of fuel inputs. The exogenous influences on fuel prices are not taken into account. In other words, the only price changes being considered in the simulation process, are those caused by the adoption of a carbon fee. However, this is less than likely as there are constant supply and demand factors perpetually changing the prices of fuel. Therefore, when interpreting the results, it is important to keep this level of uncertainty in mind. The numerical predictions for carbon fees and total abatement should thus only be taken as illustrative estimates.

On the other hand, relying on historical precedent, the exogenous real fuel price changes of coal and natural gas, seen in figure 6.3, haven't been that substantial and would pale in comparison to those induced by a carbon fee. HFO, on the other hand, is susceptible to much greater fluctuations, but as is the case with all three fuels, the general tendency is for prices to rise. Unless the market for coal experiences a complete collapse, this would only serve to slightly overshoot the abatement target.

Figure 6.3
Fuel price trends



On a final note, it would seem that a fuel specific carbon fee policy imposed on coal and HFO would be the optimal solution for this sector to attain its Kyoto objectives. The price of coal faced by energy producers would almost have to double to stimulate substitution to natural gas. The share of HFO wouldn't change very much despite its price increase, which would seem to confirm its independent role as a peak load fuel. It is important to reiterate, though, that the emissions abatement is estimated from a baseline scenario where total energy is assumed to remain fixed at current levels. This, in itself, would require Ontario Power Generation to voluntarily halt the yearly increase in output from the conventional steam sector for the carbon fee to be as effective as predicted.

Discussion

Climate change is a global phenomenon requiring a global initiative. In the absence of a world governing body with the ability to sanction individual nations, the onus will ultimately lie on the domestic ratification of international agreements such as the Kyoto Protocol. This has profound implications for the role that each nation must play to limit CO_2 emissions. At present, there is very little incentive for one country to comply with Kyoto when other nations choose to ignore it. But eventually, this apathy will subside and Canada will need to make concrete decisions on how to curtail its emissions.

In the climate change debate, there is one school of thought that firmly believes that CO_2 abatement must stem from the massive introduction of renewable technologies. Hoffert et. al. (1998) clearly illustrate that due to the unrelenting increases in the demand for energy the world over, stabilisation of CO_2 emissions at 1990 levels will require an enormous injection of non-fossil fuel based energy by the mid twenty first century. Although these findings are not in dispute here, it is hoped that this thesis demonstrates that substantial emissions reduction can be achieved for the more pressing near future by simply switching to less carbon intense fuels. This is, admittedly, a smaller step toward a more sustainable economy, but it might nevertheless be an easier step to take and pave the way to the mass adoption of renewable energy.

The most likely economic tool to induce this level of fuel switching is the market based carbon fee. It should not be inferred though, that the response to a $27/tonne fuel specific carbon fee prescribed for Ontario's conventional steam sector can be extended to other sectors on a national scale. Since the fossil fuel power generation facilities predominantly rely on coal as an input fuel, there is more room for abatement by substituting that input for a cleaner burning fuel such as natural gas. This industry then holds the greatest potential for CO_2 abatement from interfuel substitution, which is reflected in the relatively modest carbon fee needed. At this point, one could speculate that in industries that have a similar dependence on coal, equivalent results could be achieved. However, this is not the case for most of Canada's commercial and industrial emitters of CO_2 who only have a trivial reliance on coal[39]. Refined petroleum, electricity and natural gas make up the bulk of the non-power generation sector's energy input

[39] See National Climate Change Process (1999).

and so it is doubtful that a $27/tonne carbon fee would be met with the same results.

In any case research undertaken here holds promising results for CO_2 abatement from the power generation sector in Ontario as well as other regions and in other nations that utilise coal to produce electricity. It should be mentioned though, that if such a, natural gas friendly, fuel specific carbon fee policy were implemented across Canada and beyond its borders, the assumption made earlier, where the price of natural gas is exogenously determined, would most probably not hold true. Widespread use of such a policy would forcibly increase the demand for natural gas and unless its supply increased proportionally, its price would inevitably rise. This would reduce both interfuel substitution by the utilities and CO_2 abatement unless counter measures were taken to increase the supply and distribution of natural gas and effectively offset this supply side effect.

Chapter 7: Conclusion

Since the signing of the Kyoto Protocol in December 1997, there have been a number of follow-up conferences for the signatory nations to collaborate on operational policies for the abatement of CO_2. The most recent of these was held in the Hague, where negotiators for Canada and other industrialised countries convened to discuss options to achieve Kyoto's objectives. Time, however, is slowly running out. Although Canada recognises the climate altering potential of anthropogenic CO_2, its decision-makers have yet to ratify the protocol or make any serious commitments to cutting emissions. This complacency is shared by most nations and has led to the present stagnation.

Policy makers are legitimately hesitant for mainly two reasons. First, the degree of global warming and the ensuing ecological and economic repercussions that it would entail are uncertain which makes it difficult to justify the sacrifices that would have to be made by enacting an abatement policy. Second, the costs associated with this policy are often estimated to be higher than the benefits of thwarting climate change. Consequently, little action has been taken as countries continue to meet to debate these issues, and the fate of Kyoto is left in limbo.

It was hoped to be demonstrated here that the cost of emissions reduction need not be that high. It has been hypothesised that if consumers of fossil fuels can be induced to substitute coal and oil for cleaner fuels such as natural gas, then substantial abatement can be achieved without incurring too high a cost. The policy instrument best suited for this task is the carbon fee, which makes use of market mechanisms to attain the least cost method of CO_2 emissions reduction. Its effectiveness would be maximised in Canada's conventional steam power generation sector where coal remains the dominant fuel input, leaving plenty of room for interfuel substitution. The heterogeneous energy infrastructure in Canada required a province specific focus, and Ontario was chosen as the subject for this study.

To analyse the effects of a carbon fee, details of fossil fuel demand had to be ascertained. The translog cost function is a well established methodology for modelling producer's cost minimising, input substitution behaviour with more than two factors of production. It thus lends itself ideally to this study's three-fuel input model. This functional form was chosen because its firm theoretical basis assures a well-behaved production function and for the ease with which measurement of input substitution can be derived. The translog modelling procedure produces a system of expenditure share equations which sets up the framework to simultaneously test the fuel demand response to relative price changes, and make quantitative predictions on CO_2 abatement.

The simulations undertaken indicated that the effect of a typical application of a carbon fee experienced diminishing marginal returns, which would ultimately prevent Ontario's power generating sector from achieving its allotted emissions target. Two scenarios were then presented where additional concessions were made to enable this sector to attain a CO_2 abatement level in line with Kyoto's objectives. First, by combining the interfuel substitution effect of a $68/tonne carbon fee with a 10% reduction in total output, the needed 20% overall reduction in emissions from current levels could be achieved. However, these measures came at a relatively high cost of 52 million dollars. Second, by imposing a fuel specific carbon fee of $27/tonne, but exempting natural gas, the change in the relative prices would be sufficient to induce the desired interfuel substitution effect and attain the 20% emissions reduction without having to restrict output. This policy comes at a much more palatable net cost of 15 million dollars and would hence be the least cost method for Ontario's power generating sector to attain its Kyoto commitments. Furthermore, this static interpretation of the cost says nothing about the additional advantage a carbon fee would have by continually offering incentives for innovations in abatement technologies.

Further research would hence be needed in other high emissions sectors that have access to a broader range of energy inputs. Although these sectors do not rely on coal as a staple fuel such as in the power generation sector, and so only limited inter-fossil fuel substitution would be expected, they do, however, have the option to consume electricity and potentially eliminate their direct CO_2 emissions. In consequence, it would be fair to assume that the elasticities of substitution for energy inputs would differ among these sectors and almost certainly from the ones obtained in this study. By estimating each sector's response to a carbon fee and its associated costs, decision makers would thus be better equipped to design a policy that would account for this intersectoral heterogeneity.

In addition, there is a need to research the distributional impacts that the unilateral imposition of a carbon fee would entail. For instance, as already noted Canada's power generation sector, provinces have vast differences in their reliance on fossil fuels to produce electricity. A carbon fee will hence raise the cost of production disproportionately and those provinces that have a greater dependence on fossil fuels would be subject to higher costs. This in turn may affect one province's competitiveness relative to another and may lead to a redistribution of income. At present though, there is no telling how significant this effect might be and it's only with further study that this issue, and others, can be addressed to alleviate some of the uncertainties faced by policy makers today.

Next to transportation, the power generation sector is the single largest emitter of CO_2 in Canada. Ideally, its fossil fuel fired facilities should be entirely replaced with more renewable sources of energy. Given Canada's abundance of resources relative to its population, this might be a feasible option in the very long term, but not likely in the more pressing near future. Much like other industrialised nations then, Canada is forced to contend with its present infrastructure to eliminate a growing portion of its CO_2 emissions. The purpose of the present study was to demonstrate that this can be accomplished without having to sacrifice energy consumption. The scope, however, was limited to Ontario, but the framework could easily be extended to accommodate a province by province analysis and paint a more comprehensive national picture. If similar low cost results can be foreseen nationally, it might set the ball in motion for planned emissions abatement, and lift the air of complacency that's pervading Canada's policy makers.

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APPENDIX 1

Test for Multicolinearity

```
do "C:\WINDOWS\Desktop\multi.do". corr lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2
d3 d4 Scoal3
(obs=63)          | lnpcoal3  lnpgas3  lnphfo3      lnC      lnH      lnN
d2--------+------------------------------------------------------------------
lnpcoal3 |   1.0000
 lnpgas3 |   0.3474   1.0000
 lnphfo3 |   0.0796   0.4668   1.0000
     lnC |   0.0688   0.0172   0.2782   1.0000
     lnH |  -0.0945   0.0990  -0.1256  -0.2138   1.0000
     lnN |   0.2880   0.0952  -0.3066  -0.4552  -0.1558   1.0000
      d2 |   0.1064  -0.0902  -0.0153  -0.1975   0.4670  -0.3045   1.0000
      d3 |  -0.0310  -0.1061  -0.0110  -0.2128  -0.6160   0.0828  -0.3404
      d4 |  -0.1286   0.0832   0.0298  -0.0186   0.0263   0.0643  -0.3262
  Scoal3 |  -0.3740   0.3660   0.3707   0.0440   0.1628  -0.1963   0.0009

         |       d3       d4   Scoal3
---------+---------------------------
      d3 |   1.0000
      d4 |  -0.3262   1.0000
  Scoal3 |  -0.0793  -0.0196   1.0000


. quietly regress lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2 d3 d4 Scoal3

. display (R^2)
.49377883

. quietly regress lnpgas3 lnphfo3 lnC lnH lnN d2 d3 d4 Scoal3 lnpcoal3


. display R^2
.46290134

. quietly regress lnphfo3 lnC lnH lnN d2 d3 d4 Scoal3 lnpcoal3 lnpgas3

. display R^2
.34103796


. quietly regress lnC lnH lnN d2 d3 d4 Scoal3 lnpcoal3 lnpgas3 lnphfo3

. display R^2
.67526175

. quietly regress lnH lnN d2 d3 d4 Scoal3 lnpcoal3 lnpgas3 lnphfo3 lnC

. display R^2
.6132265

. quietly regress lnN d2 d3 d4 Scoal3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH

. display R^2
.63033184
```

```
. quietly regress d2 d3 d4 Scoal3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN

. display R2
.63110335

. quietly regress d3 d4 Scoal3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2

. display R2
.72782547

. quietly regress d4 Scoal3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2 d3

. display R2
.42996632

. quietly regress Scoal3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2 d3 d4

. display R2
.39376164

. corr lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2 d3 d4 Sgas3
(obs=63)

         |  lnpcoal3  lnpgas3  lnphfo3      lnC      lnH      lnN       d2
---------+---------------------------------------------------------------
lnpcoal3 |   1.0000
 lnpgas3 |   0.3474   1.0000
 lnphfo3 |   0.0796   0.4669   1.0000
     lnC |   0.0688   0.0172   0.2782   1.0000
     lnH |  -0.0945   0.0990  -0.1256  -0.2139   1.0000
     lnN |   0.2880   0.0952  -0.3066  -0.4552  -0.1558   1.0000
      d2 |   0.1164  -0.0902  -0.0153  -0.1975   0.4670  -0.3045   1.0000
      d3 |  -0.0310  -0.1061  -0.0110  -0.2128  -0.6160   0.0528  -0.3404
      d4 |  -0.1288   0.0832   0.0298  -0.0186   0.0263   0.0643  -0.3262
   Sgas3 |   0.5389  -0.1541  -0.1752   0.1815  -0.2093   0.0165  -0.0098

         |       d3       d4    Sgas3
---------+---------------------------
      d3 |   1.0000
      d4 |  -0.3262   1.0000
   Sgas3 |   0.0334   0.0565   1.0000


. quietly regress lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2 d3 d4 Sgas3

. display R2
.59109177

. quietly regress lnpgas3 lnphfo3 lnC lnH lnN d2 d3 d4 Sgas3 lnpcoal3

. display R2
.39576791

. quietly regress lnphfo3 lnC lnH lnN d2 d3 d4 Sgas3 lnpcoal3 lnpgas3

. display R2
.34539845
```

. quietly regress lnC lnH lnN d2 d3 d4 Sgas3 lnpcoal3 lnpgas3 lnphfo3

. display R^2
.67398107

. quietly regress lnH lnN d2 d3 d4 Sgas3 lnpcoal3 lnpgas3 lnphfo3 lnC

. display R^2
.61774424

. quietly regress lnN d2 d3 d4 Sgas3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH

. display R^2
.6499574

. quietly regress d2 d3 d4 Sgas3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN

. display R^2
.63183873

. quietly regress d3 d4 Sgas3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2

. display R^2
.72756966

. quietly regress d4 Sgas3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2 d3

. display R^2
.43982056

. quietly regress Sgas3 lnpcoal3 lnpgas3 lnphfo3 lnC lnH lnN d2 d3 d4

. display R^2
.45412944

end of do-file

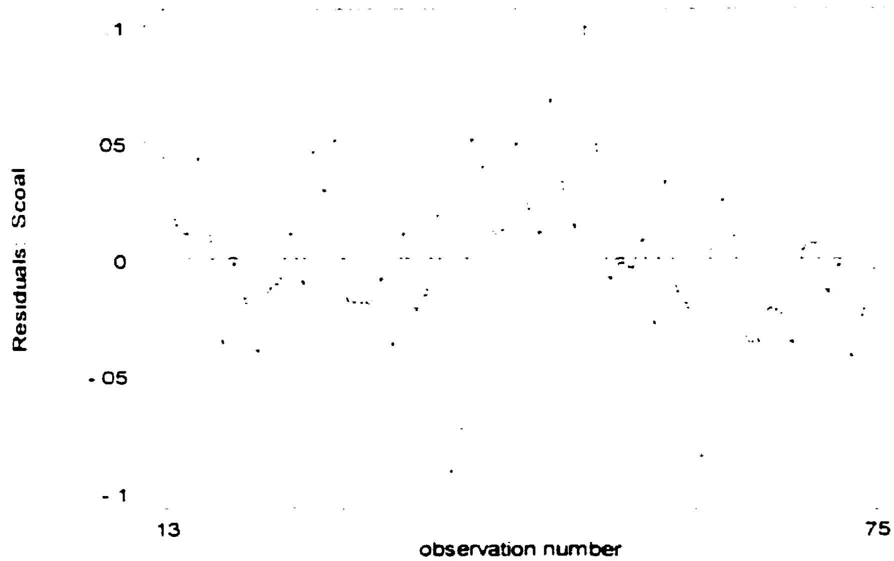
APPENDIX 2

Test for serial correlation with lagged dependent

Equation 1

```
graph ecoal no, ylabel yline(0) border connect(l)
```

Graph: A2.1

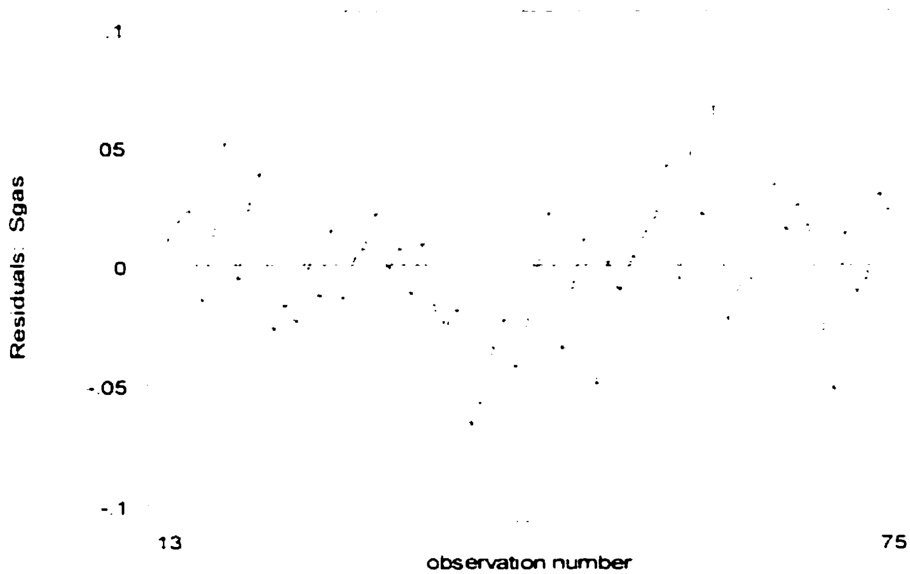



```
. corr  ecoal ecoal1 ecoal2 ecoal3 ecoal4
(obs=59)
             ecoal    ecoal1    ecoal2    ecoal3    ecoal4
---------------------------------------------------------
   ecoal    1.0000
  ecoal1    0.2956    1.0000
  ecoal2    0.0356    0.3013    1.0000
  ecoal3    0.1631    0.0441    0.2944    1.0000
  ecoal4    0.1679    0.1855    0.0492    0.3015    1.0000

. regress  ecoal ecoal1 ecoal2 ecoal3 ecoal4

  Source |       SS       df       MS                  Number of obs =      59
---------+------------------------------               F(  4,    54) =    1.96
   Model |  .00904048      4  .00226012                Prob > F      =  0.1138
Residual |  .062267086    54  .001153094               R-squared     =  0.1268
---------+------------------------------               Adj R-squared =  0.0621
   Total |  .071307566    58  .001229441               Root MSE      =  .03396

------------------------------------------------------------------------------
   ecoal |      Coef.   Std. Err.       t     P>|t|       [95% Conf. Interval]
---------+--------------------------------------------------------------------
  ecoal1 |   .3076198   .1344744     2.288   0.026       .0380148    .5772248
  ecoal2 |  -.1078972   .1387562    -0.778   0.440      -.3860907    .1702963
  ecoal3 |   .1612508   .1403081     1.149   0.256        -.12005    .4425515
  ecoal4 |   .0658867   .1345199     0.490   0.626      -.2038093    .3355827
   _cons |  -.0017746   .0044269    -0.401   0.690      -.0106499    .0071007
-------------------------------------------------------------------------------
-------
```

Equation 2

```
graph egas no, ylabel yline(0) border connect(l)
```

Graph: A2.2



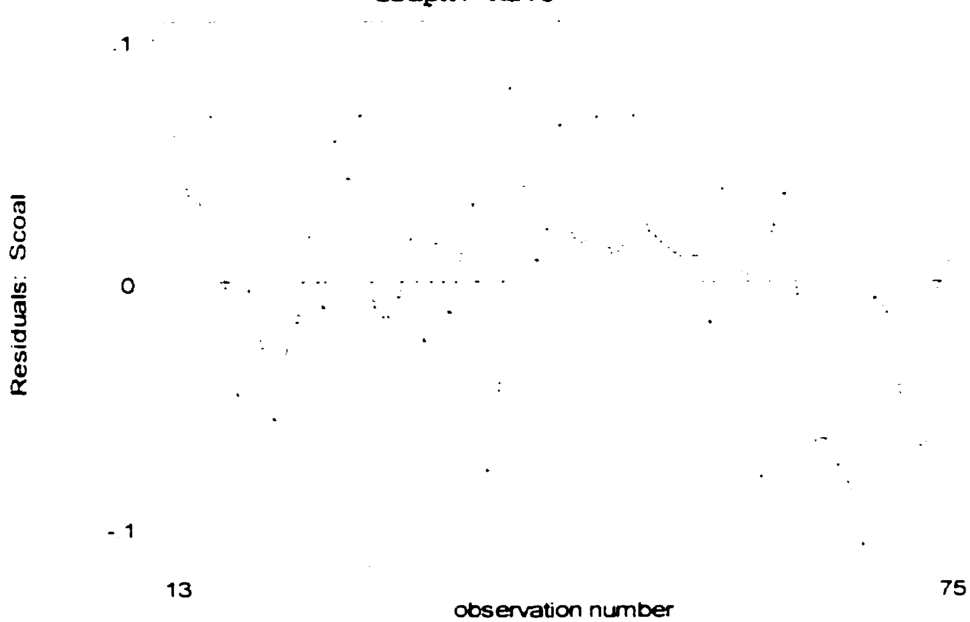

```
corr egas egas1 egas2 egas3 egas4 (obs=59)

         |     egas    egas1    egas2    egas3    egas4
---------+---------------------------------------------
    egas |   1.0000
   egas1 |   0.2986   1.0000
   egas2 |   0.2843   0.2764   1.0000
   egas3 |   0.2358   0.2792   0.2898   1.0000
   egas4 |   0.1723   0.2386   0.2942   0.2924   1.0000

. regress egas egas1 egas2 egas3 egas4

  Source |       SS       df       MS                  Number of obs =      59
---------+------------------------------               F(  4,    54) =    2.33
   Model |  .006684281     4  .00167107               Prob > F      =  0.0676
Residual |  .038732505    54  .000717269               R-squared     =  0.1472
---------+------------------------------               Adj R-squared =  0.0840
   Total |  .045416785    58  .000783048               Root MSE      =  .02678

------------------------------------------------------------------------------
    egas |      Coef.   Std. Err.       t     P>|t|       [95% Conf. Interval]
---------+--------------------------------------------------------------------
   egas1 |   .2082134   .1354996     1.537   0.130      -.0634469    .4798736
   egas2 |   .1848003   .1382121     1.337   0.187      -.0922962    .4618968
   egas3 |   .1147815   .1376705     0.834   0.408      -.1612312    .3907942
   egas4 |    .035544   .1366229     0.260   0.796      -.2383685    .3094564
   _cons |    .000038   .0034933     0.011   0.991      -.0069656    .0070416
------------------------------------------------------------------------------
```

Test for serial correlation without lagged dependent

Equation 1

```
graph ecoal no, ylabel yline(0) border connect(l)
```

Graph: A2.3



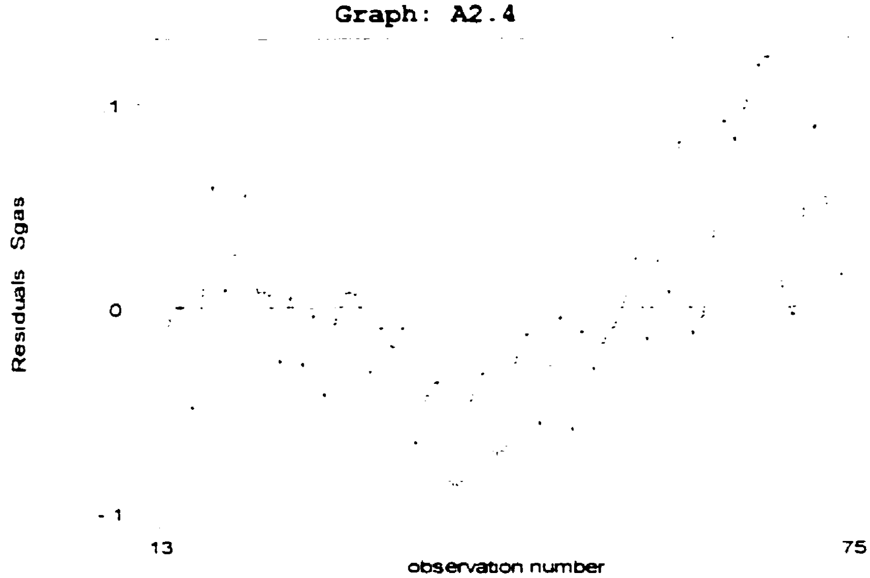

```
corr  ecoal ecoall ecoal2 ecoal3 ecoal4
(obs=59)

             ecoal   ecoall   ecoal2   ecoal3   ecoal4
------------------------------------------------------
   ecoal    1.0000
  ecoall    0.4207   1.0000
  ecoal2    0.1728   0.4304   1.0000
  ecoal3    0.2578   0.2028   0.4453   1.0000
  ecoal4    0.3067   0.2999   0.2209   0.4331   1.0000
```

```
. regress  ecoal ecoall ecoal2 ecoal3 ecoal4

  Source        SS         df       MS                  Number of obs =      59
---------------------------------------                 F(  4,    54) =    4.06
   Model    .024626306      4  .006156576               Prob > F      =  0.0060
Residual    .081877923     54  .001516258               R-squared     =  0.2312
---------------------------------------                 Adj R-squared =  0.1743
   Total    .106504229     58  .00183628                Root MSE      =  .03894

------------------------------------------------------------------------------
   ecoal        Coef.   Std. Err.        t     P>|t|       [95% Conf. Interval]
------------------------------------------------------------------------------
  ecoall     .3761394   .1332407     2.838   0.006        .1110078    .6452709
  ecoal2    -.0941243   .1408394    -0.668   0.507       -.3764903    .1882417
  ecoal3      .158351   .1425954     1.110   0.272       -.1275355    .4442375
  ecoal4     .1408042   .1352027     1.041   0.302       -.1302608    .4118692
   _cons    -.0029375   .0050908    -0.577   0.566       -.0131438    .0072689
------------------------------------------------------------------------------
```

Equation 2

```
graph egas no, ylabel yline(0) border connect(l)
```

Graph: A2.4



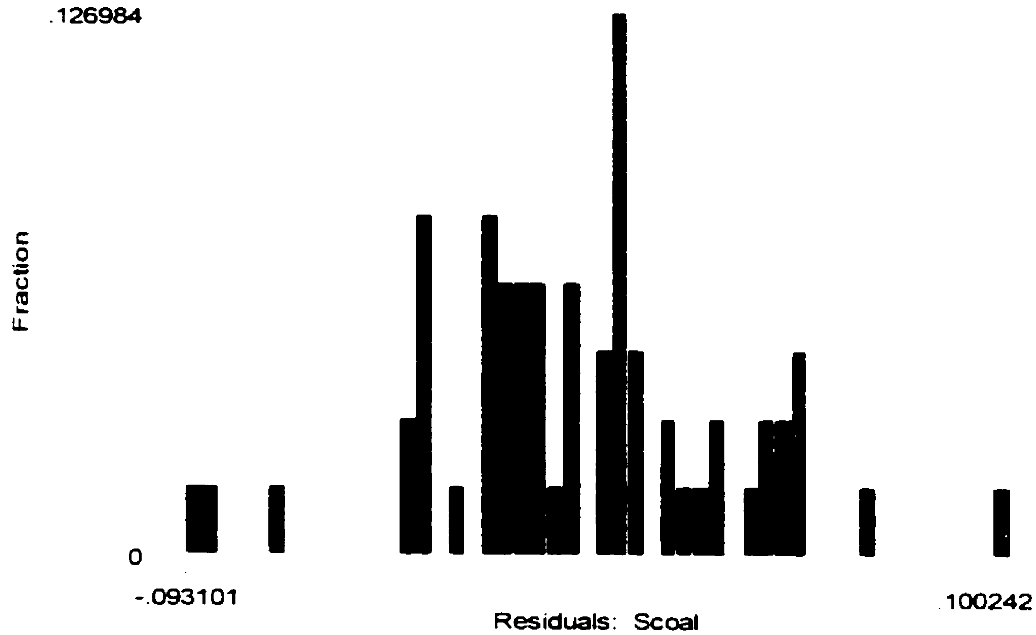

```
corr egas egas1 egas2 egas3 egas4
(obs=59)

             |     egas    egas1    egas2    egas3    egas4
-------------+---------------------------------------------
        egas |   1.0000
       egas1 |   0.6722   1.0000
       egas2 |   0.5364   0.6652   1.0000
       egas3 |   0.5148   0.5353   0.6660   1.0000
       egas4 |   0.5929   0.5386   0.5400   0.6575   1.0000

. regress egas egas1 egas2 egas3 egas4

  Source |       SS       df       MS                  Number of obs =      59
---------+------------------------------               F(  4,    54) =   15.29
   Model |  .072110808     4  .018027702               Prob > F      =  0.0000
Residual |  .063661569    54  .001178918               R-squared     =  0.5311
---------+------------------------------               Adj R-squared =  0.4964
   Total |  .135772377    58  .002340903               Root MSE      =  .03434

------------------------------------------------------------------------------
    egas |      Coef.   Std. Err.       t     P>|t|       [95% Conf. Interval]
---------+--------------------------------------------------------------------
   egas1 |   .4591797   .1291077      3.557   0.001       .2003344    .7180251
   egas2 |   .0274071   .1422613      0.193   0.848      -.2578096    .3126238
   egas3 |   .0747524    .142209      0.526   0.601      -.2103594    .3598643
   egas4 |   .2879678   .1334946      2.157   0.035       .0203269    .5556088
   _cons |    .002171   .0044853      0.484   0.630      -.0068215    .0111635
------------------------------------------------------------------------------
```

APPENDIX 3

Analysis of the disturbance

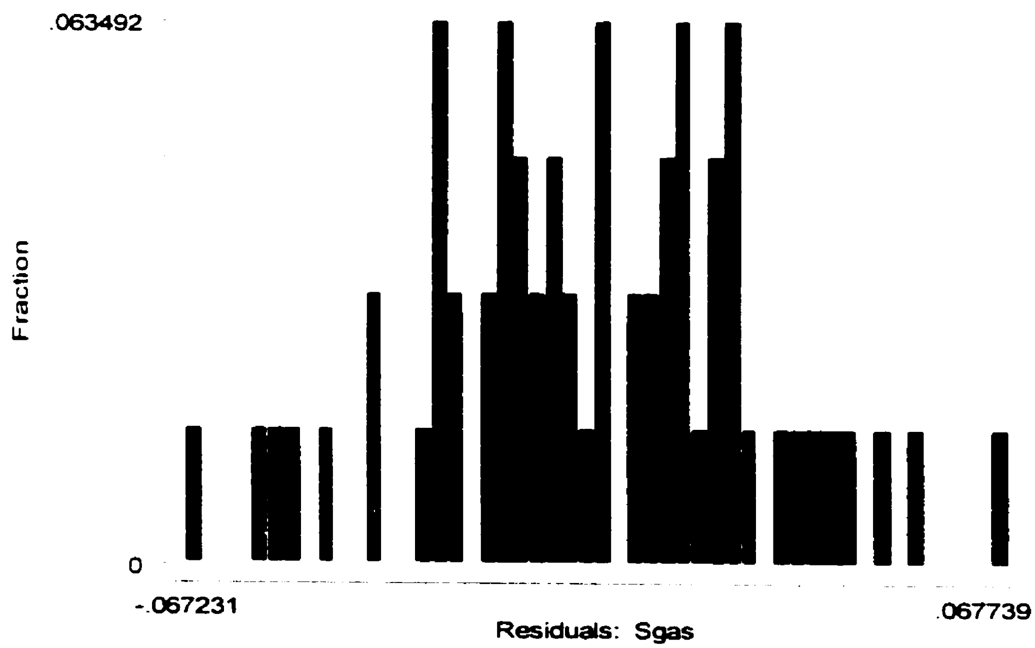
graph ecoal, bin(50)

Graph: A3.1



. graph egas, bin(50)

Graph: A3.2



```
. sktest ecoal
```

Skewness/Kurtosis tests for Normality

Variable	Pr(Skewness)	Pr(Kurtosis)	------- joint ------- adj chi-sq(2)	Pr(chi-sq)
ecoal	0.995	0.148	2.19	**0.3351**

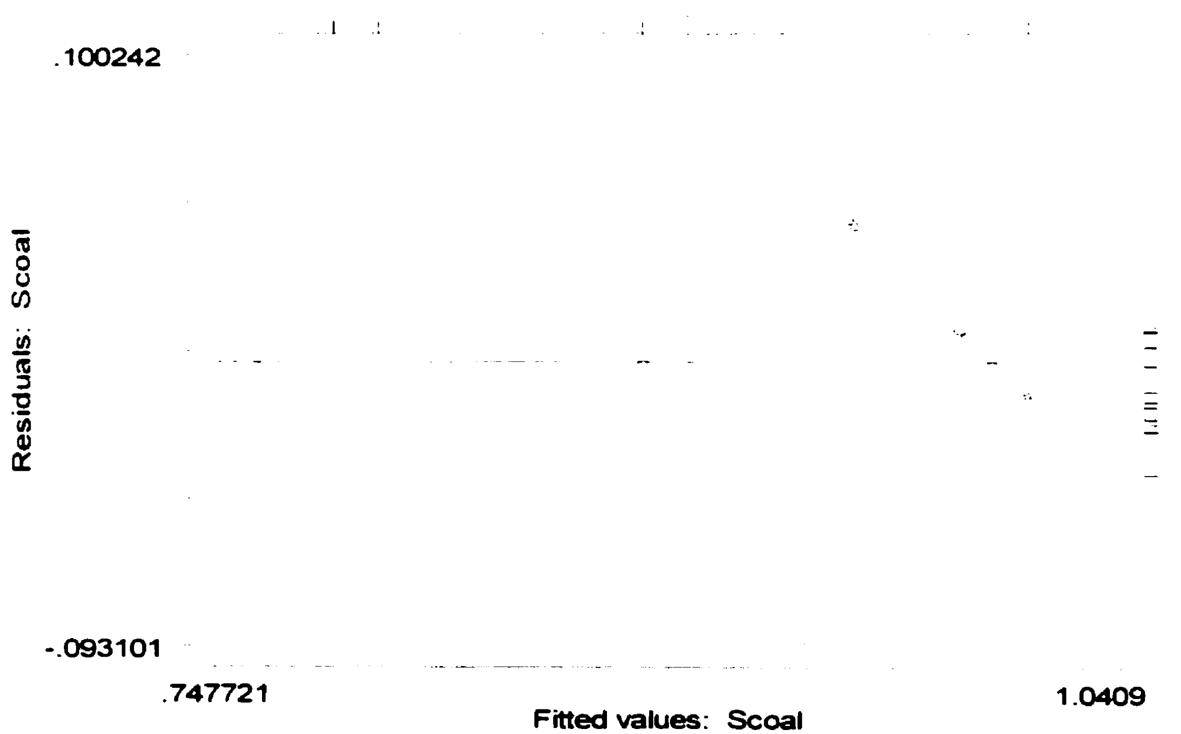
```
. sktest egas
```

Skewness/Kurtosis tests for Normality

Variable	Pr(Skewness)	Pr(Kurtosis)	------- joint ------- adj chi-sq(2)	Pr(chi-sq)
egas	0.733	0.831	0.16	**0.9221**

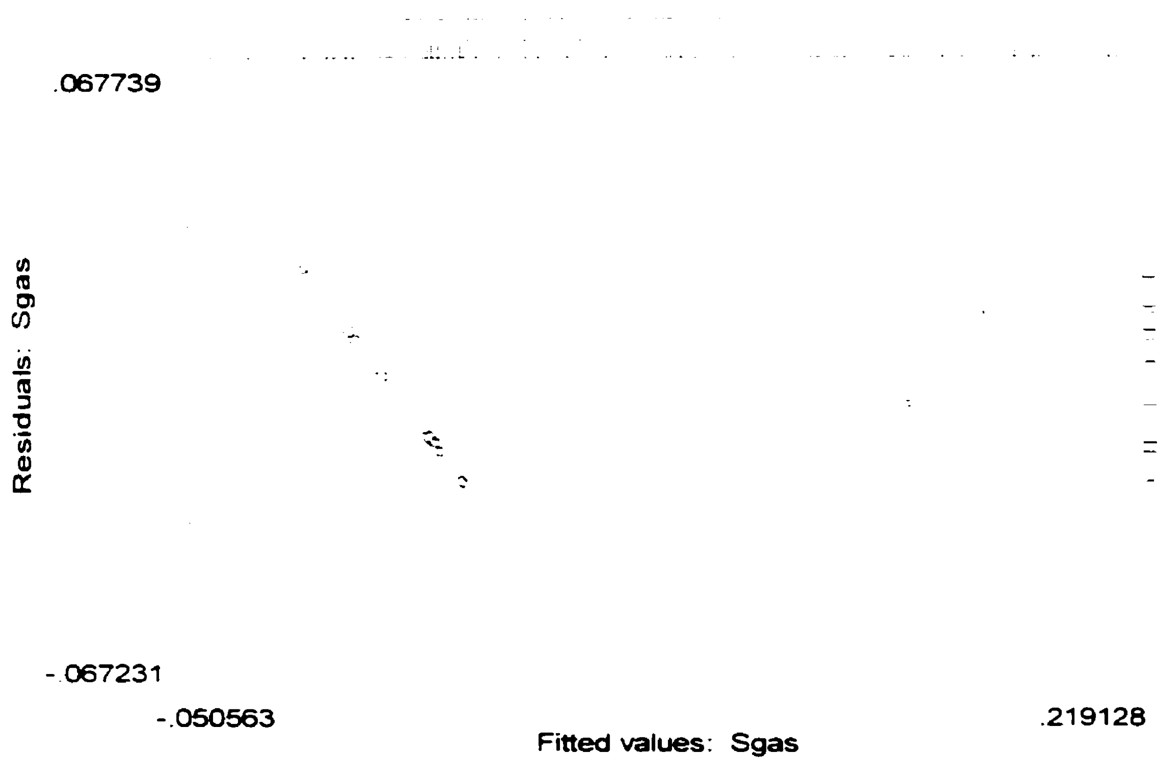
```
. graph ecoal ycoal, yline(0) oneway twoway box border
```

Graph: A3.3



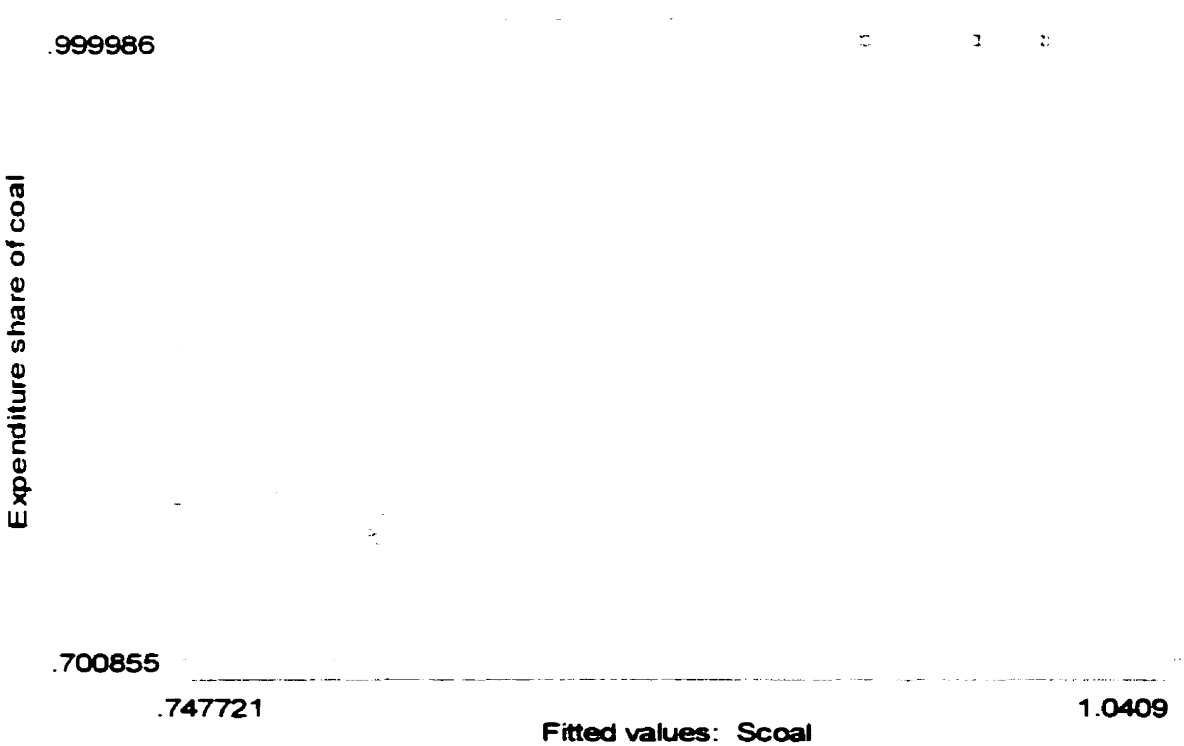
```
. graph egas ygas, yline(0) oneway twoway box border
```

Graph: A3.4



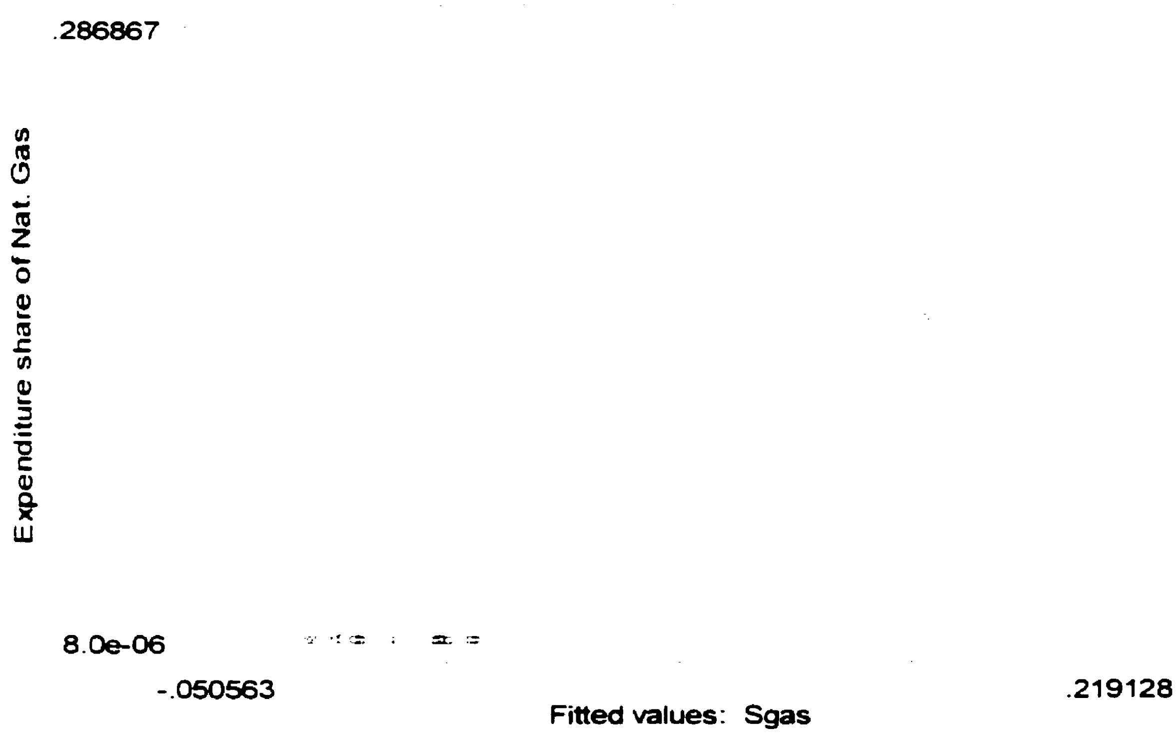

```
. graph Scoal ycoal, border
```

Graph: A3.5



```
. graph Sgas ygas, border
```

Graph: A3.6



ANOVA

```
. oneway ecoal Test
```

Analysis of Variance

Source	SS	df	MS	F	Prob > F
Between groups	7.0375e-06	1	7.0375e-06	0.01	0.9397
Within groups	.073109221	60	.001218487		
Total	.073116259	61	.001198627		

Bartlett's test for equal variances:chi2(1) = 0.0086 Prob>chi2 = 0.926

```
. oneway egas Test
```

Analysis of Variance

Source	SS	df	MS	F	Prob > F
Between groups	.002250752	1	.002250752	3.08	0.0843
Within groups	.043840702	60	.000730678		
Total	.046091454	61	.000755598		

Bartlett's test for equal variances:chi2(1) = 0.0446 Prob>chi2 = 0.833

APPENDIX 4

Calculation of total expenditures on fuel so that Ontario's conventional steam energy output remains constant.

Let: Xi = fuel i's predicted consumption in Tj.
Pi = fuel i's price in \$/Tj.
Vi = fuel i's expenditure share in \$.
Si = fuel i's expenditure share in %.
Y = total expenditure on energy (unknown)

Identities:

1. $X \equiv \Sigma_i X_i = X_1 + X_2 + X_3$ for i = 1,2,3 = coal, natural gas, HFO.
2. $X_i \equiv V_i / P_i$
3. $V_i \equiv S_i * Y$

From identities 2 and 3, $X_i = (S_i/P_i) * Y \Leftrightarrow Y = (P_i/S_i) * X_i$

$\therefore$ from identity 1, $X_1 = X - X_2 - X_3$

$\Leftrightarrow X_1 = [X - (S_2/P_2) * Y - (S_3/P_3) * Y]$

$\Leftrightarrow Y = [X - (S_2/P_2) * Y - (S_3/P_3) * Y] * (P_1/S_1)$

$\Leftrightarrow$ $\mathbf{Y = [(X * (P_1/S_1)/\lambda) / (1+1/\lambda)]}$

Where, $\mathbf{\lambda = [(S_2/P_2) * (P_1/S_1) + (S_3/P_3) * (P_1/S_1)]}$

So, for a \$10/tonne carbon fee:

X = 381,734 Tj in 1998		
P_1 = \$3,392.98	P_2 = \$2,933.19	P_3 = \$6,336.04
S_1 = 70%	S_2 = 23%	S_3 = 7%

$\therefore$ Y = \$ 1,293,048,396

APPENDIX 5

Variables and observations

Description of variables.

1	Year	Year	13	d1	Quarter 1 dummy
2	Quart	Quarter	14	d2	Quarter 2 dummy
3	Scoal	Expenditure share of coal	15	d3	Quarter 3 dummy
4	Sgas	Expenditure share of Nat. Gas	16	d4	Quarter 4 dummy
5	Shfo	Expenditure share of heavy fuel oil	17	Test	Variable splitting data in two
6	lnPcoal	ln of price of coal $/Tj	18	lnpcoal3	lnPcoal lagged by 3 years
7	lnPgas	ln of price of Nat. Gas $/Tj	19	lnpgas3	lnPgas lagged by 3 years
8	lnPhfo	ln of price of heavy fuel oil $/Tj	20	lnphfo3	lnPhfo lagged by 3 years
9	lnQ	ln of conv. elect. produced in Tj	21	Scoal3	lagged dependent
10	lnH	ln of hydro elect. produced in Tj	22	Sgas3	lagged dependent
11	lnN	ln of nuclear elect. Produced in Tj	23	ecoal	Residuals: Scoal
12	no	observation number	24	egas	Residuals: Sgas

Year	Quart	Scoal	Sgas	Shfo	lnPcoal	lnPgas	lnPhfo	lnQ	lnH
1981	1	0.961746	0.001202	0.037052	7.522121	7.373777	8.345273	10.57346	10.4148
0	2	0.996984	0.000799	0.002217	7.527825	7.410826	8.414202	9.976598	10.52482
0	3	0.99961	0.000147	0.000243	7.576984	7.498391	8.449573	10.05582	10.28682
0	4	0.996378	0.001159	0.002463	7.573884	7.506953	8.517036	10.38115	10.35464
1982	1	0.954821	0.001253	0.043926	7.600685	7.587136	8.581766	10.82002	10.30455
0	2	0.989098	0.007507	0.003396	7.658306	7.676764	8.616183	10.09988	10.41791
0	3	0.99774	0.000526	0.001734	7.670358	7.726179	8.658661	10.16283	10.27616
0	4	0.995296	0.000681	0.004024	7.663995	7.770823	8.719506	10.11746	10.50241
1983	1	0.997601	0.000652	0.001746	7.647188	7.757639	8.691479	10.40693	10.502
0	2	0.999834	0.000166	0	7.649709	7.757083	8.751702	10.06062	10.5904
0	3	1	0	0	7.654375	7.739502	8.738773	10.39505	10.29232
0	4	0.999991	9.00E-06	0	7.668948	7.718739	8.763831	10.59215	10.40944
1984	1	0.999874	0.000126	0	7.671766	7.718446	8.78538	10.79596	10.44993
0	2	0.996955	0.003045	0	7.751216	7.711817	8.790132	10.24163	10.55387
0	3	0.999922	0.000078	0	7.7262	7.72017	8.796705	10.18088	10.4134
0	4	0.999849	0.000151	0	7.732846	7.737812	8.819169	10.3146	10.43312
1985	1	0.999857	0.000143	0	7.740759	7.746513	8.858409	10.54999	10.47584
0	2	0.99841	0.001506	0.000084	7.715146	7.734702	8.85745	10.1632	10.56698
0	3	0.99943	0.00057	0	7.706348	7.702798	8.805264	9.711322	10.39982
0	4	0.998125	0.001802	0.000073	7.75186	7.710366	8.830113	10.20879	10.45799
1986	1	0.999918	0.000082	0	7.73483	7.713552	8.674973	10.49811	10.45345
0	2	0.998549	0.001451	0	7.722866	7.71499	8.359948	9.484123	10.55106
0	3	0.999977	0.000023	0	7.711095	7.707754	8.278825	9.587364	10.38126
0	4	0.999986	0.000014	0	7.737799	7.683932	8.288738	10.01079	10.4854
1987	1	0.999979	0.000021	0	7.717838	7.676467	8.378468	10.38714	10.42437
0	2	0.999972	0.000028	0	7.745996	7.680955	8.438802	10.08951	10.34316
0	3	0.999976	0.000024	0	7.744692	7.65953	8.511335	10.18394	10.16419
0	4	0.999978	0.000022	0	7.728198	7.669843	8.47587	10.34777	10.25563
1988	1	0.974335	9.00E-06	0.025656	7.664704	7.658615	8.353914	10.58205	10.36559
0	2	0.978278	0.00003	0.021693	7.611208	7.607582	8.32383	10.07801	10.45913
0	3	0.965598	0.000012	0.034389	7.596141	7.541518	8.26115	10.23002	10.23722
0	4	0.971185	0.00002	0.028796	7.598794	7.54597	8.193904	10.43182	10.5146
1989	1	0.941302	0.000015	0.058684	7.62605	7.566596	8.248129	10.67289	10.4344
0	2	0.951644	0.000013	0.048342	7.628258	7.521064	8.317901	10.01057	10.55804
0	3	0.909863	0.000023	0.090113	7.623469	7.522114	8.357732	10.15356	10.30613
0	4	0.871759	8.00E-06	0.128232	7.606336	7.560554	8.382192	10.49179	10.30641
1990	1	0.951564	9.00E-06	0.048427	7.627522	7.580554	8.432043	10.47055	10.39692
0	2	0.845577	0.000012	0.15441	7.625313	7.528739	8.351043	10.02051	10.51249
0	3	0.839692	0.000032	0.160276	7.621251	7.530823	8.330703	9.709823	10.35965
0	4	0.967608	0.000012	0.03238	7.643575	7.565257	8.535279	10.10876	10.51569
1991	1	0.967646	1.00E-05	0.032344	7.678779	7.615262	8.486812	10.35488	10.46684
0	2	0.933143	0.000053	0.066804	7.679826	7.537736	8.297544	9.972895	10.46145
0	3	0.887043	0.000025	0.112932	7.6693	7.530128	8.268466	9.978712	10.19308

0	4	0.93576	1.00E-05	0.06423	7.656877	7.589102	8.278482	10.42137	10.37332
1992	1	0.923663	0.021219	0.055118	7.752833	7.633579	8.189782	10.60129	10.41269
0	2	0.917519	0.026373	0.056108	7.761238	7.556505	8.251665	10.28742	10.46314
0	3	0.923558	0.053907	0.022534	7.708385	7.526652	8.3766	9.637721	10.35569
0	4	0.890022	0.078452	0.031526	7.678779	7.562572	8.403042	9.867567	10.54724
1993	1	0.929768	0.058889	0.011343	7.786965	7.632009	8.32449	10.35121	10.44981
0	2	0.914013	0.078027	0.007961	7.788535	7.599191	8.315589	9.388778	10.51965
0	3	0.846891	0.141346	0.011763	7.752833	7.598219	8.264989	9.304372	10.36867
0	4	0.849213	0.142613	0.008174	7.732846	7.692529	8.234218	9.501151	10.49921
1994	1	0.885482	0.087837	0.026682	7.816013	7.784642	8.187527	10.21777	10.40819
0	2	0.779222	0.190768	0.03001	7.820271	7.696946	8.318564	9.264343	10.44726
0	3	0.777879	0.214864	0.007257	7.763166	7.696355	8.430867	9.046363	10.38348
0	4	0.757633	0.238965	0.003402	7.735494	7.718739	8.392363	9.246347	10.40819
1995	1	0.839483	0.150541	0.009976	7.84336	7.630758	8.487364	9.887104	10.48589
0	2	0.756947	0.221126	0.021927	7.821789	7.483593	8.53182	9.531449	10.47678
0	3	0.765927	0.18743	0.046643	7.721192	7.478488	8.434983	9.662605	10.22217
0	4	0.700855	0.286867	0.012277	7.668594	7.508729	8.419292	9.499934	10.43663
1996	1	0.794911	0.193507	0.011582	7.80745	7.576914	8.530483	9.712831	10.4761
0	2	0.853626	0.127709	0.018665	7.846316	7.488308	8.553979	9.87187	10.58149
0	3	0.820898	0.148978	0.030124	7.824811	7.485772	8.548745	9.902375	10.41706
0	4	0.767532	0.220634	0.011834	7.80745	7.570934	8.658189	9.845753	10.4762
1997	1	0.783007	0.202209	0.014784	7.837117	7.676161	8.612742	9.885918	10.52291
0	2	0.780049	0.194917	0.025034	7.856021	7.511915	8.526734	9.871288	10.61974
0	3	0.831981	0.131706	0.036313	7.825716	7.530128	8.543484	10.36312	10.31799
0	4	0.761186	0.209565	0.029248	7.778463	7.621933	8.585056	10.10958	10.3082
1998	1	0.801306	0.162563	0.036131	7.798814	7.621611	8.411498	10.3548	10.3649
0	2	0.754866	0.160699	0.084435	7.814796	7.66773	8.339471	10.28907	10.4269
0	3	0.766765	0.14496	0.088275	7.778776	7.721323	8.339471	10.55224	10.16651
0	4	0.760505	0.204932	0.034564	7.739112	7.754033	8.319554	10.46377	10.27368
1999	1	0.758878	0.184491	0.056631	7.822089	7.81198	8.220474	10.54801	10.39446
0	2	0.756818	0.183358	0.059824	7.831428	7.776804	8.368153	10.39716	10.41369
0	3	0.770773	0.157553	0.071673	7.828427	7.798273	8.629814	10.58841	10.2039

lnN	no	d1	d2	d3	d4	Test	lnpcoal3	lnpgas3	lnphfo3	Scoal3	Sgas3
10.4184	1	1	0	0	0						
10.37428	2	0	1	0	0						
10.48741	3	0	0	1	0						
10.45508	4	0	0	0	1						
10.392	5	1	0	0	0						
10.32435	6	0	1	0	0						
10.383	7	0	0	1	0						
10.43174	8	0	0	0	1						
10.4808	9	1	0	0	0						
10.4706	10	0	1	0	0						
10.48101	11	0	0	1	0						
10.47969	12	0	0	0	1						
10.49159	13	1	0	0	0	Lower	7.522121	7.373777	8.345273	0.961746	0.001202
10.37941	14	0	1	0	0	Lower	7.527825	7.410826	8.414202	0.996984	0.000799
10.515	15	0	0	1	0	Lower	7.576984	7.498391	8.449573	0.99961	0.000147
10.64282	16	0	0	0	1	Lower	7.573884	7.506953	8.517036	0.996378	0.001159
10.73221	17	1	0	0	0	Lower	7.600685	7.587136	8.581766	0.954821	0.001253
10.31856	18	0	1	0	0	Lower	7.658306	7.676764	8.616183	0.989098	0.007507
10.80383	19	0	0	1	0	Lower	7.670358	7.726179	8.658661	0.99774	0.000526
10.80253	20	0	0	0	1	Lower	7.663995	7.770823	8.719506	0.995296	0.000681
10.89544	21	1	0	0	0	Lower	7.647188	7.757639	8.691479	0.997601	0.000652
10.81769	22	0	1	0	0	Lower	7.649709	7.757083	8.751702	0.999834	0.000166
10.84572	23	0	0	1	0	Lower	7.654375	7.739502	8.738773	1	0
10.90465	24	0	0	0	1	Lower	7.668948	7.718739	8.763831	0.999991	9.00E-06
10.97422	25	1	0	0	0	Lower	7.671766	7.718446	8.78538	0.999874	0.000126
10.84968	26	0	1	0	0	Lower	7.751216	7.711817	8.790132	0.996955	0.003045
10.93461	27	0	0	1	0	Lower	7.7262	7.72017	8.796705	0.999922	0.000078
11.02297	28	0	0	0	1	Lower	7.732846	7.737812	8.819169	0.999849	0.000151
11.08975	29	1	0	0	0	Lower	7.740759	7.746513	8.858409	0.999857	0.000143
10.9561	30	0	1	0	0	Lower	7.715146	7.734702	8.85745	0.99841	0.001506
11.02579	31	0	0	1	0	Lower	7.706348	7.702798	8.805264	0.99943	0.00057
10.98445	32	0	0	0	1	Lower	7.75186	7.710366	8.830113	0.998125	0.001802
11.07064	33	1	0	0	0	Lower	7.73483	7.713552	8.674973	0.999918	0.000082
10.94899	34	0	1	0	0	Lower	7.722866	7.71499	8.359948	0.998549	0.001451

10.95625	35	0	0	1	0	Lower	7.711095	7.707754	8.278825	0.999977	0.000023
10.94159	36	0	0	0	1	Lower	7.737799	7.683932	8.288738	0.999986	0.000014
10.91377	37	1	0	0	0	Lower	7.717838	7.676467	8.378468	0.999979	0.000021
10.68016	38	0	1	0	0	Lower	7.745996	7.680955	8.438802	0.999972	0.000028
10.93864	39	0	0	1	0	Lower	7.744692	7.65953	8.511335	0.999976	0.000024
10.98439	40	0	0	0	1	Lower	7.728198	7.669843	8.47587	0.999978	0.000022
11.13781	41	1	0	0	0	Lower	7.664704	7.658615	8.353914	0.974335	9.00E-06
10.98555	42	0	1	0	0	Lower	7.611208	7.607582	8.32383	0.978278	0.00003
11.12942	43	0	0	1	0	Lower	7.596141	7.541518	8.26115	0.965598	0.000012
10.98357	44	0	0	0	1		7.598794	7.54597	8.193904	0.971185	0.00002
11.03729	45	1	0	0	0	Upper	7.62605	7.566596	8.248129	0.941302	0.000015
10.76261	46	0	1	0	0	Upper	7.628258	7.521064	8.317901	0.951644	0.000013
11.0718	47	0	0	1	0	Upper	7.623469	7.522114	8.357732	0.909863	0.000023
11.09754	48	0	0	0	1	Upper	7.606336	7.560554	8.382192	0.871759	8.00E-06
11.11434	49	1	0	0	0	Upper	7.627522	7.580554	8.432043	0.951564	9.00E-06
11.04366	50	0	1	0	0	Upper	7.625313	7.528739	8.351043	0.845577	0.000012
11.25405	51	0	0	1	0	Upper	7.621251	7.530823	8.330703	0.839692	0.000032
11.2345	52	0	0	0	1	Upper	7.643575	7.565257	8.535279	0.967608	0.000012
11.37169	53	1	0	0	0	Upper	7.678779	7.615262	8.486812	0.967646	1.00E-05
11.27525	54	0	1	0	0	Upper	7.679826	7.537736	8.297544	0.933143	0.000053
11.33375	55	0	0	1	0	Upper	7.6693	7.530128	8.268466	0.887043	0.000025
11.2726	56	0	0	0	1	Upper	7.656877	7.589102	8.278482	0.93576	1.00E-05
11.28116	57	1	0	0	0	Upper	7.752833	7.633579	8.189782	0.923663	0.021219
11.15245	58	0	1	0	0	Upper	7.761238	7.556505	8.251665	0.917519	0.026373
11.34924	59	0	0	1	0	Upper	7.708385	7.526652	8.3766	0.923558	0.053907
11.24412	60	0	0	0	1	Upper	7.678779	7.562572	8.403042	0.890022	0.078452
11.35963	61	1	0	0	0	Upper	7.786965	7.632009	8.32449	0.929768	0.058889
10.96121	62	0	1	0	0	Upper	7.788535	7.599191	8.315589	0.914013	0.078027
11.09004	63	0	0	1	0	Upper	7.752833	7.598219	8.264989	0.846891	0.141346
11.16754	64	0	0	0	1	Upper	7.732846	7.692529	8.234218	0.849213	0.142613
11.28929	65	1	0	0	0	Upper	7.816013	7.784642	8.187527	0.885482	0.087837
10.98765	66	0	1	0	0	Upper	7.820271	7.696946	8.318564	0.779222	0.190768
10.94448	67	0	0	1	0	Upper	7.763166	7.696355	8.430867	0.777879	0.214864
10.95099	68	0	0	0	1	Upper	7.735494	7.718739	8.392363	0.757633	0.238965
10.9528	69	1	0	0	0	Upper	7.84336	7.630758	8.487364	0.839483	0.150541
10.83574	70	0	1	0	0	Upper	7.821789	7.483593	8.53182	0.756947	0.221126
10.95116	71	0	0	1	0	Upper	7.721192	7.478488	8.434983	0.765927	0.18743
10.83056	72	0	0	0	1	Upper	7.668594	7.508729	8.419292	0.700855	0.286867
10.91542	73	1	0	0	0	Upper	7.80745	7.576914	8.530483	0.794911	0.193507
10.85112	74	0	1	0	0	Upper	7.846316	7.488308	8.553979	0.853626	0.127709
11.02045	75	0	0	1	0	Upper	7.824811	7.485772	8.548745	0.820898	0.148978

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