UNIVERSITY OF
BIRMINGHAM

A STUDY ON THE EFFECT OF CLIMATE CHANGE POLICIES ON THE KOREAN ECONOMY

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A thesis will be submitted to

The University of Birmingham

for the degree of

DOCTOR OF PHILOSOPHY

Department of Economics

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ABSTRACT

The purpose of this thesis is to analyse the impacts of Climate Change policies on the Korean economy. The following chapters investigate major issues of climate change policies such as initial emission allowance allocation methods in a cap and trade policy for an electricity sector and a carbon tax policy while reforming current energy taxes and the electricity pricing system.

Chapter two assesses initial emission allowance allocation methods such as auction, uniform benchmark, fuel specific benchmark in the Korean electricity market with a Mixed Complementarity Problem (MCP) model. We found that giving away free permits makes the emission reduction more expensive, but the extra capacity triggered by the free allowances to new entrants based on the fuel-specific benchmark raises social welfare when the industry is not competitive.

Chapter three provides an integrated model that combines a top-down, macro-econometric model and the bottom-up, MCP electricity model built in chapter two in view of the importance of the electricity sector which is the largest source of CO_2 emissions in Korea. Most relations between variables in the behavioural equations are set up on theoretical grounds. Their long-term equilibrium relationships are confirmed by an Autoregressive Distributed Lag (ARDL) bounds testing approach to cointegration suggested by Pesaran et al. (2001) and standard specification tests. Conside and Mount (1984)'s dynamic linear logit

model is employed to capture fuel substitution behaviours in the macro-econometric model. The integrated model adopts a soft link method which incorporates multiple power output decisions and a price responsive demand function by the iteration method for linking the two models. The validity of the integrated model is checked by good predictive performance in an ex-post simulation exercise.

Chapter four analyses the effects of restructuring the energy tax and electricity pricing system when a carbon tax is introduced using the integrated model combining the top-down and bottom-up models provided in chapter three. Simulation results show that restructuring pre-existing energy taxes and the electricity pricing system can lessen the economic costs of CO_2 emissions reduction, which implies that adjusting the energy pricing system to reflect social costs accurately is the way to reduce emissions more efficiently. However, gradual restructuring of the current electricity pricing system would be recommended in order to minimize the negative effect on the industrial competiveness in the Korean economy.

ACKNOWLDEGEMENTS

It has been a long journey. Without Professor Richard Green’s guidance, this journey would be still drifting at the mercy of the waves. So, I especially wish to express my gratitude to Professor Richard, who provided me with a patient and enthusiastic supervision. This thesis, the outcome of the journey, would not have been possible without his intuition, suggestion and extraordinary support for research.

I wish also to record my appreciation to the two examiners, Professor David Maddison from the University of Birmingham and Doctor Alex Bowen from the Grantham Research Institute, London School of Economics and Political Science for their detailed review.

For helpful comments on previous drafts of the chapter two in this thesis, I am grateful to anonymous referees for the Energy journal, an editor, Professor Richard Tol and referees for the Energy Economics Journal, and Dong-suk Roh, a senior researcher at Korea Energy Economics Institute, for his assistance in data collection.

I certainly owe a debt of gratitude to all staff and PhD students in the Department of Economics, University of Birmingham for their encouragement. Especially, I wish to acknowledge the helpful comments from the PhD seminar participants at the University of Birmingham.

Finally, my deepest debt of gratitude goes to my family, my mother and old brother for providing all sorts of tangible and intangible support. In particular, this thesis is dedicated to the memory of my father.

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ABBREVIATIONS

AIC	Akaike Information Criterion
ARDL	Autoregressive Distribution Lag
A.U.	Auction
BAT	Best Available Technology
BAU	Business As Usual
B.U.	Bottom-Up
CBP	Cost-Based Pool
CCGT	Combined Cycle Gas Turbine
CDD	Cooling Degree Day
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CES	Constant Elasticity of Substitution
CGE	Computational General Equilibrium
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
CPI	Consumer Price Index
CRTS	Constant Return to Scale
DSGE	Dynamic Stochastic General Equilibrium
D.W.	Durbin-Watson
ECM	Error Correction Model
EU-ETS	European Union Emission Trading Scheme
F.B.	Fuel Specific Benchmark
F.O.C.	First Order Condition
GAMS	General Algebraic Modelling System
GBC	Government Budget Constraint
GHG	Greenhouse Gas
GDP	Gross Domestic Product
GT	Gas Turbine
HDD	Heating Degree Day

IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent Power Producers
JA	Jet fuel JA-1
KEPCO	Korea Electric Power Corporation
KEWP	Korea East-West Power
KHNP	Korea Hydro and Nuclear Power
KKT	Karush-Kuhn-Tucker
KOMIPO	Korea Midland Power
KOSPO	Korea Southern Power
KOSEP	Korea South-East Power
KPX	Korea Power Exchange
LDC	Load Duration Curve
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MAC	Marginal Abatement Cost
MAPE	Mean Absolute Percentage Error
MCP	Mixed Complementarity Problem
MSs	Member States
NAIRU	Non-Accelerating Inflation Rate of Unemployment
OECD	Organisation for Economic Co-operation and Development
OLS	Ordinary Least Square
PPI	Producer Price Index
RESET	Ramsey Regression Equation Specification Error Test
RORR	Rate of Return Regulation
S.C.	Schwarz Criterion
T.D.	Top-Down
TPES	Total Primary Energy Supply
TWBP	Two Way Bidding Pool
U.B.	Uniform Benchmark
UNFCCC	United Nations Framework Convention on Climate Change
UECM	Unrestricted Error Correction Model
WP	Korea Western Power

CHAPTER 1 INTRODUCTION

1.1. OBJECTIVES OF THE THESIS

The greenhouse emissions (GHG) in Republic of Korea has shown strong growth in the period from 1990 to 2010. The amount of GHG in 2010 is around 669 million tonnes CO_2, equivalent (hereafter, CO_{2e}) which ranks 9th in the world. The growth of GHG between 1990 and 2005 is 90.1%, which ranks 1st among the Organisation for Economic Co-operation and Development (OECD) countries. As for the contribution of each sector, the energy industries sector (electricity and petroleum refining) accounts for 38%, followed by manufacture and industries sector (24.9%), transport sector (12.6%), industrial processes (9.4%), and commercial and residential sector (8.7%) in 2010[1].

To help mitigate climate change, the government has operated the Inter-ministerial Committee on United Nations Framework Convention on Climate Change (UNFCCC) since 1998 and has formulated and implemented action plans for climate change every three years in order to introduce climate change policy. According to the Copenhagen Accord in 2009, Korea being a non-Annex I country is required to identify nationally appropriate mitigation actions including a GHG emission reduction target.

Therefore, the Korean Cabinet on 17 November 2009 approved the 2020 target of reducing estimated 2020 emissions by 30 per cent from "business-as-usual", (BAU) levels

[1] The statistics are from Greenhouse Gas Inventory and Research Center of Korea's website: http://www.gir.go.kr/og/hm/ic/b/OGHMICB011.do?headerValue=04&leftValue=01

which is equivalent to a 4 percent reduction from the 2005 level. Total CO_2 emissions are estimated at 813 million tonnes in the BAU case.

To achieve the Copenhagen Accord commitment of a 30 per cent reduction, the government will introduce a cap and trade scheme to be implemented in 2015 to achieve the reduction target cost-effectively. Over 300 of the largest companies emitting 60-70 per cent of the nation's greenhouse gases will be involved in the cap-and trade scheme. In the initial stage, 90 per cent of emission allowances will be allocated to emitters free of charge. The remainder would be auctioned, with the proportion to be auctioned to increase over time after the first phase. In the final phase, all allowance will be auctioned.

However, several concerns over the free allocation methods have been raised in the electricity sector which is the largest source of emissions; even though the Coase theorem states that the initial allocation method does not prevent the market from reaching the efficient solution (Coase, 1960), the free allocation method would cause two problems in the real world; 'windfall profits' and distortion of investment. Sijm et al. (2006) point out that power companies can gain considerable windfall profits through passing on the opportunity cost of the freely allocated permits. As for the second problem, Åhman and Holmgren (2006) and Neuhoff et al. (2006a) insist that the allocation methods allowing more permits to a specific carbon intensive technology such as a coal power plant give the wrong signals for investment decisions. Given the long economic life of power plants, distorted investment caused from the allocation method raises the economic cost of achieving the emission target in the long-run. Therefore, it is necessary to design an efficient initial allocation method in the initial stage of the cap and trade scheme.

In addition to the cap and trade scheme, the government is considering introducing a carbon tax policy which imposes taxes on the carbon contents of hydrocarbon energy products such as petroleum, coal, and Liquefied Natural Gas (LNG) to internalize the externality of GHG emissions caused from combusting the energy products. Currently, the tax rates on energy products do not reflect their externalities (Kim 2012)[2] and the government maintains low electricity tariffs for industrial competitiveness and price stabilization. This has led to distortions in relative prices, thereby resulting in an unreasonable energy consumption structure, in particular excessive electricity consumption. Hoeller and Coppel (1992a,b) point out that maintaining the distorted pre-existing energy taxes and adding the carbon tax would further worsen distortions. Thus, the need for rearranging current energy taxes and restructuring the electricity pricing system before introducing the carbon tax policy has been raised in order to lessen the economic cost of the carbon tax.

Under these circumstances, the purpose of this thesis is to analyse the effects of the main climate change policies on the economy in order to provide insight into the questions surrounding the issues. The two specific subjects to be examined are as follows;

1. Investigate potential effects of initial emissions permit allocation methods on output, investment, emissions, electricity and emissions permit prices, and social welfare in the Korean electricity market. Several allocation rules such as auctioning and free allocation on a uniform best available technology (BAT) benchmark or a fuel specific benchmark to existing and new investment are simulated to compare their impacts.

[2] Kim (2012) has pointed out that the Korean government impose similar level of taxes on petroleum products for vehicles, but relatively high taxes are imposed on natural gas and no taxes on electricity, diesel and coal for heating energy compared to EU's minimum level of energy and carbon taxes (Directive 2003/96EC).

2. Analyse the effects of a carbon tax policy on the economy and emissions using an integrated model. Furthermore, the role of restructuring current energy taxes and electricity pricing systems is examined in order to find a more cost-effective policy.

1.2. OVERVIEW OF THE THESIS

This thesis consists of three main chapters, exploring major climate change policy issues such as emission permit allocations and carbon tax's impacts on the economy.

Chapter 2 assesses the first main issue: the impact of initial emission allowance allocation methods in the Korean electricity market when a cap-and-trade scheme is introduced. The Korean electricity market is modelled in detail in order to quantify the effect of different emission allowances allocation plans. A multi-period version of the Mixed Complementarity Problem (MCP) structure adopted in this model allows the model to incorporate operation and capacity planning under imperfect competition along with related environmental issues at the same time. To my best knowledge, this is the first attempt to use the MCP model to incorporate investment decisions subject to the allocation rules such as auctioning, fuel specific benchmark, and uniform benchmark to new entrants.

Chapter 3 builds up an integrated model that combines a top-down and a bottom-up approach for analysing the second main issue, the impacts of carbon tax policies. Taking into consideration the importance of the electricity sector, which accounts for the largest portion of total emissions, it links the bottom-up electricity market model based on the MCP framework explained in chapter two and a top-down model, the macro-econometric model. Overall, the integrated model is more suitable to analyze the climate change policy in that it allows the model to captures the supply side in detail and macroeconomic interaction at the same time. Among integration methods, the model adopts a soft link method which is regard as the most effective system to transfer information from the electricity model dealing with the complexity of power generation to the top-down model. The macro-econometric model, in which the number of equations is 148 including 57 behavioural equations and 91 identities, employs an Autoregressive Distributed Lag (ARDL) bounds testing approach to cointegration suggested by Pesaran et al. (2001) in order to find a long-run equilibrium relationship between variables in behavioural equations which in line with economic theory. The validity of the equation is confirmed by standard specification tests. Additionally, a dynamic linear logit cost share model (Considine and Mount, 1984) which is one of the standard inter-fuel substitution models are adopted to estimate own-price and cross-price elasticities of final energy demands such as petroleum, coal, electricity, and city-gas, which determines fuel switching effects. Finally, we perform an ex-post simulation to check the model's predicative performance before executing a carbon tax policy simulation.

Chapter 4 analyses the second main issue using the integrated model established in chapter three. What are the effects of restructuring current taxes on energy products and electricity tariffs regulated from the government on the economy, emissions, and mix of energy demands when a carbon tax policy is introduced? Four scenarios are set up to compare their effects on the economy: (1) no carbon taxation; (2) a carbon tax of 50,000 won per tonne of carbon while maintaining the current taxes and electricity pricing system; (3) the carbon tax policy with reforming the current taxes on energy products by exempting kerosene, Liquefied Petroleum Gas (LPG), and LNG which are already highly taxed compared to their social cost from the carbon taxation; (4) the carbon tax policy while restructuring the tax system and the electricity pricing system by allowing an electricity supplier to impose a cost reflective tariff om customers.

Chapter 5 concludes this thesis by summarizing the main findings from the previous chapters and suggesting possible extensions.

CHAPTER 2

ASSESSMENT OF INITIAL EMISSION ALLOWANCE ALLOCATION METHODS IN THE KOREAN ELECTRICITY MARKET[3]

2.1. INTRODUCTION

On 17 November 2009 the Korean Cabinet approved the 2020 target of reducing projected CO_2 emissions for 2020 by 30 per cent from "Business-as-usual" (BAU) levels, or a 4 per cent reduction from the 2005 level of 569 million tonnes of CO_{2e}.[4] The BAU emission projection for 2020 is estimated at 813 million tonnes. The government initially set a plan for a three-phase cap-and-trade scheme, with the first phase running for three years from 2013 to 2015, then the second phase starting in 2016 to run through 2020, and the last phase commencing from 2021. Over 300 of the largest companies emitting 60-70 per cent of the nation's greenhouse gases will be involved in the cap-and trade scheme. In the initial stage, 90 per cent of emission allowances will be allocated to emitters free of charge. The remainder would be auctioned, with the proportion to be auctioned to increase over time after the first phase. In the final phase, all allowances will be auctioned.

[3] A version of this chapter was published in the journal *Energy Economics* in May, 2014. The online version is available at http://www.sciencedirect.com/science/article/pii/S0140988314000528

[4] Time series data is available at http: //www.gir.go.kr /og/hm/ic/b /OGHMICB011.do?headerValue = 04&left Value=01

However, the government decided in February 2011 to postpone emission trading, mainly due to opposition from industrial sectors. According to the revised bill, emission trading will be implemented in 2015. Besides, as vested interests' (carbon intensive industries) resistance increases, the bill would allow for a higher proportion of emission allowances to be handed for free to heavy emitters. Debates have been continuing over the amount of emissions allowances to be given to specific sectors for free and over the handling of new entrants.

This argument has also been observed in European Union Member States (MSs) since preparation for the European Union Emission Trading Scheme (EU-ETS) Phase I (2005¬2007). All MSs had to distribute allowances to industrial installations for free: at least 95 per cent of total allowances in the first ETS period and 90 per cent in the second period. The vast majority of emission allowances have been distributed to existing emitters in proportion to their historical emissions, which is referred to as grandfathering.[5] Auctioning was an option for the remainder. This goes against the efficiency-focused economic perspective that advocates the auction (see Cramton and Kerr, 2002)[6]. Nevertheless, the grandfathering allocation has remained the dominant rule in most MSs because of political resistance and concerns such as adverse effects on industrial competitiveness.

After the first phase of EU-ETS, the effect of the free emission allowances to existing firms has been investigated empirically and the potential effects of other allocation options have been assessed by scholars. In particular, studies have paid attention to the electricity sector, since electricity has been considered a special sector which is likely to determine the emission price. In fact, electricity is the largest sector in the ETS, as over 40 per cent of total

[5] More precisely, we define grandfathering as the method of allocating emission allowances to existing emitters for free based on their historical emissions in a recent base period of specific years.
[6] Cramton and Kerr (2002) point out that auctioning allows reduced tax distortions, provides more flexible ways to distribute costs, brings greater incentives for innovation, and avoids political arguments over the allocation of rents.

allowances in the ETS were distributed to the sector. Besides this, electricity was the only sector in a net short position over the initial period (Trotignon and Delbosc, 2008). This means that the situation of power generation determines the overall demand for the allowances and would have a major impact on allowance prices. The long economic life of power plants also has an enduring effect on the cost of achieving future emission targets.

Existing power plants were provided with allowances in most MSs based on historic emissions for the first phase of the EU-ETS. Historic emissions are calculated for a recent reference period within a fixed time frame or updated. Finally, adjustment factors such as expected growth and future compliance for reduction could be applied to the historic emission records.

Grandfathering has several advantages for introducing an emission trading policy; it reduces political resistance from carbon intensive industries as they are guaranteed sustainable profits under the regime (Åhman et al., 2007) and provides incentives for industries to report installations' past emissions at the same time. In particular, another reason to favour the historic emissions were that EU-MSs did not have enough time to build up a suitable benchmark, mainly because of difficulties for various sectors and legal issues at the beginning of the EU-ETS (Ellerman et al., 2010). On the other hand, most MSs applied the benchmark to new entrants from the first phase.

However, there has been a consensus that the free allocation, namely the historic emission approach, led to two main problems: 'windfall profits' and distortion of investment. Power companies gained substantial windfall profits from the grandfathered emission allowances. They could pass on the opportunity costs of CO_2 in liberalized electricity markets, as economic studies demonstrate (Sijm et al., 2006)[7], even though their monetary costs did not rise. Even worse, some allocation methods to new technology give the wrong signal to investment decisions. Generally, carbon-intensive power plants such as coal receive more allocations than lower carbon technologies such as gas, under the historic emission allocation. Therefore, the allocation distorts investment decisions towards carbon-intensive technology. Considering fossil fuel power plants' life of decades and fixed allowance budgets, distorted investment decisions significantly increase the total cost of achieving the emission target in the future (Å hman and Holmgren, 2006; Neuhoff et al., 2006a).

After the ETS phase1, there was a tendency to gradually adopt benchmarks instead of the historic emission approach. Although the majority of MSs base their allocation method on historical emissions (for an overview of allocation provisions in all MSs, refer to Rogge and Linden, 2008), this movement recognizes the adverse effects on the economy mentioned before. This study defines the benchmark as a free allocation method to both existing and new entrants using a specific emission rate per unit output (e.g. tCO_2/MWh) combined with the unit's capacity and either actual or a common operation time for each installation. Glancing at the benchmark systems adopted in MSs for the second phase, they show different provisions. But the benchmarks could be divided into two main categories. Firstly, emission values based on the best available technology (BAT) or on average performance could be applied to a particular technology group, which is called the fuel-specific benchmark in this thesis. Secondly, a single BAT emission value could be set for all plants, known as the uniform benchmark.

[7] An opportunity cost arises, because a firm is able to use the freely allocated permits to cover the emissions or sell the permits to other firms who need more permits, which represents an opportunity cost, regardless of whether the permits are freely allocated or bought in the market. Thus, in line with economic theory, a firm is expected to add the emission costs to its production or trading costs. Finally, the firm is able to gain windfall profits by means of increased electricity prices with no additional costs by grandfathering.
Giving away permits also involves an opportunity cost for the government as it government loses the chance to use the fund from an auction to finance spending or cut existing taxes.

In general, compliance and strict emission factors under the benchmark improve energy efficiency compared to the historic emission approach, but the following criticism has been made regarding the fuel-specific benchmark: it often sets a higher emission factor for more carbon-intensive power plant types, meaning that more emission allowances are provided to coal power plants than to gas power plants. As existing studies (Hepburn et al., 2006; Neuhoff et al., 2006a) point out, this creates a bias towards more carbon-intensive technology in terms of firms' operating and investment decisions. Consequently, it increases CO_2 emissions and drives up CO_2 prices. Finally, consumers face higher electricity prices[8], reflecting the CO_2 prices in the long term.

In contrast, the uniform benchmark prevents these distortion problems in that all plants receive emission allowances equally. If the emission factor is based on low-carbon technology, gas fired power plants such as CCGT are a more attractive option for investment, so that effective abatement of CO_2 in the power sector for long periods can be accomplished. However, several European countries are vulnerable to the security of natural gas supplies, with concerns about their long-term availability and an increase in dependence on a few countries. For this reason, the uniform benchmark to new entrants has been avoided in several MSs (typically, Germany) where coal-fired plants account for the majority of the power mix. These various allocation provisions in MSs will be unified through full auctioning which will be implemented in the power sector from the third phase, 2013 onwards; (European Parliament and Council, 2009)[9].

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[8] This would hold unless the allocation of permits to new plants leads to a large increase in capacity.

[9] There are four exemptions; (1) generators for district heating and cogeneration activities in respect of heating and cooling, (2) a specific MS in which the electricity network was not connected with the EU system in 2007, (3) less than 400MW in a MS which was connected by a single line in 2007, (4) a MS in which more than 30% of electricity was generated from a single fossil fuel and the GDP per capita did not exceed 50% of the average GDP per capita of the EU in 2006.

The Korean government is at the point where it needs to decide initial allocation methods given the facts that these allocations will last until 2026 and have a significant impact on investment incentives, particularly in the next few years. However, there have been few attempts to investigate the impact of the allocation plans on the Korean electricity sector so far, even though the sector is the largest source of emissions. The electricity sector is expected to play a major role in deciding the emission price given the electricity sector's high marginal abatement costs and relatively large emission size. Therefore, the purpose of this study is to assess the effect of allocation methods consisting of full auction, the fuel-specific benchmark, and the uniform BAT benchmark for existing and new entrants on social welfare in order to draw a reasoned political implication. In order to do this, this paper employs a Mixed Complementarity Problem (MCP) model which is able to incorporate operation and investment decisions, taking account of capacity and emission constraints under different allocation scenarios in the competitive electricity market. In particular, the model is designed to allow endogenous investment decisions subject to different allocation rules to new entrants, which is an advance on the existing literature. The main outcomes from the model consist of capacity mix, electricity prices, emission prices, and social welfare, under the allocation scenarios. We found that firms invest more with the fuel-specific benchmark than with auctioning, and though the cost of emissions reduction is higher, the extra investment (which had been below socially optimal levels) means that social welfare actually rises.

The remainder of this study is organized as follows. The next section explains how the emission trading market reacts to different allocation methods. Section three gives an overview of the MCP framework and describes the full model of this study. In section four, we apply the MCP model to the Korean electricity market. Section five compares the results of the electricity sector's emissions, total new investment capacity, emission allowance prices, electricity prices, and social welfare for all allocation scenarios. The final section concludes.

2.2. THEORETICAL REVIEW

Panel A in Figure 2.1 depicts how the permit price is determined under different emission permits allocation methods to existing power plants in the emission trading system. Let us assume that there are two players in the emission trading market: an aggregated electricity sector and non-electricity sector. The marginal abatement cost (MAC) curves of electricity sector and non-electricity sector are shown as MAC_e and MAC_{ne} respectively, which are equivalent to their demand function for emission permits. The origin for emissions of the electricity sector in Figure 2.1 is the left-hand axis and the origin for emissions of the non-electricity sector is the right-hand axis. The vertical line at O' represents the overall emission cap. Suppose that the MAC_e function is given by $P = a - bQ_{el}$, where a and b are parameters, P is CO_2 price, and Q_{el} is the total CO_2 emissions of the electricity sector, which is subject to $Q_{el} = Q_n + Q_i$, where Q_n is emission permits purchased in the market and Q_i is freely allocated emission permits in the initial period. Therefore, a change in free allocation permits moves the initial point along the MAC_e curves.

The emission cap is represented by the length, $\overline{OO'}$. The equilibrium permit price, P_e is determined by point E, where $MAC_e = MAC_{ne}$. The extent to which free permits are allocated to the electricity sector determines the number of permits bought or sold. Points U and F on the MAC_e represent positions corresponding to different allocations.

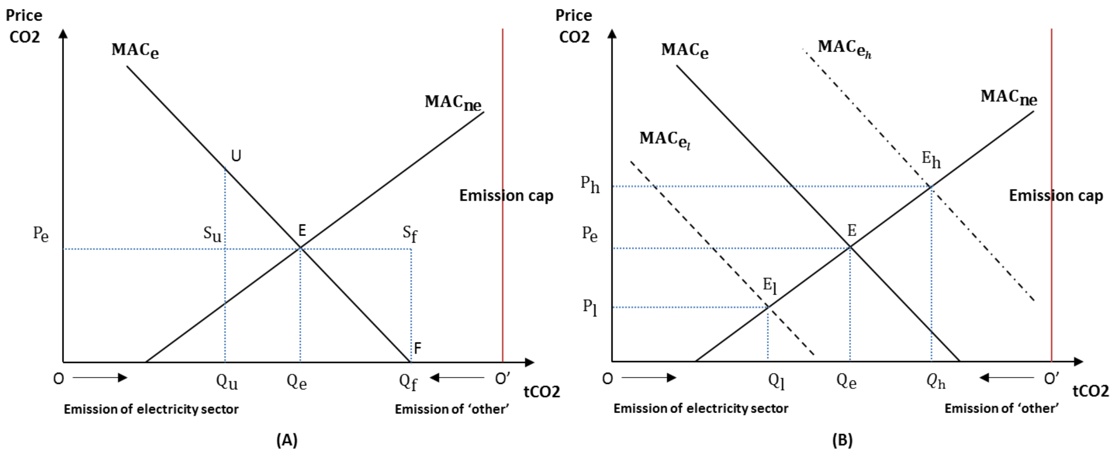

Figure 2.1. Principles of the emission trading system

At point *F*, the existing power plants are receiving the full BAU amount of freely allocated allowances and would sell the quantity of permits, $\overline{Q_eQ_f}$. With a stricter allocation method, such as the uniform benchmark to existing power plants, the relatively small allowance is shown at point *U*, where the quantity of permits the sector needs to purchase is $\overline{Q_uQ_e}$, thus the cost of purchasing permits is $\blacksquare Q_uQ_eS_uE$. With full auctioning, the electricity sector would need to purchase all its permits, $\overline{OQ_e}$. In this case, the CO_2 cost is increased to $\blacksquare OQ_eP_eE$. A generation firm needs to choose between using the emissions permits or selling them, which means an opportunity cost arises regardless of whether the permits are freely allocated or purchased. If generators pass through the opportunity cost to electricity prices in each case, different allocation methods to existing installations end up having the same effect on electricity prices[10].

[10] In principle, if firms internalize the opportunity cost of freely allocated allowances, the initial allocation methods may not make a difference to the electricity price. But, in practice, generators might not impose the full opportunity costs of emission allowances on the electricity price because of competitiveness pressures and the threat of new entrants (Reinaud, 2003). Also Sijm et al. (2006) point out that three elements: expectation of updating, voluntary agreements or regulatory threat, and uncertainties constrain opportunity cost pricing in the initial period of the EU ETS.

Panel B in Figure 1 describing the effects of different allocation methods for new investment capacity on the CO_2 prices in the market is based on the hypothesis under which the allocation rules have an impact on the investment decisions of firms. Åhman and Holmgren (2006) reach a conclusion that the allocation to new investment is very likely to affect investors through changing the operation of a specific fuel type's technology and revenues. Our simulation result supports their point (see section five). Furthermore, Neuhoff et al. (2006a) have shown that allocating permits to new plants on the basis of their emissions could cause generators to invest in a more carbon-intensive capacity mix than if investment did not attract free permits.

Firstly, let us suppose that emission cap and the non-electricity sector's MAC curve are fixed at all times. If generation firms invest more in carbon-intensive technology, which is triggered by a fuel-specific benchmark allocation to new installations, this causes the marginal abatement cost to rise as the number of carbon-intensive plants increases. Thus, MAC_e will shift to the right: to MAC_{e_h}. Consequently, the permit price rises from P_e to P_h. On the other hand, a leftward shift from MAC_e to MAC_{el} illustrates a decrease in the marginal abatement cost by the fact the generation firms invest in low-carbon technology, which is prompted by the full-auction or strict benchmark allocation to new installations. This leads to a decrease in the permit price from P_e to P_l. Therefore, we can conclude that different allocation methods to new power plants could affect the permit price in the emission trading market. It is important to note that this result does not violate the Coase theorem which states that the market equilibrium is independent of the initial allocation (Coase, 1960). The equilibrium price and quantity are not affected by the allocation rules to existing plants as seen in Panel A in Figure 1. The different outcomes seen in Panel B of Figure 1 come from the fact that investment decisions are affected by the allocation rule and so marginal abatement cost curves change. Effectively, the act of investing leads to an endogenous change in the investor's endowment, rather than the exogenous change in property rights that Coase considers.

The rest of this chapter estimates the magnitude of these effects of initial allocation methods in the Korean electricity sector.

2.3. METHODOLOGY AND MODEL

As the electricity markets have been deregulated in many countries (i.e. shifting from monopoly to competition), a Mixed Complementarity Problem (MCP) model has been extended to cope with short-term output competition and investment decisions under the oligopolistic electricity market. Ventosa et al. (2002) provide a notable model in which generation firms decide output and capacity expansion in the Cournot manner. The model fulfils the Nash-Cournot equilibrium on the condition that the first order conditions of all players are satisfied. Compared to earlier works, it shows more flexibility for extension and powerful solution processing by taking advantage of the complementarity structure. Linares et al. (2006, 2008) extended Ventosa et al.'s work in two ways. First, the Conjectural Variations (CV) approach of Garcí-Alcalde et al. (2002) is adopted for more realistic spot market simulation. Secondly, emission allowances and tradable green certificates are modelled endogenously. This model is partially based on Linares et al.'s work (2006), but Cournot competition in the short-term market is adopted, rather than the CV method, and endogenous investment decisions relevant to allocation rules to new entrants are explicitly modelled.

Formally, a non-linear program is built as the objective function of each firm in the model. The derivation of Karush-Kuhn-Tucker conditions of the objective function leads to a MCP formulation. The general MCP is defined as:

Given a function $f: R^n \to R^n$ and bounds $l, u \in R^n$, find the vectors $z, w, v \in R^n$ subject to the following constraints

$$
\begin{aligned}
s.t.: \quad & F(z) - w + v = 0 \\
& l \le z \le u, \quad w \ge 0, v \ge 0 \\
& w^T (z - l) = 0 \\
& v^T (u - z) = 0
\end{aligned}
\tag{2.1}
$$

where $-\infty \le l \le z \le u \le \infty$, T is the transposition of a matrix, and the function, F must be continuously differentiable in order to express a model. For further information, refer to Rutherford (1995) and Ferris and Munson (2000).

2.3.1. Model overview

The Korean electricity market is modelled in detail in order to quantify the effect of different allocation plans. A multi-period version of the MCP structure adopted in this model allows the model to deal with operation and capacity planning under imperfect competition along with related environmental issues at the same time.

Each firm is assumed to maximize its profit, defined as revenues minus operating costs, investment costs and purchasing emission permits costs subject to technical and environmental regulation constraints. The firm chooses an optimized decision considering others' strategy. A Nash equilibrium defines a set of strategies such that no firm wishes to change its decision unilaterally, taking competitors' decisions as given. The Nash-equilibrium in the model is achieved by satisfying the first-order optimality conditions simultaneously with respect to operation, investment, and environmental decisions. Formally, the whole model can be set as a Nash game (x, Π) where x is the vector of strategy decisions $x = (x_1, \ldots, x_e)$, Π is the vector of profits $\Pi = (\Pi_1, \ldots, \Pi_e)$ and e is a player vector $e = (e_1, \ldots, e_e)$. A Nash equilibrium is a strategy vector $x^* = (x_1^*, \ldots, x_e^*)$ such that $\Pi_e(x^*) \geq \Pi_e(x_e, x_{-e}^*)$ for all $e = (1, \ldots, e)$.

The key feature of modelling the investment decision is that the model is designed for each firm to decide new capacity taking into account the allocation rules such as auction, fuel specific benchmark, and uniform benchmark to new entrants. Consequently, the model compares equilibrium wholesale electricity prices, emission allowance prices, and new installed capacity, given different allocation plans.

2.3.2. Model assumptions

First and most importantly, in order to guarantee the existence of a unique solution, the objective function (eq. 2.2) and constraints conditions (eq. 2.3~2.7) should be strictly quasi-concave and convex respectively. The former is ensured by setting a decreasing demand function of the price and increasing cost functions and the latter is guaranteed by using linear equations in this model.

Secondly, while power plants are discrete units[11] in the real world, it is assumed that each firm's capacity (of each technology type) is a continuous variable, for the sake of simplicity. In addition, the model considers electricity demands over the course of a year at a

[11] A typical power station has units with capacities of 500 to1200MW.

time. The data are grouped as peak, plateau, and off-peak hours according to the load levels with a total of 14 blocks. The total demand for electricity at each load level is given by a linear function of the price. Besides this, the operating cost of firms is modelled as a quadratic fuel consumption function in which all fuel prices such as coal, gas, and heavy oil are assumed to be fixed over whole years. On the other hand, start-up costs and ramp rate constraints in the cost function are excluded, since those conditions have little effect on investment decisions in the long term.

Thirdly, the equilibrium electricity price and investment decisions are determined in a Cournot manner. A linear demand function is employed. Each firm chooses its output given its competitors' strategy to maximize its own profit. Then, the equilibrium electricity price is derived from substituting the summed firms' output into the inverse demand function (see eq. 8). However, before applying the oligopoly theory to the Korean electricity market, it should be noted that the market has been operating as a Cost-Based Pool (CBP) in which generators had to bid at variable cost and this set the price since 2001. Attempts to create Two Way Bidding Pool (TWBP)[12] competition, which allows distributors to submit price responsive demand bids and generators offer power at prices above variable cost, ceased in 2003 due to the change in the political environment. But the current administration continues to attempt the policy of competition. Therefore, the model assumes that the TWBP is introduced in the electricity market where distribution firms are allowed to bid in order to represent the trend of industry policy and justify application of the oligopoly theory. The assumptions of the Cournot model fit well into the properties of the deregulated electricity market: homogeneous goods, non-storable, and few firms in the electricity market. In addition, the theory assures a

[12] Under the CBP system which is a preliminary stage for TWBP, the marginal price is determined by the merit order system in which each unit is ranked according to generators' bid based on its variable cost. On the other hand, the electricity price is determined by a market mechanism in the TWBP where both the generation and distribution firms submit supply and demand bids, respectively.

unique equilibrium and avoids complex computational processes. But it often gives very high equilibrium prices compared to real data in the electricity market, because equilibrium prices are sensitive to the price elasticity of demand and firms are assumed not to react to competitors' output and price changes[13]. Therefore, this model indicates the price level in a potential market where the price is formed because of the substantial market power by dominant firms under the emission trading scheme rather than forecasting the actual future electricity prices.

Regarding investment decisions, firms are able to choose technology and capacities among nuclear, two types of coal (bituminous and anthracite), CCGT, and oil power plants in order to maximize their profit. Note that renewable investments require subsidy and are therefore exogenous, while the problems in modelling their intermittent output mean that they are best modelled by changing the residual demand curve[14]. The Cournot investment equilibrium is accomplished when no firm wishes to change its investment decision given its competitors' capacities. It is important to note that each technology has a specific time to build constraint in the real world. For example, while nuclear power plants have the longest lead time, almost 5 years, CCGT plants have the lowest time, 2 years. Although the model does not impose the time to build constraint explicitly, firms are assumed to have perfect foresight so that they are able to choose the optimal time to commence construction of new plants. In addition, they have perfect information about the government scheme for the distribution of emission allowances; when the initial allocation method is implemented by

[13] Wolfram (1999) confirms that the price predicted by the Cournot model tends to be higher than the real spot price in the British electricity market from her empirical study, and suggests that the level of the real price can be explained as the effect of threats of other companies entering the market and of regulatory action.

[14] Thus the residual demand curve shows the demand facing the traditional sources of power generation. Renewable energy sources supported from the government's policy are often given special treatment in models, because they could not be compared with the traditional technology due to their low economic efficiency and renewable energy's intermittent output. Their outputs are usually modelled by using a residual demand curve (see section 2.4.2.). Ventosa et al. (2002) and Linares (2006) have similar short lists of candidate technologies.

each scenario and an auction is introduced in the final stage (see the allocation plans in section 2.4.3.). Lastly, we assume that firms have access to enough capital through efficient capital markets to finance their desired investment programme.

Fourthly, the endogenous emission price modelling is based on Linares et al.'s work (2008). It is assumed that there are many players in a perfectly competitive emission allowances market. Players in the emission allowances market are classified into two main groups, the electricity sector and non-electricity sector. Further disaggregation would need each sector's Marginal Abatement Cost (MAC) to construct its emission allowance demand function. The electricity sector's allowances demand function is derived in this model, since firms choose buying or selling the allowances in response to output decisions. As for the non-electricity sector, it is assumed that this sector will play as a price taker (i.e. a competitive fringe) in the emission market. This assumption allows the clearing emission price to be independent of different allocation methods for the non-electricity sectors. Therefore, the residual supply curve is built up by subtracting the non-electricity sector's demand from the total supply curve, subject to the emission cap by government (see equations 2.10~12).

Fifthly, we do not model early closures of power plants, for the sake of simplicity. To my best knowledge, there have been no attempts to model decisions for investment and possible closure at the same time in the electricity market studies due to technical difficulties. Thus, this study simply reflects the plan for closing old power plants by exogenous modelling. Note that the allocation rules could also affect firms' behaviour over closures, as studies such as Neuhoff el al., 2006a and Åhman et al., 2007 point out.

Lastly, the model assumes that relative fuel prices in 2013 will be maintained during the planning horizons in this study. This assumption can be justified by the following two reasons; firstly, the prices of uranium for nuclear and coal have been stable compared to the prices of LNG and heavy-oil mainly due to relatively abundant reserves. However, LNG and heavy oil prices have been volatile, it is possible, given tight oil and shale gas, that they could be lower over the next decades than they are now, or higher because of rising energy demand. Assuming a constant level is a compromise between these. Secondly, there is already a big gap between the marginal costs of each technology (Nuclear<Coal<CCGT) in Korea because of their fuel prices and relatively similar efficiencies of power plant (CCGT has the highest one). In particular, Korea imports natural gas as liquefied natural gas, so that the marginal cost of a CCGT is approximately 3.4 times higher than the coal fired plant, which means that reasonable fuel price scenarios without extreme cases do not change the merit order system (output of each technology) in the Korean electricity market and hence the main simulation results. In other words, while the absolute level of electricity prices will depend on these fuel prices, the overall merit order will be insensitive to plausible assumption.

2.3.3. Mathematical formulation

This section provides the objective function and constraints, then derives the KKT conditions. Full notations are described in the Appendix.

2.3.3.1. Objective function

The objective of each firm, i is to maximize profit; market revenues, minus operating costs, investment costs, and net emission allowance purchase given relative constraints for years indexed by t and 14 load segments per year, indexed by l. The objective function is given by

$$(2.2)\quad Max \quad \pi_i = \sum_t \sum_l d_{t,l} r_t p_{t,l} q_{i,t,l} - \sum_{tec} \sum_t \sum_l d_{t,l} r_t v_{tec,t} (c_{i,tec} q_{i,tec,t,l} + c'_{i,tec} q^2_{i,tec,t,l}) - \sum_{tec} \sum_t r_t ci_{i,tec} I_{i,tec,t} - \sum_t r_t p_t^{emis} N_{i,t}$$

where key decision variables are electricity output $q_{i,tec,t,l}$, capacity investment $I_{i,ntec,t}$, and net emission allowance purchase $N_{i,t}$. As explained before, the electricity price $p_{t,l}$ and the emission allowance price p_t^{emis} are determined by the Cournot equilibrium and perfect competition respectively in this model. As for parameters, $v_{tec,t}$, $ci_{i,tec}$, $c_{i,tec}$, and $c'_{i,tec}$ are fuel cost, investment cost, linear and quadratic variable cost respectively. $d_{t,l}$ represents the duration of load level and r_t is the discount factor. Technology indexed by *tec* consists of nuclear, bituminous coal, anthracite coal, heavy oil, combined cycle gas turbine (CCGT), and gas-turbine (GT).

2.3.3.2. Constraints

2.3.3.2.(a) Output constraint

The output of each firm must be smaller than its total capacity, which is defined as initial capacity $\overline{K}_{i,tec,t,l}$ plus sum of new installed capacity $\sum_{t=1}^{t} I_{i,tec,t}$. θ_{tec} indicates availability of a power plant considering forced outage rates and planned maintenance days.

$$(2.3)\qquad q_{i,tec,t,l} \le \theta_{tec} \overline{K}_{i,tec} + \theta_{tec} \sum_t I_{i,tec,t} \qquad \perp \lambda^q_{i,tec,t,l} \qquad\qquad \forall i, tec, t, l$$

2.3.3.2.(b) Nuclear output constraint

The model imposes an additional output constraint on nuclear power plants. The nuclear power plant might withhold their output strategically in order to raise the electricity prices and cover their high fixed cost from the increased prices in a liberalized market despite their low variable costs. But they could not exercise their market power in the real world due to the huge start-up costs of a nuclear power plant and regulations from the government. Thus, the model imposes a 'must-run' condition, which implies that firms owning nuclear plants should produce more than the minimum output boundary set by the nuclear power plants' load factor, η_{nuc} multiplied by their capacity.

$$(2.4) \qquad \eta_{nuc}\overline{K}_{i,nuc} + \eta_{nuc}\sum_{t} I_{i,nuc,t} \le q_{i,tec,t,l} \qquad \perp \lambda^{nq}_{i,tec,t,l} \qquad \forall i,tec,t,l$$

2.3.3.2.(c) Emission constraint

The amount of pollution emitted by each firm must be less than the amount of emission allowances it owns. Each firm has three sources of emission allowances: net emission purchase, $N_{i,t}$ and free emission allowances to existing and to new investment capacity given different allocation plans. It should be noted that banking and borrowing are not allowed in this model, as banking and borrowing would be prohibited during the first stage according to the potential Act. Thus, each firm's emission and total permit should be balanced every year.

$$(2.5)\qquad \sum_{tec}\sum_{l} d_{t,l}\zeta_{tec} q_{i,tec,t,l} \le N_{i,t} + \sum_{tec} G^{C,A}\cdot \overline{K}_{i,tec} + \sum_{tec} G^{C,A}\cdot I_{i,tec,t} \qquad \perp \lambda^{e}_{i,t} \qquad \forall i,t$$

where the capacity index C consists of existing plants, e and new entrants, n in the benchmarking factor $G^{C,A}$. In addition, the allocation rules indexed by A are distinguished as the auction, α, the fuel-specific benchmark, f and the uniform benchmark, u in this model. Table 2.1 explains how the benchmarking factors are calculated in the corresponding allocation methods.

Table 2.1. Benchmarking factors in allocation methods

	Existing power plants	New power plants
Auction	$G^{e,a\cdot} = 0$	$G^{n,a\cdot} = 0$
Uniform benchmark	$G^{e,u\cdot} = sef \times shr$	$G^{n,u\cdot} = sef \times shr$
Fuel specific benchmark	$G^{e,f\cdot} = ef_{tec} \times hr_{tec}$	$G^{n,f\cdot} = ef_{tec} \times hr_{tec}$

For example, under the fuel-specific benchmark, the benchmarking factor is calculated by the emission factor times the actual operation hours per technology such that $G^{C,f\cdot} = ef_{tec} \times hr_{tec}$. Therefore, the amount of allowances to existing plants or new entrants is calculated by the benchmarking factor, $G^{C,f}$ multiplied by installed capacity, $\overline{K}_{i,tec}$ or new entrants' capacity $I_{i,tec,t}$. On the other hand, the uniform benchmark factor, $G^{C,u}$ is determined by the standard emission factor, sef multiplied by the standard operation hour, shr. In the case of auctioning, the factor $G^{C,\alpha}$ is equal to 0. It must be noted that a zero-emission technology such as nuclear is not allowed to have free allowances in this model.

2.3.3.2.(d) Net emission permit purchase constraint

The net emission permit purchase has a lower and an upper boundary. It means that the maximum permits purchased from each firm and the maximum permits each firm can sell should be less than the total number of permits in the emission market. Since permit sales occur when $N_{i,t}$ has a negative value, this second constraint implies that the value of $N_{i,t}$ must be greater than a negative floor, $N_{i,t}^{lo}$. In other words, the equations describe that the power generation sector is not able to sell or buy their permits more than total number of permits (i.e. emission cap) in the emission market at each period.

(2.6) $$N_{i,t} \leq N_{i,t}^{up} \qquad \perp \lambda_{i,t}^{nup} \qquad \forall i,t$$

(2.7) $$N_{i,t}^{lo} \leq N_{i,t} \qquad \perp \lambda_{i,t}^{nlo} \qquad \forall i,t$$

2.3.3.3. Auxiliary equation

Equation (2.8) states that the total output of each firm consists of all power plants' generation. The electricity price equation is given by a linear demand function as equation (2.9).

(2.8) $$q_{i,t,l} = \sum_{tec} q_{i,tec,t,l}$$

(2.9) $$p_{t,l} = a_{t,l} - b_{t,l} \sum_{i} q_{i,t,l}$$

The emission allowance price is obtained by the equation below[15]:

$$(2.10) \qquad P_t^{emis} = b_t^{emis}\left(\sum_{tec}\sum_{l} d_{t,l}\zeta_{tec}q_{i,tec,t,l} + N_t^{ne,0} - Cap_t\right)$$

2.3.3.4. Karush-Kuhn-Tucker conditions

Constructing a Lagrange function containing the objective function (2.2) and the inequality conditions (2.3~2.7) multiplied by their dual variables and then deriving the first order KKT conditions with respect to the decision variables yields the following equations

$$(2.13) \qquad \begin{aligned} &0 \le q_{i,tec,t,l} \perp d_{t,l}r_t(a_{t,l} - b_{t,l}(\sum_{j,j\neq i} q_{j,t,l} + 2q_{i,t,l})) - d_{t,l}r_t v_{tec,t}(c_{i,tec} + 2c'_{i,tec}q_{i,tec,t,l}) \\ &- \lambda_{i,tec,t,l}^{q} - \lambda_{i,t}^{e} d_{t,l}\zeta_{tec} + \lambda_{i,tec,t,l}^{nq} \le 0 \qquad \forall i, tec, t, l \end{aligned}$$

$$(2.14) \qquad 0 \le I_{i,tec,t} \perp -r_t ci_{i,ntec} + \theta_{tec}\sum_{l}\lambda_{i,tec,t,l}^{q} - \eta_{nuc}\sum_{l}\lambda_{i,tec,t,l}^{nq} + \lambda_{i,t}^{e} \cdot G_t^{n,A} \le 0 \qquad \forall i, tec, t$$

$$(2.15) \qquad N_{i,t}^{lo} \le N_{i,t} \perp -r_t p_t^{emis} - \lambda_{i,t}^{nu} + \lambda_{i,t}^{nl} + \lambda_{i,t}^{e} \le 0 \qquad \forall i, t$$

---

[15] Equation (2.10) is derived as the following process: The emission cap has to be equal to all allowances purchased by all sectors and grandfathered to both sectors.

$$(2.11) \qquad Cap_t = \sum_i N_{i,t}^{e} + \sum_i GF_{i,t}^{e} + N_t^{ne} + GF_t^{ne}$$

where $\sum_i GF_{i,t}^{e}$ and GF_t^{ne} are total grandfathered allowances of the electricity sector and the non-electricity sector respectively. The non-electricity sector's demand function for emission allowances is simply assumed to be a function of the allowance price and the total grandfathered allowances, which is as follows:

$$(2.12) \qquad N_t^{ne} = N_t^{ne,0} - b_t^{emis}P_t^{emis} - GF_t^{ne}$$

Then, substituting (2.11) and the emission constraint equation (2.5) into (2.12) yields the emission price equation.

The inequality constraints corresponding to dual variables are as follows

$$(2.16) \qquad 0 \le \lambda^{q}_{i,tec,t,l} \perp q_{i,tec,t,l} - \theta_{tec}\overline{K}_{i,tec} - \theta_{tec}\sum_{t} I_{i,tec,t} \le 0 \qquad \forall i, tec, t, l$$

$$(2.17) \qquad 0 \le \lambda^{nq}_{i,tec,t,l} \perp \eta_{nuc}\overline{K}_{i,nuc} + \eta_{nuc}\sum_{t} I_{i,nuc,t} - q_{i,tec,t,l} \le 0 \qquad \forall i, tec, t, l$$

$$(2.18) \qquad 0 \le \lambda^{e}_{i,t} \perp \sum_{tec}\sum_{l} d_{t,l}\zeta_{tec} q_{i,tec,t,l} - N_{i,t} - \sum_{tec} G^{e,A} \cdot \overline{K}_{i,tec,t} - \sum_{tec} G^{n,A} \cdot I_{i,tec,t} \le 0 \qquad \forall i, t$$

$$(2.19) \qquad 0 \le \lambda^{nu}_{i,t} \perp N_{i,t} - N^{up}_{i,t} \le 0 \qquad \forall i, t$$

$$(2.20) \qquad 0 \le \lambda^{nl}_{i,t} \perp N^{lo}_{i,t} - N_{i,t} \le 0 \qquad \forall i, t$$

where the symbol $\perp$ indicates the complementary slackness condition, which implies the two non-negative variables are orthogonal.

2.3.4. IMPLEMENTATION

The profit maximization problem, subject to operation, investment, and environmental constrains and auxiliary equations, has been applied to the MCP framework by deriving KKT conditions. The model has 41,475 equations and variables with 393,092 non-zero elements. The MCP model is implemented in the General Algebraic Modelling System (GAMS) and solved by the PATH solver (Ferris and Munson, 2000).

2.4. APPLICATION TO THE KOREAN ELECTRICITY MARKET

The model has been applied to the Korean electricity market in order to investigate the impact of different emission allocation policies on social welfare. Capacity mix, electricity prices and emission allowance prices are provided by means of the MCP framework, which is able to incorporate those issues endogenously. The model analyses the Korean electricity market from 2010 to 2030. In the middle of the period, the emission trading policy is assumed to be introduced in 2015 in all allocation cases.

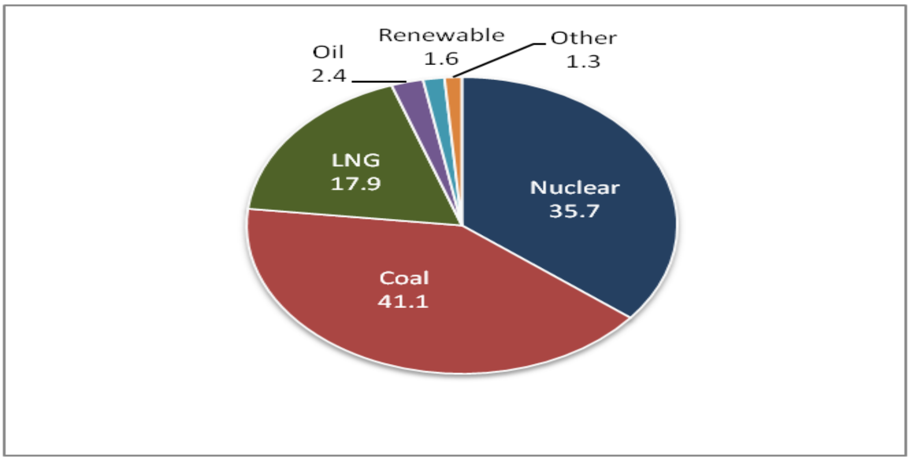

Figure 2.2. Generation mix by fuel in 2008 (unit: output share, %)

The industry had a total electricity generating capacity of 72,491 MW in 2008. Electricity generation from coal and nuclear accounts for the largest combined share of 76.8 per cent, followed by natural gas, oil, and renewable in 2008 as seen in Figure 2.2.

2.4.1. Firms

The Korean electricity industry, Korea Electric Power Corporation (KEPCO), had been operated as a vertically integrated monopoly constituting of power generation, transmission and distribution.

The basic plan for the restructuring of the electric power industry; "The Basic Plan for Restructuring of the electricity industry" was announced in 1999. Soon after, the National Assembly approved the Electricity Business Act promoting the restructuring of the electricity supply industry in 2000.

Consequently, the vertical combined structure was separated. The generation sector of KEPCO was split into six generating companies as subsidiaries of KEPCO: Korea South-East Power (KOSEP), Korea Midland Power (KOMIPO), Korea Western Power (WP), Korea Southern Power (KOSPO) and Korea East–West Power (KEWP), which have similar total capacity and types of generation facilities (for instance, coal and CCGT power plants) in order to maximize the effect of divestitures in the competitive market, and Korean Hydro and Nuclear Power (KHNP) which takes charge of all nuclear plants. For the gradual process of transition to the competitive market, the Cost Based Pool (CBP), which is a preliminary stage for the Two Way Bidding Pool (TWBP), has been operated since 2001.

Thus, the Korea Power Exchange (KPX) was established as a non-profit organisation in the same year for operating the market and system. KEPCO has operated the transmission and distribution sector. Although a few IPPs have participated in the market, they still account for a small portion, since they are operating CCGT power plants that mostly run at peak times in the market; this is called a marginal power plant as it sets electricity prices.

Therefore, the six major generation firms and Independent Power Producers (IPPs) have been included as players in the model. Table 2.2 shows the status of the generation companies in 2008.

Table 2.2. Korean generation companies in 2008 (unit: MW)

Firms	Nuclear	Bituminous Coal	Anthracite Coal	Heavy Oil	GT	CCGT
KHNP	17,716	-	-	-	-	-
KOSEP	-	6,580	325	529	-	922
KOMIPO	-	4,000	400	150	888	2,812
KOWP	-	4,000	-	1,400	-	2,280
KOSPO	-	4,000	-	600	-	3,600
KOEWP	-	4,500	400	1,800	-	2,100
IPPs	-	-	-	-	-	5,249

Source: Korea Power Exchange, Electric Power Statistics Information System

To model technology, existing power plants are divided into Nuclear, Bituminous coal, Anthracite coal, Heavy oil, GT and CCGT. Among them, the Nuclear, Bituminous coal and CCGT plants are included for new investment options. Anthracite coal, heavy oil, and open cycle gas turbines are ruled out as they are dominated by the other technology on cost grounds. While KHNP is the only company now owning nuclear plants, all firms are allowed to invest in nuclear plants. The model aggregates the same technology power plants owned by each firm into one unit in its assets to reduce the scale of the model. Lastly, we are assuming constant fuel and operating costs in real terms in view of the various possible energy market scenarios as mentioned in section 2.3.2 and their limited impact on the merit order in Korea. Their major characteristic parameters are presented in Appendix 2.

2.4.2. Electricity demands

In this model, the linear demand function is adopted as equation (2.9) in each load block. The model employs the method for the electricity demand function in each block and elasticity suggested by Borenstein and Bushnell (1999) analysing the market power in a deregulated Californian electricity market. To determine coefficients $a_{t,l}$ and $b_{t,l}$, the linear demand function has a price elasticity of demand of 0.1 in the short run based on our estimation results for Korea in next chapter[16]. Note that the elasticity value, 0.1 is also used by Borenstein and Bushnell (1999) for California. The demand function passes through a standard point at the predicted demand and average retail price excluding transmission and distribution costs in 2009. On the other hand, the elasticity in the first and second blocks (at peak loads) is assumed to be 0.01, which considers inelastic demands at peak times in the market. Since peaks are dominated by households who usually do not see real-time prices, elasticity is expected to be much lower at these times. The $b_{t,l}$ equation is calculated by the elasticity formula[17].

As for the predicted demand, it is assumed that the annual electricity demand in all periods has the same demand pattern as in 2009. We generate new load duration curves from the mathematical formula introduced in Kim et al. (2007), which satisfies the peak and total output according to the 5th basic plan of long term electricity supply and demand published by the Ministry of Knowledge Economy of Korea (2010) as shown in Table 2.3 below. The total electricity demand (GWh) and Peak demand (MW) are expected to grow at an average rate of about 3% per year during the periods. After 2020, electricity demands in all blocks are simply assumed to rise at 2% annually from 2021 to 2030. Then residual demands are derived by

[16] We estimate the own price elasticity of total electricity demand for three sectors; industry, commerce and public, households using the cost share logit model (Considine and Mount, 1984) which is one of the inter-fuel substitution models. The results show that the own electricity price elasticity of industry, commerce, and public households sectors are -0.05, -0.06, and -0.13 respectively (see section 3.4.2.7. in chapter 3).

[17] The elasticity formula is as follows

$$\varepsilon = \frac{\Delta Q}{\Delta P} \times \frac{P_{t,l}}{Q_{t,l}} = \frac{1}{b_{t,l}} \times \frac{P_{t,l}}{Q_{t,l}} \Rightarrow b_{t,l} = \frac{the\, average price}{\varepsilon \times the\ prediced\, demand}$$

means of subtracting renewable energy and pumped-storage[18] outputs from the total demands. The demand data are converted into a stepwise approximated load duration curve (LDC) with 14 blocks, in order to reduce the computational burden in this model. Finally, $a_{t,l}$ is calculated by substituting $b_{t,l}$ into the linear demand function equation.

Table 2.3. Annual electricity demand forecast

Year	Total Demand (GWh)	Peak (MW)
2011	443,786	73,713
2012	462,091	76,161
2013	482,400	79,784
2014	502,613	83,360
2015	520,842	86,754
2016	536,092	89,629
2017	550,527	92,281
2018	567,175	95,075
2019	582,461	97,405
2020	598,221	99,653

Source: Ministry of Knowledge Economy of Korea (2010)

2.4.3. Allocation plans

We assume that the emission trading scheme consists of two stages: 1st stage (2015-2025) and 2nd stage (2026-2030). An initial allocation method in the electricity sector will hold until the end of the first stage, 2025, which gives eleven years of free allocation in some cases. Then, all emission allowances will be auctioned from the second stage, 2026.

[18] There are approximately 3.9 GW of pumped-storage power plants in Korea, which pump water at cheap energy costs overnight and use it to generate when prices are higher in the day. Thus, pumped energy multiplied by an efficiency factor should be added to base load blocks.

The government's plan specifies a 4 per cent reduction from the 2005 level, so it is estimated that the economy-wide emission target would be 570.3 million tonnes CO_2 in 2020. The model assumes that the total of allowances under the ETS is consistent with the national target in 2020. The allowances in earlier years will decrease at an annual rate of 1% to reach the target in 2020. The national target in periods from 2021 to 2030 is simply assumed to be fixed at the level of 2020 in the model. Annual emission permits will be distributed to the emitters according to established allocation scenarios for the first eleven years (2015~2020) and then auctioned from 2026.

According to 'An enforcement decree for emission allowances allocation and trade' established on July, 23, 2012, the Korean government prohibits the inflow of Certified Emission Reductions (CERs), from the Clean Development Mechanism (CDM) in developing countries which are certified by the United Nations Framework Convention on Climate Change (UNFCC), entirely by the end of the second phase, 2020, in order to prompt domestic abatement activities. Besides, the available supply of CERs, their prices, and thus the effects of the CERs on the permit price in a domestic market after a decade are unknown quantities. Therefore, the allowances from the CDM have been neglected in the model.

As mentioned in section 2.3.2, the non-electricity sector's allowances demand function is modelled to build up the residual supply function, which allows the electricity sector to decide their output and investment in response to the emission price. The demand function of the non-electricity sector for emission allowances has been set up according to Lee et al.'s work (2009) estimating the MAC of industrial sectors in Korea[19].

[19] The slope parameter is estimated at 0.00132 Won/tCO2 by OLS estimation. See page 56 in Lee et al. (2009) for the other sectors' MACC.

Table 2.4. Parameters for emission allowances allocation scenarios

	Bituminous Coal	Anthracite Coal	Heavy Oil	GT	CCGT
Output(GWh)	185,826	7,978	11,970	762	41,111
Capacity(MW)	23,080	1,125	4,479	888	11,715
Load factor (%)	92	81	31	10	40
Historic operation hours (hr/year)	8051	7091	2673	858	3509
F.B. emission factor (tCO2/MWh)	0.75	0.80	0.65	0.55	0.35
Standard operation time (hr)			6000		
U.B. emission factor (tCO2/MWh)			0.35		

Note: Domestic anthracite coal power plants are receiving a subsidy so that they are running as 'must-run' plants in the market. Historic operation hours are estimated based on the Korean Electric Power Corporation (2010).

In terms of allocation scenarios during the first stage from 2015 to 2022, the model considers typical allocation methods: an auction (A.U.) and two types of grandfathering: (1) uniform benchmark with standard operation hours (U.B.) and (2) fuel-specific benchmark with historical operation hours (F.B.) are considered. The historic operation hours are calculated based on the output in 2009, since using a recent (but past) load factor is a typical method of allocating permits to plants. The standard operation hours are calculated from the average value between the bituminous coal and the CCGT plants' operation time. The specific parameters are summarized in Table 2.4.

The model is used to analyse a total of ten scenarios in initial allocation methods. There are three allocation rules (A.U., U.B., F.B.) to incumbents and the same number of rules to new entrants along with a base scenario (no emission policy case). However, in order to concentrate on contrasting cases and more realistic scenarios, five scenarios are presented here. The most realistic scenario is that the government would start the emission trade policy with the fuel specific benchmark for existing power plants and the uniform benchmark for new entrants (case 4), as several EU countries did for the second phase of the EU-ETS. Then follows the scenario (case 5) in which they might impose the same (fuel-specific benchmark) allocation rule for new entrants. Finally, base and full auction cases are provided to compare the effects of other scenarios.

1) Base case: no emission controls (Base)
2) Auction to existing power plants + Auction to new entrants (A.U. to A.U.)
3) U.B. to existing power plants + U.B. to new entrants (U.B. to U.B.)
4) F.B. to existing power plants + U.B. to new entrants (F.B. to U.B.)
5) F.B. to existing power plants + F.B. to new entrants (F.B. to F.B.)

2.5. RESULTS

Although the nation's emission target will be fulfilled in all allocation policies according to equation (2.10), they have different effects on the economy. This section summarizes key features such as the electricity price, emission allowance price, total electricity sector emissions, capacity mix, and social welfare of all allocation scenarios[20].

2.5.1. Total new investment

Without the ETS, firms are definitely in favour of a coal power plant as an investment option in the market. A total of 8,046 MW of coal power plants will be added, which

[20] Annual average results are provided in Appendix 2.

represents 57 per cent of the total new capacity. This is mainly due to its cheaper operation than gas and cheaper construction costs than nuclear power plants in the Korean market.

As shown in Figure 2.3, the ETS has changed the scale of investment and capacity mix. It can be seen that the more allowances are given to new investment, the more new capacity is built up. The largest amount of new capacity, 16,872 MW is observed with the fuel-specific benchmark to existing plants and new entrants.

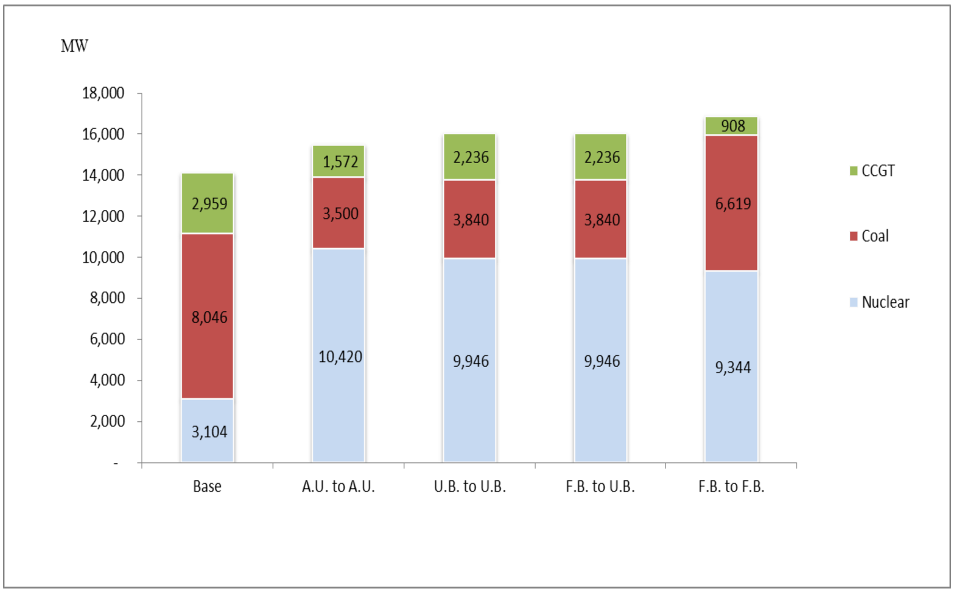

Figure 2.3. Total new investment capacity in the different allocation cases

This is because the allowance is working as a kind of subsidy. If new capacity is endowed with allowances, firms do not need to purchase a large amount of allowances in the market, so the new plants will be incentivized. As a result, the coal power plant remains a dominant technology with the fuel-specific benchmark rule, representing 39 per cent of the total new investment capacity. On the contrary, the auction rule to new entrants leads to less investment, 15,492 MW, and causes firms to mainly choose nuclear power plants, which account for 67 per cent of the new capacity. The main reason for this result is that coal and CCGT plants have to purchase all the permits they need in the auction system. Thus, the profits of those plants are significantly damaged, which makes generators prefer the nuclear power plant.

The capacity of new coal power plants is significantly reduced with the auction and the uniform benchmark rule to new entrants, since the allowances given to a coal power plant are not enough to compensate for its higher costs. Therefore, investment in coal power plants is replaced by lower carbon technology such as nuclear power.

2.5.2. Total CO_2 emissions in the electricity sector

Without the ETS, the electricity sector's emissions will reach 299.86 million tonnes of CO_2 in 2030, but the launch of the emission trading scheme with any of the allocation methods described in this model reduces expected total emissions in the electricity sector. These reductions are attributed to switching fuels from coal and oil to gas and investing in cleaner technology such as nuclear and CCGT plants.

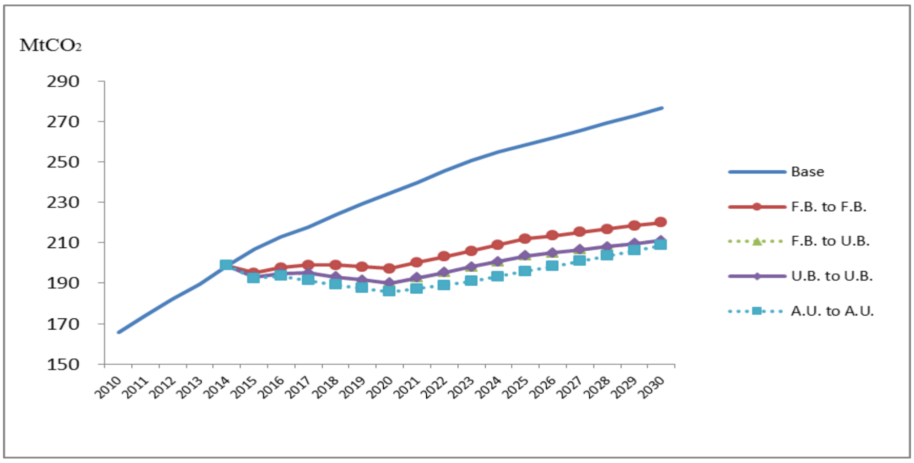

Figure 2.4. Electricity sector's total CO_2 emissions in the different allocation cases

Apart from the base case, the largest emissions are found in the full fuel-specific benchmark. As carbon-intensive technologies are endowed with more allowances here than in any other allocation methods, the output from coal power plants still occupies a relatively high portion, 41.4 per cent in 2030. In addition to the operating decision, the coal power plant is a dominant technology for investment with the fuel-specific benchmark so newly built coal power plants with high emission factors contribute to the increase in emissions. However, the full fuel-specific benchmark is able to lessen emissions compared to the base case by 20.4 per cent in 2030. This is mainly due to an increase in nuclear output compared to the base case. On the other hand, the output share of the CCGT remains almost stationary in all allocation cases. The CCGT share of electricity output in 2030 represents at least 18.7 per cent in the F.B. to F.B. case and at most 21.3 per cent in the base case. This implies that allocation policies had little effect on the marginal plants' operation times in the Korean market. This is because the nuclear power plant with low variable costs prevails over the CCGT with high fuel costs in dealing with emission constraints. In any cases, the CCGT's running will be restricted to within peak times. Thus, the amount of fuel switching from coal to gas is relatively small regardless of the allocation policies[21]. The difference in the number of freely allocated permits for existing plants between the U.B. to U.B. and the F.B. to U.B. cases does not change output decisions, as the Coase Theorem implies, which leads to identical results for emissions, emission allowance prices, and electricity prices.

The most notable increase in nuclear output is found with the auction allocation. The largest share, 43.2 per cent of the total output, is accounted for by nuclear power.

[21] The relatively small effect of fuel switching from coal to LNG is mainly due to high fuel cost of LNG. Since Korea imports natural gas as LNG, the fuel price of LNG is about 3.4 times higher than Bituminous coal's price. The marginal cost (won/MWh) of bituminous coal and CCGT plant when they add the opportunity cost of CO_2 emissions can be calculated as about 123,160 and 149,130 respectively given the maximum emission permit price. As a result, the Bituminous coal plant remains as a dominant technology in the merit order.

Consequently, the auction brings the least emissions, 209 million tonnes of CO_2 (24.5 per cent reduction from the base) in 2030. Almost identical results for emissions are observed in the full uniform benchmark and the fuel-specific benchmark to the uniform benchmark, which reduce the base emission by approximately 23.6 per cent in 2030.

2.5.3. Emission allowances prices

As the annual emission cap decreases, the allowance price increases with the passage of time, as indicated in Figure 2.5. The full auction case leads to the lowest allowance price, but the full fuel-specific benchmark induces the highest allowance price. It is interesting to note that Figure 2.5 shows little difference between the prices of different allocation cases in the initial periods. The prices start at about 42,000 won per tonne of CO_2, which is approximately equivalent to €28.2[22]. However, as time goes by, the gap between the scenarios widens to 9,340 won per tonne of CO_2 at the end of the first stage, 2025. This is because the scarcity value of an emission allowance increases with the higher-carbon investment encouraged by some allocation methods.

As mentioned earlier, the national emission cap is assumed to be met in all cases, but the fuel-specific benchmark to new entrants makes firms favour carbon intensive technology such as coal power plants, which increases electricity sector emissions significantly. Consequently, costs to achieve the emission target also rise according to the scarcity principle. Relatively higher emission allowance prices from the simulation in the Korean market as compared to the second period of the EU-ETS (€8 per tonne of CO_2 in April, 2012) might be caused by the high marginal abatement cost curves of carbon-intensive industries, dependence

[22] This article refers to the exchange rate of won per euro, 1,490 won in April, 2012.

on coal power plants in the country, or a tougher target compared to the EU after all the renewables they are building.

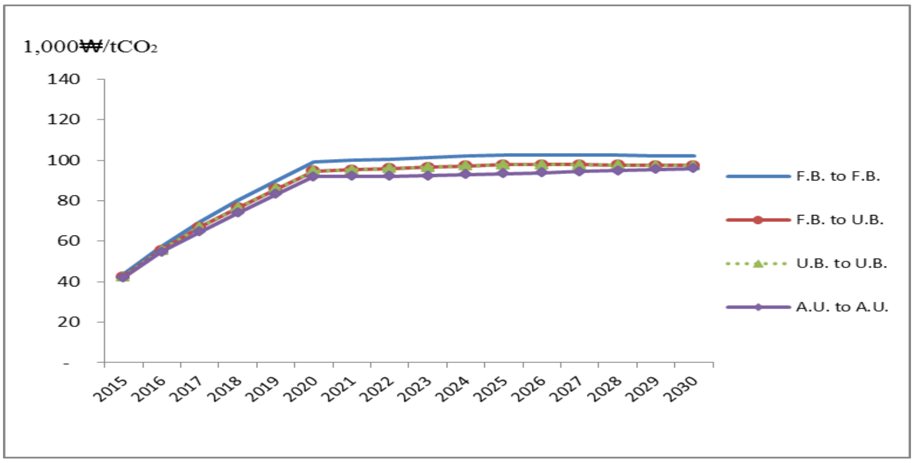

Figure 2.5. Annual average CO_2 prices in the different allocation cases

2.5.4. Electricity prices

As the electricity demand continues to rise annually, the price, in general, goes up as shown in Figure 2.6. The introduction of the emission trading policy with any allocation method increases the electricity price. The highest electricity price is observed in the A.U. to A.U. case, which follows the U.B. to U.B., the F.B. to U.B., and the F.B. to F.B. Compared to the base case, the average increase is 12.2 per cent, 10.6 per cent, 10.6 per cent, and 9.5 per cent respectively. While the A.U. to A.U. case has the lowest carbon price, it also has the lowest investment in new capacity, and this lower level of capacity gives the highest electricity price. In contrast, the F.B. case leads to more investment and relatively lower electricity prices.

Given the CO_2 prices under all scenarios, the average impact of CO_2 cost pricing is estimated at 28₩/kWh in the A.U, 24₩/kWh in the U.B. to U.B. and the F.B. to U.B., and 22₩/kWh in the F.B. to F.B, which are equivalent to €14.8/MWh ~ €18.8/MWh. These results are in line with the German case in Sijm et al.'s (2006) work that estimates electricity price increases due to CO_2 costs at €20/tCO_2 using the COMPETES simulation model. That study shows the price increase in Germany is higher than in any of the other countries modelled. This is mainly due to the fuel mix, with a high dependence on coal. It implies that the extent which electricity prices increase due to the ETS is determined by the share of carbon-intensive power generation such as coal power plants in an electricity market.

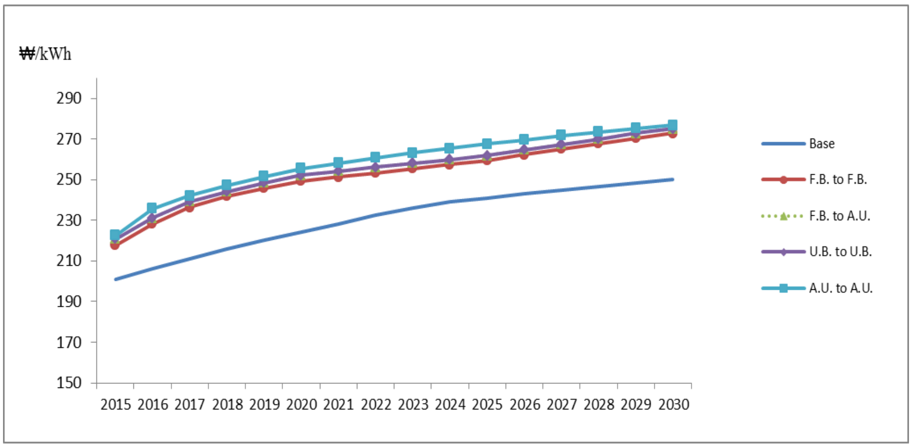

Figure 2.6. Annual average electricity prices in the different allocation cases

However, taking account of dynamic investment behaviour, the results above show that free allocation to new entrants gives generators incentives to build up new capacities. In particular, the fuel-specific benchmark to new entrants accelerates investment in coal-fired plants. This results in higher competition in the electricity market, which lowers electricity prices.

2.5.5. Social welfare

Taking into consideration the external effect of the emission allowance allocation method in the electricity on the emission market, the model estimates social welfare in a partial equilibrium setting, internalizing the external effect into the electricity sector. Social welfare in this model is the sum of consumers' surplus, the firms' profits, and the revenue from selling permits to the electricity sector, less the pass-along cost that measures external costs caused by the allocation rule to electricity sector. In other words, if the electricity sector cuts its emissions by less, other industrial sectors need to incur additional costs to reduce their emissions by enough to meet the overall national target.

We assume that all the revenues from selling permits to the electricity sector are simply redistributed to households. As Burtraw et al. (2001) point out, if the revenue is used to decrease pre-existing distortionary taxes, it could create additional economic value, but in order to limit the scope of this study, we rule out analysing the effect of such tax interaction on welfare. Therefore, the agents are assumed to return all of the revenue from selling permits to consumers in this model, since this is regarded as the least valuable option, increasing consumers' surplus only by the face value of the revenue. We do measure these revenues as a separate item in our welfare analysis, however.

In terms of the external effect, recall that total emissions are assumed to be the same in each scenario. Therefore, the impact of increased emissions in the electricity sector on other sectors, named the pass-along cost, is defined as the cost that is incurred by reduction of additional emissions in the non-electricity sector instead of the electricity sector. If the electricity sector purchases emission allowances instead of reducing its own emissions, the sector selling those allowances must incur the cost of lower emissions. We call this cost the pass-along cost.

Figure 2.7 demonstrates this pass-along cost concept. Point C gives the level of emissions in the electricity sector, Q_c , and the permit price, P_c, in the scenario with the lowest electricity emissions. In some other scenario, in which the electricity sector emits Q_e tCO_2, the permit price is P_e , determined by the emission allowance price equation (10). The increase in the permit price from P_c to P_e is caused by the additional investment in higher-carbon plant discussed earlier. Therefore, the trapezoid area, Q_cQ_eCE represents the pass-along cost that the non-electric sector must bear. This cost is normalised relative to the non-electricity sector's emissions level from the full auction case, determined by ex-ante simulation.

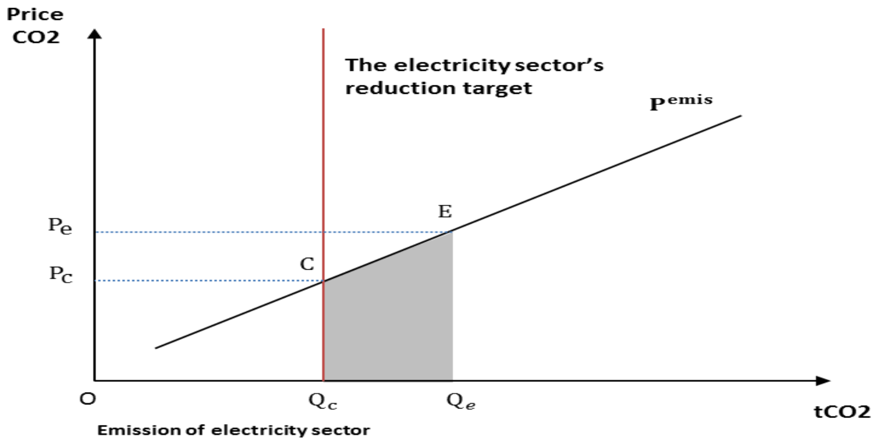

Figure 2.7. Pass-along cost determination

Note: the slope parameter is obtained from Korean research, Lee et al. (2009).

Table 2.5 shows the results for social welfare, given the different allocation methods. Numerical values in parentheses indicate changes relative to the base case. It is also important to note that although the difference in electricity sector emissions between the cases is in fact offset by changes in the non-electricity sector, valued at a social cost of carbon of $25 per ton[23] in 2010 dollars the electricity reductions are worth between approximately 390 and 469 billion won.

[23] The value was chosen on the basis of a survey by Tol (2013) which provides the mean, $25 and a standard deviation, $22 of values from the literature using a 3 percent discount rate.

Table 2.5. Social welfare in the different allocation cases (unit: trillion Won)

	Base	A.U. to A.U.	U.B. to U.B.	F.B. to U.B.	F.B. to F.B.
Consumer Surplus	3,336.18	3,179.84 (-156.34)	3,207.04 (-129.14)	3,207.04 (-129.14)	3,226.34 (-109.84)
Producer profit	1,451.03	1,403.42 (-47.61)	1,424.23 (-26.80)	1,467.67 (16.64)	1,447.31 (-3.72)
Revenue from selling permits to electricity sector	-	198.61	152.71	109.28	121.72
Pass-along cost	-	-	5.10	5.10	12.92
Social welfare (Net surplus)	4,787.21	4,781.87 (-5.34)	4,778.88 (-8.33)	4,778.88 (-8.33)	4,782.45 (-4.76)
Reduction in the electricity sector (1,000 tCO_2)	-	67,730	65,240	65,240	56,350

Although it appears that relatively minor changes in social welfare occur among scenarios, significant differences in distributional effects depend on the different initial allocation methods. Generally, increased electricity prices in all allocation scenarios cause a reduction in consumer surplus. In the auction case, even though the allowance price is lowest, the lower investment levels drive up electricity prices and firms pass the highest carbon costs through to electricity prices, and so the losses in consumer surplus are greatest.

The emission allocation methods' effect on producer profit shows diverse results. The profit of generation firms decreases in the full auction and the uniform benchmark cases. Generally, as the marginal power plant, CCGT sets higher electricity prices due to the ETS; infra marginal units such as nuclear and coal power plants benefit from increased electricity prices. But, the increases in electricity prices do not exceed the increases in costs of purchasing emission allowances (i.e., the cost pass-through rate is less than one). For this reason, if all allowances are distributed by the auction or the uniform benchmark, the generation firms' profit will be reduced. In contrast, the firms realize windfall profits from the fuel-specific benchmark to incumbents and uniform benchmark to entrants and the full fuel-specific benchmark cases during the initial period. This implies that existing coal power plants are not faced with relatively high costs of purchasing their emission allowances with the fuel-specific benchmark allocation. Furthermore, they earn additional rents by passing through the opportunity cost of free emission allowances to electricity prices. However, from the second stage, generators' profits are significantly reduced in the full fuel-specific benchmark, since firms must purchase all permits as much as they expanded capacity of carbon intensive power plants such as the coal power plant in the first stage.

Overall, the fuel-specific benchmark to all power plants ranks at the top in social welfare, even though it is only slightly higher than in the auction case. It can be interpreted that giving away free permits makes the emission reductions more expensive as seen in the pass-along cost and emission permit prices, but the extra capacity triggered by the free allowances to new entrants based on the fuel-specific benchmark raises social welfare when the industry is not very competitive.

2.6. CONCLUSION

This study has investigated the effect of different allocation methods on the Korean electricity market by using an MCP model that incorporates operation, investment, and emission problems in an oligopolistic manner. Taking into account the importance of the electricity sector in the ETS policy, emission prices are determined partially by the electricity sector's emissions and then interact with electricity prices and investment decisions in the model. In particular, the allocation rules are explicitly modelled by separating existing power plants and new entrants. As for the allocation rules, an auction for both existing power plants and new entrants, a uniform benchmark for all plants, a fuel-specific benchmark to existing power plants and uniform benchmark to new entrants, and a fuel-specific benchmark for all plants have been analysed in order to compare the effects of the allocation rules on emission prices, electricity prices, the capacity mix and social welfare.

We found that generation firms act differently depending on the allocation of permits to new investments, (although not to existing plant), which brings various impacts on the economy. The ETS would push up electricity prices by at least 9.5 per cent in the full fuel-specific benchmark case and by at most 12.2 per cent in the full auction case. Thus, consumer surplus is reduced in all allocation scenarios. On the other hand, increases in producer surplus during the initial period are observed in the F.B. to U.B. and the F.B. to F.B. cases, since opportunity costs of the permit price are passed on to electricity prices. As for the level of emissions in the electricity sector, the auction and the uniform benchmark shift operation and investment toward lower-carbon technology such as nuclear and CCGT, which leads to relatively lower levels of emissions, 208.7-211.2 million tonnes of CO_2 in 2030 respectively. On the other hand, investment in carbon-intensive technology, typically coal power plant, and its operations are incentivized by the fuel-specific benchmark. As a result, this method records the largest emission level among the allocation scenarios, 220.1 million tonnes of CO_2 in 2030. The greater emissions from the electricity sector result in additional abatement costs in the other sector to achieve the national emission target.

The model derives practical implications for the market organization by means of scoring the social welfare of all of the allocation methods. We close the discussion by summarizing the properties of the allocation methods in the initial period.

Firstly, the auction is the most powerful policy to reduce the electricity sector's emissions, without imposing the pass-along cost on the other sector. Besides, the auction has several merits: it satisfies the polluter pays principle and does not create any incentives around carbon-intensive technology. The government gains the highest revenues from an auction, which can be redistributed in various ways, for example investment in new green technology or reducing income taxes of households. But the reality is that the ETS is facing political resistance from the industries involved. The auction would be unhelpful in gaining political agreement from these industries.

Secondly, using the uniform benchmark for new and existing plants has almost as much impact in reducing emissions as the auction, but it incurs the highest social costs as shown in social welfare, since compared to the auction case, the more carbon-intensive investment increases the electricity sector's externality as measured by the pass-along cost calculation and the lower revenues from selling permits to electricity market. However, it has a merit among the methods with freely allocated permits; the uniform benchmark corresponds with the principle of equality.

Thirdly, the F.B. to U.B. in which existing plants are endowed with allowances by the fuel-specific benchmark and new investment capacity is provided with allowances by the uniform benchmark combines advantages from both allocation methods: it lessens opposition to the ETS by providing a relatively large amount of allowances to existing power plants in the initial ETS period, and using the uniform benchmark for new investment means that it is still a relatively effective way to abate emissions. It is interesting to confirm that as predicted by theory, the U.B. to U.B. and the F.B. to U.B. yield the same outcomes in output, investment, electricity prices and emission permit prices. This result proves the Coase theorem holds with respect to allocation rules to existing power plants[24].

Lastly, the government could consider the fuel-specific benchmark allocation method for the initial period when the market possesses a tight capacity to meet the electricity demand which is expected to increase continuously in next decades, since this allocation method encourages new investment as seen in the result. But it is important to mention that although the fuel-specific benchmark to existing and new entrants ranks the highest in social welfare, interpretation of the results requires attention, since the difference in social welfare compared to the all-auction case is not very large and the allocation method creates distorting effects on the economy. As highly incentivized coal fired plants become a prominent option for new capacity, their emissions increase the demand for emission allowances and thus inflate the allowance prices. This case shows relatively lower electricity prices than other cases in its early years. However, in view of the long economic life span of the plant, the allowance prices remain at a higher level in the long term. This gives a valuable insight into the dynamic interaction between allocation methods and emission prices. If the government sticks to this allocation method in order to minimize early impacts on electricity prices, this increases the cost of carbon to the economy by raising emission prices. It is also noteworthy to mention that firms would realize significant windfall profits under the fuel-specific benchmark without government intervention.

There are, however, two questions for the ETS that remain to be explained. This model is unable to assess various closure rules, in that retired power plants continue to hold and could sell grandfathered allowances in this model. This is also a controversial issue in the

[24] We also find this when comparing the results of other allocation scenarios that also have the same allocation rules to new investment such as auction to uniform benchmark, though we do not describe these due to space limitations.

European member states that own numerous somewhat aged power plants. The MCP framework required us to treat investment as a continuous variable, rather than modelling the decision to build an integer number of plants of standard sizes. Clearly, further research is needed to address these limitations.

$_{i,t}$

APPENDIX 2

A.2.1. Notation

A.2.1.1. Indices

Firms

t Periods (years)

l Load levels

C Capacity types $\in \{e, n\}$

e and n stand for existing power plants and new entrants respectively.

A Emission allowances allocation types $\in \{\alpha, f, u\}$

$\alpha, f,$ and u stand for auction, fuel specific benchmark, and uniform benchmark respectively.

A.2.1.2. Parameters

$a_{l,t}$ Intercept of demand function in load level *l* in period *t*

$b_{l,t}$ Slope of electricity demand function in load level *l* in period *t*

b_t^{emis} Slope of emission allowances demand function of non-electricity sector in period *t*

$c_{i,tec}, c'_{i,tec}$ Linear and quadratic heat rate of technology ($Mcal/MWh, Mcal/MWh^2$)

Cap_t Total amount of emission allowances in period *t* (tCO_2)

ci_{teh} Capacity investment cost of technology (*1,000 ₩*)

$d_{l,t}$ Duration of load level *l* in period *t* (*hours*)

$FI_{i,t}$ Annual investment budget of firm *i* in period *t* (*thousand won*)

ef_{tec} Emission factor of technology (tCO_2/MWh)

hr_{tec} Operation hours of technology (*hours*)

$G^{C,A}$ Benchmarking factor by capacity types and allocation rules (tCO_2 / MW)

$\overline{K}_{i,tec,t}$ Existing technology capacity in period t

$N_{i,t}^{up}$ Net emission permit purchase upper bound in period t (tCO_2)

$N_{i,t}^{lo}$ Net emission permit purchase lower bound in period t (tCO_2)

$N_t^{ne,0}$ Non-electricity sector's demand for emission allowances at price zero in period t (tCO_2)

sef_{tec} Standard emission factor of technology (tCO_2 / MWh)

shr_{tec} Standard operation hours of technology (*hours*)

r_t Discount rate in period t

η_{nuc} Load factor of nuclear power plant

θ_{tec} Availability of capacity in period t

ζ_{tec} Emission rate of technology (tCO_2 / MWh)

$v_{teh,t}$ Fuel cost of technology in period t (*1,000₩*)

A.2.1.3. Decision variables

$I_{i,tec,t}$ Investment capacity of technology in period t (MW)

$N_{i,t}$ Net emission permit purchase in the permit market in period t (tCO_2)

$q_{i,tec,t,l}$ Power generation by technology in load l in period t (MW)

A.2.1.4. Dual variables

$\lambda_{i,t}^{k}$ Constraint of capacity investment in period t

$\lambda_{i,t}^{e}$ Constraint of emissions in period t

$\lambda^{nq}_{i,tec,t,l}$ Constraint of nuclear power plant generation in load level *l* in period *t*

$\lambda^{nu}_{i,t}$ Constraint of net emission permit purchase upper bound in period *t*

$\lambda^{nl}_{i,t}$ Constraint of net emission permit purchase lower bound in period *t*

$\lambda^{q}_{i,tec,t,l}$ Constraint of technology generation in load level *l* in period *t*

A.2.1.5. Auxiliary variables

$p_{t,l}$ Electricity price in load *l* in period *t* (*1,000*₩/MWh)

p^{emis}_{t} Emission allowances price in period *t* (*1,000*₩/tCO_2)

$q_{i,t,l}$ Total power generation of firm in load level *l* in period *t* (MW)

A.2.2. Parameters of technology

Table A.2.1. Parameters of the construction cost, operation cost, and emission rate

	NUCLEAR	Bituminous Coal	CCGT	Anthracite Coal	Heavy Oil	GT
Construction cost (*1000Won/MW*)	1,956,000	1,008,000	804,000	-	-	-
Fuel cost (*1000Won/Mcal*)	0.00129	0.01803	0.06111	0.02615	0.06323	0.06111
Linear heat rate (*MCal/MWh*)	2,213	2,061	1,704	2,273	2,195	2,195
Emission Rate (tCO_2/MWh)	0	0.86	0.45	0.95	0.80	0.66

Source: Author's calculation based on Roh and Choi (2010) and Korean Electric Power Corporation (2010).

A.2.3. Annual average results

Table A.2.2. The results of the BASE case

Time	Emissions ($MtCO_2$)	Prices(thousand won)		Capacity (MW)							Output (GWh)						
		Elec.	Emission	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total
2010	165.85	177.31	-	17,716	23,970	1,125	16,998	4,479	888	65,176	131,910	164,300	9,362	55,505	986	4,879	366,942
2011	174.02	180.81	-	17,716	24,207	1,125	16,998	4,479	888	65,413	131,910	170,860	9,362	59,819	1,291	6,229	379,471
2012	182.03	184.16	-	17,716	24,447	1,125	16,998	4,479	888	65,653	131,910	177,180	9,362	64,214	1,599	7,577	391,842
2013	189.56	188.22	-	17,716	24,745	1,125	16,998	4,479	888	65,951	131,910	183,070	9,362	68,216	1,961	8,916	403,435
2014	198.70	194.07	-	17,716	25,186	1,125	16,998	4,479	888	66,392	131,910	190,360	9,362	72,740	2,436	10,528	417,337
2015	206.86	200.79	-	17,716	25,704	1,125	16,998	4,479	888	66,910	131,910	197,180	9,362	76,357	2,809	11,908	429,526
2016	213.03	206.35	-	17,716	26,148	1,125	16,998	4,479	888	67,354	131,910	202,430	9,362	78,981	2,997	12,979	438,659
2017	217.78	210.98	-	17,716	26,528	1,125	16,998	4,479	888	67,734	131,910	206,550	9,362	80,865	3,154	13,795	445,636
2018	223.80	215.75	-	17,716	26,949	1,125	17,129	4,479	888	68,286	131,910	211,370	9,362	84,242	3,346	14,727	454,957
2019	229.45	220.10	-	17,716	27,349	1,125	17,290	4,479	888	68,847	131,910	215,940	9,362	87,601	3,467	15,487	463,767
2020	234.71	223.98	-	17,716	27,722	1,125	17,440	4,479	888	69,371	131,910	220,190	9,362	90,807	3,604	16,160	472,034
2021	240.00	228.15	-	17,716	28,131	1,125	17,608	4,479	888	69,946	131,910	224,480	9,362	94,002	3,730	16,824	480,308
2022	245.25	232.32	-	17,716	28,554	1,125	17,792	4,479	888	70,554	131,910	228,770	9,362	97,317	3,860	17,376	488,595
2023	250.53	236.19	-	17,716	28,970	1,125	18,045	4,479	888	71,223	131,910	232,980	9,362	101,010	3,945	17,891	497,098
2024	255.17	239.11	-	17,878	29,325	1,125	18,363	4,479	888	72,058	133,260	236,630	9,362	104,690	3,991	18,186	506,119
2025	258.59	241.07	-	18,361	29,611	1,125	18,608	4,479	888	73,072	137,280	239,520	9,362	107,210	4,002	18,304	515,678
2026	262.07	242.97	-	18,851	29,903	1,125	18,873	4,479	888	74,118	141,360	242,460	9,362	109,790	4,012	18,426	525,410
2027	265.58	244.84	-	19,354	30,201	1,125	19,143	4,479	888	75,190	145,540	245,410	9,362	112,390	4,024	18,564	535,291
2028	269.14	246.62	-	19,851	30,501	1,125	19,409	4,479	888	76,252	149,720	248,340	9,362	115,120	4,047	18,711	545,300
2029	272.71	248.29	-	20,338	30,799	1,125	19,680	4,479	888	77,309	153,870	251,220	9,362	117,870	4,088	18,894	555,304
2030	276.44	249.87	-	20,820	31,126	1,125	19,957	4,479	888	78,395	158,080	254,290	9,362	120,570	4,123	19,129	565,555

Table A.2.3. The results of A.U. to A.U. case

Time	Emissions ($MtCO_2$)	Prices(thousand won)		Capacity (MW)							Output (GWh)						
		Elec.	Emission	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total
2010	165.85	177.31	-	17,716	23,970	1,125	16,998	4,479	888	65,176	131,910	164,300	9,362	55,505	986	4,879	366,942
2011	174.02	180.81	-	17,716	24,207	1,125	16,998	4,479	888	65,413	131,910	170,860	9,362	59,819	1,291	6,229	379,471
2012	182.03	184.16	-	17,716	24,447	1,125	16,998	4,479	888	65,653	131,910	177,180	9,362	64,214	1,599	7,577	391,842
2013	189.56	188.22	-	17,716	24,745	1,125	16,998	4,479	888	65,951	131,910	183,070	9,362	68,216	1,961	8,916	403,435
2014	198.70	194.07	-	17,716	25,186	1,125	16,998	4,479	888	66,392	131,910	190,360	9,362	72,740	2,436	10,528	417,337
2015	192.43	222.60	42.09	17,716	25,186	1,125	16,998	4,479	888	66,392	131,910	183,550	9,362	82,833	1,902	4,472	414,029
2016	193.49	235.68	54.68	17,716	25,186	1,125	17,058	4,479	888	66,452	131,910	182,740	9,362	87,836	1,992	4,008	417,849
2017	191.42	242.01	64.67	18,459	25,186	1,125	17,140	4,479	888	67,276	138,100	180,320	9,362	89,346	1,760	3,204	422,093
2018	189.27	247.12	74.08	19,568	25,186	1,125	17,191	4,479	888	68,437	147,330	177,940	9,362	90,390	1,537	2,511	429,070
2019	187.45	251.54	83.16	20,573	25,186	1,125	17,223	4,479	888	69,475	155,690	175,650	9,362	91,337	1,331	2,191	435,561
2020	185.66	255.56	91.94	21,526	25,186	1,125	17,247	4,479	888	70,451	163,620	173,220	9,362	92,199	1,093	2,128	441,622
2021	187.31	258.20	92.03	22,202	25,186	1,125	17,350	4,479	888	71,229	169,240	174,420	9,362	93,793	1,173	2,128	450,116
2022	188.98	260.79	92.11	22,892	25,186	1,125	17,456	4,479	888	72,026	174,990	175,620	9,362	95,411	1,267	2,128	458,778
2023	190.99	263.18	92.39	23,560	25,277	1,125	17,555	4,479	888	72,885	180,550	177,340	9,362	96,827	1,330	2,177	467,586
2024	193.43	265.35	92.91	24,202	25,463	1,125	17,646	4,479	888	73,803	185,890	179,670	9,362	98,055	1,361	2,257	476,595
2025	195.90	267.49	93.42	24,858	25,652	1,125	17,738	4,479	888	74,740	191,350	182,040	9,362	99,309	1,395	2,338	485,793
2026	198.37	269.59	93.92	25,529	25,846	1,125	17,835	4,479	888	75,703	196,940	184,370	9,362	100,570	1,452	2,418	495,113
2027	200.88	271.62	94.42	26,204	26,040	1,125	17,958	4,479	888	76,694	202,600	186,710	9,362	101,990	1,508	2,470	504,640
2028	203.44	273.47	94.93	26,857	26,225	1,125	18,157	4,479	888	77,731	208,190	188,920	9,362	103,940	1,556	2,442	514,411
2029	206.04	275.25	95.44	27,515	26,409	1,125	18,373	4,479	888	78,789	213,840	191,150	9,362	105,970	1,609	2,413	524,344
2030	208.71	276.81	95.97	28,136	26,580	1,125	18,570	4,479	888	79,778	219,500	193,420	9,362	108,080	1,639	2,405	534,406

Table A.2.4. The results of U.B. to U.B. case

Time	Emissions ($MtCO_2$)	Prices(thousand won)		Capacity (MW)							Output (GWh)					
		Elec.	Emission	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total
2010	165.85	177.31	-	17,716	23,970	1,125	16,998	4,479	888	65,176	131,910	164,300	9,362	55,505	986	4,879	366,942
2011	174.02	180.81	-	17,716	24,207	1,125	16,998	4,479	888	65,413	131,910	170,860	9,362	59,819	1,291	6,229	379,471
2012	182.03	184.16	-	17,716	24,447	1,125	16,998	4,479	888	65,653	131,910	177,180	9,362	64,214	1,599	7,577	391,842
2013	189.56	188.22	-	17,716	24,745	1,125	16,998	4,479	888	65,951	131,910	183,070	9,362	68,216	1,961	8,916	403,435
2014	198.70	194.07	-	17,716	25,186	1,125	16,998	4,479	888	66,392	131,910	190,360	9,362	72,740	2,436	10,528	417,337
2015	193.15	220.75	42.55	17,716	25,481	1,125	17,078	4,479	888	66,767	131,910	185,170	9,362	82,244	1,760	4,135	414,581
2016	194.87	231.15	55.56	17,716	25,764	1,125	17,368	4,479	888	67,340	131,910	185,550	9,362	87,551	1,641	3,292	419,305
2017	194.96	239.27	66.92	17,889	25,947	1,125	17,600	4,479	888	67,928	133,360	184,490	9,362	91,229	1,496	2,702	422,640
2018	193.19	244.13	76.53	18,931	25,987	1,125	17,737	4,479	888	69,147	142,020	182,130	9,362	92,726	1,272	2,224	429,734
2019	191.58	248.37	85.72	19,882	25,992	1,125	17,860	4,479	888	70,227	149,940	179,620	9,362	94,288	1,024	2,128	436,361
2020	189.98	252.09	94.60	20,754	25,992	1,125	18,030	4,479	888	71,268	157,200	176,810	9,362	96,183	840	2,128	442,523
2021	192.61	254.05	95.26	21,259	26,145	1,125	18,231	4,479	888	72,127	161,400	179,050	9,362	98,251	870	2,128	451,061
2022	195.29	256.06	95.91	21,797	26,334	1,125	18,458	4,479	888	73,081	165,870	181,410	9,362	100,180	884	2,128	459,834
2023	198.02	258.02	96.59	22,342	26,526	1,125	18,702	4,479	888	74,062	170,410	183,830	9,362	102,160	895	2,128	468,785
2024	200.79	259.94	97.25	22,898	26,721	1,125	18,956	4,479	888	75,068	175,040	186,260	9,362	104,200	908	2,128	477,898
2025	203.59	261.82	97.92	23,464	26,920	1,125	19,234	4,479	888	76,110	179,750	188,710	9,362	106,260	939	2,128	487,149
2026	205.13	264.62	97.83	24,281	26,920	1,125	19,234	4,479	888	76,926	186,540	190,080	9,362	107,190	1,056	2,128	496,356
2027	206.64	267.36	97.72	25,116	26,920	1,125	19,234	4,479	888	77,762	193,510	191,430	9,362	108,160	1,146	2,128	505,736
2028	208.10	270.05	97.57	25,965	26,920	1,125	19,234	4,479	888	78,611	200,750	192,700	9,362	109,130	1,235	2,128	515,305
2029	209.57	272.69	97.42	26,834	26,920	1,125	19,234	4,479	888	79,480	208,160	193,990	9,362	110,080	1,332	2,128	525,051
2030	211.20	275.06	97.35	27,662	26,920	1,125	19,234	4,479	888	80,308	215,450	195,320	9,362	111,190	1,440	2,191	534,954

Table A.2.5. The results of F.B. to U.B. case

Time	Emissions ($MtCO_2$)	Prices(thousand won)		Capacity (MW)							Output (GWh)						
		Elec.	Emission	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total
2010	165.85	177.31	-	17,716	23,970	1,125	16,998	4,479	888	65,176	131,910	164,300	9,362	55,505	986	4,879	366,942
2011	174.02	180.81	-	17,716	24,207	1,125	16,998	4,479	888	65,413	131,910	170,860	9,362	59,819	1,291	6,229	379,471
2012	182.03	184.16	-	17,716	24,447	1,125	16,998	4,479	888	65,653	131,910	177,180	9,362	64,214	1,599	7,577	391,842
2013	189.56	188.22	-	17,716	24,745	1,125	16,998	4,479	888	65,951	131,910	183,070	9,362	68,216	1,961	8,916	403,435
2014	198.70	194.07	-	17,716	25,186	1,125	16,998	4,479	888	66,392	131,910	190,360	9,362	72,740	2,436	10,528	417,337
2015	193.15	220.75	42.55	17,716	25,481	1,125	17,078	4,479	888	66,767	131,910	185,170	9,362	82,244	1,760	4,135	414,580
2016	194.87	231.15	55.56	17,716	25,764	1,125	17,368	4,479	888	67,340	131,910	185,550	9,362	87,551	1,641	3,292	419,305
2017	194.96	239.27	66.92	17,889	25,947	1,125	17,600	4,479	888	67,928	133,360	184,490	9,362	91,229	1,496	2,702	422,640
2018	193.19	244.13	76.53	18,931	25,987	1,125	17,737	4,479	888	69,147	142,020	182,130	9,362	92,726	1,272	2,224	429,734
2019	191.58	248.37	85.72	19,882	25,992	1,125	17,860	4,479	888	70,227	149,940	179,620	9,362	94,288	1,024	2,128	436,361
2020	189.98	252.09	94.60	20,754	25,992	1,125	18,030	4,479	888	71,268	157,200	176,810	9,362	96,183	840	2,128	442,523
2021	192.61	254.05	95.26	21,259	26,145	1,125	18,231	4,479	888	72,127	161,400	179,050	9,362	98,251	870	2,128	451,061
2022	195.29	256.06	95.91	21,797	26,334	1,125	18,458	4,479	888	73,081	165,870	181,410	9,362	100,180	884	2,128	459,834
2023	198.02	258.02	96.59	22,342	26,526	1,125	18,702	4,479	888	74,062	170,410	183,830	9,362	102,160	895	2,128	468,785
2024	200.79	259.94	97.25	22,898	26,721	1,125	18,956	4,479	888	75,068	175,040	186,260	9,362	104,200	908	2,128	477,898
2025	203.59	261.82	97.92	23,464	26,920	1,125	19,234	4,479	888	76,110	179,750	188,710	9,362	106,260	939	2,128	487,149
2026	205.13	264.62	97.83	24,281	26,920	1,125	19,234	4,479	888	76,926	186,540	190,080	9,362	107,190	1,056	2,128	496,356
2027	206.64	267.36	97.72	25,116	26,920	1,125	19,234	4,479	888	77,762	193,510	191,430	9,362	108,160	1,146	2,128	505,736
2028	208.10	270.05	97.57	25,965	26,920	1,125	19,234	4,479	888	78,611	200,750	192,700	9,362	109,130	1,235	2,128	515,305
2029	209.57	272.69	97.42	26,834	26,920	1,125	19,234	4,479	888	79,480	208,160	193,990	9,362	110,080	1,332	2,128	525,051
2030	211.20	275.06	97.35	27,662	26,920	1,125	19,234	4,479	888	80,308	215,450	195,320	9,362	111,190	1,440	2,191	534,954

Table A.2.6. The results of F.B. to F.B. case

Time	Emissions ($MtCO_2$)	Prices(thousand won)		Capacity (MW)							Output (GWh)						
		Elec.	Emission	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total	Nuclear	B.coal	A.coal	CCGT	GT	Oil	Total
2010	165.85	177.31	-	17,716	23,970	1,125	16,998	4,479	888	65,176	131,910	164,300	9,362	55,505	986	4,879	366,942
2011	174.02	180.81	-	17,716	24,207	1,125	16,998	4,479	888	65,413	131,910	170,860	9,362	59,819	1,291	6,229	379,471
2012	182.03	184.16	-	17,716	24,447	1,125	16,998	4,479	888	65,653	131,910	177,180	9,362	64,214	1,599	7,577	391,842
2013	189.56	188.22	-	17,716	24,745	1,125	16,998	4,479	888	65,951	131,910	183,070	9,362	68,216	1,961	8,916	403,435
2014	198.70	194.07	-	17,716	25,186	1,125	16,998	4,479	888	66,392	131,910	190,360	9,362	72,740	2,436	10,528	417,337
2015	195.01	217.72	43.76	17,716	26,214	1,125	16,998	4,479	888	67,420	131,910	189,690	9,362	79,428	1,502	3,505	415,398
2016	197.62	228.19	57.32	17,716	26,811	1,125	17,013	4,479	888	68,032	131,910	192,220	9,362	82,368	1,383	2,808	420,050
2017	198.99	236.28	69.47	17,716	27,269	1,125	17,178	4,479	888	68,656	131,910	192,980	9,362	85,464	1,240	2,290	423,246
2018	199.01	241.85	80.19	18,444	27,609	1,125	17,276	4,479	888	69,820	137,970	192,660	9,362	86,852	984	2,128	429,956
2019	198.20	245.81	89.84	19,323	27,862	1,125	17,330	4,479	888	71,007	145,280	191,390	9,362	87,650	781	2,128	436,591
2020	197.25	249.38	99.07	20,151	28,118	1,125	17,375	4,479	888	72,136	152,180	189,910	9,362	88,558	583	2,128	442,721
2021	200.17	251.39	99.85	20,655	28,395	1,125	17,450	4,479	888	72,992	156,370	192,880	9,362	89,866	601	2,128	451,207
2022	203.10	253.38	100.62	21,175	28,680	1,125	17,528	4,479	888	73,875	160,700	195,880	9,362	91,180	623	2,128	459,873
2023	205.98	255.47	101.34	21,739	29,008	1,125	17,614	4,479	888	74,852	165,390	198,860	9,362	92,393	633	2,128	468,766
2024	208.91	257.52	102.05	22,314	29,344	1,125	17,701	4,479	888	75,850	170,180	201,890	9,362	93,637	642	2,128	477,839
2025	211.87	259.52	102.77	22,899	29,699	1,125	17,789	4,479	888	76,880	175,050	204,950	9,362	94,919	649	2,128	487,057
2026	213.55	262.34	102.71	23,709	29,699	1,125	17,789	4,479	888	77,690	181,790	206,570	9,362	95,748	734	2,128	496,332
2027	215.18	265.11	102.62	24,540	29,699	1,125	17,789	4,479	888	78,521	188,700	208,110	9,362	96,578	852	2,128	505,730
2028	216.79	267.82	102.50	25,383	29,699	1,125	17,789	4,479	888	79,364	195,860	209,610	9,362	97,471	940	2,128	515,370
2029	218.36	270.48	102.36	26,246	29,699	1,125	17,789	4,479	888	80,227	203,210	211,030	9,362	98,397	1,035	2,128	525,162
2030	220.09	272.85	102.30	27,060	29,699	1,125	17,906	4,479	888	81,158	210,250	212,280	9,362	100,100	1,118	2,128	535,238

CHAPTER 3

AN INTEGRATED MODEL COMBINING TOP-DOWN AND BOTTOM-UP APPROACHES TO ENERGY–ECONOMY MODELLING

3.1. INTRODUCTION

Traditional models for the quantitative assessment of economic impacts induced by energy and environment policies could be identified as either a top-down model that focuses on the macroeconomic feedbacks or a bottom-up model that concentrates more on the physical energy flow system and technology options. After the first oil shock of 1973~74, energy experts have been aware of the important changes it caused; substitutions between energy sources, technology innovations, and impacts on energy policies such as subsidies and taxes. These challenges in terms of both the demand and the supply sides could not be captured simultaneously by the single method. Consequently, modellers started to build up integrated models that combine the top-down and bottom-up models in order to exploit the comparative advantages of both types of model: economic interaction and rich technology respectively. Furthermore, growing concerns over climate change issues incentivised development of the integrated method. Hourcade et al. (2006) point out that the performance of an integrated model satisfies three dimensions; technologically explicit, behaviourally realistic and with macroeconomic feedback, which is able to provide a more reliable tool in assessing effects of climate change policies; the government's emission target, carbon tax, and distribution of specific technology in the economy. For these reasons, the integrated model has become a dominant tool in energy and environment policy modelling.

As the Korean government needs to mitigate the emission of greenhouse gases (GHG) it is considering introducing various policies such as an emission trading scheme and carbon taxes which are regarded as an effective economic instrument policy. Therefore, in recent years, several studies have been made to quantify the effect of carbon policies on the economy in Korea. However, most of these studies are conducted by a single method such as Computational General Equilibrium (CGE) or optimisation models for analysing the effects on the national economy and specific energy intensive industries respectively. Recently, there have been two studies (Noh, 2009; Oh, 2012) that built up integrated models for the assessment of climate change policies. However, the former study does not specify an electricity sector and the latter does not reflect each generation technology's capacity constraints and the demand side's load duration curves, even though the electricity sector is the most important sector accounting for the largest emission source.

As explained earlier, the single method has limitations in capturing technology and economic interactions together. In the case of CGE models, the approach is suitable to capture medium and long-run effects and analyse multiple industrial sectors. But, it is often criticized for reliance on external sources for parameter values, which often lack adequate econometric justification in their models and for using a simple production function for the complexities of real industries. Depending on assumed parameters on demand and supply sides' cross-price elasticities to determine fuel switching from carbon-intensive energy to less intensive fuels, the results show significant differences in terms of the economic costs of GHG mitigation.

On the other hand, the optimization studies, typically using MARKAL, have a tendency to underestimate the mitigation costs on the basis modellers pass over various hidden costs, transaction costs, other constraints, or exaggerate the scale of technologies that have low or even negative costs. Therefore, the effect on GDP is likely to be undervalued significantly (Helm, 2003). Helm recommends that research should estimate the main costs and supply curves involved in all technology options and avoid unrealistic projections of technical progress and innovation to evaluate the carbon cost fairly.

In other words, more sophisticated methods for capturing the supply side's engineering information and robust parameters on macroeconomic variables are required to investigate the effect of climate change policies.

Taking into account the current state of the literature, this study provides an integrated model that combines top-down and bottom-up models for analysing the climate change policy. Overall, the integrated model is more suitable to analyse the climate change policy in that it captures technological diversity in detail and interactions between the supply side and economic variables at the same time through overcoming the weaknesses and taking the advantages of both methods. In view of the importance of two factors (the possibility of fuel-switching and the electricity sector) that play a critical role in determining GHG mitigation costs, this study builds up an integrated model combining a bottom-up MCP electricity market model established in the previous Chapter Two and a top-down model: the macro-econometric model in which most behavioural equations are set up in line with economic theory and a long-run relationship between variables is confirmed by an Autoregressive Distributed Lag (ARDL) bounds testing approach to cointegration (Pesaran et al., 2001) and standard specification tests. In addition, a dynamic linear logit model (Considine and Mount, 1984) is adopted to measure inter-fuel substitution possibilities. The macro-econometric model consists of seven blocks: supply side, demand side, prices and wage, fiscal and monetary, finance, foreign trade, and energy and environment blocks with total 150 equations including 73 behavioural equations and 73 identities.

The remainder of this chapter is organized as follows. The next section overviews the modelling for energy and economy methods, inter-fuel substitution models, and the econometric methodology for behavioural equations. Section three explains the structure of the integrated model and describes the result of estimating the equations. Section four performs an ex-post simulation and evaluates the model's performance. Section five concludes this chapter.

3.2. LITERATURE REVIEW

The section reviews three subjects; (1) modelling approaches for energy and economy, (2) inter-fuel substitution models, and (3) the econometric methodology for behavioural equations. The first subject classifies the models analysing the effect of energy issues on the economy. The second investigates the proper econometric model for analysing the effect of inter-fuel substitution, which plays an important role in determining emissions and the costs incurred in policy simulations. The last subject examines cointegration methods to overcome the spurious regression problem which has often occurred in estimating macroeconomic variables. The literature on these subjects has been surveyed by many published articles. For example, the classification of energy models is well documented in Bhattacharyya and Timilsina (2009). An integrated model's advantages and the detailed integration methods are described in Hourcade et al. (2006) and Bohringer and Rutherford (2008) respectively. As for the second subject, Considine and Mound (1984) provide a linear logit regression model adopted in an economic model. Besides, Urga and Walters (2003) compares translog and logit models. The review for the ARDL bounds test adopted as one of the cointegration methods in this model is mainly conducted by summarizing Pesaran et al.(2001) and application studies, Mah (2000) and Narayan (2005) which point out that the bounds test is superior to the methods provided by Engle and Granger (1987) and Johansen (1991, 1995) for small sample sizes.

3.2.1. Modelling approaches for energy and economy

Modelling methods for energy and environmental policies could be divided into top-down (T.D.) b2ottom-up (B.U.), and integrated models linking the two approaches. This section overviews the properties of each type of model.

3.2.1.1. Top-down approach

The T.D. approach can be generally divided into three types of models; (i) Input-Output, (ii) Computational General Equilibrium (CGE), and (iii) Macro-econometric models. Overall, this structure is well suited to assess the effects of price instrument policies such as taxes and emission allowance permits on the economy. But, a production function in the T.D. models is not able to feature the detailed properties of technologies such as the split between fixed and operation costs, capacity limitations, potential options of new energy technologies, and the physical restrictions of energy system. The following sub-section briefly overviews the three main model types of the T.D. approach.

3.2.1.1.(a) Input-Output model

The input-output model has long been used for various economic analyses. It provides a framework that represents the relationships between different national sectors in terms of value added and input and output coefficients relative to total production. The input-output tables are generally used via their economic indicators (e.g. employment per value added), Thus, the model derives the direct and indirect energy demand through inter-industry transactions. It also can capture changes in energy demands and outputs from given scenarios such as energy policies.

However, most input-output models have several limitations; fixed input-output relations over time, limited ability to capture inter-fuel substitutability and technological advances. Typical studies using the input-output model for energy demand and energy issues can be found in Wei et al. (2006) and Nathani et al. (2006).

3.2.1.1.(b) Computable General Equilibrium model

The Computable General Equilibrium (CGE) model has been widely used for analysing recent climate change policy issues. Based on the Walrasian concept of equilibrium, the CGE model assumes utility maximisation and cost minimisation behaviours by households and firms respectively. Thus, the model draws equilibrium prices and quantities when all markets clear. The CGE model is suitable to analyse effects of price-induced policies such as taxes, subsidies, or other changes in energy prices on the economy. The method adopted powerful solution algorithms which allow modellers to include multiple sectors and countries in a system (i.e., it has good expandability).

While the CGE approach is able to describe choices between technologies by adopting a type of substitution function, it is, however, still difficult to describe specific technological properties as in the input-output model. In addition, the CGE model is criticised for the parametric specifications, which can lack adequate econometric justification. Therefore, the results from CGE models are heavily dependent on the size of parameters specified in models. Notable extended models designed for climate change policy can be found in GEM-E3 (General Equilibrium Model for Europe and the World, Capros et al. 1997), and EPPA (The MIT Emissions Prediction and Policy Analysis Model, Babiker et al 2001). EPPA is an example of a recursive dynamic model that assumes that agent behaviour depends on the current and past states of the economy, whereas a model such as WITCH (Bossetti et al., 2009) assumes forward-looking behaviour.

3.2.1.1.(c) Macro-econometric model

The macro-econometric model was first introduced by Tinbergen; the model has been used for analysing economic policy in a nation. The model's structure was based on four antecedents; general equilibrium by Leon Walras, the business cycle, Keynes' general theory, and the empirical literature on Keynes' general theory (Bodkin et al. 1991). The macro-econometric model consists of a number of equations linking economic variables. The choice of variables is mainly based on economic theories, and the coefficients on variables are determined by econometric methods using historical data. The model accounting for the operation of the economy provides a tool for economic policy experiments such as monetary, fiscal, and energy policy in the short and medium-term.

The macro-econometric model was expanded to represent the relationships between intermediate industries by Duesenberry et al.(1965). It firstly provided the foundation combining a macro-econometric model and the Leontief input-output system[25]. This method has been named the macro-econometric and input-output model. A notable model for the energy system is Energy-Environment-Economy Model for Europe (E3ME) which consists of 41 consumers and 42 industries in 29 European countries (Barker, 1998).

However, the traditional aggregated macro-econometric model is vulnerable to the Lucas critique (1976); policy conclusions or predictions from the model, in which equations are built up by observed historical correlations between macroeconomic variables, would be invalid. This is because the agent does not simply repeat their behaviour but responds optimally when new policies are introduced, so that the historical correlations would change.

To overcome the Lucas critique, the equations derived from inter-temporal optimization with rational expectation methods based on micro-foundations have been introduced in macro-econometric models. In particular, Dynamic Stochastic General Equilibrium (DSGE) is evaluated as a model which is free from the Lucas critique. The DSGE consists of equations derived from micro-economic foundations, which are able to represent agents' preferences and rationality. The parameters in equations are mainly obtained by econometric methods. The model represents the real world with the assumption of price and wage rigidities and imperfect competition[26]. Nowadays a number of policy-making institutions, such as central banks have employed the DSGE method to analyse monetary policies. Recent DSGE models have been extended by adding an energy production sector in

[25] A conventional macro-econometric and input-output model adopts econometric methods to estimate final demands such as consumption, investment, and net exports, which in turn are transformed into each sector's final demand by the input-output system. Then industrial sectors' value-added are calculated given the Leontief inverse and value addition matrixes. Finally, national GDP is counted by summing up the sector's value added.

[26] The DSGE modelling methodology is well documented in Woodford (2003).

which energy serves as an intermediate input in final goods production. Many of these models have been built for the analysis of the macroeconomic effects of oil price shocks (Lee and Ni, 2002; Kormilitsina, 2001; Sánchez, 2011; Roger, 2005; Bodenstein et al., 2012).

However, it has drawbacks when used to analyse climate change policies; simulations for the specific level of variables such as carbon taxes or emission permit prices cannot be performed, since the DSGE adopts a log-linearization method which takes the log-deviation of a variable from its steady-state in order to estimate nonlinear specifications. If modellers experiment with an exogenous proportional change in a decision variable, modellers face the problem of how to define the steady-state variable that can be changed by external effects[27]. Even worse, it is unreasonable to require the modeller to specify a growth rate or proportional change in carbon tax rates in a country in which the carbon tax policy is not implemented yet, because establishing scenarios for change in the carbon tax rate is not available. Note that even modern macro-econometric models rule out the log-linearization method to retain decision rules in levels in order to examine shocks that change the steady stage of the model (see Harrison et al.'s description of the Bank of England Quarterly Model (2005)).

For this reason, the traditional macro-econometric model is still generally used rather than the DSGE for studying climate change issues. On the other hand, DSGE models have been mainly used for analysing the effects of shocks on macroeconomic variables.

3.2.1.2. Bottom-up approach

The B.U. model describes the specific energy sectors' technology. The majority of these models employ optimization programs which find a solution for the most cost-effective

[27] If we log-linearize the following equation; $z_t = x_t + y_t$, the following equation is derived; $\hat{z}_t = \frac{\bar{x}}{\bar{z}}\hat{x}_t + \frac{\bar{y}}{\bar{z}}\hat{y}_t$ where, $\hat{z}_t$ is a log-linearized variable indicating log-deviation form a steady state, $\log(\frac{z_t}{\bar{z}})$ and $\bar{z}$ is a steady-state variable respectively.

arrangement of energy technology given the demands, technical and political constraints. This approach provides an efficiency standard when the government introduces command and control type policies. However, the bottom-up model cannot explain the macroeconomic feedbacks such as consumer income and rebound effects, and interactions with energy inputs' prices and demand. The models are generally classified into two approaches; (i) accounting and simulation and (ii) optimization models.

3.2.1.2.(a) Account and simulation model

The first generation of bottom-up model, accounting methods have been used since the 1970s. Most variables are mainly exogenous; price variables are not explicitly included in a static structure. Simulation models stem from the accounting method. The models simulate energy-consuming and converting technologies and the diffusion of specific technologies. The total amount of energy demand and supply are calculated by identity equations for a complex aggregation of data. Because of the clear structure and practical results, such models have been preferred by government agencies. In particular, Heaps' (2012) Long-range Energy Alternatives Planning System (LEAP) model has been used and updated for analysing energy and climate change related policies for developed and developing countries[28].

3.2.1.2.(b) Optimization model

The optimization model which typically adopts a linear programming method optimizes multiple objective functions subject to technical restrictions and energy-policy

[28] The LEAP applications are available at http://www.energycommunity.org/default.asp?action=45.

constraints. The model assumes that consumers or suppliers behave rationally under various constraints, and then choose a best option. This method has the best features to tackle questions on energy flow in the energy system, investment needs, possible energy savings, and the minimal discounted cost of producing energy subject to technical, economic and environmental constraints. For these reasons, commercial optimization models (typically MARKAL) have gained prominence and are widely used for analysing the effect of energy-environmental policies on energy-intensive industries. While this method provides the least cost least solution among various current and future technology options, the result could bring overly radical solutions, since the model lacks micro-economic realities in terms of agents' decision making when choosing technologies; agents' pathway dependence or preferences are not considered in the model.

3.2.1.3. Integration approach

As explained in the introduction, in recent years, numerous studies have attempted to build up integrated models compensating for the limitations of the T.D. and B.U. approaches. According to Böhringer and Rutherford (2009), the integrated method could be classified into the three approaches, (i) combining between a reduced form version of the T.D. or B.U. model and the other one, (ii) integration in a single format, and (iii) linking independent T.D. and B.U. models.

3.2.1.3.(a) Integration between a reduced form and the other model

The first approach dates back to Manne (1977). They provide the integration method to couple a technology-rich bottom-up model (MARKAL) with a single macroeconomic neoclassical growth model which adopts a nested CES production function with three input factors: labour, capital, and aggregated energy. The aggregated energy demand and cost calculated from the bottom-up model are fed into the macro model. Using the first order conditions, the input factors demands are derived from the macro model, which in turn are passed back to the bottom-up model. This iteration proceeds until the convergence criteria of the difference between sequential values of the computed variables is fulfilled.

3.2.1.3.(b) Hard-link

Böhringer (1998) provides the second approach, which integrated both T.U. and B.U. models in a single format, named as the completely integrated model or hard-link, which is based on the framework of mixed complementarity problems (MCP)[29]. The model is able to capture both the technological detail of a bottom-up energy system and the macro-economy through setting weak inequalities and complementarity conditions between decision variables and market equilibrium conditions in a single format. Böhringer and Rutherford (2009) suggest a decomposition technique in order to overcome the earlier literature's algebraic complexity and dimensionality. When it comes to strengths and weaknesses of the complete integration model, while the agents' behaviours are consistent in each model through a well-defined linking approach, the modelling system is still complex and less flexible in terms of extension and compatibility compared to the other integrated methods. For those reasons, relatively little literature has attempted to use this approach for analysing climate change policy issues. Oh (2012) applied the method proposed by Böhringer and Rutherford (2009) to the Korean economy. The hybrid model links the electricity sector component and a

[29] See Dirkse and Ferris (1995), Rutherford (1995) for the algorithms of MCP.

conventional CGE model. Each technology has a Decreasing Returns to Scale production function in the electricity sector and the model allows the electricity generation mix to change endogenously. The results show that a carbon price of about 60$/tC would cause a GDP loss of 0.61 percent with an emission trading system.

3.2.1.3.(c) Soft-link

The last approach, linking independently developed T.D. and B.U. models, often called 'soft link', has been formulated in order to compensate for the simplicity of a single macroeconomic neoclassical growth model in the first approach, Manne (1977). Large scale macro-economic models such as an Input-Output, CGE, or macro-econometric model have been adopted in the T.D. model, which in turn are linked with a technologically detailed linear programming model in the B.U. model. After building the two different models, first run the T.D. model which provides energy prices and demand values to the B.U. model; secondly execute the B.U. model given these values and then pass optimal energy production and costs into the T.D. model. This process repeats until the convergence criteria of the energy demand and prices are reached. While the soft–link method has gained popularity with modellers as existing models are conveniently linked with each other, it is often criticised for inconsistencies in agents' behaviour assumptions between the two models.

It is worthwhile to describe Labandeira et al.'s work (2009), which is similar to our intention for modelling in terms of developing a more realistic electricity model. They analyse the effect of the EU-ETS on the Spanish economy in the period 2005~2012 by the soft-link method combining the CGE and the electricity engineering model taking into account the importance of the electricity sector. They point out that the soft-linking method is the most flexible and effective method among the integration methods to capture the electricity output decisions for multiple periods. Furthermore, they deliver a solution for the consistent agent's behaviour by adopting the MCP framework, instead of a linear programming, for modelling the electricity market, which allows an electricity demand function to respond to electricity prices in both B.U. and T.D. models. The main results are summarised in Table 3.1.

Table 3.1. Results with and without integration

	CGE alone without integration	Integrated modelling framework
Price of electricity	+8.6%	(+17.0%, +21.5%)
GDP	-0.7%	-1.0%
Welfare	-0.3%	-0.5%
CPI	+0.2%	+0.2%

(Source: Labandeira et al., 2009)

They found that the integrated approach yields different results of the real effect of the EU-ETS on electricity price, GDP, welfare, and CPI compared to the CGE-alone model. The CGE-alone method underestimated the effect of related policies on the economy, whereas the result from the integration method shows more realistic results. It implies that a top-down approach is likely to underestimate the effect of climate change policies on the economy.

It is important to note that this finding; the effect on GDP in an integrated model is higher than one in a top-down model alone, may not always hold, particularly in the electricity market which has higher marginal abatement cost curves than many other industries, since power plants cannot substitute fuels as easily as the CGE model assumes.

In other words, the results with an integrated model can be lower than CGE models that assume that there are no negative cost options, so that there is a real question of whether we can actually expect agents to adopt the negative cost options, because the integrated model is able to reflect ‘negative cost’ options which are assumed to be easily installed by agents using an optimization model in a supply-side module; however, in practice these options have already been available and are not taken up.

To sum up, the integrated model is regarded as the most adequate method to reflect available technology options which have negative cost options and unique energy supply industries such as electricity in which power sources cannot be substituted easily.

3.2.2. Inter-fuel substitution models

This section overviews the econometric methods of inter-fuel substitution; translog cost function and logit cost share models, which measure the impact of relative price changes on energy demands empirically. The estimated cross-price elasticities which indicate substitution possibilities from more to less carbon-intensive energy sources is a key determinant of emission reductions when price instrument policies are introduced. There have been attempts to devise elaborate econometric models for analysing inter-fuel substitution. Typically, translog cost function and logit cost share models have been widely used recently. The following section begins by investigating the translog model.

3.2.2.1. Translog cost function model

Christensen et al. (1971, 1973) introduced the translog production function cost function. Then, numerous studies applied the translog cost function to empirical models estimating energy demand. Among those studies, Fuss (1977) provided the two-stage factor inputs model in which six energy elements are explicitly included in the set of factors of production. Pindyck (1979a) modified the price of aggregated energy, called the energy index, by a homothetic translog cost function with constant returns to scale. We examine Fuss's (1977) two-stage translog model in detail. The production function can be assumed as

$$(3.1) \qquad Q = f[E(E_1, \cdots, E_N), L, M, K]$$

where Q is gross output; L, M, and K are labour, materials, and capital input respectively; E, an aggregated energy input, is a function of N energy elements. The corresponding cost function can be represented by the translog second-order approximation, and has a non-homothetic production form

$$(3.2) \qquad \ln C = \ln \alpha_o + \sum_i \alpha_i \ln P_i + \alpha_q \ln Q + \frac{1}{2}\sum_i \sum_j \gamma_{ij} \ln P_i \ln P_j + \sum_i \gamma_{iQ} \ln Q \ln P_i + \frac{1}{2}\gamma_{QQ}(\ln Q)^2$$

where C is total cost and P_i or P_j, $i, j = E, L, M, K$ are factor prices. From Shephard's lemma implying $X_i = \partial C/\partial P_i$, the demand function is derived by differentiating the cost function with respect to the prices. Therefore, the cost share equation is given by $S_i = \partial \ln C / \partial \ln P_i = (P_i X_i)/C$, or

$$(3.3) \qquad S_i = \alpha_i + \sum_j \gamma_{ij} \ln P_j + \gamma_{iQ} \ln Q_i$$

The cost shares must add to 1, and the following parameter restrictions must be imposed to satisfy the properties of neoclassical production theory.

$\sum_i \alpha_i = 1,$ (Identifiability of the distribution parameters constraint)

(3.4) $\sum_j \gamma_{ij} = \sum_i \gamma_{ij} = 0,$ (Cournot aggregation constraint)

$\sum_i \gamma_{iQ} = 0,$ (Engel aggregation constraint)

$\gamma_{ij} = \gamma_{ji}, \quad i \neq j,$ (Slutsky symmetry constraint).

To measure price responsiveness, the Allen-Uzawa partial elasticity of substitution, σ_{ij} and the price elasticity of demand, η_{ij} have been employed. These measures can be computed in the translog cost function

$$(3.5) \qquad \sigma_{ij} = C\frac{\partial^2 C/\partial P_i \partial P_j}{(\partial C/\partial P_i)(\partial C/\partial P_j)}$$

$$(3.6) \qquad \eta_{ij} = \sigma_{ij} S_j$$

The price index of energy, P_E in the equation (3.2) is a unit of function consisting of *N* energy elements, which can be represented by the translog form

$$(3.7) \qquad \ln P_E = \ln \beta_o + \sum_i \beta_i \ln P_{Ei} + \frac{1}{2}\sum_i \sum_j \beta_{ij} \ln P_{Ei} \ln P_{Ej}$$

Diewert (1975) demonstrates that the Divisia index is exact for this aggregate function. The Divisia index is a weighted sum of growth rate, where the weights are the components' shares in total value. It has advantages over the Btu aggregation, in the sense that the Divisia index does not assume perfect substitution and equality of prices per Btu. Nguyen (1987) has shown that the measures lead to different results of income and price elasticity to energy demand.

The cost share functions for each energy elements can be derived as

(3.8) $$S_{Ei} = \beta_i + \sum_j \beta_{ij} \ln P_{Ej}$$

Analogous to the set of constraints (3.4), the following restrictions are imposed as

$$\sum_i \beta_i = 1,$$

(3.9) $$\sum_j \beta_{ij} = 0,$$

$$\beta_{ij} = \beta_{ji}, \quad i \neq j.$$

As for estimation, the two-stage procedure is needed. In the first stage, estimate the system equations (3.8) under the restrictions (3.9), and obtain an estimate of the aggregate price index, $\hat{P}_E$ by substituting the corresponding estimated parameters of the equations (3.8), which is entered into the energy price index, P_E, that is, it serves as an instrumental variable in the next states. Finally, using the instrumental variable, $\hat{P}_E$ for P_E, estimate the system equations (3.3) subject to the restrictions (3.4).

3.2.2.2. Considine and Mount's logit model

3.2.2.2(a). Static logit model

Considine and Mount (1984) introduced more elaborate linear logit models for a system of cost share equations, which are designed to satisfy three theoretical properties of the input-demand function derived from the producer's cost minimization assumption. The properties are (i) non-negativity of inputs, (ii) zero-degree homogeneous function in prices, and (iii) negative own-price along with symmetric cross-price effects. The non-negativity is automatically ensured by adopting exponential functions for cost shares. The other properties are guaranteed by imposing additional conditions. Firstly, a static model will be examined in the following section. A static linear logit model of cost share is given by

$$(3.10) \quad w_i = \frac{P_i Q_i}{C} = \frac{\exp(f_i)}{\sum_{j=1}^{n} \exp(f_j)}$$

where w_i is the share of i^{th} input cost in total cost, P_i and Q_i are the price and quantity of the i^{th} input respectively, C is the total cost, and f_i is a function of all input prices, P_i, and the level of output, Y, which is as follows

$$(3.11) \quad f_i = a_i + \sum_{j=1}^{N} c_{ij} \ln P_j + g_i \ln Y \qquad \forall\, i$$

where a_i, c_{ij}, g_i, and h_i are unknown parameters; ε_{it} are random-error terms. The share elasticities with respect to prices and output under non-restriction are derived as

$$(3.12) \quad H_{ik} = \frac{\partial \ln w_i}{\partial \ln P_k} = c_{ik} - \sum_{j=1}^{N} w_j^* c_{jk}$$

$$(3.13) \quad H_{iY} = \frac{\partial \ln w_i}{\partial \ln Y} = g_i - \sum_{j=1}^{N} w_j^* g_j$$

Using Shephard's Lemma and the share elasticities equation (3.12) and (3.13), the price elasticity for the i^{th} input and the cross-price elasticities are derived as

$$(3.14) \quad E_{ii} = \frac{\partial \ln Q_i}{\partial \ln P_i} = H_{ii} + w_i \quad - 1$$

$$(3.15) \quad E_{ik} = \frac{\partial \ln Q_i}{\partial \ln P_k} = H_{ik} + w_k$$

The linear logit model of cost share satisfies the second property, zero-degree homogenous function in prices which implies that the sum of the N price elasticities should be zero. Given the equations (3.14) and (3.15), this property is summarized in the following equation which means that the sum of the share elasticities should be zero;

$$(3.16) \quad \sum_{j=1}^{N} E_{ij} = \sum_{j=1}^{N} (H_{ij} + w_j) - 1 = \sum_{j=1}^{N} H_{ij} = 0$$

Symmetry of the cross-price effects in the third property implies that

$$(3.17) \quad E_{ik} w_i \;=\; E_{ki} w_k$$

To satisfy these above equations, two constraints are imposed in the model. The first one is given by

$$(3.18) \quad \sum_{j=1}^{N} c_{ij} = d$$

where d is an arbitrary constant. Another constraint imposed is as follows:

$$(3.19) \quad w_i^* c_{ij} = w_j^* c_{ji}$$

The price coefficients are redefined as

$$(3.20) \quad c_{ij}^* = c_{ij}/w_j^*$$

where w_j^* is defined as the predicted shares for each observation to deal with an endogeneity problem in the stage of estimation. See the estimation part below for further information.

Then, using the redefined equation (3.20) and imposing constraints (3.18) and (3.19), the linear logit function (3.11) can be rewritten as:

$$(3.21) \quad f_i = a_i + c_{11}^* w_1^* \ln\left(\frac{P_1}{P_N}\right) + c_{12}^* w_2^* \ln\left(\frac{P_2}{P_N}\right) + \cdots + c_{1N-1}^* w_{N-1}^* \ln\left(\frac{P_{N-1}}{P_n}\right) + d \ln P_N$$
$$+ g_1 \ln Y$$
$$\vdots$$
$$f_N = a_N + c_{1N}^* w_1^* \ln(P_1/P_N) + c_{2N}^* w_2^* \ln(P_2/P_N) + \cdots + c_{N,N-1}^* w_{N-1}^* \ln(P_{N-1}/P_n)$$
$$+ dlnP_N + g_N lnY$$

where

$$(3.22) \quad c_{ij}^* = \frac{1}{w_i}\left(d - \sum_{k=1}^{i-1} w_k^* c_{ki}^* - \sum_{k=1+1}^{N} w_k^* c_{ik}^*\right) \qquad \forall\, i = 12, \cdots, N-1$$

Adding an error term, ε_i into each f_i and using logarithms for the share equation, (3.10) can be written as a linearized form for estimation:

$$(3.23)\ \ln\left(\frac{w_i}{w_N}\right) = (a_i - a_N)$$

$$+\sum_{k=1}^{i-1}(c_{ki}^* - c_{kN}^*)w_k^* ln\left(\frac{P_k}{P_N}\right) + \left[d - \sum_{k=1}^{i-1} w_k^* c_{ki}^* - \sum_{k=i+1}^{N} w_k^* c_{ki}^* - w_i^* c_{iN}^*\right]\ln\left(\frac{P_i}{P_N}\right)$$

$$+\sum_{k=i+1}^{N-1}(c_{ki}^* - c_{kN}^*)w_k^* \ln\left(\frac{P_k}{P_N}\right) + (g_i - g_N)\ln Y + (\varepsilon_i - \varepsilon_N) \qquad \forall\, i = 1,\cdots,N-1$$

where

$$(3.24)\qquad w_k^* = \exp(f_i - f_N)/(\sum_{j=1}^{n-1}(\exp(f_i - f_N)) + 1)$$[30]

Three identifying restrictions, $a_N = g_N = d = 0$, are required to identify the remaining coefficients for estimating the system of $N-1$ equations. These normalizing constraints do not affect the estimates of the elasticities. Finally, using the symmetry condition ($c_{ij}^* = c_{ji}^*$) and homogeneity condition ($c_{ii}^* = -\sum_{j\neq i} c_{ij}^* w_k^*/w_i^*$) the cross-price elasticities are derived as

$$(3.25)\qquad E_{ik} = w_k^*(c_{ik}^* + 1) \qquad\qquad \forall i \neq k$$

and the own-price elasticities are as follows:

$$(3.26)\qquad E_{ii} = w_i^*(c_{ii}^* + 1) - 1 \qquad\qquad \forall i = 1,2,\cdots,N$$

As for estimation methods, either the iterative Zellner's seemingly unrelated regression estimation or the full information maximum likelihood estimation can be implemented.

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[30] The terms $f_i - f_N$ are simply the predicted logarithmic share ratios which are obtained via estimating the equation (3.24).

3.2.3.2 (b) A dynamic linear logit model

The above static linear logit model assumes that demand converges to long-run equilibrium immediately. However, the factor demand would be not flexible due to various constraints such as fixed factors for production, technological elements, and producers' rational expectations meaning that they respond to expected prices. Therefore, demands for input factors respond to price changes gradually. For those reasons, Considine and Mount (1984) applied Tradeway's (1971) optimal path to adjustment process in the linear logit model, and called it the dynamic logit model. The optimal path equation is given by

$$(3.27) \quad \dot{x} = M^*(x^*, r)[x - x^*]$$

where x^* is the stationary equilibrium, and $M^*(x^*, r)$ is an $N \times N$ matrix with elements that are functions of x^* and the discount rate, r.

Substituting $Q_{jt}^* = w_{jt}^* C_t^* / P_{jt}$, where the asterisk denotes the equilibrium level of the corresponding variable, into a logarithmic approximation of equation (3.27) gives a dynamic form of the linear logit model. Therefore, the i^{th} quantity change can be written as

$$(3.28) \quad \ln Q_{it} - \ln Q_{it-1} = \sum_{j=1}^{N} L_{ij}\left(\ln w_{jt}^* + \ln C_t^* - \ln P_{jt} - \ln Q_{jt-1}\right) \qquad \forall i$$

where L_{ij} is an element of the matrix M^* in the equation (3.27), and Q_{it} is the i^{th} element of x in the equation (3.27). Given the equation (3.28), the quantity ratio can be derived as

$$(3.29) \quad \ln\left(\frac{Q_{it}}{Q_{Nt}}\right) = \sum_{j=1}^{N}\left(L_{ij} - L_{Nj}\right)\left(\ln w_{jt}^* + \ln C_t^* - \ln P_{jt} - \ln Q_{jt-1}\right) + \ln(Q_{it-1} - Q_{Nt})$$

Imposing conditions that $L_{ij} = 0$ for $i \neq j$ and $L_{ii} = \mathrm{L}$ for all i in the equation (3.29) yields the following cost share ratio:

$$(3.30) \quad \ln\left(\frac{w_{it}}{w_{Nt}}\right) = L \ln\left(\frac{w_{it}^*}{w_{Nt}^*}\right) + (1-L)\ln\left(\frac{P_{it}}{P_{Nt}}\right) + (1-L)\ln\left(\frac{P_{it}}{P_{Nt}}\right) + (1-L)\ln\left(\frac{Q_{it-1}}{Q_{Nt-1}}\right)$$

Using a linear logit model corresponding to the equation (3.10) and (3.11), the equilibrium share ratio can be defined as:

$$(3.31) \quad \ln\left(\frac{w_{it}^*}{w_{Nt}^*}\right) = (A_i - A_N) + \sum_{j=1}^{N}\left(C_{ij} - C_{Nj}\right)\ln P_{jt} + (G_i - G_N)\ln Y_t$$

where A_i, C_{ij}, and G_j are the parameters in the equilibrium state. Substituting the equation (3.31) and the equation (3.30) yields the following equations

$$(3.32) \quad \ln\left(\frac{w_{it}}{w_{Nt}}\right)$$

$$= L(A_i - A_N) + \sum_{j=1}^{N}\left(C_{ij} - C_{Nj}\right)\ln P_{jt} + L(G_i - G_N)\ln Y_t - (1-L)\ln\left(\frac{P_{it}}{P_{Nt}}\right)$$

$$+ (1-L)\ln\left(\frac{Q_{it-1}}{Q_{Nt-1}}\right)$$

The equations (3.32) are for estimation purposes, which corresponds to the following linear logit model for the i^{th} share

$$(3.33) \quad w_{it} = \frac{\exp(f_{it})}{\sum_{j=1}^{n}\exp(f_{jt})} \qquad \forall\, i$$

with

$$(3.34) \quad f_{it} = a_i + \sum_{j=1}^{N} c_{ij} \ln P_{jt} + g_i \ln Y_t + \lambda \ln Q_{it-1}$$

The dynamic model is distinguished by introducing a time subscript and the lagged quantity with partial adjustment coefficient, λ. The short-run price elasticities are same as in the static model and the long-run price elasticities can be computed as

$$(3.35) \quad E_{ij}^{LR} = E_{ij}^{SR}/(1-\lambda)$$

where E_{ij}^{SR} is the short-rum elasticity given in the equations (3.25) and (3.26). If the partial coefficient, λ is greater than 0, it guarantees the Le Chatelier principle that the short-run price elasticities can never be greater than the long-run price elasticities.

As for estimation, a two-step iterative Zellner estimation is employed to estimate a system of implicit share equations. Note that the iterative Zellner estimation method provides the parameters which are invariant to the selection of the base input. Besides, the two-step iterative procedure handles an endogeneity problem of the cost shares variables. In the first step, using actual data for the endogenous variables w_k^* on the right side of the equations (3.23), estimate parameters in the equations (3.23) and compute predicted shares given by the equation (3.24). In the second step, these initial predicted shares from the first stage are used to re-estimate parameters in the equations and generate the predicted shares. Then, the predicted shares instead of the actual data are re-entered into the endogenous variables w_k^* in the first step. This iteration is repeated until the convergence criteria for the parameter changes between two steps, which is set at less than 0.1%, is reached.

Overall, the logit model outperforms the translog model when the two models' estimation results are compared. According to Urga and Walters (2003)'s work, the static translog model has parameters that violate concavity conditions of the cost function. Furthermore, the residual of the model is serially correlated and has non-normal errors. Another study, Kim (2006), employing the translog model for analysing Korean industrial sectors' energy demand, observed that the translog model often yields non-negative price elasticities of energy demand. On the other hand, the logit model has superiorities; the model satisfies the non-negativity of the input share, and shows reasonable parameters for own- and cross-price elasticities. In the case of the dynamic logit model, the model guarantees the Le Chatelier principle by giving short-run elasticities that are less than their long-run counterparts. For those reasons, we adopt the dynamic logit model among inter-fuel substitution models for the energy demand block.

3.2.3. The econometric methodology for behavioural equations

This section is devoted to explaining the estimation method for behavioural equations. In particular, it explains the process of the bounds test for cointegration method adopted in this model.

Most macroeconomic variables, for example GDP, consumption, export, and prices, are non-stationary time series, as they are trended. Terminologically, the non-stationary time-series is said to be integrated. The order of integration is the minimum number of times the series needs to be differenced to make a stationary series. The problem of non-stationary, i.e. over I(1), which indicates integrated of order one, is that the standard Ordinary Least Square (OLS) regression cannot be applied to estimate the non-stationary data, since the OLS estimation leads to the spurious regression problem: it is well-known that the R^2 converge to functionals of Brownian motions, the t-ratios have a non-standard distribution, and the

Durbin-Watson statistic converges in probability to zero. Consequently, it certainly produces incorrect inferences[31]. Since then, testing and estimating the non-stationary time series has been one of the central issues in econometrics. As part of allowing for non-stationary data, the 'cointegration' framework has been established and developed. If there may exist some linear combination in the level of two or more series individually integrated, then the series is said to be cointegrated, and the linear relationship in the level variables is interpreted as a long-run equilibrium.

Several cointegration tests have been introduced: typically, Engle and Granger (1987) provides a residual based test, Hansen (1992) and Park's (1992) suggest an instability test and an added variables test respectively. In addition, fully efficient estimation methods have been invented: while Fully Modified OLS (Phillips and Hansen 1990), Canonical Cointegrating Regression (Park 1992), and Dynamic OLS (Stock and Watson 1993) have been proposed to estimate a single equation cointegrating relationship, Johansen (1991, 1995) provides a system maximum likelihood approach for multivariate cointegration.

As a single cointegration approach, Pesaran et al. (2001) develop the bounds testing approach using an Autoregressive Distributed Lag (ARDL) framework. The bounds testing method has been widely used for analysing long-run relationships between non-stationary variables, as it has certain advantages over the other approaches. First, the bounds testing is valid regardless of whether the underlying variables are purely I(0), purely I(1), or fractionally integrated with each other. Second, under the ARDL framework, estimators are super-consistent in small sample sizes. Mah (2000) points out that the Engle and Granger (1987) and Johansen (1991, 1995) methods of cointegration are not robust for small sample sizes

[31] See Granger and Newbold (1974, 1977), Plosser and Schwert (1978), and Phillips (1986) for the details of the spurious regressions.

(Mah, 2000). Narayan (2005) also argues that bounds testing is far superior to the Johansen's multivariate cointegration method. Pesaran and Shin (1999) prove that the OLS estimators of the short-run parameters are consistent in the ARDL framework and estimators of the long-run coefficients are super-consistent in small sample sizes. Third, unlike the Engle and Granger approach, the bounds test does not lead to an endogeneity problem.

The bounds testing procedure is as follows: Let $z_t = (y_t, x_t')'$ where y_t is a dependent variable and x_t is a vector of regressors. Note that the regressors are selected based on economic theories in order to give meaning to the estimated parameters on the variables in the equation. The first differenced variable Δy_t is modelled as an Unrestricted Error-Correction Model (UECM) in order to test whether there exists at most one long-run equilibrium relationship between y_t and x_t, which is given by

$$(3.36)\quad \Delta y_t = \beta_0 + \beta_t t + \pi_{yy} y_{t-1} + \pi_{yx} x_{t-1} + \sum_{i=1}^{p} \gamma_i \, \Delta y_{t-i} + \sum_{i=0}^{q} \delta_i \, \Delta x_{t-i} + \varepsilon_t$$

where Δ represents log-first-difference, π_{yy} and π_{yx} are long-run multipliers, β_0 is a intercept coefficient and t is time trend, γ_i and δ_i are short-run dynamic coefficients on the lagged values of Δy_t and current and lagged values of Δx_t respectively, and ε_t is an error term. After the UECM equation above by the OLS, the existence of cointegration is tested by exclusion of the lagged level variables y_{t-1} and x_{t-1} in the equation above. That is, restrict all estimated coefficients of the lagged level variables by the null hypothesis H_0 and alternative hypothesis H_1 which are defined as:

$$(3.37)\quad H_0: \pi_{yy} = 0,\ \pi_{yx} = 0'$$

$$H_1: \pi_{yy} \neq 0, \pi_{yx} \neq 0' \ or\ \pi_{yy} \neq 0, \pi_{yx} = 0' \ or\ \pi_{yy} = 0, \pi_{yx} \neq 0'$$

The Wald test calculates an *F*-statistic in order to test these hypotheses in the above equation. Pesaran et al. (2001) provides asymptotic critical value bounds which consist of two sets: the lower bound when the regressors are I(0) and the upper bound when the regressors are I(1). If the computed *F* statistic is higher than the critical values of the upper bound, then the null hypothesis of no cointegration is rejected and it concludes that there exists a long-run equilibrium relationship between the variables without any knowledge of the order of integration. On the other hand, if the *F* statistic is less than the critical values of the lower bound, then the null hypothesis of no cointegration is accepted. If, however, the *F* statistic falls between the critical values of the lower and the upper bound, then the relationship cannot be inferred conclusively. The critical value bounds are given in Table C1(v) in Pesaran et al. (2001) and in the footnote below[32].

As discussed earlier, a number of papers employ bounds testing when they have small sample sizes. In our case, fiscal and sector energy demands data are only available since 1990, which is subject to small sample problems when trying to find the long-run equilibrium relationship. Therefore, the bounds testing approach is adopted in order to estimate macroeconomic variables with non-stationary time series.

After rejecting the null hypothesis, a behavioural equation is set up based on a partial adjustment model[33] that includes a lagged dependent variable among the explanatory

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[32] Table 3.2. The critical values of lower and upper bound

Significance	10%		5%		1%	
No. of variables	FL	FU	FL	FU	FL	FU
2	4.19	5.06	4.87	5.85	6.34	7.52
3	3.47	4.45	4.01	5.07	5.17	6.36
4	3.03	4.06	3.47	4.57	4.40	5.72
5	2.75	3.79	3.12	4.25	3.93	5.23

Source: Pesaran et al. (2001)

[33] Fundamentally, choosing lag lengths of the model has the following process; the maximum of lags is set equal to 2, as Pesaran and Shin (1999) suggest for annual data. And then, we select lag order of the ARDL that

variables. The estimated parameters provide information on short-run and long-run elasticities, and the speed of adjustment from the short-run to long-run equilibrium. The partial adjustment specification is given by:

$$\text{(3.38)} \quad \log y_t = \beta_0 + \beta_1 \log y_{t-1} + \sum_{i=1}^{k} \delta_i \log x_{i,t} + \varepsilon_t$$

where the β_0 is a constant. The β_1 and δ_i are coefficients of the lagged variable y and the set of explanatory variables, x_i respectively. Finally, ε_t is an error term that is normally distributed with mean zero constant variance. If the equation cannot reject the null hypothesis, the equation is estimated in log first difference form after checking if the variable is stationary by the unit root test.

It is important to note that having established the long-run equilibrium relationship by equation (3.38), the Error Correction Model (ECM) which models deviations from the long-run relationships could be built up in this study, which is able to capture an agent's dynamic adjustment behaviour when a new policy is to be imposed. However, there is a trade-off between the ability to explain short-run dynamics and simulation performance. The errors caused from the coefficients on the short-run variables in the ECM equation pass through to all the other equations by the feedback mechanisms in the system model. Consequently, insignificant short-run coefficients in the ECM worsen the simulation results of the system model. For this reason, this study adopts the partial adjustment specification rather than the ECM model in order to obtain stability of the system model by isolating divergences of the simulated values of the differenced variables from their actual values.

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minimises Schwarz criterion (SC) or Akaike Information criteria (AIC). Generally, the partial adjustment specification shows a minimum value of Schwarz criterion (SC) and Akaike Information criteria (AIC).

We report the estimation result of each equation in a table that consists of three parts, the first part, (a) describes estimated parameters on variables, standard error, t-value, and p-value for testing significance of coefficient. The second part (b) indicates the Bounds test for cointegration. $F_Y(Y|X)$ represents F-statistic of no-cointegration hypothesis, where Y is a dependent variable, and X are a vector of explanatory variables. If the F-statistic, denoted by $F_Y(Y|X)$> the upper bound, FU, the null of no-cointegration can be rejected, IF $F_Y(Y|X)$< the lower bound, FL, the null cannot be rejected, and thus no long-run relationship exists. If FL< $F_Y(Y|X)$<FU, the inference in inconclusive. Diagnostic tests are described in the last part, (c). $\bar{R}^2$ represents adjusted R-squared, $\hat{\sigma}$ and D.W. indicate standard error of regression and Durbin-Watson test statistic respectively. F is F statistic for overall significance of the model, where k and n are the number of variables and observation respectively. In addition, we implement four major diagnostic tests; the Ramsey Regressions Specification Error Test (RESET) for general misspecification (Ramsey, 1969), the Breusch-Godfrey test for serial correlation in residuals (Breusch, 1978; and Godfrey, 1978), the Breusch-Pagan test for heteroskedasticity in residuals (Breush and Pagan, 1979), and Jarque-Berra test for normality of residuals in order to guarantee robustness of the OLS estimators (Jarque and Berra, 1990). Notations for the diagnostic tests are summarised in Table 3.3.

Table 3.3. Lists of diagnostic tests

Notation	Definition	Null hypothesis
F_{Reset}	F statistic of Ramsey RESET	Correct specification
F_{Auto}	F statistic of the Breusch-Godfrey test	No serial correlation in residuals
F_{Hetero}	F statistic of the Breusch-Pagan test	No heteroskedasticity in residuals
χ^2_{Norm}	χ^2 statistic of Jarque-Berra test	Normality of residuals

3.3. MODEL FORMULATION

3.3.1. THE STRUCTURE OF THE MODEL

The integrated model consists of three modules; macroeconomic, electricity market, and integration modules. The macroeconomic module represents a national economy by adopting a top-down approach: the macro-econometric model described here. The electricity market module models the power generation sector based on a bottom-up approach: the MCP model built in chapter two. The macroeconomic and electricity market modules are combined by the integration module. Figure 3.1 shows the basic structure of the integrated model and depicts how variables in the modules interact with each other.

The macro-econometric model uses annual data rather than quarterly in order to analyse medium-term impacts of carbon tax policies and link efficiently to the electricity module which uses an annual load duration curve (LDC).

The macro-econometric model consists of seven blocks: supply side, demand side, prices and wage, fiscal and monetary, finance, foreign trade, and energy and environment blocks. The total number of equations is 148 in which 57 behavioural equations and 91 identities exist. In terms of variables, there are 148 endogenous variables and 58 exogenous variables.

Potential GDP, investment, labour demand, the rate of operation, and the unemployment rate are dealt with in the supply block. The potential GDP, estimated by a two input Cobb-Douglas production function in which natural labour and capital are employed as input factors and energy is also included indirectly, serves as a supply side factor affecting inflation. This acts to complement the way in which traditional Keynesian macroeconomic models are demand-driven. Investment and labour demand are estimated using the first order conditions (F.O.C.) of profit maximisation for the Cobb-Douglas function.

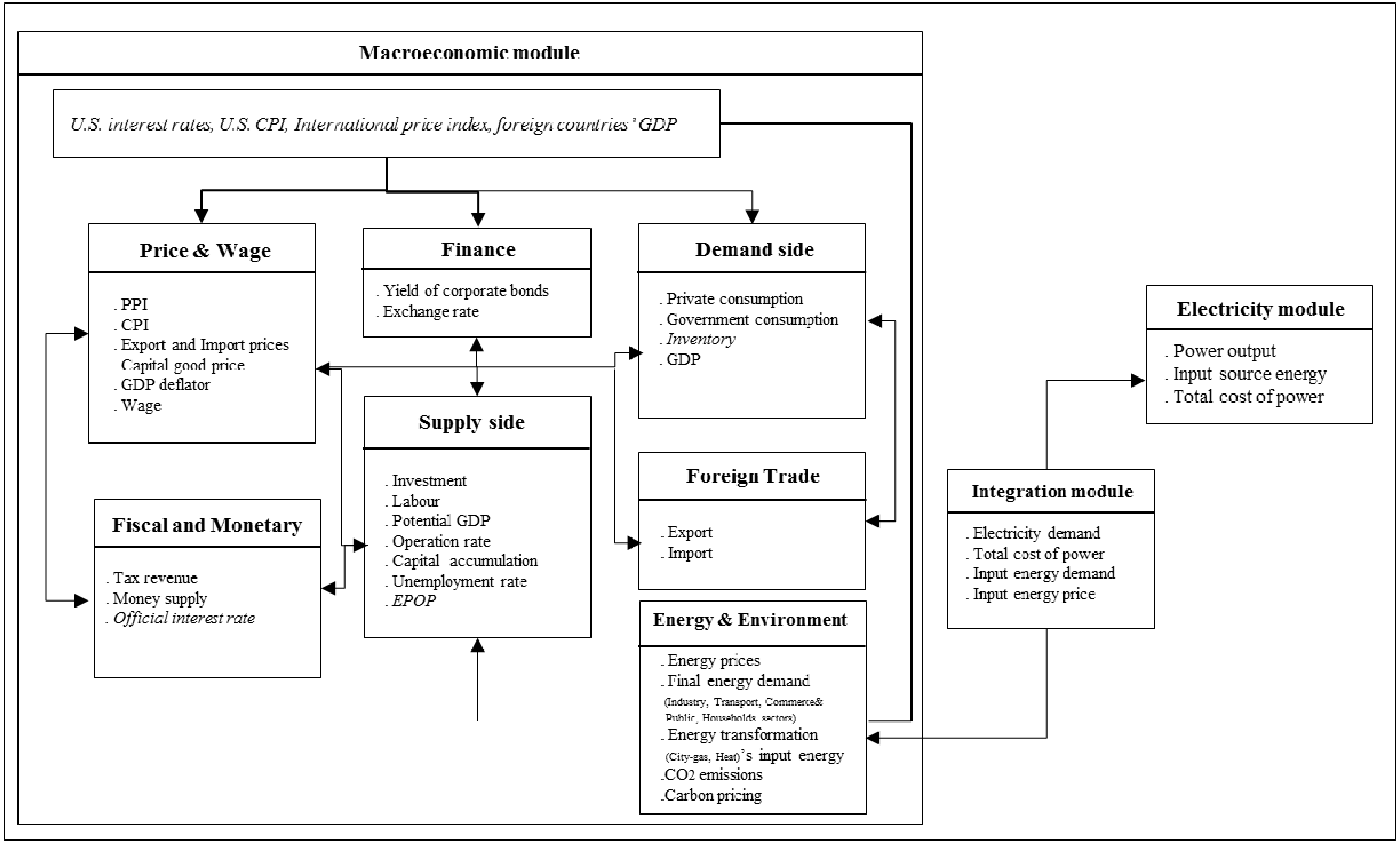

Figure 3.1. The structure of the integrated model

Note: italic letters denote exogenous variables.

The demand side block determines private consumption and government's final consumption expenditure. The private consumption function is built up based on Keynes' absolute income hypothesis. The reasons for this choice, and other modelling decisions, are discussed below. The government's consumption function is derived from the government budget constraint.

The price and wage block estimates producer prices, consumer prices, wage, export and import prices. The producer price is estimated by the imported raw materials' price index and the energy price index. The consumer export price is mainly determined by the producer price, the GDP gap defined as the log difference between actual GDP and potential GDP in this model, and the energy price index facing households. The export price measured in dollars is a function of the producer price, and the import price measured in dollars is a function of the exchange rate and foreign prices treated as an exogenous variable.

The fiscal and monetary block covers tax revenue and money supply. The tax revenue is a function of GDP, which decides the disposal income and government consumption. The money supply, modelled based on liquidity preference theory, affects the yield of corporate bonds in this model.

The finance block deals with the yield of corporate bonds and the exchange rate which play an important role in determining investment and foreign trade respectively. An official interest rate decided from the central bank is a main explanatory variable for the yield of corporate bonds function. The exchange rate is determined by the difference between the foreign and domestic interest rates.

Export supply and import demand are determined in the foreign trade block. Based on the elasticity approach, exports and imports are estimated using relative prices and economic activity variables.

The energy and environment block estimates the demands and prices of energy, measures CO_2 emissions, and implements a carbon price. Energy demands are divided into final energy demand of industry, transport, commerce and the public sector, and households, the "other" energy demands, and energy input needs of energy transformation sectors such as the city-gas and heat sectors. Using identities and IPCC (1996)'s carbon emission factors, the block calculates CO_2 emissions from energy use and models a carbon pricing policy.

The electricity market module models the power generation sector explicitly using the MCP framework. The electricity demand estimated in the macroeconomic module is transfomed into load duration cruves. Electricity supply and input sources are calcuated in the electricity market module.

The integration module links the macoeconomic module and the electricity market module by the soft-link method. Electricity demand and input energy prices from the macroeconomic module are fed into the electricity market module. In turn, the quantity of input energy and the total cost of power generation computed in the electricity market module is transmitted to the macroeconomic module. These iteration is repeated until the convergence criteria on the electricity demand is reached.

3.3.2. Macroeconomic module

It important to note that building up a macro-econometric model is, to a large extent, determined by the data. The reason is well summarised in Harrison et al.'s description of the Bank of England Quarterly Model (2005);

> *"Models with a high degree of theoretical coherence are helpful for analysing economic issues but are unlikely to match the data as well as purely statistical models that have been designed to maximise coherence with the data. Such theoretical models might have many parameters but these would be chosen purely on the basis of statistical fit and would be hard to relate to the underlying economics of how agents and markets behave. So macroeconomic modellers face an inherent trade-off, even among 'state of the art' models, between achieving theoretical consistency and coherence with the data" (Harrison et al. (2005), page 21)*

Besides, a practical way for modelling is suggested as follows;

> *"One approach to matching movements in the data, commonly used for macroeconomic models, is to treat the theory as a guide to the economic variables that appear in econometric regressions" (ibid, page 13)*

Therefore, the model specification was selected for the final equation in which estimated parameters do not violate the standard decision theories among possible behavioural functions in this thesis. We also consider goodness of fit and its stability for simulation. All equations in this model are derived carefully based on existing literature and available data before the empirical tests.

This model of this chapter refers to the Bank of Korea's quarterly macro-econometric model, BOK04 (Hwang et al. 2004) which is designed for forecasting economy and policy analysis, including the effects of the change in foreign economies on Korea, a typical small open economy. As for equations in the fiscal and monetary, finance, and foreign trade blocks and data selection, taking into account the current System of National Accounts (SNA) in Korea published in Bank of Korea which serve as a main source of data for existing macro-econometric models.

This model also refers to Hervé et al.'s OECD model (2010) in order to cover a limitation of a traditional macro-econometric model. They provide a model which is able to make up for a demand-driven structure regarded as the weak point of macro-econometric models by combining short-term Keynesian-type dynamics with a consistent neo-classical supply-side in the long run. For example, nominal rigidities in wage- and price-setting serve to slow the processes of adjustment to external events. A representative firm is assumed to have a constant returns-to-scale Cobb-Douglas production function, with the demand for labour and capital derived from the first-order condition for profit maximisation. Therefore, the output is, by and large, demand-driven in the short term, but supply driven in the long run.

In this model, demand side expenditure variables such as private consumption, government's final consumption expenditure, investment, export and import determine output in the short-term by the GDP identity from the expenditure side. The potential output and input factors; capital and labour are determined by the Cobb-Douglas production function. The prices and wages are designed to have rigidities; adjust slowly to reduce the gap between actual and potential output in both product and labour markets. Consequently, output is mainly demand-driven in the short run, but supply-driven in the longer run.

In addition to this fundamental structure, agents' inter-fuel substitution behaviors are modeled in the energy block. Aggregated energy price indices determined by energy mix serve to have impact on both supply and demand sides. The following sub-section describes the structure and estimation results of the major behavioural equations. All behavioural equations, identities, and data sources are described in Appendix 3.

Note that dummy variables are used in the behaviour equations. A main role of a dummy variable is to account for data outliers. The dummy variables were primarily used for the outliers incurred by the Asian financial crisis in 1998 and global financial crisis in 2007~08. However, it is natural in some cases to have outliers incurred from suspicious measurement errors, incidents, and unknown policy actions. In these cases, dummies are used if this improves the statistics of diagnostics and does not change the value of the coefficient significantly. Additionally, given the purpose of all macro-econometric models constructed for forecasting and policy evaluation, dummies are retained if they improve the system model's stability for simulation performance by reducing the divergence of the simulated values from actual values which makes the model unable to capture the larger picture, the overall dynamic structure of the model.

3.3.2.1. The supply side block

The supply block determines potential GDP, investment, labour demand, and the rate of operation by estimated behaviours equations. The other variables such as gross fixed capital accumulation and the unemployment rate are calculated by a bridge and an identity equation respectively. A Cobb-Douglas production function with labour and capital inputs is employed to derive investment and labour demand and estimate the potential GDP in this block.

3.3.2.1.(a) Investment and labour

Firstly, the long-run relationship between capital, output and the user cost of capital is derived from the first order condition (F.O.C.), which is that the value of the marginal product of capital is equal to the price of capital, with respect to capital from a profit-maximising firm.

$$(3.39) \quad \log(K_t) = \log(Y_t) - \log(c_t) + \log(\alpha)$$

where K_t denotes the capital stock, Y_t GDP, α the output elasticity of capital, c_t the real capital cost. According to Hall and Jorgenson (1967), the real capital cost can be defined as:

$$(3.40) \quad c_t^k = P_t^i \times (r_t + \delta_t)$$

where P_t^i corresponds to the price of capital goods, r_t the real interest rate, and δ_t the depreciation rate.

The investment variable is not observed yet, so that an additional specification for the relationship between capital and investment is imposed using the capital accumulation identity, which is as follows:

$$(3.41) \quad K_t = (1 - \delta_t)K_{t-1} + I_t$$

where K_t denotes the capital stock and I_t investment expenditure. Taking natural logarithms in the capital accumulation identity implies in the steady state,

$$(3.42) \quad \log(K) = \log(I) - \log(\delta + g^K)$$

where δ corresponds to the rate of depreciation, g^k the growth rate of capital. Substituting equation (3.42) into (3.41) yields the desired level of investment in the long-run, which is as follows:

$$(3.43) \quad \log I_t^* = \log Y_t - \log c_t + \log \alpha + \log(\delta + g^k)$$

As we assumed earlier, firms might not adjust the actual investment completely to obtain the desired level in any given period. Thus, the adjustment process can be expressed as:

$$(3.44) \quad \log I_t - \log I_{t-1} = \lambda(\log I_t^* - \log I_{t-1})$$

where λ is the adjustment coefficient. Rearranging the two equations for investment yields the following equation[34]:

$$(3.45) \quad \log I_t = \beta_0 + \beta_1 \times \log I_{t-1} + \beta_2(\log Y_t - \log c_t) + \varepsilon_t, \quad \varepsilon_t \sim N(0, \sigma^2)$$

Note that the capital cost includes the real interest rate in equation (3.44), thus the investment is a function of the real interest rate.

In the same manner as with the investment decision, modelling labour employment adopts a partial adjustment mechanism based on two assumptions: the actual increase in labour employment is related to the discrepancy between the desired level and the previous labour employment. Second, the firm chooses the desired level of labour inputs so as to maximize its profits. Thus, the desired level of labour employment is derived from the first order condition (F.O.C.) for profit maximization, which is given by:

$$(3.46) \quad \log(L_t{}^*) = \log(Y_t) - \log(\frac{w_t}{P_t^d}) + \log(1 - \alpha)$$

[34] $\log(\alpha)$ and $\log(\delta + g^k)$ can be reduced, as they are assumed to be constant, which does not affect the estimation of equation xx.

where L^* represents the desired level of the labour employment, Y and $\frac{w}{Pd}$ indicate the GDP and real wage respectively. As we assumed earlier, employers might not adjust the actual employment completely to obtain the desired level in any given period. Thus, the adjustment process can be expressed as:

$$(3.47)\quad \log(L_t) - \log(L_{t-1}) = \lambda(\log L^* - \log L_{t-1})$$

where λ is the adjustment coefficient. Rearranging the two equations for L yields the labour employment equation as follows[35]:

$$(3.48)\quad \log L_t = \beta_0 + \beta_1 \times \log L_{t-1} + \beta_2 \left(\log GDP_t - \log \frac{w_t}{P_t^d} \right) + \varepsilon_t, \quad \varepsilon_t \sim N(0, \sigma^2)$$

Table 3.4 provides the comparison of estimation results for the investment equation (3.45) and labour equation (3.48) correspondingly. The calculated F statistics for the ARDL bounds testing, which are higher than the upper bound critical value at 10% level, indicate that a long term equilibrium relationship exists between dependent and explanatory variables in both equations (3.45) and (3.48).

The coefficients on the lagged and desired level of investment are statistically significant and have the expected sign. The coefficient of the independent variables can be interpreted as the value of elasticity in the short-run. The coefficient of the lagged dependent variable is regarded as the speed of adjustment from the short-rum equilibrium to the long-run equilibrium. The lagged variable of the investment and labour equation shows that around 48% and 15% of the adjustment to the long-run desired level take place in each year respectively.

[35] The output elasticity, $\log(1-\alpha)$ can be reduced, as it is a constant which does not affect the estimation of equation (3.45).

The results show that investment is more responsive to the output and cost than labour in the short-run; the F.O.C. short-run elasticity of investment and labour are 1.251 and 0.086 respectively. While the F.O.C long-run elasticity[36] of investment, 2.156, is higher than unity in the specification of Cobb-Douglas function, the labour elasticity, 1.037, is found to be consistent with the Cobb-Douglas function. These results are verified by a set of diagnostic tests indicated in Table 3.4; no serial correlation and heteroskedasticity in the error term, and no problem with normality of the error term and functional formation.

Table 3.4. Estimation of investment and labour equations

Parameter	Investment (sample: 1987~2011)	Labour (sample: 1970~2011)
β_0 (*Constant*)	-18.026** (0.04)	-0.756 (0.045)
β_1 (*Lagged variable*)	0.420*** (0.001)	0.915*** (0.000)
β_2 (*F.O.C.*)	1.251*** (0.000)	0.086*** (0.008)
Bounds test	5.545*	5.493*
Diagnostic tests		
$\bar{R}^2$	0.977	0.998
$D.W.$	1.604	2.241
F_{Auto}	0.859 (0.367)	0.405 (0.528)
χ^2_{Norm}	0.633 (0.729)	0.733 (0.693)
F_{Reset}	1.614 (0.125)	1.254 (0.270)
F_{Hetero}	2.232 (0.104)	0.885 (0.483)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.
The investment estimation includes dummy variables equal to unity for the period 1988, and 1990
The labour estimation includes dummy variables equal to unity for the period 1984, and 1998
AR(1) Cochrane-Orcutt procedure is conducted to adjust the investment model for serial correlation in the error term

3.3.2.1.(b) Potential GDP

This model employs a production function approach for the potential GDP estimation. The production function approach requires estimating a production function. We adopt the

[36] The long elasticity can be computed by dividing the short-run elasticity by one minus the coefficient of one lagged dependent variable.

Cobb-Douglas function with two input factors; natural labour and capital and under the assumption of Hicks neutral technological progress. Note that we do not include an energy variable, since the preliminary estimation result of the Cobb-Douglas with energy input yields an insignificant and negative elasticity coefficient, which is caused by the simplicity of substitution elasticity assumed in the Cobb-Douglas function. Therefore, the model adopts an alternative approach based on the Bank Of Korea's macro-econometric model (Hwang et al. 2004) in which the potential GDP is indirectly determined by the energy variable by means of the rate of operation which is set up as a function of energy prices. This is more reasonable given the purpose of this study which gives priority to analyse impacts of increases in energy prices rather than energy supply disturbances. The Cobb-Douglas function is given by:

$$(3.49) \quad Y_t = Ae^{\tau t} L_t^{1-\alpha} (\rho_t K_t \ )^{\alpha}$$

where Y denotes GDP, K capital stock, L labour, and A total factor productivity e^{rt} the rate of technology progress. The parameters $(1-\alpha)$ and α are the output elasticity of labour and capital respectively. The parameter ρ is the rate of operation. Given the assumption of constant returns to scale (CRTS), the production function is normalised by the labour factor to satisfy CRTS, and then taking natural logarithm on both sides of equation (3.49) yields:

$$(3.50) \quad \log(\frac{Y_t}{L_t}) = \log(A) + \tau t + \alpha \log(\frac{\rho_t K_t}{L_t})$$

The process for calculating the potential GDP is as follows; firstly estimate equation (3.50). And then substitute natural labour inputs; L^* and K^* into the corresponding input factor in the estimated parameters $(\hat{A}, \hat{\alpha}, \hat{r})$ in the production function. The natural labour and capital inputs are as follows:

$$(3.51) \quad L_t^* = (1 - u_t^*) \times EPOP_t$$

(3.52) $K_t^* = \rho_t^* \times K_t$

where u_t^* is the non-accelerating inflation rate of unemployment (NAIRU) and $EPOP_t$ is economically active population. ρ_t^* is the natural rate of operation[37].

Table 3.5 describes the estimation result for equation (3.50). All of the coefficients on variables have the expected sign. The rate of technological progress is found to equal 0.014, and the output elasticity of capital 0.306. As seen in the cointegration, a long-run relationship between the variables exists. The equation passes a set of diagnostic tests.

Table 3.5. Estimation of the Cobb-Douglas function

(a) Regression model

Dependent Variable : $\log(Y_t/L_t)$ Sample : 1980 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	11.416	0.944	12.092	0.139
t	0.014^{***}	0.005	3.125	0.005
$log(\rho_t K_t/L_t)$	0.306^{***}	0.005	5.879	0.000

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.
The estimation includes a dummy variable equal to unity for the period 1997~1999
AR(1) Cochrane-Orcutt procedure is conducted to adjust the model for serial correlation in the error term

(b) Cointegration test : $F_{CG}(CG|\rho K/L) = 15.364^{***}$

(c) Diagnostic tests

$\bar{R}^2 = 0.999$	$D.W. = 1.823$
$\hat{\sigma} = 0.012$	$F = 812.291\ (0.000)$
$F_{Auto} = 0.021\ (0.886)$	$\chi^2_{Norm} = 0.218\ (0.897)$
$F_{Reset} = 1.174\ (0.290)$	$F_{Hetero} = 0.932\ (0.477)$

Note: the right-hand side value in parentheses indicates p-value

[37] Based on "Putty-Clay" hypothesis ρ_t^* is derived as: $\rho_t^* = [(1-u_t^*)/(1-u_t)]\rho$

3.3.2.1.(c) The rate of operation

The rate of operation is assumed to be a function of the lagged dependent variable, the gap between the actual and the natural rate of unemployment ($\frac{u}{u^*}$), GDP, and the industrial energy price index (P_i^e). The rate of operation function is given by:

$$(3.53)\quad \log(\rho_t) = \beta_0 + \beta_1 \times \log(\rho_{t-1}) + \beta_1 \times \log(\frac{u_t}{u_t^*}) + \beta_2 \log(Y_t) + \beta_3 \log(P_{i,t}^e) + \varepsilon_t$$

The estimation result is described in Table 3.6. The F statistics for the ARDL bounds testing shows that it is higher than the upper bound critical value at 1% level, which implies that a long term equilibrium relationship exists between dependent and explanatory variables in equations (3.45). All the coefficients on variables have the expected sign; the unemployment and energy price have a negative impact and GDP has a positive impact on the rate of operation, which are all statistically significant.

Table 3.6. Estimation of the rate of operation

(a) Regression model (sample: 1989~2011)

Dependent Variable : $log(\rho_t)$ Sample : 1989 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	2.072	1.237	1.675	0.116
$log(\rho_{t-1})$	-0.503***	0.091	-5.533	0.000
$\log(u_t/u_t^*)$	-0.118***	0.016	-7.535	0.000
$log(Y_t)$	0.165***	0.045	3.675	0.003
$log(P_{i,t}^e)$	-0.090**	0.033	-2.702	0.017

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis. The estimation includes a dummy variable equal to unity for the period 2004~2011

(b) Cointegration test : $F_{CG}(\rho|\frac{u}{u^*}, Y, P_i^e)$ = 10.059***

(c) Diagnostic tests	
$\bar{R}^2$ = 0.897	$D.W.$ = 2.421
$\hat{\sigma}$ = 0.002	F = 27.216 (0.000)
F_{Auto} = 1.359 (0.264)	χ^2_{Norm} = 3.389 (0.184)
F_{Reset}= 2.467 (0.140)	F_{Hetero}= 0.400 (0.887)

Note: the right-hand side value in parentheses indicates p-value

3.3.2.2. The demand side block

The demand side block covers private consumption and government's final consumption expenditure. This block determines GDP by the GDP expenditure identity condition given inventory levels treated exogenously, and exports and imports which are estimated in the foreign trade block[38]. The private and government consumption are based on the Keynes' absolute income hypothesis and the government budget constraint models respectively.

3.3.2.2.(a) Private consumption

The private consumption function in this model is fundamentally based on Keynes' absolute income hypothesis (1967) in which the real consumption is a function of the real disposable income. The linear function of the consumption in the absolute income hypothesis provides three principles: first, the marginal propensity to consume has a value between zero and one. Second, the average propensity to consume decreases as income increases. Last, current income determines consumption, since the interest rate is regarded as an ineffective variable.

While the Keynesian consumption function has been proven to work successfully in the short term periods, empirical estimation of the long term periods contradicted the second principle of the absolute hypothesis by showing that the average propensity to consume is constant over long periods of time (Kuznets, 1942). In other words, the result shows the conflict between the consumer's behaviour in the short run and the long run, which is called

[38] The use of chained indices in the national account has a non additivity problem, as weights are changed over time. This study uses an error term, ε^Y defined as the difference between real GDP and the sum of GDP expenditure components such as $CP + CG + I + INVD + EX - IM$ for calculating the real GDP.

the Kuznets paradox. This empirical result of long time-series has facilitated the development of alternative consumption functions.

Two prominent alternative hypotheses have been proposed in the 1950s. The life-cycle hypothesis proposed by Modigliani and Brumberg (1968) emphasize consumption smoothing by supplementing the current income regarded as the unique determinant of consumption in the Keynesian consumption function with the present value of lifetime earnings which is called wealth. The permanent income hypothesis as proposed by Friedman (1957) also explains a constant ratio of consumption to income in the long term by suggesting that consumption is mainly determined by permanent income.

Both models are based on Irving Fisher's intertemporal optimization approach (1930) in which the forward-looking consumers make decisions on their current income and expected income in the future. These theories provide the modern macroeconomist with a foundation. The intertemporal utility maximization method has been applied to dynamic mathematical methods, which is called the Euler equation approach, in the modern consumption theories and the models have been extended to deal with uncertainty and expectations.

Although it is desirable to include the wealth variable in the consumption function in view of the importance of wealth pointed out in the literature, this model does not include the wealth variable in the behavioural equation of private consumption for the sake of simplicity and unavailable data in this version. Modelling wealth is relatively difficult, since few economic theories explaining the relationship between wealth and other economic variables exist. In addition, creating the wealth series requires modelling the prices of real estate and financial assets variables and the quantity of them consumers hold. Such stock price indices have considerable volatility. Several papers simply use a stock price index as a proxy for wealth. However, the error from endogenously modelling such a volatile index would worsen the results of the simulation. If the wealth variable is treated exogenously, it requires an additional assumption for simulation. Besides, the current System of National Accounts (SNA) published in Bank of Korea does not provide the 'wealth' data and so official data is not available.

For those reasons, we stick to the fundamental consumption function, 'absolute income' hypothesis which is defined as a function of real disposable income and price of the category in this model. The consumption function is given by:

$$\text{(3.54)} \quad \log(CP_t) = \beta_0 + \beta_1 \times \log(CP_{t-1}) + \beta_2 \times \log(P^c) + \beta_3 \times \log(YD_t) + \varepsilon_t$$

where CP is the real consumption. The lagged real consumption expenditure, CP_{t-1} is included to measure the habit persistence which indicates the effect of the previous period's consumption on the current consumption as Brown (1952) suggested. P^c is the consumer price index. YD represents the real disposal income.

Table 3.7. Estimation of the private consumption function

(a) Regression model

Dependent Variable : $log(CP_t)$ Sample : 1970 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	-0.233	0.547	-0.427	0.672
$log(CP_{t-1})$	0.654^{***}	0.070	9.290	0.000
$log(YD_t)$	0.358^{***}	0.067	5.300	0.000
$log(P_t^c)$	-0.051^{***}	0.017	-3.007	0.005

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
The estimation includes dummy variables equal to unity for the period 1998 and 2001~2011.

(b) Cointegration test : $F_{CP}(CP|GDPD, P^c) = 8.155^{***}$

(c) Diagnostic tests

$\bar{R}^2$ = 0.999	$D.W.$ = 1.487
$\hat{\sigma}$ = 0.018	F = 13193.10 (0.000)
F_{Auto} = 2.035 (0.163)	χ^2_{Norm} = 1.593 (0.451)
F_{Reset} = 0.043 (0.837)	F_{Hetero} = 0.934 (0.471)

Note: the right-hand side value in parentheses indicates p-value

The result of a log-linear form for estimation is described in Table 3.7. We confirm that there is a long-run relationship between consumption and disposable income and consumer price index by the ARDL bounds testing; the calculated *F* statistic is higher than the upper bound critical value at 5% significance level. All of the coefficients on variables are significant and have the expected sign; the coefficient of disposable income is positive and the coefficient of consumer price index is negative. The lagged variable indicates that around 35% of the adjustment process to the desirable level in long-run takes place in the first year. The result shows that the short-run and long-run elasticity of disposable income are 0.358 and 1.032 respectively, meaning that a 1% increase in disposable income raises consumption by approximately 0.36% and 1% in the short term and long term respectively. The short-run and long-run own-price elasticity are -0.051 and -0.146 correspondingly. The marginal propensity to consume (MPC) is 0.250 in the short-run and 0.721 in the long-run[39].

3.3.2.2.(b) Government consumption

The government consumption on goods and service belongs to this component of GDP. The consumption is chosen by the fiscal policy that determines taxes and spending.

Normally, fiscal and government spending areas in macro-econometrics models generally build up a fiscal reaction function based on the government budget constraint condition as mentioned earlier. It is desirable in that the government is assumed to retain a specific robust fiscal rule, which is regarded as best practice, in order to examine unexpected shocks of the fiscal policy (and monetary policies) on agents' behaviour; this should be modelled based on micro-foundations such as preferences and resource constraints rather than

[39] We calculate the MPC by multiplying the income elasticity by the average ratio of consumption to disposable income for the period 1970~2011.

simple parameters estimated entirely on the basis of relationships observed in historical data to represent the agent's prediction for the change in policy (Lucas, 1976).

When it comes to modelling the government consumption in the system model, it is often modelled by an exogenous variable of government expenditure to analyse the ripple effect of fiscal policy on the economy. However, the disadvantage of the external fiscal policy approach for simulation is that it requires an additional assumption for the fiscal policy decision when the policy experiment is conducted in the model. An arbitrary assumption for the government spending could underrate or exaggerate the effect of the policy experiment on output in the simulation analysis. Therefore, we build up a behavioural equation for government consumption that is able to respond to external conditions properly.

The model follows the assumption from Harrison et al.'s BEQM model (2005) for the government consumption function; the government has targets for spending, so that it would not generally follow a balanced budget each period. Moreover, spending is allowed to vary temporarily from target levels following a shock. The target level is defined as the relationship between spending and tax revenues in this model. The model specification refers to the Government Budget Constraint by Barro (1974) and Sargent and Wallace (1981) [40]. The equation is built up in order to evaluate the effect of the change in tax revenues on the government consumption based on these theoretical relationships.

According to the government budget constraint (GBC), the government consumption is equal to the total tax revenue at a point in time and across time. We check the long-run relationship between the government final consumption expenditure (CG) and real tax revenue

[40] The intertemporal equation of the GBC was firstly applied by Barro (1974). The modern application of the GBC has been developed from Sargent and Wallace (1981). Overall, the intertemporal GBC contributes to the development of theoretical works in monetary and fiscal policy studies.

($\frac{TAX}{P^d}$) by the cointegration test, and then the government consumption expenditure is modelled as follows:

$$(3.55)\quad \log(CG_t) = \beta_0 + \beta_1 \times \log(CG_{t-1}) + \beta_2 \times \log(\frac{TAX_t}{P_t^d}) + \varepsilon_t$$

Table 3.8. Estimation of the government consumption function

(a) Regression model

Dependent Variable : $log(CG_t)$ Sample : 1971 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	1.522***	0.473	3.219	0.001
$log(CG_{t-1})$	0.891***	0.041	21.334	0.000
$log(TAX_t / P_t^d \times 100)$	0.063**	0.027	2.430	0.025

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
The estimation includes a dummy variable equal to unity for the period 1990

(b) Cointegration test : $F_{CG}(CG|TAX/P^d)$ = 5.444**

(c) Diagnostic tests

$\bar{R}^2$ = 0.999	$D.W.$ = 1.610
$\hat{\sigma}$ = 0.017	F = 18005.75 (0.000)
F_{Auto} = 1.516 (0.226)	χ^2_{Norm} = 1.306 (0.757)
F_{Reset}= 2.597 (0.116)	F_{Hetero}= 1.119 (0.354)

Note: the right-hand side value in parentheses indicates p-value

Table 3.8 summarises the estimation result of government consumption. We found a long-run equilibrium relationship between government consumption and the tax revenue, meaning that the government's plan for consumption has not been made in isolation from the tax revenue. The coefficient on the lagged government consumption variable has a high value which is close to one, implying that the government's consumption is subject to substantial inertia meaning the adjustment process to the long run equilibrium relationship is slow. The short-run and long-run elasticity of real tax revenue are 0.063 and 0.578, which means that the government gradually increases consumption as the tax revenue rises for the long-run.

3.3.2.3. Prices and Wage block

The prices and wage block consists of consumer prices, producer prices, GDP deflator, export and import prices, and the wage. The model reflects demand-pull and cost-push inflation by estimating the consumer price using demand and cost factors. In view of the impact of international commodity price shocks, imported raw material price index and energy price index for industry are included as explanatory variables for the producer price. The wage estimated by the labour productivity and unemployment rate is also included to capture the impact the unit cost of labour on the producer price. The export and import prices are mainly determined by the producer price adjusted by the exchange rate and foreign prices respectively. The GDP deflator measuring the general price level is modelled as a bridge equation using the consumer and capital prices.

3.3.2.3.(a) Consumer prices

The consumer price (P^c) is mainly determined by demand and cost factors. Namely, excess demand or supply caused from the gap between actual GDP and potential GDP ($\frac{Y}{PY}$) is regarded as the demand factor, and the producer price (P^w)and the household energy price index (P_h^e) are considered as the cost factors. The consumer price function is as follows:

(3.56) $$\log(P_t^c) = \beta_0 + \beta_1 \times \log(P_{t-1}^c) + \beta_2 \times \log(\frac{Y_t}{PY_t}) + \beta_3 \times \log(P_t^w) + \beta_4 \times \log(P_{h,t}^e) + \varepsilon_t$$ [41]

where the household energy price, P_h^e is a quantity-weighted index generated by adding the prices of individual final energy multiplied by the value of quantity share in the index.

[41] Note that import prices fed in through the producer price indirectly affect the consumer price. The model specification was chosen to avoid the phenomena of multicollinearity

Table 3.9 presents estimated parameters, cointegration and diagnostic tests. There exists a long run equilibrium relationship between these variables. The coefficient on the lagged dependent variable indicates that the rate of adjustment is about 43% in the first year. The output gap and cost factors affect the consumer price positively. The producer prices have the largest elasticity, followed by the aggregate energy prices of households and the output gap.

Table 3.9. Estimation of the consumer price function

(a) Regression model

Dependent Variable : $\log(P_t^c)$ Sample : 1990 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	-0.600^{**}	0.243	-2.472	0.024
$\log(P_{t-1}^c)$	0.572^{***}	0.080	7.112	0.000
$\log(Y_t/PY_t)$	0.121^{*}	0.052	2.341	0.032
$\log(P_t^w)$	0.244^{**}	0.101	2.418	0.027
$\log(P_{h,t}^e)$	0.206^{***}	0.068	3.023	0.008

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.

(b) Cointegration test : $F_{P^c}(P^c|\frac{Y}{PY}, P^w, P_h^e) = 4.437^{*}$

(c) Diagnostic tests

$\bar{R}^2 = 0.999$	$D.W. = 1.470$
$\hat{\sigma} = 0.001$	$F = 3810.530\ (0.000)$
$F_{Auto} = 1.637\ (0.219)$	$\chi^2_{Norm} = 3.702\ (0.157)$
$F_{Reset} = 0.322\ (0.578)$	$F_{Hetero} = 1.509\ (0.244)$

Note: the right-hand side value in parentheses indicates p-value

3.3.2.3.(b) Producer prices

We assume that a firm adds a constant percentage to the full cost of a good in imperfect competition. Then, the desired level of the firm's price, based on mark-up pricing, can be written as

$$(3.57) \quad P^{w*} = (1+m)(\sum_j a_j P_j + bW)$$

where P_j^{x*} is the desired level of price, p_j is the cost of intermediate goods, W is the wage. a_j, b are weighting coefficients with respect to the intermediate goods and wage respectively. m is the mark-up rate. Based on the mark-up pricing, the producer price function is assumed to be:

$$(3.58) \log(P_t^w) = \beta_0 + \beta_1 \times \log(P_{t-1}^w) + \beta_2 \times \log(FP_t^{rm} \times ER_t) + \beta_3 \times \log(\frac{W_t}{Y_t/L_t}) + \beta_4 \times \log(P_t^e) + \varepsilon_t$$

where P^w is the producer price, P_i^e is the industry energy price representing energy input costs derived from a quantity weighted method as the households, and $\frac{W}{Y/L}$ is the unit cost of labour. In addition, taking into account the effect of international raw material prices on the export-centered Korean economy, the raw material index FP^{rm} with exchange rate ER is included as an explanatory variable in the producer price function.

The estimation result for producer prices is presented in Table 3.10. The small and insignificant adjustment coefficient explains that the dynamic response of the produce prices in reaching long-run equilibrium level is almost instantaneous, which is in contrast to the consumer prices. These results are conceivable given the historical movement of the producer and consumer prices. Costs factors such as energy prices, raw material prices with the exchange rate, and the unit cost of labour have positive impacts on producer prices, with the largest elasticity being for the unit cost of labour. The smallest elasticity, 0.034 is found in imported raw material prices adjusted by the exchange rate, which is relatively much lower than the other factors in the short-run.

Table 3.10. Estimation of the producer price function

(a) Regression model

Dependent Variable : $\log(P_t^w)$ Sample : 1990 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	1.869***	0.506	3.693	0.002
$\log(P_{t-1}^w)$	0.104	0.162	0.644	0.529
$\log(FP_t^{rm} \times ER_t)$	0.034**	0.016	2.159	0.048
$\log(W_t/(Y_t/L_t))$	0.202***	0.055	3.672	0.002
$\log(P_{i,t}^e)$	0.183***	0.049	3.702	0.002

Note: ***,**, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes dummy variables equal to unity for the period 1999 and 2011.

(b) Cointegration test : $F_{P^w}(P^w|FP^{metal} \cdot ER, P_i^e, W/(Y/L),\ )$ = 10.766***

(c) Diagnostic tests

$\bar{R}^2$ = 0.996	$D.W.$ = 2.118
$\hat{\sigma}$ = 0.003	F = 592.345 (0.000)
F_{Auto} = 0.169 (0.687)	χ^2_{Norm} = 0.136 (0.935)
F_{Reset} = 0.150 (0.705)	F_{Hetero} = 1.302 (0.315)

Note: the right-hand side value in parentheses indicates p-value

3.3.2.3.(c) Export and Import prices

The export price measured in dollars is predominantly determined by the domestic producer price and exchange rate. It reflects that exporting firms set the export prices based on the corresponding domestic producer prices adjusted for the exchange rate. The import price is influenced by the foreign price of products. The export and import price functions are given by:

(3.59) $\log(P_t^{ex}) = \beta_0 + \beta_1 \times \log(P_{t-1}^{ex}) + \beta_2 \times \log(P_t^w) + \beta_3 \times \log(ER_t) + \varepsilon_t$

(3.60) $\log(P_t^{im}) = \beta_0 + \beta_1 \times \log\left(P_{t-1}^{im}\right) + \beta_2 \times \log(FP_t^{oil}) + \beta_3 \times \log(FP_t^{rm}) + \varepsilon_t$

where P^{ex} is the export price, P^{x} is the producer price, and ER is the exchange rate. The import price, P^{im} is set as a function of the main imported goods' prices, oil (FP^{oil}) and raw materials (FP^{rm}).

Table 3.11. Estimation of the export price function

(a) Regression model

Dependent Variable : $log(P_t^{ex})$ Sample : 1972 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	2.612***	0.409	6.382	0.000
$log(P_{t-1}^{ex})$	0.773***	0.050	15.415	0.000
$log(P_t^{w})$	0.222***	0.045	4.907	0.000
$log(ER_t)$	-0.369***	0.066	-5.606	0.000

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes a dummy variable equal to unity for the period 2009

(b) Cointegration test : $F_{P^{ex}}(P^{ex}|P^{w}, ER)$ = 6.513**

(c) Diagnostic tests

$\bar{R}^2$ = 0.962	$D.W.$ = 1.613
$\hat{\sigma}$ = 0.086	F = 68.240 (0.000)
F_{Auto} = 1.005 (0.323)	χ^2_{Norm} = 0.671 (0.715)
F_{Reset}= 0.412 (0.525)	F_{Hetero} = 0.399 (0.808)

Note: the right-hand side value in parentheses indicates p-value

As seen in Table 3.11, the export prices equation has the expected sign for all coefficients. As the export price measured in dollars stems from the producer price along with the exchange rate, the export price is positively related to the export price and negatively correlated to the exchange rate. It appears that the export price is more sensitive to the exchange rate than producer prices in the international trade market. The adjustment rate is relatively slow; approximately 23% of the adjustment between the short and long run takes place in the first year.

Table 3.12 provides the estimation results for import prices. Major commodity prices affect the import price positively. The coefficient of the lagged dependent variable shows a more rapid rate of adjustment, about 61%, than the export price one.

Table 3.12. Estimation of the import price function

(a) Regression model

Dependent Variable : $log(P_t^{im})$ Sample : 1980 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	1.300***	0.343	3.792	0.000
$log(P_{t-1}^{im})$	0.412***	0.108	3.814	0.000
$log(FP_t^{oil})$	0.041*	0.022	1.876	0.072
$log(FP_t^{rm})$	0.274***	0.055	6.752	0.000

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes a dummy variable equal to unity for the period 2009

(b) Cointegration test : $F_{pim}(P^{im}|FP^{oil}, FP^{metal})$ = 4.704*

(c) Diagnostic tests

$\bar{R}^2$ = 0.961	$D.W.$ = 1.668
$\hat{\sigma}$ = 0.042	F = 192.689 (0.000)
$F_{Auto}(1,26)$ = 0.696 (0.412)	$\chi^2_{Norm}(2)$ = 0.894 (0.639)
$F_{Reset}(1,26)$ = 0.098 (0.757)	$F_{Hetero}(4,27)$ = 1.446 (0.246)

Note: the right-hand side value in parentheses indicates p-value

3.3.2.3.(d) Wages

This model adopts the real wage index which is the average nominal wage deflated by the consumer price index denoted by $\frac{W}{CPI}$. The explanatory variables are labour productivity which is measured by the GDP divided by the labour supply, i.e. $\frac{Y}{L}$ and the gap between the actual and the natural rate of unemployment, denoted by $\frac{u}{u^*}$ which represents the gap between the labour demand and supply in the labour market. The real wage function can be written as:

$$(3.61) \quad \log(\frac{W_t}{P_t^c}) = \beta_0 + \beta_1 \times \log\left(\frac{W_{t-1}}{P_{t-1}^c}\right) + \beta_2 \times \log(\frac{Y_t}{L_t}) + \beta_3 \times \log(\frac{u_t}{u_t^*}) + \varepsilon_t$$

The real wage is expected to be positively related to labour productivity, since higher output per worker leads to an increase in labour compensation unless the labour supply curve is perfectly elastic. Several empirical studies (Lavi and Sussman, 2001; Strauss and Wohar, 2004; Kumar et al., 2009) support a long-term co-integrating relationship between the real wage and labour productivity. On the other hand, the gap between the actual and the natural rate of unemployment (NAIRU), ($\frac{u}{u^*}$) is expected to negatively affect the real wage, because an increasing gap (high unemployment) between labour demand and supply decreases the equilibrium real wage. The unemployment rate is also interpreted as a sign of bargaining power (Blanchflower and Oswald, 1994). High unemployment above the NAIRU reduces workers' bargaining power, therefore forcing lower real wages.

Table 3.13. Estimation of the wage function

(a) Regression model

Dependent Variable : $log(W_t/P_t^c)$ Sample : 1971 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	-2.182^{**}	0.900	-2.426	0.020
$log(W_{t-1}/P_{t-1}^c)$	0.748^{***}	0.069	10.863	0.000
$log(Y_t/L_t)$	0.270^{***}	0.090	2.982	0.005
$log(u_t/u_t^*)$	-0.140^{***}	0.027	-5.274	0.000

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes a dummy variable equal to unity for the period 1999

(b) Cointegration test : $F_{W/P^c}(W/P^c|GDP/L, \frac{u}{u^*}) = 4.874^{*}$

(c) Diagnostic tests

$\bar{R}^2$ = 0.997	$D.W.$ = 1.559
$\hat{\sigma}$ = 0.053	F = 3839.151 (0.000)
F_{Auto} = 1.584 (0.217)	χ^2_{Norm} = 1.387 (0.500)
F_{Reset}= 1.817 (0.757)	F_{Hetero}= 1.460 (0.235)

Note: the right-hand side value in parentheses indicates p-value

The estimation results for wages are provided in Table 3.13. The model yields significant coefficients on variables and expected signs. The adjustment process is relatively slow; approximately 25% takes place in the first year. The wage is positively related to labour productivity. We also found an inverse relationship between the real wage and the gap between the actual and natural unemployment rates.

3.3.2.3.(e) Capital goods prices

The price of capital goods which determines investment is modelled as a function of the lagged dependent variable, imported metal prices, and the exchange rate, which is as follows:

$$(3.62)\quad \log(P_t^i) = \beta_0 + \beta_1 \times \log\left(P_{t-1}^i\right) + \beta_2 \times \log(FP_t^{rm}) + \beta_3 \times \log(ER_t) + \varepsilon_t$$

Table 3.14. Estimation of the capital good price function

(a) Regression model

Dependent Variable : $log(P_t^i)$ Sample : 1990 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	-0.174	0.215	-0.809	0.429
$log(P_{t-1}^i)$	0.754***	0.056	13.490	0.000
$log(FP_t^{rm})$	0.075***	0.021	3.629	0.002
$log(ER_t)$	0.140**	0.051	2.763	0.013

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.

(b) Cointegration test : $F_{P^i}(P^i|P^{metal}, ER)$ = 5.882**

(c) Diagnostic tests

$\bar{R}^2$ = 0.992	$D.W.$ = 1.687
$\hat{\sigma}$ = 0.008	F = 922.329 (0.000)
F_{Auto} = 0.381 (0.545)	χ^2_{Norm} = 0.294 (0.863)
F_{Reset} = 0.226 (0.641)	F_{Hetero} = 0.441 (0.726)

Note: the right-hand side value in parentheses indicates p-value

The estimation result is given in Table 3.14. Overall, the capital goods' price model fits the data well and passes a set of diagnostic tests, which indicates that the price of capital goods are strongly related to the imported raw material prices and the exchange rate.

3.3.2.3.(f) GDP deflator

The GDP deflator measures the general price level in the economy. The nominal fiscal and monetary variables are often converted into real variables by utilising the GDP deflator. We estimate the GDP deflator by the consumer price (P^c) and the price of capital goods (P^i). The function for the GDP deflator (P^d) is as follows:

$$(3.63) \quad \log(P_t^d) = \beta_0 + \beta_1 \times \log(P_{t-1}^d) + \beta_2 \times \log(P_t^c) + \beta_3 \times \log(P_t^i) + \varepsilon_t$$

Table 3.15. Estimation of the GDP deflator function

(a) Regression model

Dependent Variable : $log(P_t^d)$ Sample : 1970 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	0.820^{**}	0.381	2.154	0.038
$log(P_{t-1}^d)$	0.153	0.094	1.630	0.112
$log(P_t^c)$	0.477^{***}	0.118	4.047	0.000
$log(P_t^i)$	0.196^{**}	0.080	2.440	0.020

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes a dummy variable equal to unity for the period 1978
AR(1) Cochrane-Orcutt procedure is conducted to adjust the model for serial correlation in the error term

(b) Cointegration test : $F_{P^i}(P^d|P^c, P^i)$ = 4.486^{*}

(c) Diagnostic tests

$\bar{R}^2$ = 0.999	$D.W.$ = 1.459
$\hat{\sigma}$ = 0.008	F = 24856.080 (0.000)
F_{Auto} = 2.595 (0.117)	χ^2_{Norm} = 0.123 (0.940)
F_{Reset} = 1.128 (0.296)	F_{Hetero} = 0.730 (0.578)

Note: the right-hand side value in parentheses indicates p-value

As seen in Table 3.15, the combination of consumer prices and capital goods price provides a robust estimation result[42] and it captures the GDP deflator's movement very well.

3.3.2.4. Fiscal and Monetary policy block

The fiscal and monetary policy block determines tax revenue and money supply. The tax which is a main source of the government's spending has an impact on disposable income. The central bank controls liquidity through determining money supply and an official interest rate which are a function of the yield of corporate bonds.

3.3.2.4.(a) Tax revenue

The aggregated nominal tax revenue which determines the disposable income is assumed to be a function of the lagged dependent variable and nominal GDP (YP), which is as follows:

$$(3.64) \quad \log(TAX_t) = \beta_0 + \beta_1 \times \log(TAX_{t-1}) + \beta_3 \times \log(YP_t) + \varepsilon_t$$

The estimation result is described in Table 3.16. As seen in the calculated F statistics, each tax has a long-run equilibrium relationship with the determinant variables which are found to be positively related to the taxes. The coefficient of the lagged dependent variable shows a rapid rate of adjustment, around 77%, and the coefficient of the nominal GDP indicates an elasticity of the nominal GDP of 0.799.

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[42] The combination with other consumer prices, such as producer prices often created a multicollinearity problem.

Table 3.16. Estimation of the tax function

(a) Regression model

Dependent Variable : $log(TAX_t)$ Sample : 1970 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	-2.332**	0.996	-2.343	0.025
$log(TAX_{t-1})$	0.232	0.142	1.631	0.112
$log(YP_t)$	0.799**	0.162	4.930	0.000

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
AR(1) Cochrane-Orcutt procedure is conducted to adjust the model for serial correlation in the error term

(b) Cointegration test : $F_{TAX}(TAX|YP)$ = 6.873**

(c) Diagnostic tests

$\bar{R}^2$ = 0.999	$D.W.$ = 1.759
$\hat{\sigma}$ = 0.036	F = 18226.39 (0.000)
F_{Auto} = 1.339 (0.256)	χ^2_{Norm} = 0.989 (0.610)
F_{Reset} = 1.222 (0.277)	F_{Hetero} = 0.199 (0.937)

Note: the right-hand side value in parentheses indicates p-value

3.3.2.4.(b) Money supply

Based on the quantity theory of money suggested by Irving Fisher (1911), nominal money supply ($M3$) is modelled as a function of the lagged dependent variable ($M3_{t-1}$), and nominal GDP in this model. The money supply function is given by:

(3.65) $\log(M3_t) = \beta_0 + \beta_1 \times \log(M3_{t-1}) + \beta_2 \times \log(YP_t) + \varepsilon_t$

Table 3.17 provides the estimation results for money supply. We establish a long-run equilibrium relationship between the money supply and nominal GDP variables, which indicates that money growth is in proportion to the economic activity. The statistically significant coefficient on lagged variables indicates that the rate of adjustment is approximately 26 % in each year. The short-run and long-run nominal output elasticities are found to be around 0.29 and 1.098 respectively[43].

Table 3.17. Estimation of the money supply function

(a) Regression model

Dependent Variable : $log(M3_t)$ Sample : 1987 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	-0.713	1.365	-0.523	0.607
$log(M3_{t-1})$	0.736^{***}	0.084	8.746	0.000
$log(YP_t)$	0.290^{**}	0.124	2.346	0.029

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
AR(1) Cochrane-Orcutt procedure is conducted to adjust the model for serial correlation in the error term

(b) Cointegration test : $F_{M3}(M3|YP)$ = 6.020^{**}

(c) Diagnostic tests

$\bar{R}^2$ = 0.999	$D.W.$ = 1.757
$\hat{\sigma}$ = 0.007	F = 18324.580 (0.000)
F_{Auto} = 0.729 (0.404)	χ^2_{Norm} = 1.363 (0.506)
F_{Reset} = 0.036 (0.852)	F_{Hetero} = 1.730 (0.202)

Note: the right-hand side value in parentheses indicates p-value

3.3.2.5. Finance block

The finance block covers the yield of corporate bonds and the exchange rate. The yield on corporate bonds is determined by an official interest rate by a central bank, which allows the model to analyse the effects of the current monetary policy utilising an official interest rate on the real sector of the economy. The exchange rate determined by the difference between foreign and domestic interest rates has impacts on exports and imports in the foreign trade block.

[43] It is important to note that the GDP variable on the right hand side is an independent variable, so that the GDP is not designed to be affected by the money supply in this model. Thus, we do not need to impose any restrictions on the coefficient in order to satisfy a theory of neutrality of money.

3.3.2.5.(a) Yield of corporate bonds

Determining the official interest rate by an independent central bank is the main monetary instrument to control inflation and stabilize output in the short-term. In practice, the call rate is the key interest rate that Bank of Korea charges commercial banks for secured overnight lending. The mechanism that transmits central bank policy actions to the real sector is as follows: a change in the official interest rate is transmitted to market interest rates, the exchange rate and asset prices. These changes in turn affect individual and firms' behaviours in terms of consumption, production, saving, and investment.

However, the transmission channel is somewhat complex, since the indirect effects can take various forms depending on macroeconomic aspects, financial market structure, and the regulatory framework. Numerous studies have attempted to explain how changes in central banks' policy rates transmit to market-determined rates (Dodds and Ford, 1972; Diebold and Li, 2006; Diebold et al., 2006; Hoffmeister et al., 2010). A common reduced form is that the interest rate is a function of the official interest rate (*CALL*) and macroeconomic variables such as GDP (*Y*) and money supply (*M3*) representing the demand of fund and total liquidity in a nation respectively.

$$(3.66)\quad \log(YCB_t) = \beta_0 + \beta_1 \times \log(YCB_{t-1}) + \beta_2 \times \log(CALL_t) + \beta_3 \times \log(Y_t) + \beta_4 \times \log(M3_t) + \varepsilon_t$$

The estimation results for the yield of corporate bonds are described in Table 3.18. The calculated *F* statistics shows that a long-run equilibrium relationship among variables exists. The coefficients on explanatory variables have all right sign; the yield of corporate bonds is positively related to output and negatively affected by liquidity, but are statistically significant only for the lagged dependent variable and the official rate. Even though the historical relationships between the output and liquidity are not solid, the model retains the variables for simulation, since the sign and magnitude of coefficients does not violate macroeconomic theory.

Table 3.18. Estimation of the yields corporate bonds function

(a) Regression model

Dependent Variable : $log(YCB_t)$ Sample : 1971 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	-15.017	16.536	-0.908	0.379
$log(YCB_{t-1})$	0.474^{***}	0.137	3.451	0.004
$log(CALL_t)$	0.525^{***}	0.070	7.475	0.000
$log(M3_t)$	-0.162	0.254	-0.638	0.534
$log(Y_t)$	0.605	0.731	0.828	0.422

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes dummy variables equal to unity for the period 2000 and 2009.

(b) Cointegration test : $F_{YCB}(YCB|CALL, Y, M3)$ = 4.982^{**}

(c) Diagnostic tests

$\bar{R}^2$ = 0.970	$D.W.$ = 2.227
$\hat{\sigma}$ = 0.097	F = 110.004 (0.000)
F_{Auto} = 0.929 (0.353)	χ^2_{Norm} = 0.048 (0.976)
F_{Reset} = 0.610 (0.449)	F_{Hetero} = 0.716 (0.643)

Note: the right-hand side value in parentheses indicates p-value

3.3.2.5.(b) Exchange rate

This model uses the nominal exchange rate of Korean won to U.S. dollar for two reasons; first, the U.S. dollar is the key currency, so that the majority of international trade in Korea is settled by the U.S. dollar. Second, an official Real Effective Exchange Rate (REER)[44] is not readily available in the current SNA system.

[44] REER is weighted average of a country's currency relative to a basket of other major currencies adjusted for the effects of inflation

As for model specification, given a major factor, the U.S.'s interest rate in a small open economy, most macro-econometric models published in the bank of Korea and national economic institutes in Korea model the exchange rate equation by the difference between domestic and foreign interest rates. It is consistent with the theory of the Uncovered Interest-Rate Parity (UIP).

The nominal exchange rate (ER) is modelled by the ratio of the domestic interest rate and the foreign interest rate. The exchange rate function is given by:

$$(3.67)\quad \log(ER_t) = \beta_0 + \beta_1 \times \log(ER_{t-1}) + \beta_2 \times \log(\frac{CALL}{R_t^{US}}) + \varepsilon_t$$

where the official interest rate ($CALL$) is adopted as the domestic interest rate and United States' government bond yield for 10 year is employed as the foreign interest rate.

Note that a difference between equation (3.67) and the UIP is whether the expected future spot exchange rate is included or not. The traditional macro-econometric model has a limited ability to model the expectation variable (the expected future spot exchange rate at time, $t+k$) contained in the UIP. It can be estimated under the assumption of perfect foresight (using real data at $t+k$). But it cannot be solved for simulation in a system model as it contains a future variable. Overall, the model has to consider both the theoretical and practical aspects of the problem

The estimation result for the log linearized form of equation (3.67) is presented in Table 3.19. The short-run and long-run elasticity of exchange rate with respect to the ratio of the domestic interest rate and the foreign interest rate are -0.076 and -0.123 respectively. Although the coefficient on the difference between domestic and foreign interest rates is not statically significant, the coefficients have the right sign; an increase in the domestic interest rate decreases the exchange rate (i.e. the domestic currency appreciates).

Table 3.19. Estimation of the exchange rate function

(a) Regression model

Dependent Variable : $log(ER_t)$ Sample : 1990 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	2.461**	1.136	2.167	0.047
$log(ER_{t-1})$	0.644***	0.163	3.959	0.001
$log(CALL_T/R_t^{US})$	-0.076	0.083	-0.914	0.375

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes dummy variables equal to unity for the period 2001 and 2008.

(b) Cointegration test : $F_{ER}(ER|CALL/R^{US})$ = 8.614***

(c) Diagnostic tests

$\bar{R}^2$ = 0.937	$D.W.$ = 1.756
$\hat{\sigma}$ = 0.042	F = 52.810 (0.000)
F_{Auto} = 0.139 (0.715)	χ^2_{Norm} = 6.226 (0.044)
F_{Reset}= 0.027 (0.871)	F_{Hetero}= 0.573 (0.720)

Note: the right-hand side value in parentheses indicates p-value

3.3.2.5. Foreign trade block

The foreign trade block estimates exports and imports which are components of the GDP expenditure side. The models for exports and imports have a symmetric structure in which foreign and domestic economic activity and relative prices are adopted as explanatory variables.

3.3.2.5.(a) Exports and Imports

The traditional empirical formulation of import demand and export supply functions, often called the elasticity approach, has a symmetric structure. The demand function of imports has determinant variables such as domestic economic activity and the ratio of the prices of imported goods to domestic substitutes. Correspondingly, the export supply function is determined by the economic activity of the rest of the world and the ratio of the export price to foreign substitutes' prices.

In the empirical literature, Khan (1974), Warner and Kreinin (1983), and Bahmani-Oskooee (1986) modified the trade formulation and analysed trade policy issues; typically investigating the effect of devaluation of a country's currency on the trade balance. Later studies, Bahmani-Oskooee and Niroomand (1998) and Bahmani-Oskooee (1998) firstly estimated the export and import demand functions using Johansen (1988) and Johansen-Juselius (1990) cointegration analyses in order to overcome spurious results.

Following the related empirical studies, the function for the export supply (EX) employs the traditional formulation in which the price of exports relative to foreign prices ($\frac{P^{ex}}{P^{c}_{US}}$) and the rest of the world's GDP (FY) are adopted for explanatory variables. The import demand (IM) function includes the relative price of foreign goods adjusted by the real exchange rate and domestic price ($\frac{P^{im}\times(\frac{ER}{P^d}\times 100)}{P^x}$) and the relevant domestic activity variables such as GDP. The export and import functions are as follows:

$$(3.68)\quad \log(EX_t) = \beta_0 + \beta_1 \times \log(EX_{t-1}) + \beta_2 \times \log(FY_t) + \beta_3 \times \log(\frac{P^{ex}_t}{P^{c}_{US,t}}) + \varepsilon_t$$

$$(3.69)\quad \log(IM_t) = \beta_0 + \beta_1 \times \log(IM_{t-1}) + \beta_2 \times \log(Y_t) + \beta_3 \times \log(\frac{P^{im}_t \times (ER_t/P^d_t \times 100)}{P^x_t}) + \varepsilon_t$$

Table 3.20. Estimation of the export function

(a) Regression model

Dependent Variable : $log(EX_t)$ Sample : 1970 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	6.081***	1.044	5.825	0.000
$log(EX_{t-1})$	0.670***	0.066	10.164	0.000
$log(FY_t)$	1.059***	0.279	3.795	0.001
$log(P_t^{ex})$	-0.230***	0.079	-2.909	0.006

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes dummy variables equal to unity for the period 1971 and 2001.

(b) Cointegration test : $F_{EX}(EX|FY, P^{ex})$ = 8.572**

(c) Diagnostic tests

$\bar{R}^2$ = 0.998	$D.W.$ = 1.944
$\hat{\sigma}$ = 0.066	F = 3698.320 (0.000)
F_{Auto} = 0.010 (0.919)	χ^2_{Norm} = 0.120 (0.942)
F_{Reset}= 0.381 (0.541)	F_{Hetero}= 1.340 (0.271)

Note: the right-hand side value in parentheses indicates p-value

The results of exports and imports estimation are provided in Table 3.20 and 3.21. In terms of the bounds cointegration test, the calculated F-statistics are higher than the upper bound. Thus, the null hypotheses of no cointegration are rejected, implying that there exists a long-run relationship amongst the variables. All the coefficients on variables in exports and imports are statistically significant in equation (3.68) and (3.69), and they have the right sign; the prices have a negative impact and economic activity affects the dependent variables positively. Finally, the diagnostic tests results for exports and imports indicate that the relationships between variables estimated in these equations are robust.

Based on our model estimates presented in Table 3.20, the short-run elasticity of exports with respect to foreign GDP and export prices are 1.059 and -0.230 correspondingly. The long-run elasticity of exports with respect to foreign GDP and export prices can be computed as 3.211 and -0.697 respectively. The relatively high foreign GDP elasticity of exports indicates that the export-centred economy has been sensitive to the foreign trade. On the other hand, the low export price elasticity of exports can be interpreted as high export competitiveness on non-price factors.

Table 3.21. Estimation of the import function

(a) Regression model

Dependent Variable : $log(IM_t)$ Sample : 1980 ~ 2011

Regressor	Coefficient	Standard Error	T-value	P-value
Constant	-59.917^{***}	8.768	-6.834	0.000
$log(IM_{t-1})$	0.045	0.075	0.598	0.556
$log(Y_t)$	2.689^{***}	0.241	11.165	0.000
$log((P^{im} \cdot \left(\frac{ER}{P^d} \cdot 100\right))/P^w)$	-0.179^{*}	0.104	-1.728	0.097

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively.
Estimation includes dummy variables equal to unity for the period 2001, 2002 and 2009.
AR(1) Cochrane-Orcutt procedure is conducted to adjust the model for serial correlation in the error term

(b) Cointegration test : $F_{IM}(IM|Y,(P^{im} \cdot \left(\frac{ER}{P^d} \cdot 100\right))/P^w) = 4.851^{*}$

(c) Diagnostic tests

$\bar{R}^2 = 0.999$	$D.W. = 2.257$
$\hat{\sigma} = 0.033$	$F = 3131.713$ (0.000)
$F_{Auto} = 0.901$ (0.353)	$\chi^2_{Norm} = 0.994$ (0.608)
$F_{Reset} = 3.624$ (0.070)	$F_{Hetero} = 2.992$ (0.810)

Note: the right-hand side value in parentheses indicates p-value

Table 3.21 indicates that the short-run elasticities of imports with respect to domestic GDP and relative import prices are 2.689 and -0.179 correspondingly. The long-run elasticity of imports with respect to the domestic GDP and to import prices can be derived as 2.816 and -0.188 respectively.

3.4.2.7. Energy and environment block

This section explains the properties of the energy system flow and methods for estimating energy demands and prices by sources and sector. First of all, energy is classified into primary energy and secondary energy. According to United Nations (1982), primary energy is defined as;

> *"Primary energy should be used to designate those sources that only involve extraction or capture, with or without separation from contiguous material, cleaning or grading, before the energy embodied in that source can be converted into heat or mechanical work."*

On the other hand, secondary energy is defined as;

> *"Secondary energy should be used to designate all sources of energy that results from transformation of primary sources."*

For example, secondary energy consists of electricity and heat energy generated from several input energy sources, city-gas transformed from LNG or LPG, refined petroleum products, and renewable energy. The secondary energy is the type of final products that are transformed from the primary energy and then consumed by each sector's consumers. Final energy demand is defined as the energy used by final user such as households and firms outside the energy sector, i.e. the energy which is not being used for transformation process.

The transformation process normally involves a significant amount of energy loss incurred by low conversion efficiency. Therefore, the total amount of energy supply should be larger than the total amount of energy demand. The total energy supply refers to Total

Primary Energy Supply (TPES)[45] that is the sum of all primary energy sources before losses in the conversion process occurs.

In order to capture the properties of energy processes, the energy module describes two sectors individually; the final energy demand of various sectors and the energy transformation sector's energy demand. In the final energy demand, it estimates final energy demand by source and sector. The final energy demand is classified into coal, petroleum, electricity, and city-gas. The sectors are divided into industry, transportation, commerce and public administration (hereafter, commerce and public), and households. Each sector's final demand is estimated by the econometric method; the cost share logit model as one of the inter-fuel substitution methods explained in the literature review. We use an aggregated estimate of the other final energy demands of each sector that account for relatively minor portions, and then divide the aggregated energy demand into each sector's demand using share ratio coefficients.

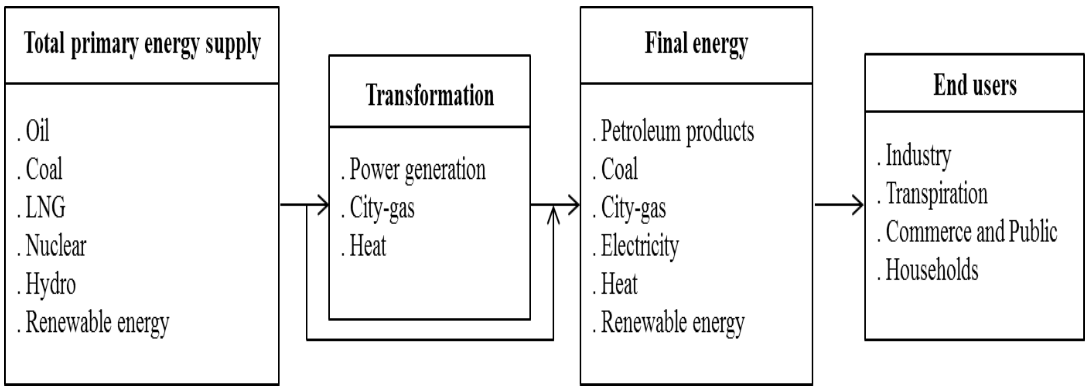

Figure 3.2. Energy sector's classification

The transformation sector consists of power generation, city-gas, and heat energy. As mentioned in the introduction, the power generation sector is modelled by the bottom-up

[45] The TPES provide a more suitable measure than total final energy demand (electricity, city-gas, heat, and refined petroleum products) in measuring carbon emissions.

approach taking into account the importance of the sector in the impact of carbon-related energy policy. City-gas and heat energy's demand for input energy sources are derived by identities that reflect supply factors such as own use and loss, conversion efficiency, and share ratio of energy sources in order to fulfil the demand for final energy which is taken from the final energy demand sector. Finally, TPES is measured by summing up the final energy and transformation sectors' demands of coal, petroleum, and LNG. The whole process of estimating energy demands is depicted in Figure 3.2.

Lastly, this block measures CO_2 emissions from energy use and models the impact of a carbon pricing policy using identities. The model adopts the IPCC (1996)'s carbon emission factor for each fuel with the fraction of fuel combustion factor. The carbon pricing policy is modelled by increasing the level of energy prices in proportion to a carbon tax rate.

3.4.2.7.(a) Final energy demand

The final energy demands of industry, commerce and public, and household sectors are estimated for the following energy products; bituminous coal, aggregated energy petroleum goods, city-gas, and electricity by Considine and Mount (1984)'s dynamic linear logit model in order to examine inter-fuel substitution possibilities in the energy demand block triggered by the carbon tax policy. It is important to note that Considine (1989) and Urga and Walters (2003) point out that including non-energy data in inter-fuel substitution models can lead to no sensible own- or cross-price elasticties, since fuels used for non-energy reasons in industry sectors have few substitutes so that their prices may have almost no effect on their non-energy demand. Therefore, non-energy fuel use needs to be excluded from the aggregated energy source. To deal with this issue, we exclude non energy oil such as asphalt, naphtha, and the other petroleum products (lubricant, petroleum coke, solvent, other products) from aggregated petroleum products that comprise gasoline, kerosene, diesel, heavy oil, propane, and butane. In addition, coking coal is taken out from the bituminous coal. As explained in the literature review, the cost share equations of four energy sources are given by:

$$(3.70)\quad \log\left(\frac{w_1}{w_4}\right) = (\alpha_1 - \alpha_4) - [\beta_{12}^* w_2^* + \beta_{13}^* w_3^* + \beta_{14}^*(w_1^* + w_4^*)]\log\left(\frac{P_1}{P_4}\right) + (\beta_{12}^* - \beta_{24}^*)w_2^* \log\left(\frac{P_1}{P_4}\right) + (\beta_{13}^* - \beta_{34}^*)w_3^* \log\left(\frac{P_3}{P_4}\right) + \lambda \log\left(\frac{x_1}{x_4}\right)_{t-1} + (\varepsilon_1 - \varepsilon_4)$$

$$\log\left(\frac{w_2}{w_4}\right) = (\alpha_2 - \alpha_4) - [\beta_{12}^* w_1^* + \beta_{23}^* w_3^* + \beta_{24}^*(w_2^* + w_4^*)]\log\left(\frac{P_2}{P_4}\right) + (\beta_{12}^* - \beta_{14}^*)w_1^* \log\left(\frac{P_1}{P_4}\right) + (\beta_{23}^* - \beta_{34}^*)w_3^* \log\left(\frac{P_3}{P_4}\right) + \lambda \log\left(\frac{x_2}{x_4}\right)_{t-1} + (\varepsilon_2 - \varepsilon_4)$$

$$\log\left(\frac{w_3}{w_4}\right) = (\alpha_3 - \alpha_4) - [\beta_{13}^* w_2^* + \beta_{23}^* w_3^* + \beta_{34}^*(w_3^* + w_4^*)]\log\left(\frac{P_3}{P_4}\right) + (\beta_{13}^* - \beta_{14}^*)w_1^* \log\left(\frac{P_1}{P_4}\right) + (\beta_{23}^* - \beta_{24}^*)w_2^* \log\left(\frac{P_3}{P_4}\right) + \lambda \log\left(\frac{x_3}{x_4}\right)_{t-1} + (\varepsilon_3 - \varepsilon_4)$$

where w_i is the cost share of the i^{th} input. P_i is the energy price of P_i the i^{th} input, the subscript numbers; from one to four represent oil, city-gas, electricity, and coal respectively, and α_i, β_{ij}, λ are parameters to be estimated. As explained earlier, we adopt the two-step iterative Zellner estimation method in order to estimate the system of input share equations (3.70). For the convenience of estimation, a normalizing constant $\alpha_4 = 0$ is imposed on the system of equations. Note this constant does not affect the estimated elasticities (Considine and Mount, 1984). Error terms ($\varepsilon_i - \varepsilon_4$) are assumed to follow a normal distribution. After estimation, own- and cross-price elasticities are computed by equations (3.25) and (3.26) as explained in the literature review. Table 3.22 summarises the sectors' energy demands in the cost share logit model. These final energy demands account for the majority of the sectors' energy expenditure. In the case of the transportation sector, petroleum products, city-gas, and electricity are used. Even though electricity and city-gas are used in subway trains and CNG buses respectively, they represent a minute fraction. Among the petroleum products, gasoline, diesel, and Liquefied Petroleum Gas (LPG) for vehicles are mostly consumed in the transportation sector. LPG can be seen as a substitute for gasoline and diesel. Therefore, the model focuses on the major energy products consumed in vehicles; Gasoline and diesel are aggregated into one petroleum good, which is assumed to have a competitive relationship with LPG in the cost share logit model.

Table 3.22. Sectors' final energy demands in the logit model

Sector	Final energy products (cost share of the i^{th} input)
Industry	1. Petroleum 2.Electricity 3. City-gas 4.Bituminous coal
Commerce and Public	1. Petroleum 2.City-gas 3.Electricity
Households	1. Petroleum 2.Electricity 3. City-gas 4.Anthracite coal

1) Industry

Table 3.23 provides parameter estimates and goodness of fit of the dynamic logit model for industry. Overall the model has a good measurement of fit as seen by high R^2 and 8 of 10 significant coefficients in Table 3.23. The estimated lambda indicates that the rate of adjustment in attaining the long-run desired level is approximate by 20% in the first year.

Given the estimated parameters, price and substitution elasticities are derived as seen in Table 3.24. Own price elasticities of all energy sources are negative. All of the own price elasticities in the short-run are less than one. The most elastic demand with respect to price in the long-run is for city-gas, whereas the other energy sources have still inelastic demands in the long-run. We found positive cross-price elasticities in most cases, the largest being petroleum with respect to the price of city-gas.

Table 3.23. The estimation of the dynamic logit model for the industry sector

Parameter	Estimate	Standard error	t-value
$c_1{}^{***}$	0.288	0.108	2.676
c_2	-0.103	0.109	-0.939
$c_3{}^{***}$	0.355	0.101	3.519
c_{12}	-0.013	0.213	-0.062
$c_{13}{}^{***}$	-0.821	0.026	-31.189
$c_{14}{}^{***}$	-1.015	0.079	-12.853
$c_{23}{}^{***}$	-0.928	0.118	-7.836
$c_{24}{}^{***}$	-1.352	0.389	-3.478
$c_{34}{}^{***}$	-0.857	0.064	-13.482
λ^{***}	0.802	0.039	20.600
R^2		0.959	
		0.995	
		0.961	

Table 3.24. Price and substitution elasticities of the industry sector

Demand \ Price	Petroleum		City-Gas		Electricity		Coal	
	Short-run	Long-run	Short-run	Long-run	Short-run	Long-run	Short-run	Long-run
Petroleum	**-0.2057**	**-1.0398**	0.0840	0.4246	0.1223	0.6182	-0.0006	-0.0030
City-Gas	0.1915	0.9682	**-0.2266**	**-1.1459**	0.0488	0.2466	-0.0136	-0.0689
Electricity	0.0348	0.1759	0.0061	0.0308	**-0.0464**	**-0.2347**	0.0055	0.0280
Coal	-0.0030	-0.0151	-0.0299	-0.1514	0.0975	0.4930	**-0.0646**	**-0.3266**

On the other hand, complementarity relationships exist between coal and petroleum and between coal and city-gas, but the values of these negative elasticities are negligible in magnitude in the short-run. This implies that a small amount of coal can be substituted with the other inputs in industry. But, the relationship between coal and city-gas is hardly conceivable given engineering properties and historical trends. For the sake of a realistic simulation, this model sets the cross price elasticity equal to zero through calibrating the coefficients.

2) Commerce and Public administration

The estimation results for the commerce and public administration sector are presented in Table 3.25 The model yields significant coefficients. The adjustment coefficient shows the long-run response is slower than industry's.

Table 3.25. The estimation of the dynamic logit model for the commerce and public sector

Parameter	Estimate	Standard error	t-value
c_1***	-0.293	0.089	-3.274
c_2***	-0.504	0.192	-2.633
c_{12}**	-0.674	0.268	-2.514
c_{13}***	-0.776	0.141	-5.521
c_{23}***	-0.661	0.166	-3.971
λ***	0.837	0.094	8.898
R^2		0.880	
		0.936	

Table 3.26. Price and substitution elasticities of the commerce and public sector

Demand \ Price	Petroleum		City-Gas		Electricity	
	Short-run	Long-run	Short-run	Long-run	Short-run	Long-run
Petroleum	**-0.201**	**-1.234**	0.028	0.172	0.173	1.062
City-Gas	0.046	0.282	**-0.308**	**-1.889**	0.262	1.607
Electricity	0.032	0.194	0.029	0.178	**-0.061**	**-0.372**

All input demands have negative own-price elasticities as seen in Table 3.26, in which electricity has been found to be the most inelastic, and have positive cross price elasticities and the largest own-price elasticity of the demand for city-gas in commerce and public sector.

3) Households

Finally, households' estimation result and price elasticities are provided in Table 3.27 and 3.28. 10 of 12 parameters are statistically significant. Similar to the other sectors, the adjustment coefficient is relatively slow; 11% of adjustment process occurs in the first year.

Table 3.27. The estimation of the dynamic logit model for the household sector

Parameter	Estimate	Standard error	t-value
c_1***	1.280	0.239	5.355
c_2***	1.342	0.220	6.101
c_3***	1.385	0.249	5.552
c_{12}***	-0.899	0.174	-5.162
c_{13}***	-0.829	0.067	-12.373
c_{14}***	-0.483	0.204	-2.368
c_{23}***	-0.834	0.128	-6.500
c_{24}	-0.231	0.246	-0.936
c_{34}	-0.301	0.190	-1.587
λ***	0.889	0.024	37.808
R^2		0.968	
		0.994	
		0.979	

All four energy products have negative own price elasticities and positive cross price elasticities. A relatively large own price elasticity and cross price elasticities with respect to the other energy are found in coal demand, which reflects the high substitution possibilities in the household sector.

Table 3.28. Price and substitution elasticities of the household sector

Demand \ Price	Petroleum		City-Gas		Electricity		Coal	
	Short-run	Long-run	Short-run	Long-run	Short-run	Long-run	Short-run	Long-run
Petroleum	**-0.129**	**-1.165**	0.027	0.241	0.072	0.649	0.031	0.275
City-Gas	0.026	0.233	**-0.141**	**-1.272**	0.070	0.629	0.045	0.410
Electricity	0.044	0.394	0.044	0.396	**-0.129**	**-1.162**	0.041	0.372
Coal	0.132	1.190	0.204	1.836	0.294	2.651	**-0.630**	**-5.677**

The cost share of the energy product, i is estimated by equation (3.70). The demand for each input energy source can be computed in two ways; firstly, estimate the cost share of the i^{th} input by the inter-fuel substitution model and the total energy cost directly using an energy price index and sector's GDP variables when the quantity of the i^{th} demand is derived by following an identity equation:

$$(3.71) \quad Q_i = \frac{TC \times w_i}{P_i}$$

Secondly, based on Harvey and Pablo (1991), the quantity of the i^{th} demand can be computed as follows:

STEP 1. Estimate the cost share of the i^{th} input by the inter-fuel substitution model

STEP 2. Compute the aggregate energy price index (P^e) with the equation below

$$(3.72) \quad P^e = \sum_i s_i P_i$$

where s_i is the share in total quantity and P_i is the price of final energy *i*.

STEP 3. Estimate the total demand for energy (TQ) using a long-run equilibrium model

STEP 4. Compute the total cost of energy using the equation below

(3.73) $TC = P^e \times TQ$

STEP 5. Finally, equation (3.71) gives the individual input demand of that energy source.

The first method, the direct estimation of the total cost has limitations; the aggregate energy price index may have negative or positive effects on nominal expenditure on energy. Thus, the direct impact of the carbon tax on total demand for energy cannot be observed. Therefore, we employ the second method provided by Harvey and Pablo (1991).

When it comes to the estimation of sectors' total main energy demand (TQ), the equations for each sector's total main energy demand adopt the following form:

(3.74) $\log(TQ_{j,t}) = \beta_0 + \beta_1 \times \log(TQ_{j,t-1}) + \beta_2 \times \log(P^e_{j,t}) + \beta_3 \times \log(\Omega_t) + \beta_4 \times \log(WT_t) + \varepsilon_t$

where subscript *j* denotes the sector: industry, commerce and public, and households. the aggregate energy price index computed by equation, the weather variable (WT) summing up Heating Degree Days (*HDD*) and Cooling Degree Days (*CDD*) representing temperature's effect on energy demand, and GDP (Ω) indicating economic activity are adopted as explanatory variables for industry and commerce and public's energy demand. In the case of households' energy demand, disposable income (*YD*) is used rather than GDP. Finally, ε_t is the error term assumed to be normally distributed.

In the first step, calculated *F*-statistics presented in Table 3.29 in each sector are higher than the upper bound critical value. Thus, there is a long-run equilibrium relationship between variables. Once, we confirmed that a long-run equilibrium exists, equation 3.66 is estimated by the OLS method. Estimation results for these sectors' energy demand with diagnostic tests are summarised in Table 3.29.

Table 3.29. Estimation of the total energy demand function

Dependent Variable : $log(TQ_{j,t})$ Sample : 1991 ~ 2011

Regressor	Industry	Commerce & Public	Households
Constant	-8.580*** (0.000)	-12.080*** (0.000)	-1.928 (0.858)
$log(TQ_{j,t-1})$	0.587 (0.556)	0.428*** (0.000)	0.241* (0.075)
$log(P^e_{j,t})$	-0.195*** (0.000)	-0.256*** (0.006)	-0.658*** (0.001)
$log(Y_t)$	0.429* (0.097)	0.730*** (0.000)	N.A.
$log(YD_t)$	N.A.	N.A.	0.587* (0.082)
$log(WT_t)$	0.447*** (0.000)	N.A.	0.438** (0.039)
Dummy periods (year)	2004	1991,1997,1999	2004,2005,2008
Bounds test	14.389***	4.657*	4.383*
Diagnostic tests			
$\bar{R}^2$	0.982	0.989	0.930
$D.W.$	2.578	2.724	2.004
F_{Auto}	2.578 (0.131)	2.821 (0.117)	0.021 (0.887)
χ^2_{Norm}	1.103 (0.576)	2.713 (0.258)	3.715 (0.156)
F_{Reset}	0.628 (0.544)	1.754 (0.103)	0.903 (0.388)
F_{Hetero}	0.251 (0.933)	0.893 (0.526)	0.650 (0.709)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.
AR(1) Cochrane-Orcutt procedure is conducted to adjust the households model for serial correlation in the error term.

All of the coefficients have the expected sign and are statistically significant; the demand for energy is positively related to economic activity and weather variables, and on the other hand, negatively related to its own price. However, the weather variable in commerce and public sector neither had the right sign and nor was statistically significant, so that we rule out the weather variable in the commerce and public sector's equations. The households' price elasticity of energy has the highest value: -0.496 in short and -1.332 long-run, which follows commerce and public; -0.205 and -0.802, and industry; -0.196 and -0.474. This gives implications for energy policy related price regulations; energy price regulations or taxes could offer a potentially cost-effective means for demand control or reducing emissions in the households and commerce and public sector. In addition, it is worthy to mention that the GDP elasticity of industry is higher than the commerce and public's one, which implies that shrinkage of economic activity such as consumption and exports decreases industry's energy demands more than the other sectors', since energy is directly used to produce goods as a input factor in the industry sector.

4) Transportation

The transport sector is the second largest sector accounting for 19.1% of Korea's final energy demand in 2010. In view of the importance of the sector, modelling individual energy products is desirable in order to evaluate emissions accurately. Energy demands in the transportation sector are very closely related to the number of motor vehicles, trains, ships, airplanes, and other conveyances. These transport assets generally use one particular fuel for their lifespan. In other words, the demand for a specific energy product is mainly determined by the number and usage of the type of conveyance that run on that product. Thus, we set up a dependent variable as demand for a specific fuel relative to the scale of conveyances (the number of vehicles and trains or tonnes of ships), and estimate this dependent variable using economic activity and the fuel's price. We treat the conveyance variable exogenously. It is important to note that modelling endogenous choice of the conveyance along with efficiency would be better, since the type of conveyance is an important factor determining fuel demands and emissions in long run. However, modelling this as an endogenous choice remains a question for further research, given the relatively short simulation period available to date.

As for the type of conveyance (*CV*), this is broadly classified into three types; general, freight, and commercial vehicles. Each sector's energy demand is assumed to be a function of the quantity of the main type of conveyance, for example, gasoline, diesel, and LPG are used in general, freight, and commercial vehicles respectively, thus the total number of corresponding vehicles are adopted as explanatory variables. In the case of heavy-oil and electricity in the transportation sector, the total tons of ships and trains are employed as a determinant. The conveyance's energy demand function is follows:

$$\text{(3.75)} \quad \log\left(\frac{Q_{j,t}}{CV_{i,t}}\right)= \beta_0+\beta_1\times\log\left(\frac{Q_{j,t-1}}{CV_{i,t-1}}\right)+\beta_2\times\log(P_{j,t}^{pet})+\beta_3\times\log(Y_t)+ \varepsilon_t$$

Table 3.30. Estimation of the transport energy demand function

Dependent Variable : $log(\frac{Q_{j,t}}{CV_{i,t}})$

Regressor	Gasoline (Sample: 1990~2011)	Diesel (Sample: 1990~2011)	Heavy-oil (Sample: 1990~2011)	Butane (Sample: 1990~2011)	Electricity (Sample: 1990~2011)
Constant	-5.914* (0.072)	-12.688** (0.013)	1.646*** (0.000)	3.633*** (0.000)	2.513* (0.097)
$log(\frac{Q_{j,t-1}}{CV_{i,t-1}})$	0.817*** (0.000)	0.836*** (0.000)	0.943*** (0.000)	0.609*** (0.000)	0.916*** (0.000)
$log(P_{j,t}^{pet})$	-0.341*** (0.000)	-0.189*** (0.006)	-0.141*** (0.000)	-0.190*** (0.001)	-0.098* (0.064)
$log(Y_t)$	0.312*** (0.008)	0.452*** (0.010)	N.A.	N.A.	N.A.
Dummy periods (year)	1999, 2000	1998	2006, 2007	1998-99, 2002, 2010, 2011	
Bounds test	5.799**	9.092***	8.810***	10.891***	5.446**
Diagnostic tests					
$\bar{R}^2$	0.999	0.978	0.977	0.990	0.966
$D.W.$	1.811	1.717	2.177	2.046	2.323
F_{Auto}	4.470 (0.876)	0.374 (0.551)	0.228 (0.640)	0.003 (0.954)	0.002 (0.361)
χ^2_{Norm}	3.416 (0.119)	3.742 (0.154)	0.090 (0.956)	0.954 (0.621)	4.448 (0.590)
F_{Reset}	4.092 (0.857)	0.144 (0.888)	0.141 (0.712)	1.727 (0.145)	2.918 (0.159)
F_{Hetero}	0.323 (0.922)	0.205 (0.932)	1.052 (0.412)	1.219 (0.408)	0.923 (0.511)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.

Table 3.30 provides a comparison of the estimation results of energy products in transportation. Firstly, the calculated F statistics confirm that there exists a long run equilibrium relationship between the variables. We drop the GDP variable indicating economic activity in the demand for heavy-oil and butane, since they are neither significant, nor have the expected sign. Overall, gasoline has the most price elastic demand among petroleum products. These results are robust to the diagnostic tests.

5) The other final energy demands

In the case of the other energy sources representing a relatively small share, we aggregate all sectors' energy demand such as non-energy petroleum product in the industry, commerce and public, and household sectors, coking coal in the industry sector, anthracite coal in the industry and commerce and public sectors, Jet Fuel JA-1 (JA) in the transportation and commerce and public sectors, heat energy in the commerce and public and household sectors, the transportation sector's demand for electricity and the other petroleum products and then estimate using a long-run equilibrium model directly in which energy prices, weather (HDD and CDD), and GDP variables are related to the demand for energy. Finally, we allocate the estimated energy demands into each sector using the share ratio of sectors which is treated as exogenous. The equation for the other energy demand is given by:

$$(3.76) \qquad \log(Q_{j,t}) = \beta_0 + \beta_1 \times \log(Q_{j,t-1}) + \beta_2 \times \log(P^e_{j,t}) + \beta_3 \times \log(Y_{\mathrm{t}}) + \beta_4 \times \log(WT_t) + \varepsilon_t$$

Note that renewable energy, city-gas in transportation, and AVI-G (petroleum) are modelled exogenously. Renewable energy is being developed as an alternative to fossil fuels from the government policy. Modelling the supply of renewable energy endogenously often faces difficulties due to the intermittency of renewable energy. As for city-gas in transportation, a CNG bus using city-gas has been introduced only from 2001 so that there is not enough time-series data for estimation. AVI-G comprises only small part of energy expenditure. For those reasons, they are treated as exogenous. Table 3.31 summarises the other energy demands in corresponding sectors.

Table 3.31. The other final energy demands in sectors

Final energy product (*i*)	Sector (*s*)	Variable
Non-energy petroleum	Industry, Commerce and Public, Household	Endogenous
Coking coal	Industry	Endogenous
Anthracite coal	Industry, Commerce and Public	Endogenous
JA	Transportation, Commerce and Public	Endogenous
Heat energy	Commerce and Public, Household	Endogenous
Renewable energy	Industry, Commerce and Public, Household	Exogenous
City-gas	Transportation	Exogenous
AVI-G	Transportation	Exogenous

Table 3.32 provides a comparison of estimation results for the other demand energy. First of all, we established that a long-run cointegration relationship exists amongst the variables in each energy product. In general, demand for the other energy products does not react to weather conditions and price.

The price elasticity was not statistically significant for coking coal, JA, or anthracite coal[46]. Non-energy petroleum's price elasticity is relatively very low, -0.033 in the short run and -0.122 in the long run. The weather variable is statistically insignificant in each equation. Thus, we removed the weather variable.

[46] Note that the result of the price elasticity of anthracite coal demand should be interpreted with caution, since the price of anthracite coal has been under price control from the government.

Table 3.32. Estimation of the other energy demand function

(a) Regression model

Dependent Variable : $log(Q_{j,t})$

Regressor	N.E. Petroleum (Sample: 1982~2011)	Coking Coal (Sample: 1991~2011)	Anthracite Coal (Sample: 1979~2011)	JA (Sample: 1991~2011)	HEAT (Sample: 1991~2011)
Constant	-2.957 (0.104)	-3.761** (0.027)	-9.776*** (0.001)	-13.913*** (0.003)	-15.063*** (0.000)
$log(Q_{j,t-1})$	0.723*** (0.000)	-0.156 (0.480)	0.846*** (0.000)	0.354* (0.073)	0.462*** (0.000)
$log(P^e_{j,t})$	-0.033** (0.028)	N.A.	N.A.	-0.058 (0.263)	-0.093 (0.159)
$log(Y_t)$	0.223*** (0.003)	0.663*** (0.000)	0.354*** (0.001)	0.698*** (0.001)	0.617*** (0.000)
$log(HDD_t)$	N.A.	N.A.	N.A.	N.A.	0.339*** (0.000)
Dummy periods (year)	1981-90, 1992,1997	2008, 2010	1990, 1997		1991, 1992, 1994
Bounds test	5.029*	6.224**	5.321**	7.121***	4.705*
Diagnostic tests					
$\bar{R}^2$	0.999	0.962	0.977	0.961	0.999
$D.W.$	2.239	2.129	1.976	1.891	1.811
F_{Auto}	0.560 (0.229)	0.318 (0.581)	0.001 (0.975)	0.037 (0.834)	0.025 (0.876)
χ^2_{Norm}	4.574 (0.948)	2.407 (0.300)	0.768 (0.681)	0.622 (0.747)	0.265 (0.876)
F_{Reset}	0.000 (0.783)	0.823 (0.379)	0.067 (0.797)	0.007 (0.908)	0.184 (0.857)
F_{Hetero}	6.914 (0.179)	1.914 (0.149)	1.618 (0.198)	0.243 (0.751)	0.338 (0.922)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.

3.4.2.7.(b) Energy transformation

It is necessary to derive input energy sources in an energy transformation sector along with final energy demand in order to estimate total primary energy. Input energy sources in the transformation sector means energy materials for producing final energy products such as electricity, city-gas, and heat energy. According to the current statistical system for energy supply in Korea, the energy transformation sector is classified into three sectors; electric generation, gas manufacture, and district heating. Note that the electricity power generation sector is modelled explicitly by the electricity module. Therefore, this section covers the input energy sources of the city-gas and heat sectors. We take account of each energy conversion process of final energy products meaning that city-gas and heat energy are modelled individually. Using the method proposed by Park (2004), final energy demand estimated from the econometric method is treated as an exogenous variable, and we then derive input energy sources in the transformation sector which is needed to meet the final energy demand. In the conversion process, the total supply of input sources are derived reflecting own use, loss, and conversion efficiency factors.

1) City-gas

First of all, it is necessary to estimate total city-gas demand in order to derive the quantity of input energy for city-gas. Total city-gas demand is calculated by summing up all sectors' demand for city-gas derived from the econometric method in the final energy demand section and the co-generation sector's input demand for producing heat. Then, considering an own use and loss factor, the total quantity of city-gas supply is calculated given the total city-gas demand. After the total supply of city-gas is determined, the total quantity of energy sources is derived using a conversion efficiency factor. Finally, we allocate the total quantity of energy input into each input fuel such as LPG and LNG using the share ratio of energy. Figure 3.3 represents the process of producing city-gas.

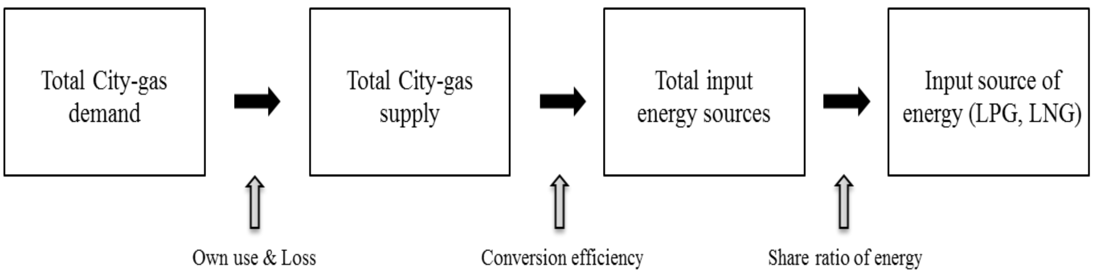

Figure 3.3. The process of city-gas production

Source: Park (2004)

2) Heat

In the same manner as for city-gas, the quantity of input energy for heat energy is determined through estimating heat energy. Total heat energy demand is determined by the econometric method. Taking into consideration an own use and loss factor, total heat supply is calculated given the total heat energy demand. The total heat supply comes from two sources; power generation (waste heat recovery power generation from combined heat and power, CHP) and district heating. The waste heat recovery power generation from CHP should be ruled out in order to calculate the input energy for heat energy, since input energy for the generation is collected in generation sectors, which yields the problem of double counting. Using a share ratio of power and heating, the supply of district heating is calculated, and then the total quantity of input energy sources is computed from dividing supply of district heating by a conversion efficiency factor. Finally, the inputs of petroleum, LNG, and city-gas are derived using share ratios of input energy.

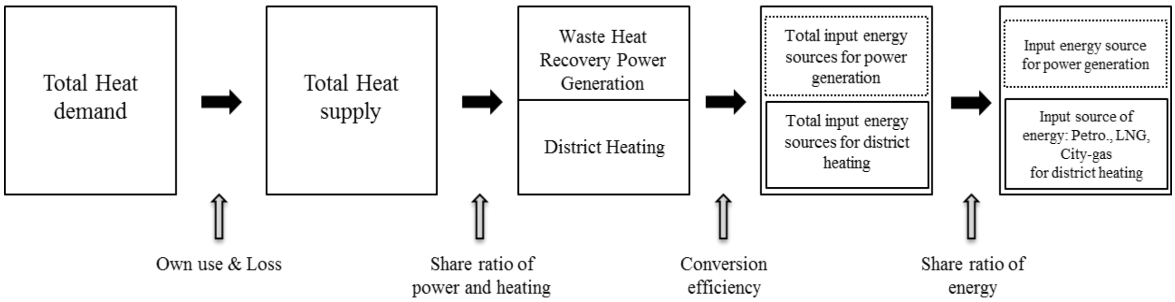

Figure 3.4. The process of heat energy production

Source: Park (2004)

3.4.2.7.(c) Energy prices[47]

The purpose of modelling energy prices is to utilise them as determinant variables for estimating energy demands. Energy prices are classified by sources and sectors corresponding to energy demands. Energy supply in Korea is mostly dependent on imported energy sources such as crude oil, bituminous coal, and LNG from foreign countries, which means prices of international primary energy and the exchange rate have a major impact on the prices of final energy. In particular, the price of crude oil plays a key role in determining the other prices of imported primary energy, since most contracts are linked with the oil price in international energy markets. The pricing mechanism of individual energy types are modelled as follows:

1) Coal

All bituminous coals in Korea are imported from foreign countries. Therefore, the price of imported bituminous coal is modelled as a function of the international coal price index (FP_t^{caol}) and the exchange rate, which is as follows:

(3.77) $\log(P_{j,t}^{coal}) = \beta_0 + \beta_1 \times \log(P_{j,t-1}^{coal}) + \beta_2 \times \log(FP_t^{coal}) + \beta_3 \times \log(ER_{\mathrm{t}}) + \varepsilon_t$

where the subscript, *j* indicates a sector that includes industry and power generation denoted by *i* and *pg* respectively. Note that the prices of domestic anthracite coal and briquette are set exogenously, since the products have been under price control of the government; the prices have been maintained at a constant level for a long time.

[47] Time-series data for the fuel prices of power generation is available only from 2001. Consequently, fuel prices for power generation and electricity prices estimation could be biased due to the short horizon of data. However, the estimation results are reasonable compared to the other energy sources and pass all diagnostic tests. So, we adhere to these equations for the simulation analysis.

Table 3.33. Estimation of coal price function

Dependent Variable : $log(P_{j,t}^{bcoal})$

Regressor	Industry (Sample: 1989~2011)	Power Generation (Sample: 2001~2011)
Constant	2.212*** (0.002)	-0.704 (0.828)
$log(P_{j,t-1}^{bcoal})$	0.039** (0.333)	0.215 (0.322)
$log(FP_t^{bcoal})$	0.784*** (0.000)	0.603*** (0.005)
$log(ER_t)$	0.811*** (0.000)	1.031*** (0.057)
Dummy periods (year)	2005, 2006	
Bounds test	13.741***	8.717***
Diagnostic tests		
$\bar{R}^2$	0.996	0.944
$D.W.$	1.518	2.922
F_{Auto}	1.327 (0.269)	0.599 (0.224)
χ^2_{Norm}	0.752 (0.687)	1.920 (0.674)
F_{Reset}	1.405 (0.182)	0.316 (0.783)
F_{Hetero}	0.994 (0.452)	0.727 (0.236)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.
AR(1) Cochrane-Orcutt procedure is conducted to adjust the industry's coal model for serial correlation in the error term.

The estimations results for bituminous coals for industry and power generation are provided in Table 3.33. The variables in both equations have a long-run equilibrium relationship according to computed F-statistics. The adjustment coefficients are relatively low, and power generation's coefficient is statistically insignificant, which implies that importers immediately pass through the purchase cost and exchange rate into final prices. The elasticity of the exchange rate on imported coal prices is larger than the elasticity of the production cost in power generation.

2) Petroleum

As the model uses aggregated petroleum for energy use by a sector, the prices of energy-petroleum are classified into industry (*i*), commerce and public (*cp*), households (*h*), and transportation (*tr*). In addition, heavy oil for power generation, JA, LPG for transport and aggregated petroleum for non-energy use are modelled explicitly. These refined petroleum products are modelled as a function of the international crude oil price and the exchange rate, which is as follows:

$$\text{(3.78)} \quad \log(P_{j,t}^{petro}) = \beta_0 + \beta_1 \times \log(P_{j,t-1}^{petro}) + \beta_2 \times \log(FP_t^{oil}) + \beta_3 \times \log(ER_{\mathrm{t}}) + \varepsilon_t$$

Table 3.34 summarises the estimation results of aggregated petroleum prices for these sectors. We found that there is a long-run cointegration relationship between the petroleum product's price and explanatory variables in each equation. All of coefficients on explanatory variables have the expected signs; the final prices are positively related to cost factors. The coefficient of the lagged dependent variable values are in a range approximately from 0.005 to 0.2, indicating that a relatively instant adjustment process takes place in each period.

The estimation results for individual refined petroleum products are provided in Table 3.35. Each equation has a long-run equilibrium relationship between a petroleum product price and cost factors; imported unit price of crude oil and exchange rate. The results of petroleum prices show common properties in the adjustment coefficient; approximately 30~50% of the adjustment between the short-run and long-run level takes place in each year. It is interesting to mention that the elasticity of the exchange rate in the short-run has a wide range of estimated values; 0.332~1.282. It is reasonable, since large amount of domestic refined petroleum products are produced, and even exported to foreign countries[48]. But industries depend on several products such as NAPHTHA (Non-energy petroleum), LPG, and heavy-oil, which have relatively high elasticities of the exchange rate in their equations.

Table 3.34. Estimation of aggregated petroleum price function

Dependent Variable : $log(P_{j,t}^{petro})$ Sample : 1991 ~ 2011

Regressor	Industry	Commerce & Public	Households
Constant	10.650 (0.495)	6.591** (0.035)	3.004* (0.073)
$log(P_{j,t-1}^{petro})$	-0.215 (0.236)	-0.005 (0.976)	-0.041 (0.757)
$log(FP_t^{oil})$	0.458*** (0.003)	0.523*** (0.000)	0.644*** (0.000)
$log(ER_t)$	1.226*** (0.000)	0.785*** (0.000)	1.257*** (0.000)
Dummy periods (year)		1998	
Bounds test	4.587*	5.396**	4.860*
Diagnostic tests			
$\bar{R}^2$	0.992	0.996	0.998
$D.W.$	1.464	2.018	1.746
F_{Auto}	0.195 (0.668)	0.331 (0.575)	0.043 (0.839)
χ^2_{Norm}	0.234 (0.889)	0.644 (0.725)	1.407 (0.495)
F_{Reset}	1.090 (0.299)	1.035 (0.319)	0.145 (0.887)
F_{Hetero}	1.391 (0.289)	1.508 (0.250)	0.254 (0.857)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis. AR(1) Cochrane-Orcutt procedure is conducted to adjust all models for serial correlation in the error term.

Except for heavy oil used for power generation, one or two dummies are imposed on each equation to capture outliers in Asian financial crisis of 1998 and global financial crisis of 2007~08. A few other dummies are imposed for unknown incidents and better simulation performance.

[48] It was recorded at total 49,020 nominal U.S. dollar export, total 27,050 nominal U.S. dollar import in 2011

Table 3.35. Estimation of petroleum product price function

Dependent Variable : $log(P^i_{j,t})$

Regressor	Gasoline (Sample: 1983~2011)	Diesel (Sample: 1983~2011)	Heavy-oil for P.G. (Sample: 2001~2011)	Heavy-oil (Sample: 1982~2011)	LPG (Sample: 1982~2011)	JA (Sample: 1982~2011)	Non Energy (Sample: 1982~2011)
Constant	0.289 (0.000)	-1.400 (0.356)	-1.303 (0.441)	-2.079 (0.324)	-0.606*** (0.001)	-1.980*** (0.004)	-6.774*** (0.000)
$log(P^i_{j,t-1})$	-0.593*** (0.000)	-0.539*** (0.000)	0.149* (0.269)	0.594*** (0.000)	0.699*** (0.000)	0.576*** (0.000)	0.553*** (0.000)
$log(FP^{oil}_t)$	0.191*** (0.001)	0.353*** (0.000)	0.843*** (0.000)	0.384*** (0.000)	0.229*** (0.000)	0.444*** (0.000)	0.428*** (0.000)
$log(ER_t)$	0.693*** (0.000)	0.925*** (0.000)	1.282*** (0.005)	0.854*** (0.000)	0.569** (0.005)	0.332*** (0.002)	1.054*** (0.000)
Dummy periods (year)	1998, 2009	2009		1995, 2007	2009, 2011	2009	1985
Bounds test	8.264	5.428	12.410	5.947	19.486	5.723	9.719
Diagnostic tests							
$\bar{R}^2$	0.989	0.972	0.988	0.990	0.974	0.976	0.991
$D.W.$	1.279	2.083	2.314	2.096	2.114	2.591	1.570
F_{Auto}	2.845 (0.107)	0.308 (0.585)	0.266 (0.625)	0.622 (0.439)	0.020 (0.892)	0.260 (0.380)	1.044 (0.317)
χ^2_{Norm}	0578 (0.749)	2.554 (0.279)	0.962 (0.618)	3.523 (0.171)	0.017 (0.992)	0.202 (0.729)	3.146 (0.207)
F_{Reset}	1.295 (0.209)	1.543 (0.137)	1.413 (0.208)	1.623 (0.118)	1.031 (0.350)	0.957 (0.580)	0.291 (0.774)
F_{Hetero}	0.620 (0.686)	0.607 (0.662)	0.134 (0.937)	1.140 (0.367)	1.657 (0.277)	1.395 (0.420)	0.317 (0.864)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.

AR(1) Cochrane-Orcutt procedure is conducted to adjust gasoline and diesel models for serial correlation in the error term.

3) LNG

As explained earlier, the price of international crude oil has an impact on the price of LNG in Korea. Therefore, the prices of LNG for power generation and city-gas are modelled as a function of the international oil price index and exchange rate.

(3.79) $\log(P_{j,t}^{LNG}) = \beta_0 + \beta_1 \times \log(P_{j,t-1}^{LNG}) + \beta_2 \times \log(FP_t^{oil}) + \beta_3 \times \log(ER_{\mathrm{t}}) + \varepsilon_t$

Table 3.36 provides the estimation results of equation (3.77) for power generation and city-gas. As expected, the price of LNG is positively related to the price of crude oil and the exchange rate; both coefficients are statistically significant. The coefficients of the lagged dependent variables are statistically insignificant, meaning that the adjustment process instantaneously occurs in each period.

Table 3.36. Estimation of LNG price function

Dependent Variable : $log(P_{j,t}^{LNG})$

Regressor	Industry (Sample: 1989~2011)	Power Generation (Sample: 2001~2011)
Constant	3.840*** (0.005)	2.548 (0.108)
$log(P_{j,t-1}^{LNG})$	-0.482** (0.016)	0.111 (0.449)
$log(FP_t^{oil})$	0.238*** (0.002)	0.610*** (0.001)
$log(ER_t)$	0.287 (0.175)	0.939** (0.015)
Dummy periods (year)	1998, 2001	
Bounds test	21.527***	6.050**
Diagnostic tests		
$\bar{R}^2$	0.960	0.981
$D.W.$	2.248	1.866
F_{Auto}	2.141 (0.163)	0.008 (0.930)
χ^2_{Norm}	2.017 (0.365)	1.139 (0.566)
F_{Reset}	0.324 (0.750)	0.875 (0.422)
F_{Hetero}	0.832 (0.545)	0.775 (0.549)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.

4) City-gas

LNG is the main source of city-gas. Thus, the prices of city-gas for industry, commerce and public, and households can be modelled as a function of the LNG price as following:

(3.80) $\log(P_{j,t}^{cgas}) = \beta_0 + \beta_1 \times \log(P_{j,t-1}^{cgas}) + \beta_2 \times \log(P_t^{LNG}) + \varepsilon_t$

As seen in equation (3.78), the price of LNG is a key determinant of the price of city-gas. The estimation results of equation (3.78) are provided in Table 3.37. The coefficient of the lagged dependent variable and the price elasticity of LNG show different aspects depending on the sector; the adjustment process takes about one year to be completed for households, but occurs over about two years in the commerce and public and industry sectors.

Table 3.37. Estimation of city-gas price function

Dependent Variable : $log(P_{j,t}^{cgas})$ Sample : 1991 ~ 2011

Regressor	Industry	Commerce & Public	Households
Constant	-3.107*** (0.001)	0.116 (0.711)	1.110*** (0.000)
$log(P_{j,t-1}^{cgas})$	0.573*** (0.000)	0.508*** (0.000)	0.131*** (0.000)
$log(P_{j,t}^{LNG})$	0.660*** (0.000)	0.490*** (0.000)	0.771*** (0.000)
Dummy periods (year)	1990, 1999, 2002	1998, 1999, 2002	1989, 2000-11
Bounds test	7.823***	5.350*	5.853**
Diagnostic tests			
$\bar{R}^2$	0.994	0.992	0.999
$D.W.$	1.505	1.553	2.431
F_{Auto}	1.376 (0.260)	0.917 (0.352)	0.958 (0.341)
χ^2_{Norm}	1.980 (0.372)	0.245 (0.885)	0.128 (0.938)
F_{Reset}	0.762 (0.459)	1.138 (0.892)	0.906 (0.378)
F_{Hetero}	0.153 (0.976)	1.737 (0.180)	1.573 (0.224)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.
AR(1) Cochrane-Orcutt procedure is conducted to adjust the industry model for serial correlation in the error term.

5) Electricity

The prices of electricity for industry, commerce and public, and households can be a function of the total cost in power generation sector, which is computed in the electricity module. In other words, the generation cost is passed on to customers.

(3.81) $\log(P_{j,t}^{elec}) = \beta_0 + \beta_1 \times \log(P_{j,t-1}^{elec}) + \beta_2 \times \log(TC_t^{elec}) + \varepsilon_t$

where $P_{j,t}^{elec}$ is the price of electricity for sector j and TC^{elec} is the wholesale price index computed in the power generation module endogenously.

Table 3.38 summarises the estimation results for each sector. All coefficients are statistically significant and have the expected magnitude and sign; the relatively slow adjustment process and positive coefficient of the total cost variable represent the current electricity pricing under government control.

Table 3.38. Estimation of electricity price function

Dependent Variable : $\log(P_{j,t}^{elec})$ Sample : 2001 ~ 2011

Regressor	Industry	Commerce & Public	Households
Constant	5.524^{**} (0.028)	4.203 (0.153)	5.106^{**} (0.012)
$\log(P_{j,t-1}^{elec})$	0.418^{**} (0.042)	0.638^{**} (0.012)	0.490^{***} (0.007)
$\log(TC_t^{elec})$	0.078^{***} (0.009)	0.028^{**} (0.042)	0.067^{***} (0.002)
Dummy periods (year)	2009-11	2001, 2009	2002, 2009
Bounds test	23.948^{***}	90.071^{***}	897.44^{***}
Diagnostic tests			
$\bar{R}^2$	0.985	0.909	0.980
$D.W.$	2.554	2.644	2.365
F_{Auto}	0.812 (0.409)	1.742 (0.257)	0.304 (0.605)
χ^2_{Norm}	0.924 (0.630)	0.284 (0.867)	0.253 (0.881)
F_{Reset}	1.410 (0.218)	0.804 (0.467)	0.626 (0.559)
F_{Hetero}	0.573 (0.693)	2.503 (0.151)	0.641 (0.653)

Note: ***, **, and * indicate significance at 1 %, 5 %, and 10 % respectively. The p-values are given in parenthesis.
AR(1) Cochrane-Orcutt procedure is conducted to adjust the *cp* model for serial correlation in the error term.

3.4.2.7.(d) CO_2 emissions

This model uses identities to measure total carbon dioxide (CO_2) emissions from energy use which represent the highest share of GHG emissions sources; approximately 85.3% in 2010. To focus on the energy use related issues, we estimate CO_2 emissions from energy use, but the other GHG sources are not considered in this model yet. To measure the CO_2 emissions from energy use, this study adopts the carbon emission factor for each fossil fuel proposed by the Intergovernmental Panel on Climate Change (IPCC) guidelines (1996, 2006). The identity for measuring CO_2 emissions by specific energy consumption is as follows:

(3.82) $CO_2^i = \gamma_i \times \beta_i \times Q_i$

where β_i is a carbon emission factor of energy *i* (tC/TOE) which follows IPCC's coefficients which are provided in appendix[49]. γ_i is a conversion factor from carbon to carbon dioxide (tCO2/tC).

3.4.2.7.(e) Carbon pricing

To perform a carbon tax policy simulation, carbon pricing is modelled by increasing the level of energy prices under the assumption that firms are assumed to completely pass through the cost of the carbon tax to consumers. The introduction of carbon taxation can be written as follows:

(3.83) $PC_i^e = P_i^e + (CTAX_i \times \beta_i)$

[49] According to IPCC (1996), carbon emissions are calculated by the following equation:
$C = \alpha_i \times \beta_i \times Q_i - \delta_i$
where α_i denotes a fraction of carbon oxidized factor and δ_i a fraction of carbon sequestered factor.
Note that we assume perfect combustion (i.e. $\alpha_i = 1$) as the faction of incomplete oxidization is relatively small, which means excluding the fraction of carbon sequestered factor as in IPCC (2006).

where PC_i^e is the final price of energy i (won/TOE), P_i^e is the original price of energy *i* which reflects the pre-existing taxes (won/TOE), i.e. the after tax price and $CTAX_i \times \beta_i$ is the rate of carbon tax (won/TOE) in which $CTAX_i$ is carbon tax (won/TC).

3.4.3. Electricity module

The electricity module adopts the MCP electricity model built in Chapter Two. The model covers all technology's power output, including nuclear, bituminous and anthracite coal, heavy-oil, gas-turbine, and CCGT power plants. Hydro, pumped storage and renewable energy are treated exogenously, as they account for a minor share of generation mix (see Figure 2.27 in Chapter Two). The power generation sector is much better captured in the MCP model than econometric methods in that the MCP model incorporates each technology's engineering properties with capacity constraints and output decisions for multiple periods (the electricity module sets 14 sub-periods in each year in view of the level of electricity demand). Aggregated power output estimated by the econometric method using annual data is not adequate to compute the amount of input energy needed for power generation due to the complexity of power generation, thereby giving misleading estimates of total generation costs and emissions in the power generation sector. For these reasons, this study adopts the MCP model for the electricity market.

The electricity demand adjusted by a factor for transmission losses and prices of input energy sources which were estimated in the macro-econometric module are fed into the MCP electricity module. Then, the electricity module calculates the total electricity output, cost of power generation, and input energy demands for nuclear, coal, heavy oil, and LNG using exogenous capacity variables in this study.

As explained in chapter two, currently the electricity market has been operated under the Cost Based Pool (CBP) system since 2001 in Korea. Under the CBP system, the marginal price is determined by the merit order system in which each generation unit is ranked according to bids based on its variable cost. The generation unit with the lowest variable cost among all the units is firstly granted a purchase order for electricity. The generation unit with the highest variable cost which is lastly chosen in the merit order to meet electricity demand in each period determines the marginal price. Such a system can be modelled suitably by perfect competition which assumes that all firms are price takers and no one influences the price of the product. Therefore, we adopt the perfect competition model rather than the Cournot model used in Chapter Two, because the Cournot model yields very high equilibrium prices by dominant firms' market power.

This chapter replaces the objective function equation (2.2) with the following new objective function for a carbon tax policy to be simulated in next chapter, which is given by:

$$(3.84) \quad Max \quad \pi = \sum_{t}\sum_{l} d_{t,l} r_t p_{t,l} q_{i,tec,t} - \sum_{tec}\sum_{t}\sum_{l} d_{t,l} r_t v_{tec,t} (c_{i,tec} q_{i,tec,t,l} + c'_{i,tec} q^2_{i,tec,t,l}) - \sum_{tec}\sum_{t}\sum_{l} d_{t,l} r_t C^{tax}_t \zeta_{tec} q_{i,tec,t,l}$$

where C^{tax}_t defines a carbon tax rate (won/tCO_2). As a consequence, the corresponding Karush-Kuhn-Tucker condition (2.13) should be substituted by the following equation based on the perfectly competitive equilibrium;

$$(3.85) \quad \begin{aligned} &0 \le q_{i,tec,t,l} \perp d_{t,l} r_t (a_{t,l} - b_{t,l} (\sum_{j,j \ne i} q_{j,t,l} + 2 q_{i,t,l})) - d_{t,l} r_t v_{tec,t} (c_{i,tec} + 2 c'_{i,tec} q_{i,tec,t,l}) \\ &- d_{t,l} r_t p^{tax}_t \zeta_{tec} \le 0 \qquad \forall i, tec, t, l \end{aligned}$$

3.4.4. Integration module

The model adopts the soft-link method which provides the best solution among the other integration methods for linking the electricity engineering model and the top-down model in terms of capturing multiple periods' output and consistency in agent's behavior. The soft-link method starts with a top-down model, and then the results will be fed into the bottom-up model. The iteration process stops when a convergence criterion is fulfilled. Convergence between the two models is defined in terms of the electricity demand. The process is as follows:

Step 1: Run the macro-economic module and provide information as below:

- Electricity demand (MWh), fuel prices (coal, oil, and LNG), which will be fed into the MCP model in the electricity market module. Aggregated electricity demand (MWh) from the macro-economic module will be transferred into the load duration curve.

Step 2: Run the MCP model in the electricity market module and generate a data set as below:

- The electricity price and each technology plant's fuel demand

Step 3: Re-run the macro-economic module given the data set from the electricity market module

- The information will be re-entered into the electricity market module.

Steps 2 and 3 are repeated until a convergence criterion of the electricity demand is reached. The model set the convergence criterion at a 3 percent change between the values generated by the two models in the last year. The value of convergence criteria was chosen as a compromise between precision and the amount of time needed to perform each model run; it should be noted that the convergence was much closer for most years within each run. Many published studies do not disclose their convergence criteria and so no community standard exists.

3.5. SIMULATION AND MODEL EVALUATION

This section performs an ex post (historical) simulation in order to evaluate the model's predictive performance. The simulation methodology is well documented in Pindyck and Rubinfeld (1997). The *ex-post* simulation starts in year T_1 (see Figure 3.5) and goes forward until year T_2. Historical values in year T_1 are provided as initial conditions for the endogenous variables and historical series beginning in T_1 and ending T_2 are used for the exogenous variables. The endogenous variables are not reinitialized; the simulation solution determines the values of the endogenous variables after year T_1. A comparison between the original data series and the simulated series of endogenous variables provides a test of the validity of the model, which is a main purpose of this section. The *ex-post* simulation also can be used for policy analysis by letting exogenous policy follow different time paths in order to examine what might have happened as a result of alternative policies, which will be implemented in chapter 4.

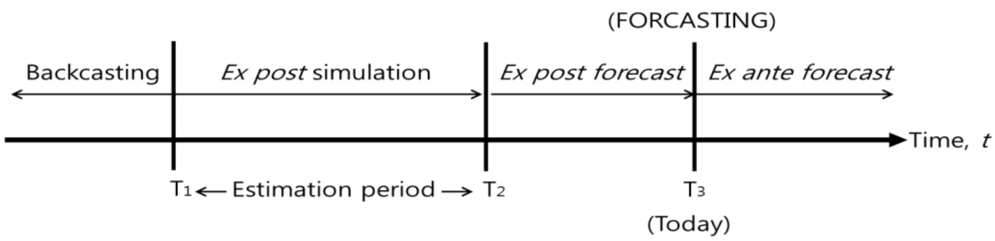

Figure 3.5. Simulation time horizons (source: Pindyck and Rubinfeld, 1997)

Forecasting is a type of simulation in which endogenous variables are generated forward in time beyond the estimation period, which requires a set of assumptions about the exogenous variables. An *ex-post* forecast beginning at the end of the estimation period is performed to test the forecasting accuracy of a model by comparing the results with available data. An *ex-ante* forecast begins the simulation in the current year and extends it into the future, which can be used for predictive purposes and for sensitivity and policy analysis.

The ex-post simulation for evaluation of the model covers the time period from 2005 to 2011. To measure the predictive accuracy of the model, we adopt the Mean Absolute Percentage Error (MAPE) method among the quantitative measures which examine how close simulated variables follow their corresponding actual values. The MAPE is defined as follows:

$$(3.86) \quad MAPE = \frac{100}{T}\sum_{t=1}^{T}\left|\frac{Y_{i,t}^{s} - Y_{i,t}^{a}}{Y_{i,t}^{a}}\right|$$

where, $Y_{i,t}^{s}$ and $Y_{i,t}^{a}$ are the simulated and actual value of i^{th} variable in period t, and T is the number of periods in the simulation. The MAPE indicates the extent to which the simulated values are far from the actual values. In general, the value of MAPE less than 3 per cent is considered excellent for the predicative accuracy, less than 5 per cent is assessed as good, and more than 8 per cent is regarded as not acceptable (Bu, 2003).

Table 3.39 reports the values of the MAPE for main macroeconomic and energy variables in the macro-econometric module and main output variables in the electricity module. Overall, the MAPE of most variables are below 8%, which implies that the model is stable. While the macroeconomic variables' statistics show a good performance for predictive power, they are below 3%, finance variables such as exchange rate and yield of corporate bonds exceed 5% respectively, but these are regarded as reasonable levels, given the high volatility of the time series. The MAPE of price variables in the energy module are within 7 per cent. As seen in Table 3.39, the dynamic logit model generally provides acceptable levels of the statistic for the three sectors' individual energy demands.

Table 3.39. The MAPE of major variables

(a) Main macroeconomic variables

Variable	MAPE (%)	Variable	MAPE (%)
GDP	0.96	Producer price index	0.84
Private consumption	1.11	GDP deflator	1.43
Government consumption	1.04	Exchange rate	5.70
Investment	2.42	Yield of corporate bonds	5.16
Export	3.26	Money supply	1.45
Import	3.09	Labour employment	0.36
Consumer price index	0.52	Wage	2.23

(b) Main energy variables

(b.1) Price

Bituminous Coal	4.70	City-gas for industry	6.43
LNG	5.50	City-gas for commerce and public	4.27
Non-energy petroleum	5.64	City-gas for households	4.04
Aggregated oil for industry	4.57	Electricity for industry	1.00
Aggregated oil for commerce and public	4.70	Electricity for commerce and public	0.86
Aggregated oil for households	5.38	Electricity for households	0.77

(b.2) Demand

Anthracite coal	3.94	Industry’s city-gas	2.59
Industry’s bituminous coal	5.73	Commerce and public’s city-gas	5.66
Non-energy petroleum	2.49	Households’ city-gas	2.38
Industry’s aggregated oil	2.49	Industry’s electricity	2.59
Commerce and public’s aggregated oil	8.30	Commerce and public’s electricity	2.42
Households ‘ aggregated oil	6.42	Households’ electricity	2.11

Figures 3.6~3.8 compare the actual and corresponding simulated values for the main endogenous variables in order to provide a general picture of the predictive performance of the model. Table A.3.3 in the appendix to this chapter presents all variables’ MAPE and the percentage distribution of the results. Broadly, the values of simulated variables show similar trends to the actual values and closely track the actual values well despite some deviations. Therefore, this section reaches the conclusion that the model’s predictive ability is satisfactory,

so that this model can be used to perform policy simulation such as the imposition of a carbon tax which will be analysed in the next chapter.

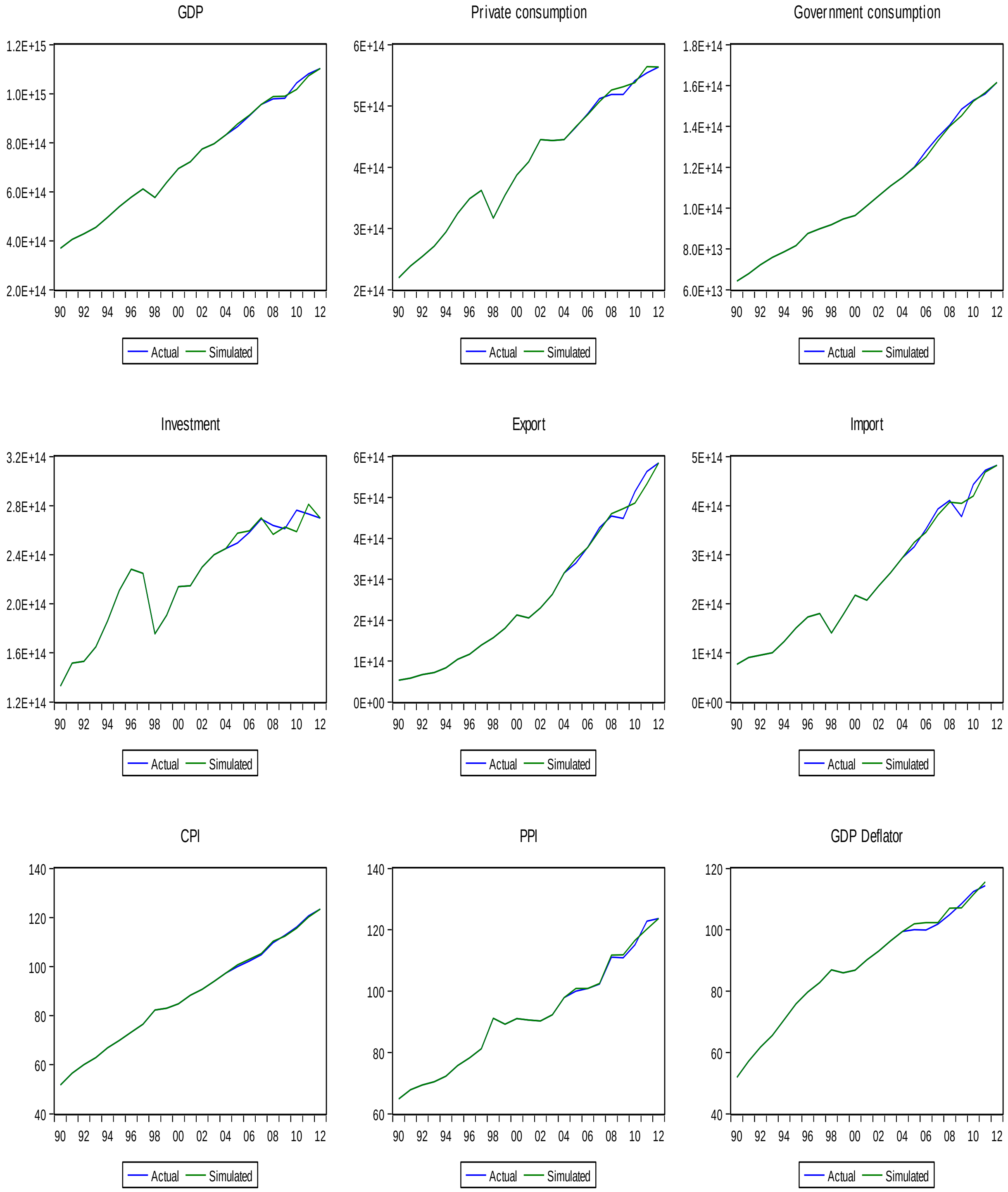

Figure 3.6. Main macroeconomic variables

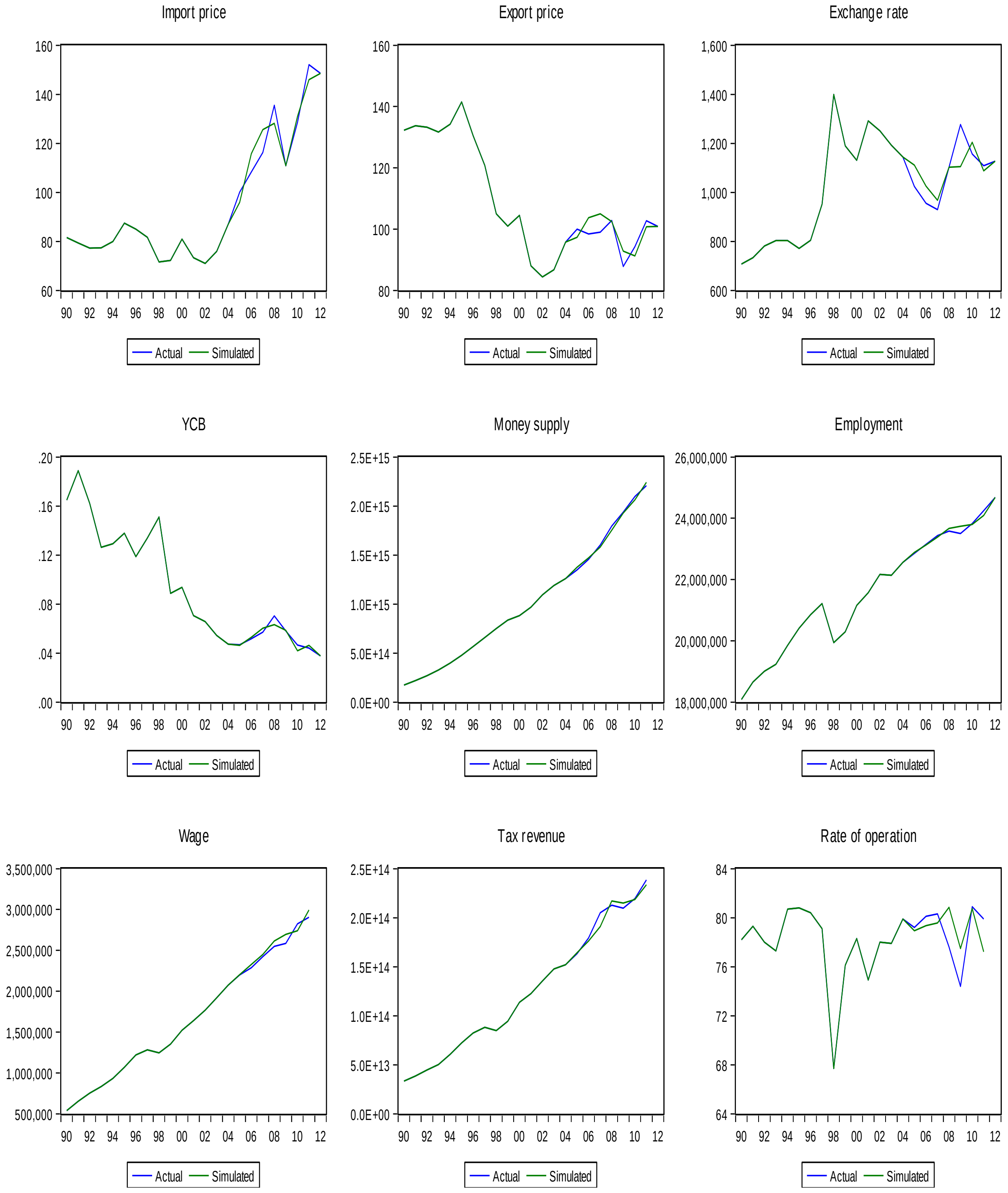

Figure 3.6. (continued)

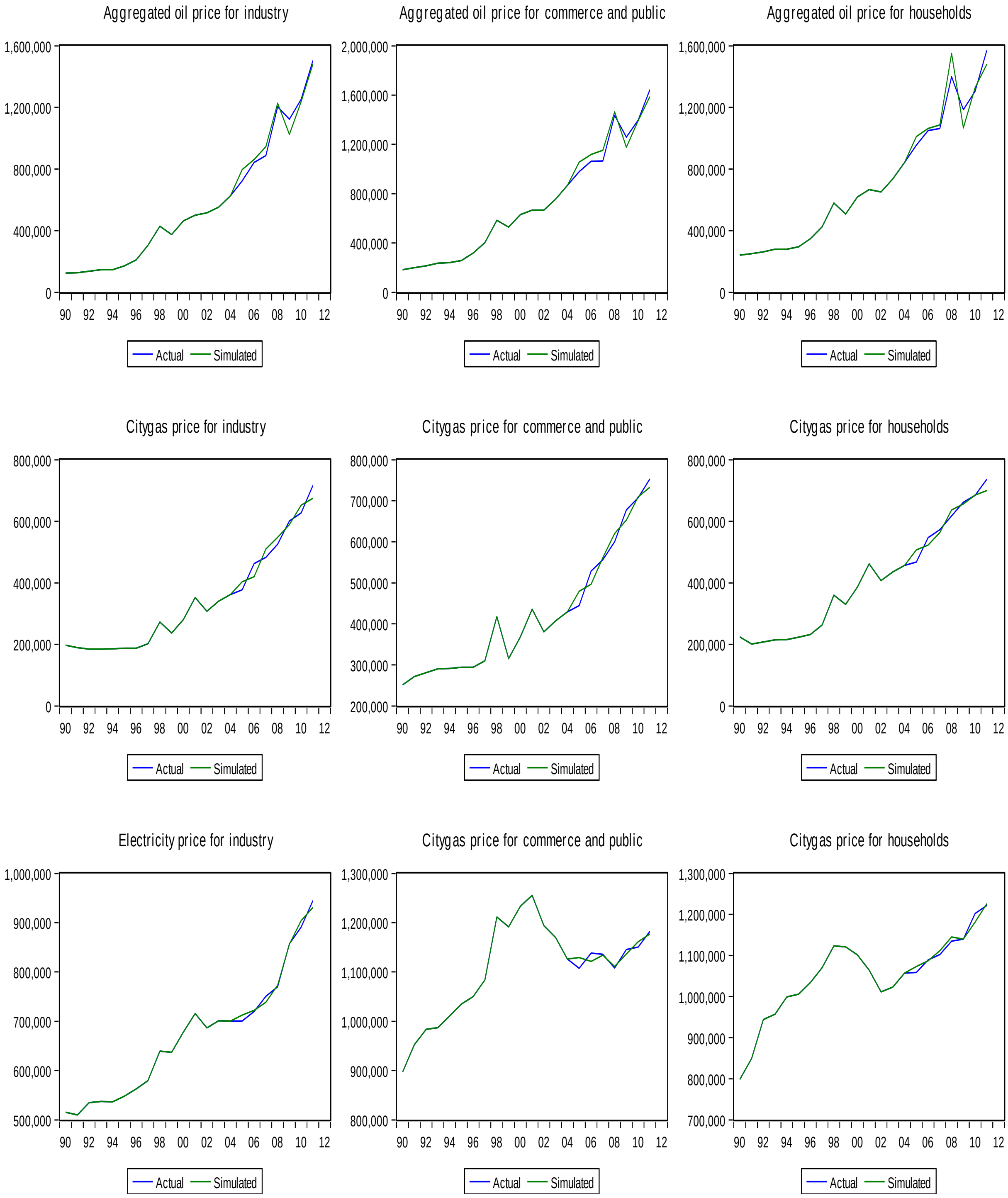

Figure 3.7. Main energy price variables

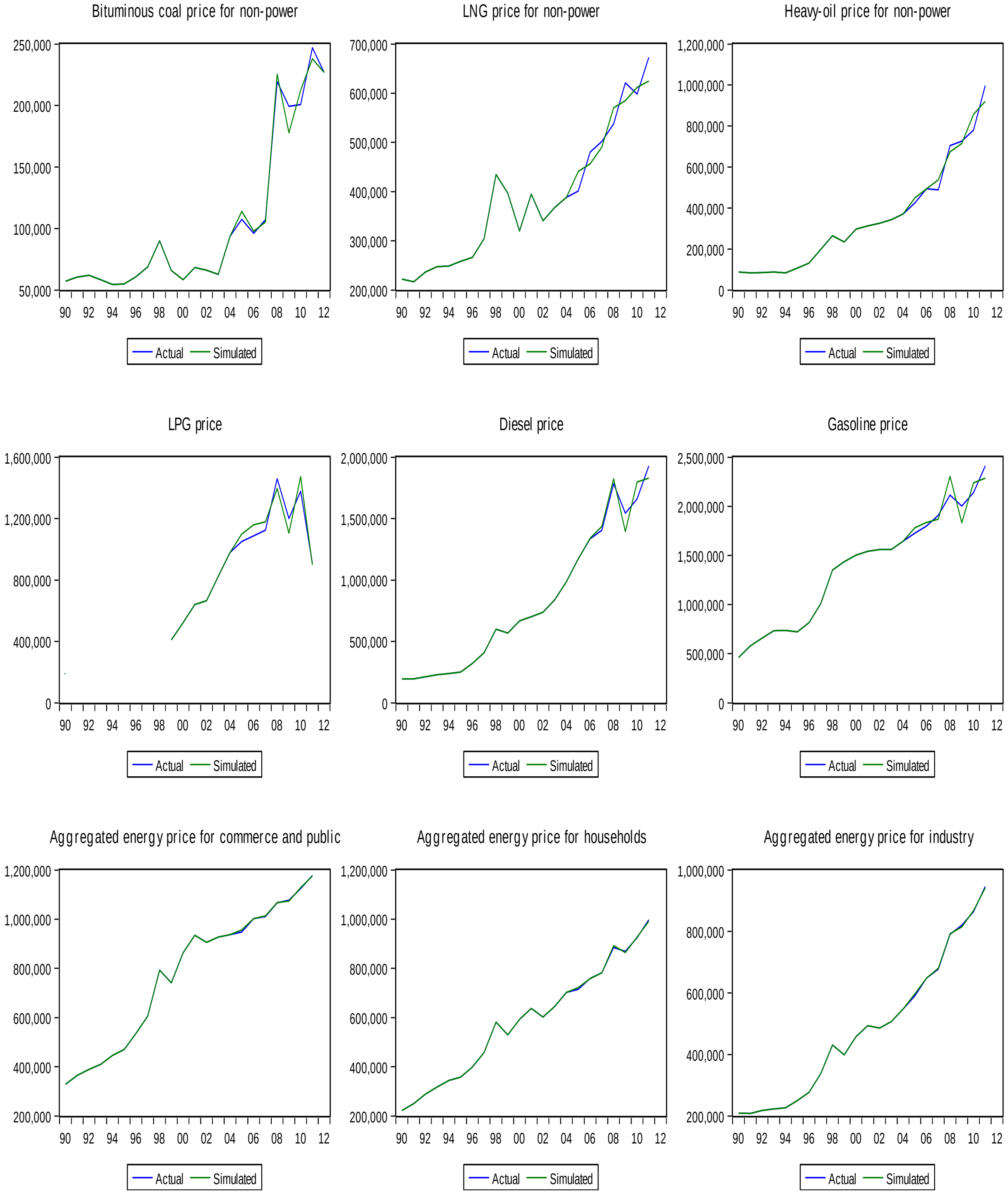

Figure 3.7. (continued)

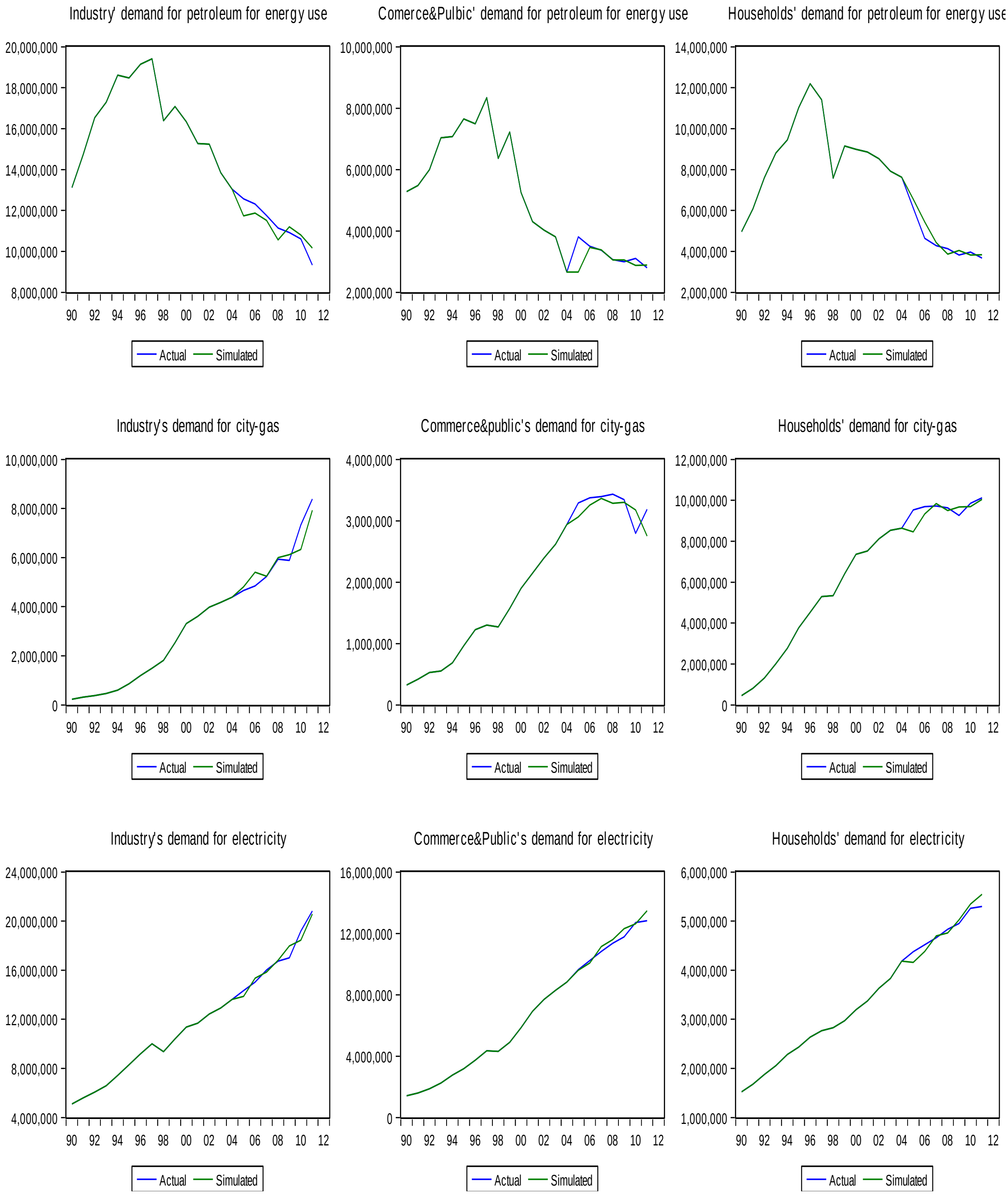

Figure 3.8. Main energy demand variables

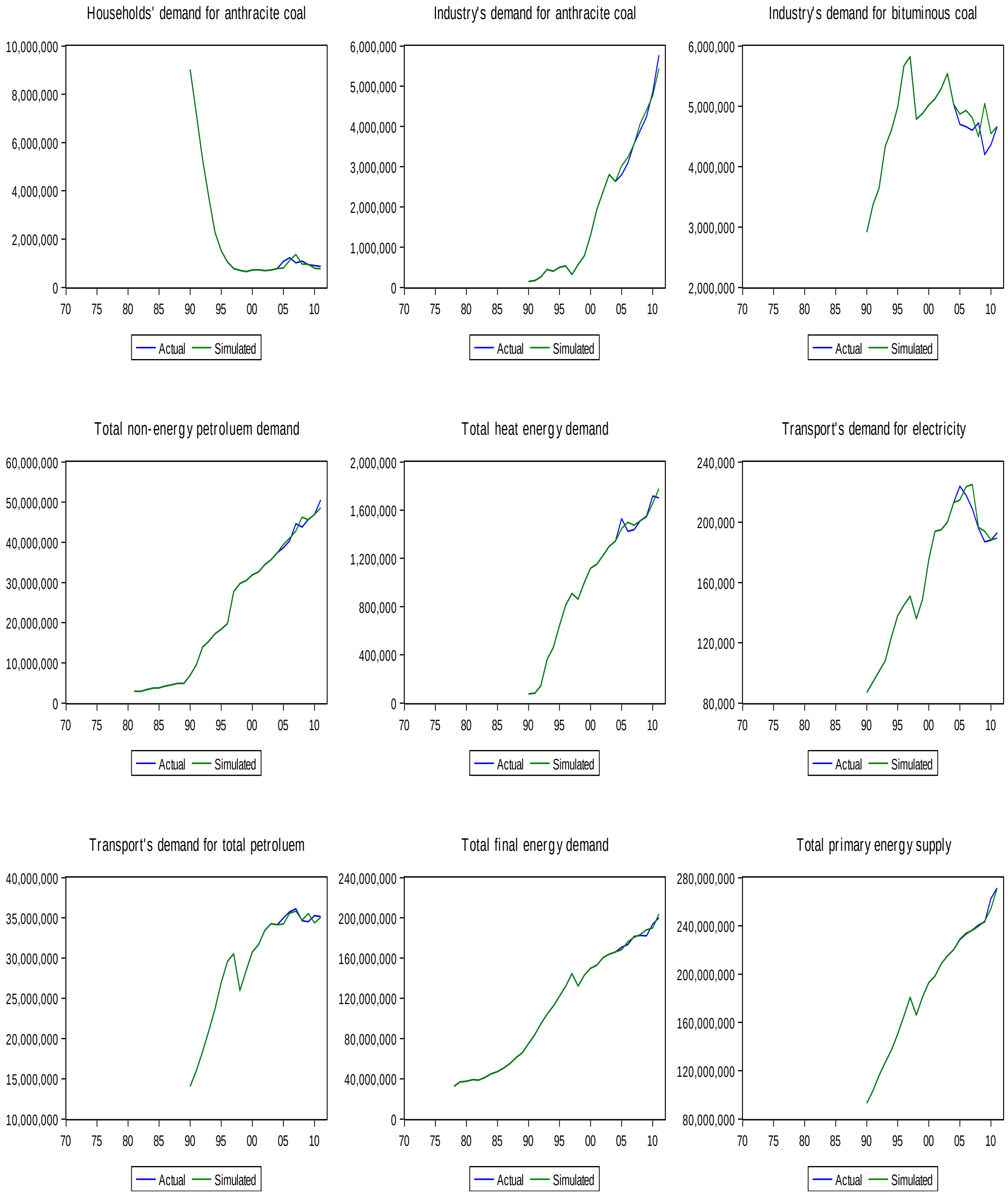

Figure 3.8. (continued)

3.6. CONCLUSION

Taking into account the importance of the electricity sector, this chapter builds up an integrated model that combines a top-down macro-econometric and a bottom-up electricity model in order to provide a tool for assessing the effect of climate change policies on the Korean economy.

For the top-down model representing a national economy, a macro-econometric model is employed rather than the CGE model to obtain robust parameters on variables in each behavioural equation, as confirmed by the ARDL bounds testing and the standard specification tests, leading to more objective results for macroeconomic policy experiments. The macro-econometric model follows the OECD model's (Hervé et al, 2010) fundamental structure in which output is determined by the demand side consistent with Keynesian views, but by the supply side in the long-term according to a neo-classical perspective on growth modelling. The macro-econometric model has seven blocks; supply side, demand side, prices and wage, fiscal and monetary, finance, foreign trade, and energy and environment blocks. In the energy block, the economy is classified into four sectors: industry, transport, commerce and public, and households. This study employs the dynamic logit cost share model which satisfies the neo-classical theoretical properties of the input-demand function in order to measure the sectors' cross-price elasticities which determines fuel-switching effects when relative energy prices change.

In the case of the bottom-up electricity model, the Mixed Complementarity Problem (MCP) framework is adopted in view of the complexity of the power generation sector and the largest share of emissions. The MCP electricity model employs the perfect competition theory to obtain realistic results for output and costs given the current CBP system in the power generation market.

These two models are integrated via the soft-link method which adopts an iteration process that repeats the two models subsequently sharing information on input energy prices, generation cost, and demand variables until the value of the electricity demand variable is laid within convergence criteria. The soft link method is the most suitable method to support the integrated model consisting of two separate models through according an agent's behaviour and representing the multiple periods' power generation subject to technology constraints using the electricity model.

The last section performs an ex-post simulation to test the validity of the integrated model. The result shows that the model's predictive ability is satisfactory, as most variables have acceptable levels of statistical standard errors. Therefore, the next step, performing policy simulation experiments, can be carried out in the following chapter.

APPENDIX 3

A.3.1 VARIABLE DEFINITIONS AND DATA SOURCES

This section describes all variables in the macro-econometric model, designed for use with the model specification in appendix a.3.2. The following tables list variables alphabetically and include type designation, source, and unit of each variable. In terms of the type designation, the following classification is used:

1. EN(B): Endogenous variable estimated by a behavioural equation
2. EN(I): Endogenous variable estimated by an identity equation
3. EX: Exogenous variable

The database used in this study is obtained from six external sources:

1. BOK: Bank of Korea, economic statistics system (http://ecos.bok.or.kr)
2. SK: Statistics Korea, Korean statistical information service (http://kosis.kr)
3. KPX: Korea Power Exchange, electric power statistics information system (http://epsis.kpx.or.kr)
4. KITA: Korea International Trade Association (http://kita.net)
5. KEEI: Korean Energy Economic Institute, Korea energy statistics information system (http://kesis.net), KEEI (2012)
6. IMF: International Financial Statistics (2013)
7. C: author's calibration

In the cases of data that were not directly available, data are derived from calibration of data within the fundamental data base, which is denoted by a "C/fundamental source" in the source column. In particular, each energy price (won/TOE) is derived using energy conversion factors/oil equivalent denoted by the Energy Use Rationalization Act, which is available in KEEI (2012).

Table A.3.1. List of variables definitions

Notation	Type	Definition	Unit	Source
β^{acoal}	EX	Carbon emission factor of anthracite coal	tCO_2/TOE	IPCC
β^{bcoal}	EX	Carbon emission factor of bituminous coal	tCO_2/TOE	IPCC
β^{briq}	EX	Carbon emission factor of briquette	tCO_2/TOE	IPCC
β^{diesel}	EX	Carbon emission factor of diesel	tCO_2/TOE	IPCC
$\beta^{gasoline}$	EX	Carbon emission factor of gasoline	tCO_2/TOE	IPCC
β^{heavyo}	EX	Carbon emission factor of heavy oil	tCO_2/TOE	IPCC
β^{LNG}	EX	Carbon emission factor of LNG	tCO_2/TOE	IPCC
β^{LPG}	EX	Carbon emission factor of LPG	tCO_2/TOE	IPCC
β_{cp}^{petro}	EX	Carbon emission factor of aggregated petro. in com.&public	tCO_2/TOE	C/KEEI
β_{h}^{petro}	EX	Carbon emission factor of aggregated petro. in households	tCO_2/TOE	C/KEEI
β_{i}^{petro}	EX	Carbon emission factor of aggregated petro. in industry	tCO_2/TOE	C/KEEI
CALL	EX	Call interest rate	%	BOK
CDD	EX	Cooling degree day	Num.	KEEI
CG	EN(B)	Government consumption	2005 ₩	BOK
c^k	EN(I)	Capital cost	index	BOK
$CO2^{coal}$	EX	CO_2 emissions by coal use	tCO_2	*N.A.*
$CO2^{e}$	EX	CO_2 emissions in electricity sector	tCO_2	*N.A.*
$CO2^{petro}$	EN(I)	CO_2 emissions by petroleum use	tCO_2	*N.A.*
$CO2^{gas}$	EN(I)	CO_2 emissions by natural gas	tCO_2	*N.A.*
CO2	EN(I)	Total CO_2 emissions from energy use	tCO_2	*N.A.*
CP	EN(B)	Private consumption	2005 ₩	BOK
CV_{train}	EX	Total tons of train	Tons	SK
$CV_{vfreight}$	EX	Total number of freight vehicles for diesel	Num.	KEEI
$CV_{vgeneral}$	EX	Total number of general vehicles for gasoline	Num.	KEEI
CV_{vcom}	EX	Total number of commercial vehicles for LPG	Num.	KEEI
CV_{ship}	EX	Total tons of ships	Tons	SK
CTAX	EX	Carbon tax rate	Current ₩/tCO_2	-
EPOP	EX	Economically active population	Person	BOK
ER	EN(B)	Exchange rate	Current ₩/$	BOK
EX	EN(B)	Exports	2005 ₩	BOK
FY	EX	Foreign countries (advanced economies)' GDP	2005=100	IMF
FP^{coal}	EX	Coal Australia price index	2005=100	IMF
FP^{rm}	EX	Raw material price index	2005=100	IMF
FP^{oil}	EX	Petroleum Dubai spot price	$/Barrel	IMF
HDD	EX	Heating degree day	Num.	KEEI
I	EN(B)	Investment (Gross fixed capital accumulation)	2005 ₩	BOK
IM	EN(B)	Imports	2005 ₩	BOK
INVD	EN(B)	Inventory	2005 ₩	BOK
K	EN(B)	Tangible fixed asset	Current ₩	SK
L	EN(B)	Employment	Person	BOK
L^*	EN(I)	Natural employment	Person	C/BOK

Table A.3.1. (continued)

Notation	Type	Definition	Unit	Source
$LNSR1_{cp}$	EN(B)	Cost share log ratio of petro. to elec. in commerce & public	-	C/KEEI
$LNSR1_{h}$	EN(B)	Cost share log ratio of petro. to acoal in households	-	C/KEEI
$LNSR1_{i}$	EN(B)	Cost share log ratio of petro. to bcoal in industry	-	C/KEEI
$LNSR2_{cp}$	EN(B)	Cost share log ratio of city-gas to elec. in commerce & public	-	C/KEEI
$LNSR2_{h}$	EN(B)	Cost share log ratio of city-gas to acoal in households	-	C/KEEI
$LNSR2_{i}$	EN(B)	Cost share log ratio of city-gas to bcoal in industry	-	C/KEEI
$LNSR3_{h}$	EN(B)	Cost share log ratio of elec. to acoal in households	-	C/KEEI
$LNSR3_{i}$	EN(B)	Cost share log ratio of elec. to bcoal in industry	-	C/KEEI
$M3$	EN(B)	Money supply	2005 ₩	BOK
P_{np}^{acoal}	EX	Price of anthracite coal for non-power	Current ₩ /TOE	C/KEEI
P_{pg}^{acoal}	EX	Price of anthracite coal for power	Current ₩ /TOE	C/KPX
P_{np}^{bcoal}	EN(B)	Price of bituminous coal for non-power	Current ₩ /TOE	C/KEEI
P_{pg}^{bcoal}	EN(B)	Price of bituminous coal for power	Current ₩ /TOE	C/KPX
P^{briq}	EX	Price of briquette	Current ₩ /TOE	C/KEEI
P_{t}^{butane}	EN(B)	Price of butane for transport	Current ₩ /TOE	BOK
P^{c}	EN(B)	Domestic consumer price index	2005=100	BOK
P_{US}^{c}	EX	U.S. consumer price index	1982-84=100	BOK
P_{cp}^{cgas}	EN(B)	Price of city-gas for commerce and public sector	Current ₩ /TOE	C/KEEI
P_{h}^{cgas}	EN(B)	Price of city-gas for household sector	Current ₩ /TOE	C/KEEI
P_{i}^{cgas}	EN(B)	Price of city-gas for industry sector	Current ₩ /TOE	C/KEEI
P_{tr}^{cgas}	EX	Price of city-gas for transport sector	Current ₩ /TOE	C/KEEI
P^{d}	EN(B)	GDP deflator	2005=100	BOK
P^{diesel}	EN(B)	Price of diesel	Current ₩ /TOE	C/KEEI
P_{cp}^{elec}	EN(B)	Price of electricity for commerce and public sector	Current ₩ /TOE	C/KEEI
P_{h}^{elec}	EN(B)	Price of electricity for household sector	Current ₩ /TOE	C/KEEI
P_{i}^{elec}	EN(B)	Price of electricity for industry sector	Current ₩ /TOE	C/KEEI
P^{ex}	EN(B)	Export price	2005=100 ($)	BOK
P_{cp}^{e}	EN(I)	Aggregated energy price index of commerce and public	Current ₩ /TOE	C/KEEI
P_{h}^{e}	EN(I)	Aggregated energy price index of households	Current ₩ /TOE	C/KEEI
P_{i}^{e}	EN(I)	Aggregated energy price index of industry	Current ₩ /TOE	C/KEEI
$P^{gasoline}$	EN(B)	Price of gasoline	Current ₩ /TOE	C/KEEI
P_{np}^{heavyo}	EN(B)	Price of heavy-oil for non-power	Current ₩ /TOE	C/KEEI
P_{pg}^{heavyo}	EN(B)	Price of heavy-oil for power	Current ₩ /TOE	C/KPX
P^{i}	EN(B)	Investment price (Gross fixed capital accumulation deflator)	2005=100	BOK
P^{im}	EN(B)	Import price index	2005=100 ($)	BOK
P^{ja}	EN(B)	Price of JA	2005=100	BOK
P_{np}^{LNG}	EN(B)	Price of LNG for non-power	Current ₩ /TOE	C/KEEI
P_{pg}^{LNG}	EN(B)	Price of LNG for power	Current ₩ /TOE	C/KPX
P^{npetro}	EN(B)	Price index of non-energy petroleum	2005=100	C/BOK
P_{cp}^{petro}	EN(B)	Price of aggregated petroleum for commerce and public	Current ₩ /TOE	C/KEEI
P_{h}^{petro}	EN(B)	Price of aggregated petroleum for households	Current ₩ /TOE	C/KEEI

Table A.3.1. (continued)

Notation	Type	Definition	Unit	Source
P_i^{petro}	EN(B)	Price of aggregated petroleum for commerce and public	Current ₩ /TOE	C/KEEI
P^w	EN(B)	Producer price index	2005=100	BOK
PC_{np}^{acoal}	EN(I)	Price of anthracite coal for non-power after carbon tax	Current ₩ /TOE	-
PC_{pg}^{acoal}	EN(I)	Price of anthracite coal for power after carbon tax	Current ₩ /TOE	-
PC_{np}^{bcoal}	EN(I)	Price of bituminous coal for non-power after carbon tax	Current ₩ /TOE	-
PC_{pg}^{bcoal}	EN(I)	Price of bituminous coal for power after carbon tax	Current ₩ /TOE	-
PC^{briq}	EN(I)	Price of briquette after carbon tax	Current ₩ /TOE	-
PC_{tr}^{butane}	EN(I)	Price of butane for transport	Current ₩ /TOE	-
PC_{cp}^{cgas}	EN(I)	Price of city-gas after carbon tax for commerce and public	Current ₩ /TOE	-
PC_h^{cgas}	EN(I)	Price of city-gas after carbon tax for households	Current ₩ /TOE	-
PC_i^{cgas}	EN(I)	Price of city-gas after carbon tax for industry	Current ₩ /TOE	-
PC_{tr}^{cgas}	EN(I)	Price of city-gas after carbon tax for transport	Current ₩ /TOE	-
PC^{diesel}	EN(I)	Price of diesel	Current ₩ /TOE	-
$PC^{gasoline}$	EN(I)	Price of gasoline	Current ₩ /TOE	-
PC_{np}^{heavyo}	EN(I)	Price of heavy-oil for non-power	Current ₩ /TOE	-
PC_{pg}^{heavyo}	EN(I)	Price of heavy-oil for power	Current ₩ /TOE	-
PC^{ja}	EN(I)	Price of JA	Current ₩ /TOE	-
PC_{np}^{LNG}	EN(I)	Price of LNG for non-power	Current ₩ /TOE	-
PC_{pg}^{LNG}	EN(I)	Price of LNG for power	Current ₩ /TOE	-
PC^{npetro}	EN(I)	Price index of non-energy petroleum	Current ₩ /TOE	-
PC_{cp}^{petro}	EN(I)	Price of aggregated petroleum for commerce and public	Current ₩ /TOE	-
PC_h^{petro}	EN(I)	Price of aggregated petroleum for commerce and public	Current ₩ /TOE	-
PC_i^{petro}	EN(I)	Price of aggregated petroleum for commerce and public	Current ₩ /TOE	-
PY	EN(I)	Potential GDP	Current ₩	BOK
Q_{cp}^{acoal}	EN(I)	Anthracite coal demand by commerce and public	TOE	KEEI
Q_{elec}^{acoal}	EX*	Anthracite coal demand by power generation	TOE	KEEI
Q_h^{acoal}	EN(I)	Anthracite coal demand by households	TOE	KEEI
Q_i^{acoal}	EN(I)	Anthracite coal demand by industry	TOE	KEEI
Q_{nh}^{acoal}	EN(I)	Anthracite coal demand by non-households	TOE	KEEI
Q^{avig}	EX	AVI-G demand	TOE	KEEI
Q^{coke}	EN(B)	Coke coal demand	TOE	KEEI
Q_i^{bcoal}	EN(I)	Bituminous coal demand by industry	TOE	KEEI
Q_{cp}^{cgas}	EN(I)	City-gas demand by commerce and public	TOE	KEEI
Q_{heat}^{cgas}	EN(I)	City-gas input demand by heat energy	TOE	KEEI
Q_h^{cgas}	EN(I)	City-gas demand by households	TOE	KEEI
Q_i^{cgas}	EN(I)	City-gas demand by industry	TOE	KEEI
Q_{tr}^{cgas}	EX	City-gas demand by transport	TOE	KEEI
Q_{tr}^{diesel}	EN(B)	Diesel demand by transport	TOE	KEEI
Q_{cp}^{elec}	EN(I)	Electricity demand by commerce and public	TOE	KEEI
Q_h^{elec}	EN(I)	Electricity demand by households	TOE	KEEI
Q_i^{elec}	EN(I)	Electricity demand by industry	TOE	KEEI

Note: EX* is determined in the electricity module.

Table A.3.1. (continued)

Notation	Type	Definition	Unit	Source
Q_{tr}^{elec}	EN(B)	Electricity demand by transport	TOE	KEEI
$Q_{tr}^{gasoline}$	EN(B)	Gasoline demand by transport	TOE	KEEI
Q_{tr}^{heavyo}	EN(B)	Heavy-oil demand by transport	TOE	KEEI
Q^{heat}	EN(B)	Total heat energy demand	TOE	KEEI
Q^{ja}	EN(B)	Total JA demand	TOE	KEEI
Q_{cp}^{ja}	EN(I)	JA demand by commerce and public	TOE	KEEI
Q_{tr}^{ja}	EN(I)	JA demand by transport	TOE	KEEI
Q_{cgas}^{LNG}	EN(I)	City-gas sector demand for LNG by City-gas	TOE	KEEI
Q_{elec}^{LNG}	EX*	LNG demand by power generation	TOE	KEEI
Q_{heat}^{LNG}	EN(I)	LNG demand by Heat energy	TOE	KEEI
Q_{tr}^{LPG}	EN(B)	LPG demand by transport	TOE	KEEI
Q^{npetro}	EN(B)	Total non-energy petroleum demand	TOE	KEEI
Q_{cp}^{npetro}	EN(I)	Non-energy petroleum demand by commerce and public	TOE	KEEI
Q_{h}^{npetro}	EN(I)	Non-energy petroleum demand by households	TOE	KEEI
Q_{i}^{npetro}	EN(I)	Non-energy petroleum demand by industry	TOE	KEEI
Q_{cp}^{petro}	EN(I)	Aggregated oil demand by commerce and public	TOE	KEEI
Q_{cgas}^{petro}	EN(I)	Petroleum demand by City-gas	TOE	KEEI
Q_{elec}^{petro}	EX*	Petroleum demand by power generation	TOE	KEEI
Q_{heat}^{petro}	EN(I)	Petroleum demand by Heat energy	TOE	KEEI
Q_{h}^{petro}	EN(I)	Aggregated oil demand by households	TOE	KEEI
Q_{i}^{petro}	EN(I)	Aggregated oil demand by industry	TOE	KEEI
r_{US}	EX	U.S. Long-term government bond yields (10year)	Rate	IMF
s_{cp}^{acoal}	EX	Commerce and public's anthracite coal share	-	C/KEEI
s_{i}^{acoal}	EX	Industry's anthracite coal share	-	C/KEEI
s_{cp}^{ja}	EX	Commerce and public's JA share	-	C/KEEI
s_{tr}^{ja}	EX	Transport's JA share	-	C/KEEI
s_{cp}^{npetro}	EX	Commerce and public's non-energy petroleum share	-	C/KEEI
s_{h}^{npetro}	EX	Households' non-energy petroleum share	-	C/KEEI
s_{i}^{npetro}	EX	Industry's non-petroleum share	-	C/KEEI
s_{heat}^{np}	EX	Non-power's share in heat energy's input energy	-	C/KEEI
s_{heat}^{petro}	EX	Petro. share in non-power input energy for heat	-	C/KEEI
s_{heat}^{cgas}	EX	City-gas share in non-power input energy for heat	-	C/KEEI
s_{heat}^{LNG}	EX	LNG share in non-power input energy for heat	-	C/KEEI
s_{cgas}^{petro}	EX	Petro. share in city-gas input energy	-	C/KEEI
s_{cgas}^{LNG}	EX	LNG share in city-gas input energy	-	C/KEEI
$time$	EX	Trend	-	-
TAX	EN(B)	Tax revenue	Current ₩	BOK
TC_{cp}	EN(I)	Total main energy cost	Current ₩	C/KEEI
TC_{elec}	EX*	Total cost of power generation	Current ₩	C/KPX
TC_{h}	EN(I)	Total main energy cost	Current ₩	C/KEEI
TC_{i}	EN(I)	Total main energy cost	Current ₩	C/KEEI

Note: EX* is determined in the electricity module.

Table A.3.1. (continued)

Notation	Type	Definition	Unit	Source
TQ^{acoal}	EN(I)	Total anthracite coal demand	TOE	KEEI
TQ^{bcoal}	EN(I)	Total bituminous coal demand	TOE	KEEI
TQ^{cgas}	EN(I)	Total city-gas demand	TOE	KEEI
TQ_h^e	EN(I)	Aggregated main energy demand by households	TOE	KEEI
TQ_i^e	EN(I)	Aggregated main energy demand by households	TOE	KEEI
TQ_{cp}^e	EN(I)	Aggregated main energy demand by commerce and public	TOE	KEEI
TQ^{elec}	EN(I)	Total electricity demands	TOE	KEEI
TQ^{fe}	EN(I)	Total final energy demands	TOE	KEEI
TQ^{petro}	EN(I)	Total petroleum energy demand	TOE	KEEI
TQ_{cp}^{petro}	EN(I)	Total petroleum energy demand by commerce and public	TOE	KEEI
TQ_h^{petro}	EN(I)	Total petroleum energy demand by households	TOE	KEEI
TQ_i^{petro}	EN(I)	Total petroleum energy demand by industry	TOE	KEEI
TQ_{tr}^{petro}	EN(I)	Total petroleum energy demand by transport	TOE	KEEI
TS^{cgas}	EN(I)	Total City-gas supply	TOE	KEEI
TS^{elec}	EN(I)	Total power generation supply	TOE	KEEI
TS^{heat}	EN(I)	Total heat energy supply	TOE	KEEI
TS^{pe}	EN(I)	Total primary energy supply	TOE	KEEI
TS^{renew}	EX	Total hydro and renewable energy supply	TOE	KEEI
W	EN(B)	Nominal average wage	Current ₩	BOK
w_h^{acoal}	EN(I)	Cost share of anthracite coal by households	-	C/KEEI
w_i^{bcoal}	EN(I)	Cost share of bituminous coal by industry	-	C/KEEI
w_{cp}^{elec}	EN(I)	Cost share of electricity by commerce and public	-	C/KEEI
w_{cp}^{cgas}	EN(I)	Cost share of City-gas by commerce and public	-	C/KEEI
w_h^{cgas}	EN(I)	Cost share of City-gas by households	-	C/KEEI
w_i^{cgas}	EN(I)	Cost share of City-gas by industry	-	C/KEEI
w_h^{elec}	EN(I)	Cost share of electricity by households	-	C/KEEI
w_i^{elec}	EN(I)	Cost share of electricity by industry	-	C/KEEI
w_{cp}^{petro}	EN(I)	Cost share of aggregated oil by commerce and public	-	C/KEEI
w_h^{petro}	EN(I)	Cost share of aggregated oil by households	-	C/KEEI
w_i^{petro}	EN(I)	Cost share of aggregated oil by industry	-	C/KEEI
u	EN(I)	Unemployment rate	%	BOK
u^*	EN(I)	Non-accelerating inflation rate of unemployment	%	C/BOK
Y	EN(I)	Gross Domestic Product (GDP)	2005 ₩	BOK
YCB	EN(b)	Yields of corporates bonds (OTC, 3year, AA-)	Rate	BOK
YD	EN(I)	Disposable income	2005 ₩	C/BOK
YP	EN(I)	Nominal GDP	Current ₩	BOK
ε^y	EX	Error term in the sum of GDP expenditure	2005 ₩	C/BOK
η^{elec}	EX	Conversion factor of electricity	-	C/BOK
η^{cgas}	EX	Conversion factor of city-gas	-	C/BOK
η^{heat}	EX	Conversion factor of heat energy	-	C/BOK
ρ	EN(B)	Rate of operation	%	SK
ρ^*	EN(I)	Natural rate of operation	%	C/SK

A.3.2. MDOEL SPECIFICATION

1. Supply side block

1.1. Investment

$$\log(I_t) = -18.026 + 0.420\times\log(I_{t-1}) + 1.251\times(\log(Y_t) - \log(c_t^k)) - 0.253\times D_{88}$$
(0.038) (0.009) (0.000) (0.153)

$$- 0.041\times D_{90}$$
(0.185)

$$\varepsilon_{i_t} = 0.722\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.977	$D.W.$	1.604	$\hat{\sigma}$	0.	F	0.
F_{Auto}	0.367	χ^2_{Norm}	0.729	F_{Reset}	0.125	F_{Hetero}	0.104

1.2. Labour employment

$$\log(L_t) = -0.792 + 0.904\times\log(L_{t-1}) + 0.100\times(\log(Y_t) - \log(\frac{w_t}{P_t^d})) - 0.041\times D_{84}$$
(0.041) (0.000) (0.001) (0.001)

$$- 0.081\times D_{98}$$
(0.000)

$\bar{R}^2$	0.998	$D.W.$	2.241	$\hat{\sigma}$	0.010	F	0.000
F_{Auto}	0.405	χ^2_{Norm}	0.733	F_{Reset}	1.254	F_{Hetero}	0.885

1.3. Rate of operation

$$\log(\rho_t) = 2.072 - 0.503\times\log(\rho_{t-1}) - 0.118\times\log(\frac{u_t}{u_t^*}) + 0.165\times\log(Y_t) - 0.090\times\log(P_{i,t}^e)$$
(0.116) (0.000) (0.000) (0.003) (0.017)

$$- 0.026\times D_{0411} - 0.026\times D_{02} - 0.026\times D_{09}$$
(0.046) (0.081) (0.000)

$\bar{R}^2$	0.897	$D.W.$	2.421	$\hat{\sigma}$	0.002	F	0.000
F_{Auto}	0.264	χ^2_{Norm}	0.184	F_{Reset}	1.140	F_{Hetero}	0.887

1.4. Capital accumulation

$$\log(K_t) = 0.158 + 0.910\times\log(K_{t-1}) + 0.092\times\log(I_t) - 0.039\times D_{77} - 0.048\times D_{80}$$
$$\quad (0.921) \quad (0.000) \qquad\qquad (0.000) \qquad\qquad (0.000) \qquad\quad (0.000)$$

$$+ 0.039\times D_{89} - 0.048\times D_{97}$$
$$\quad (0.921) \qquad\quad (0.000)$$

$$\varepsilon_{i_t} = 0.385\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.999	$D.W.$	2.005	$\hat{\sigma}$	0.007	F	0.000
F_{Auto}	0.980	χ^2_{Norm}	0.270	F_{Reset}	0.724	F_{Hetero}	0.097

1.5. Potential GDP

$$PY = \exp(11.825 + 0.018 \times time + 0.276 \times \log(\frac{\rho_t K_t}{L_t})) \times L_t^*$$

1.6. Unemployment rate

$$U_t = (EPOP_t - L_t) / EPOP_t \times 100$$

1.7. Natural employment

$$L_t^* = (1 - \frac{u_t^*}{100}) \times L_t$$

1.8. Natural rate of operation

$$\rho_t^* = [(1 - u_t^*)/(1 - u_t)]\rho$$

2. Demand side block

2.1. Private Consumption Expenditure

$$\log(CP_t) = -0.233 + 0.654\times\log(CP_{t-1}) + 0.358\times\log(YD_t) - 0.051\times\log(P_t^c) - 0.060\times D_{98}$$
$$\quad (0.672) \quad (0.000) \qquad\qquad (0.000) \qquad\qquad (0.005) \qquad\qquad (0.005)$$

$$-0.033\times D_{0111}$$
$$(0.000)$$

$\bar{R}^2$	0.999	$D.W.$	1.487	$\hat{\sigma}$	0.018	F	0.000
F_{Auto}	0.163	χ^2_{Norm}	0.451	F_{Reset}	0.837	F_{Hetero}	0.471

2.2. Government Consumption Expenditure

$$\log(CG_t) = 1.522 + 0.891\times\log(CG_{t-1}) + 0.063\times\log(\frac{TAX_t}{P_t^d}\times 100) - 0.042\times D_{90}$$
$$(0.001) \quad (0.000) \qquad (0.025) \qquad (0.020)$$

$\bar{R}^2$	0.999	$D.W.$	1.610	$\hat{\sigma}$	0.017	F	0.000
F_{Auto}	0.226	χ^2_{Norm}	0.757	F_{Reset}	0.116	F_{Hetero}	0.354

2.3. Real GDP

$$Y_t = CP_t + CG_t + I_t + EX_t - IM_t + \varepsilon_t^y$$

2.4. Nominal GDP

$$YP_t = Y_t \times P^d/100$$

2.5. Disposable income

$$YD_t = Y_t - \frac{TAX_t}{P^d}\times 100$$

3. Prices and Wage block

3.1. Consumer price

$$\log(P_t^c) = - 0.600 + 0.572\times\log(P_{t-1}^c) + 0.121\times\log(\frac{Y_t}{PY_t}) + 0.244\times\log(P_t^w) + 0.206\times\log(P_{h,t}^e)$$
$$(0.024) \quad (0.000) \qquad (0.032) \qquad (0.027) \qquad (0.008)$$

$\bar{R}^2$	0.999	$D.W.$	1.470	$\hat{\sigma}$	0.001	F	0.000
F_{Auto}	0.219	χ^2_{Norm}	0.157	F_{Reset}	0.578	F_{Hetero}	0.244

3.2. Producer price

$$\log(P_t^w) = 1.869 + 0.104\times\log(P_{t-1}^w) + 0.034\times\log(FP_t^{rm}\times ER) + 0.202\times\log(\frac{W_t}{GDP_t/L_t})$$
$$(0.002) \quad (0.529) \qquad (0.048) \qquad (0.002)$$

$$+ 0.183\times\log(P_{i,t}^e) + 0.045\times D_{99} + 0.055\times D_{11}$$
$$(0.002) \qquad (0.061) \qquad (0.000)$$

$\bar{R}^2$	0.996	$D.W.$	2.118	$\hat{\sigma}$	0.003	F	0.000
F_{Auto}	0.687	χ^2_{Norm}	0.935	F_{Reset}	0.705	F_{Hetero}	0.315

3.3. Export price

$$\log(P_t^{ex}) = 2.612 + 0.773\times\log(P_{t-1}^{ex}) + 0.222\times\log(P_t^{w}) - 0.369\times \log(ER_t) - 0.128\times D_{09}$$
(0.000) (0.000) (0.000) (0.002) (0.017)

$\bar{R}^2$	0.962	$D.W.$	1.613	$\hat{\sigma}$	0.086	F	0.000
F_{Auto}	0.323	χ^2_{Norm}	0.935	F_{Reset}	0.705	F_{Hetero}	0.315

3.4. Import price

$$\log(P_t^{im}) = 1.300 + 0.412\times\log(P_{t-1}^{im}) + 0.041\times\log(FP_t^{oil}) + 0.274\times\log(FP_t^{rm}) - 0.132\times D_{09}$$
(0.001) (0.001) (0.072) (0.000) (0.025)

$\bar{R}^2$	0.961	$D.W.$	1.668	$\hat{\sigma}$	0.042	F	0.000
F_{Auto}	0.412	χ^2_{Norm}	0.639	F_{Reset}	0.757	F_{Hetero}	0.246

3.5. Wage

$$\log(\frac{W_t}{P_t^c}) = -2.182 + 0.748\times \log\left(\frac{W_{t-1}}{P_{t-1}^c}\right) + 0.270\times \log(\frac{Y_t}{L_t}) - 0.140\times \log(\frac{u_t}{u_t^*}) + 0.109\times D_{99}$$
(0.000) (0.000) (0.005) (0.000) (0.019)

$\bar{R}^2$	0.997	$D.W.$	1.559	$\hat{\sigma}$	0.053	F	0.000
F_{Auto}	0.217	χ^2_{Norm}	0.500	F_{Reset}	0.757	F_{Hetero}	0.235

3.6. Capital goods price

$$\log(P_t^{i}) = -0.174 + 0.754\times\log(P_{t-1}^{i}) + 0.075\times\log(FP_t^{rm}) + 0.140\times\log(ER_t)$$
(0.429) (0.000) (0.002) (0.013)

$\bar{R}^2$	0.992	$D.W.$	1.687	$\hat{\sigma}$	0.008	F	0.000
F_{Auto}	0.545	χ^2_{Norm}	0.863	F_{Reset}	0.641	F_{Hetero}	0.726

3.7. GDP deflator

$$\log(P_t^{d}) = 0.820 + 0.153\times\log(P_{t-1}^{d}) + 0.477\times\log(P_t^{c}) + 0.196\times\log(P_t^{i}) + 0.031\times D_{78}$$
(0.000) (0.000) (0.005) (0.000) (0.019)

$$\varepsilon_{i_t} = 0.902\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.999	$D.W.$	1.459	$\hat{\sigma}$	0.008	F	0.000
F_{Auto}	0.117	χ^2_{Norm}	0.940	F_{Reset}	0.296	F_{Hetero}	0.578

3.8. Inflation

$$c_t^k = P_t^i \times (r_t + \delta_t)$$

4. Fiscal and Monetary policy block

4.1. Tax revenue

$$\log(TAX_t) = \underset{(0.026)}{0.820} + \underset{(0.109)}{0.153}\times\log(TAX_{t-1}) + \underset{(0.000)}{0.477}\times\log(YP_t) - \underset{(0.000)}{0.148}\times D_{72} - \underset{(0.005)}{0.137}\times D_{73}$$

$$\varepsilon_{i_t} = 0.614\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.999	$D.W.$	1.759	$\hat{\sigma}$	0.056	F	0.000
F_{Auto}	0.256	χ^2_{Norm}	0.610	F_{Reset}	0.277	F_{Hetero}	0.937

4.2. Money supply

$$\log(M3_t) = \underset{(0.607)}{-0.713} + \underset{(0.000)}{0.736}\times\log(M3_{t-1}) + \underset{(0.029)}{0.290}\times\log(YP_t)$$

$$\varepsilon_{i_t} = 0.403\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.999	$D.W.$	1.757	$\hat{\sigma}$	0.007	F	0.000
F_{Auto}	0.404	χ^2_{Norm}	0.506	F_{Reset}	0.852	F_{Hetero}	0.202

5. Finance block

5.1. Yield of corporate bonds

$$\log(YCB_t) = -\underset{(0.379)}{15.017} + \underset{(0.004)}{0.447}\times\log(YCB_{t-1}) + \underset{(0.000)}{0.525}\times\log(CALL_t) - \underset{(0.534)}{0.162}\times\log(M3_t)$$

$$+ \underset{(0.422)}{1.527}\times\log(Y_t) + \underset{(0.014)}{0.140}\times D_{00} + \underset{(0.011)}{0.242}\times D_{09}$$

$\bar{R}^2$	0.970	$D.W.$	2.227	$\hat{\sigma}$	0.097	F	0.000
F_{Auto}	0.353	χ^2_{Norm}	0.976	F_{Reset}	0.449	F_{Hetero}	0.643

5.2. Exchange rate

$$\log(ER_t) = 2.461 + 0.644\times\log(ER_{t-1}) - 0.076\times\log(\frac{CALL_t}{r_t^{US}}) + 0.449\times D_{98} + 0.173\times D_{01}$$
(0.047) (0.001) (0.375) (0.000) (0.028)

$$+ 0.166\times D_{08}$$
(0.033)

$\bar{R}^2$	0.937	$D.W.$	1.756	$\hat{\sigma}$	0.042	F	0.000
F_{Auto}	0.139	χ^2_{Norm}	0.044	F_{Reset}	0.871	F_{Hetero}	0.720

6. Foreign trade block

6.1. Exports

$$\log(EX_t) = 6.081 + 0.670\times\log(EX_{t-1}) + 1.059\times\log(FY_t) - 0.230\times\log(\frac{P_t^{ex}}{P_{US,t}^{c}}) - 0.180\times D_{71}$$
(0.047) (0.001) (0.375) (0.000) (0.028)

$$- 0.174\times D_{01}$$
(0.047)

$\bar{R}^2$	0.998	$D.W.$	1.944	$\hat{\sigma}$	0.066	F	0.000
F_{Auto}	0.010	χ^2_{Norm}	0.120	F_{Reset}	0.381	F_{Hetero}	0.271

6.2. Imports

$$\log(IM_t) = -59.917 + 0.045\times\log(IM_{t-1}) + 2.689\times\log(Y_t) - 0.179\times\log(\frac{P_t^{im}\times(\frac{ER_t}{P_t^d}\times 100)}{P_t^W})$$
(0.000) (0.556) (0.000) (0.097)

$$- 0.090\times D_{01} - 0.085\times D_{02} - 0.050\times D_{09}$$
(0.005) (0.007) (0.071)

$$\varepsilon_{i_t} = 0.933\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.999	$D.W.$	2.257	$\hat{\sigma}$	0.033	F	0.000
F_{Auto}	0.353	χ^2_{Norm}	0.608	F_{Reset}	0.070	F_{Hetero}	0.810

7. Energy and environment block

a) Demands

7.1. Aggregated main energy demand by industry

$$\log(TQ^{e}_{i,t}) = -\,8.580 + 0.587\times\log(TQ_{i,t-1}) - 0.195\times\log\left(P^{e}_{i,t}\right) + 0.429\times\log(Y_t)$$
$$\quad\quad (0.000) \quad (0.556) \quad\quad\quad (0.000) \quad\quad\quad (0.097)$$

$$+\, 0.447\times\log(HDD_t + CDD_t) - 0.067\times D_{04}$$
$$(0.000) \quad\quad\quad\quad\quad (0.556)$$

$\bar{R}^2$	0.982	$D.W.$	2.578	$\hat{\sigma}$	0.022	F	0.000
F_{Auto}	0.131	χ^2_{Norm}	0.576	F_{Reset}	0.540	F_{Hetero}	0.933

7.2. Aggregated main energy demand by commerce and public

$$\log(TQ^{e}_{cp,t}) = -\,12.080 + 0.428\times\log(TQ_{cp,t-1}) - 0.256\times\log\left(P^{e}_{cp,t}\right) + 0.730\times\log(Y_t) - 0.110\times D_{91}$$
$$\quad\quad (0.000) \quad (0.000) \quad\quad\quad (0.006) \quad\quad\quad (0.000) \quad\quad\quad (0.016)$$

$$+\, 0.096\times D_{97} - 0.113\times D_{99}$$
$$(0.017) \quad\quad (0.006)$$

$\bar{R}^2$	0.989	$D.W.$	2.724	$\hat{\sigma}$	0.033	F	0.000
F_{Auto}	0.117	χ^2_{Norm}	0.258	F_{Reset}	0.103	F_{Hetero}	0.526

7.3. Aggregated main energy demand by households

$$\log(TQ^{e}_{h,t}) = -\,1.928 + 0.241\times\log(TQ_{h,t-1}) - 0.658\times\log\left(P^{e}_{h,t}\right) + 0.587\times\log(YD_t)$$
$$\quad\quad (0.858) \quad (0.075) \quad\quad\quad (0.001) \quad\quad\quad (0.082)$$

$$+\, 0.438\times\log(HDD_t + CDD_t) - 0.029\times D_{04} - 0.029\times D_{05} - 0.057\times D_{08}$$
$$(0.039) \quad\quad\quad\quad\quad (0.458) \quad\quad (0.313) \quad\quad (0.051)$$

$$\varepsilon_{i_t} = 0.822\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.930	$D.W.$	2.004	$\hat{\sigma}$	0.031	F	0.000
F_{Auto}	0.887	χ^2_{Norm}	0.156	F_{Reset}	0.388	F_{Hetero}	0.709

7.4. Total non-energy petroleum product demand

$$\log(Q_t^{npetro}) = \underset{(0.104)}{-2.957} + \underset{(0.000)}{0.723}\times\log(Q_{t-1}^{npetro}) - \underset{(0.028)}{0.033}\times\log\left(P_t^{npetro}\right) + \underset{(0.003)}{0.223}\times\log(Y_t)$$

$$- \underset{(0.000)}{0.288}\times D_{8190} - \underset{(0.000)}{0.178}\times D_{92} + \underset{(0.000)}{0.235}\times D_{97}$$

$\bar{R}^2$	0.999	$D.W.$	2.239	$\hat{\sigma}$	0.036	F	0.000
F_{Auto}	0.229	χ^2_{Norm}	0.948	F_{Reset}	0.783	F_{Hetero}	0.179

7.5. Coking coal demand

$$\log(Q_t^{coke}) = \underset{(0.027)}{-3.761} - \underset{(0.480)}{0.156}\times\log(Q_{t-1}^{coke}) + \underset{(0.000)}{0.663}\times\log(Y_t) - \underset{(0.002)}{0.254}\times D_{08} + \underset{(0.000)}{0.331}\times D_{10}$$

$\bar{R}^2$	0.962	$D.W.$	2.129	$\hat{\sigma}$	0.046	F	0.000
F_{Auto}	0.581	χ^2_{Norm}	0.300	F_{Reset}	0.379	F_{Hetero}	0.149

7.6. Anthracite coal demand by non-households

$$\log(Q_{nh,t}^{acoal}) = \underset{(0.001)}{-9.776} + \underset{(0.000)}{0.846}\times\log(Q_{nh,t-1}^{acoal}) + \underset{(0.001)}{0.354}\times\log(Y_t) - \underset{(0.010)}{0.566}\times D_{90} - \underset{(0.001)}{0.769}\times D_{97}$$

$\bar{R}^2$	0.977	$D.W.$	1.976	$\hat{\sigma}$	0.196	F	0.000
F_{Auto}	0.975	χ^2_{Norm}	0.681	F_{Reset}	0.797	F_{Hetero}	0.198

7.7. Total JA demand

$$\log(Q_t^{ja}) = \underset{(0.003)}{-13.913} + \underset{(0.073)}{0.345}\times\log(Q_{t-1}^{ja}) - \underset{(0.263)}{0.058}\times\log\left(P_t^{ja}\right) + \underset{(0.001)}{0.698}\times\log(Y_t)$$

$\bar{R}^2$	0.961	$D.W.$	1.891	$\hat{\sigma}$	0.054	F	0.000
F_{Auto}	0.834	χ^2_{Norm}	0.747	F_{Reset}	0.908	F_{Hetero}	0.751

7.8. Total heat energy demand

$$\log(Q_t^{heat}) = -15.063 + 0.462\times\log(Q_{t-1}^{heat}) - 0.093\times\log\left(P_{npt}^{lng}\right) + 0.617\times\log(Y_t)$$
$$(0.000)\ (0.000)\qquad\qquad(0.159)\qquad\qquad(0.000)$$

$$+ 0.339\times\log(HDD_t) - 1.128\times D_{91} - 0.587\times D_{93} - 0.587\times D_{94}$$
$$(0.000)\qquad\qquad(0.041)\qquad(0.000)\qquad(0.000)$$

$\bar{R}^2$	0.999	$D.W.$	1.811	$\hat{\sigma}$	0.036	F	0.000
F_{Auto}	0.876	χ^2_{Norm}	0.876	F_{Reset}	0.857	F_{Hetero}	0.922

7.9. Gasoline demand by transportation

$$\log\left(\frac{Q_{tr,t}^{gasoline}}{CV_{vgeneral,t}}\right) = -5.914 + 0.817\times\log\left(\frac{Q_{tr,t-1}^{gasoline}}{CV_{vgeneral,t-1}}\right) - 0.341\times\log\left(P_t^{gasoline}\right) + 0.312\times\log(Y_t)$$
$$(0.072)\ (0.000)\qquad\qquad(0.000)\qquad\qquad(0.008)$$

$$+ 0.150\times D_{99} + 0.066\times D_{00}$$
$$(0.000)\qquad(0.026)$$

$\bar{R}^2$	0.999	$D.W.$	1.811	$\hat{\sigma}$	0.036	F	0.000
F_{Auto}	0.876	χ^2_{Norm}	0.876	F_{Reset}	0.857	F_{Hetero}	0.922

7.10. Diesel demand by transportation

$$\log\left(\frac{Q_{tr,t}^{diesel}}{CV_{vfreight,t}}\right) = -12.688 + 0.836\times\log\left(\frac{Q_{tr,t-1}^{diesel}}{CV_{vfreight,t-1}}\right) - 0.189\times\log\left(P_t^{diesel}\right) + 0.452\times\log(Y_t)$$
$$(0.013)\ (0.000)\qquad\qquad(0.006)\qquad\qquad(0.010)$$

$$- 0.145\times D_{98}$$
$$(0.002)$$

$\bar{R}^2$	0.978	$D.W.$	1.717	$\hat{\sigma}$	0.028	F	0.000
F_{Auto}	0.551	χ^2_{Norm}	0.154	F_{Reset}	0.888	F_{Hetero}	0.932

7.10. Heavy-oil demand by transportation

$$\log(\frac{Q_{tr,t}^{heavyo}}{CV_{ship,t}}) = 1.646 + 0.943\times\log(\frac{Q_{tr,t-1}^{heavyo}}{CV_{ship,t-1}}) - 0.141\times\log\left(P_{np,t}^{heavyo}\right) + 0.228\times D_{06} - 0.228\times D_{07}$$

(0.000) (0.000) (0.000) (0.008) (0.005)

$\bar{R}^2$	0.977	$D.W.$	2.177	$\hat{\sigma}$	0.068	F	0.000
F_{Auto}	0.640	χ^2_{Norm}	0.956	F_{Reset}	0.712	F_{Hetero}	0.412

7.11. LPG demand by transportation

$$\log(\frac{Q_{tr,t}^{LPG}}{CV_{vcom,t}}) = 3.633 + 0.609\times\log(\frac{Q_{tr,t-1}^{LPG}}{CV_{vcom,t-1}}) - 0.190\times\log(P_t^{butane}) - 0.167\times D_{9899} - 0.056\times D_{02}$$

(0.000) (0.000) (0.001) (0.037) (0.037)

$$- 0.052\times D_{10} - 0.192\times D_{11}$$

(0.050) (0.000)

$\bar{R}^2$	0.990	$D.W.$	2.046	$\hat{\sigma}$	0.017	F	0.000
F_{Auto}	0.954	χ^2_{Norm}	0.621	F_{Reset}	0.145	F_{Hetero}	0.408

7.12. Electricity demand by transportation

$$\log(\frac{Q_{tr,t}^{elec}}{CV_{train,t}}) = 2.513 + 0.916\times\log(\frac{Q_{tr,t-1}^{elec}}{CV_{train,t-1}}) - 0.098\times\log\left(P_{i,t}^{elec}\right)$$

(0.097) (0.000) (0.064)

$\bar{R}^2$	0.966	$D.W.$	2.323	$\hat{\sigma}$	0.053	F	0.000
F_{Auto}	0.361	χ^2_{Norm}	0.590	F_{Reset}	0.159	F_{Hetero}	0.511

7.13. Bituminous coal demand by industry

$$Q_{i,t}^{bcoal} = (TC_{i,t}^{e} \times w_{i,t}^{bcoal})/P_{i,t}^{bcoal}$$

7.14. Anthracite coal demand by households

$$Q_{h,t}^{acoal} = (TC_{h,t}^{e} \times w_{i,t}^{acoal})/P_{i,t}^{briq}$$

7.15. Aggregated petroleum demand by industry

$$Q_{i,t}^{petro} = (TC_{i,t}^{e} \times w_{i,t}^{petro})/P_{i,t}^{petro}$$

7.16. Aggregated petroleum demand by commerce and public

$$Q_{cp,t}^{petro} = (TC_{cp,t}^{e} \times w_{cp,t}^{petro})/P_{cp,t}^{petro}$$

7.17. Aggregated petroleum demand by households

$$Q_{h,t}^{petro} = (TC_{h,t}^{e} \times w_{h,t}^{petro})/P_{h,t}^{petro}$$

7.18. City-gas demand by industry

$$Q_{i,t}^{cgas} = (TC_{i,t}^{e} \times w_{i,t}^{cgas})/P_{i,t}^{cgas}$$

7.19. City-gas demand by commerce and public

$$Q_{cp,t}^{cgas} = (TC_{cp,t}^{e} \times w_{cp,t}^{cgas})/P_{cp,t}^{cgas}$$

7.20. City-gas demand by households

$$Q_{h,t}^{cgas} = (TC_{h,t}^{e} \times w_{h,t}^{cgas})/P_{h,t}^{cgas}$$

7.21. Electricity demand by industry

$$Q_{i,t}^{elec} = (TC_{i,t}^{e} \times w_{i,t}^{elec})/P_{i,t}^{elec}$$

7.22. Electricity demand by commerce and public

$$Q_{cp,t}^{elec} = (TC_{cp,t}^{e} \times w_{cp,t}^{elec})/P_{cp,t}^{elec}$$

7.23. Electricity demand by commerce and public

$$Q_{h,t}^{elec} = (TC_{h,t}^{e} \times w_{h,t}^{elec})/P_{h,t}^{elec}$$

7.24. Anthracite coal demand by industry

$$Q_{i,t}^{acoal} = Q_{nh,t}^{acoal} \times s_{i}^{acoal}$$

7.25. Anthracite coal demand by commerce and public

$$Q_{cp,t}^{acoal} = Q_{nh,t}^{acoal} \times s_{cp,t}^{acoal}$$

7.26. Non-energy petroleum demand by industry

$$Q_{i,t}^{npetro} = Q_{t}^{npetro} \times s_{i,t}^{npetro}$$

7.27. Non-energy petroleum demand by commerce and public

$$Q_{cp,t}^{npetro} = Q_t^{npetro} \times s_{cp,t}^{npetro}$$

7.28. Non-energy petroleum demand by households

$$Q_{h,t}^{npetro} = Q_t^{npetro} \times s_{h,t}^{npetro}$$

7.29. JA demand by commerce and public

$$Q_{cp,t}^{ja} = Q_t^{ja} \times s_{cp,t}^{ja}$$

7.30. JA demand by transport

$$Q_{tr,t}^{ja} = Q_t^{ja} \times s_{tr,t}^{ja}$$

7.31. Petroleum demand by heat energy

$$Q_{heat,t}^{petro} = (TS_t^{heat} \times s_{heat}^{np})/\eta^{heat} \times s_{heat}^{petro}$$

7.32. LNG demand by heat energy

$$Q_{heat,t}^{LNG} = (TS_t^{heat} \times s_{heat}^{np})/\eta^{heat} \times s_{heat}^{LNG}$$

7.33. City-gas demand by heat energy

$$Q_{heat,t}^{cgas} = (TS_t^{heat} \times s_{heat}^{np})/\eta^{heat} \times s_{heat}^{cgas}$$

7.34. Petroleum demand by city-gas

$$Q_{cgas,t}^{petro} = (TS_t^{cgas})/\eta^{cgas} \times s_{cgas}^{petro}$$

7.35. LNG demand by city-gas

$$Q_{cgas,t}^{LNG} = (TS_t^{cgas})/\eta^{cgas} \times s_{cgas}^{LNG}$$

7.36. Total final energy demand of anthracite coal

$$TQ_t^{acoal} = Q_{i,t}^{acoal} + Q_{cp,t}^{acoal} + Q_{h,t}^{acoal}$$

7.37. Total final energy demand of bituminous coal

$$TQ_t^{bcoal} = Q_{i,t}^{bcoal} + Q_t^{coke}$$

7.38. Total petroleum demand by industry

$$TQ_{i,t}^{petro} = Q_{i,t}^{petro} + Q_{i,t}^{npetro}$$

7.39. Total petroleum demand by commerce and public

$$TQ_{cp,t}^{petro} = Q_{cp,t}^{petro} + Q_{cp,t}^{npetro} + Q_{cp,t}^{ja}$$

7.40. Total petroleum demand by households

$$TQ_{h,t}^{petro} = Q_{h,t}^{petro} + Q_{h,t}^{npetro}$$

7.41. Total petroleum demand by transport

$$TQ_{tr,t}^{petro} = Q_{tr,t}^{gasoline} + Q_{tr,t}^{diesel} + Q_{tr,t}^{heavyo} + Q_{tr,t}^{LPG} + Q_{tr,t}^{ja}$$

7.42. Total final energy demand of petroleum

$$TQ_{t}^{petro} = TQ_{i,t}^{petro} + TQ_{cp,t}^{petro} + TQ_{h,t}^{petro} + TQ_{tr,t}^{petro}$$

7.43. Total city-gas demand

$$TQ_{t}^{cgas} = TQ_{i,t}^{cgas} + TQ_{cp,t}^{cgas} + TQ_{h,t}^{cgas} + TQ_{tr,t}^{cgas}$$

7.44. Total electricity demand

$$TQ_{t}^{elec} = TQ_{i,t}^{elec} + TQ_{cp,t}^{elec} + TQ_{h,t}^{elec} + TQ_{tr,t}^{elec}$$

7.45. Total electricity supply

$$TS_{t}^{elec} = TQ_{t}^{elec}/\eta^{elec}$$

7.46. Total city-gas supply

$$TS_{t}^{cgas} = TQ_{t}^{cgas}/\eta^{cgas}$$

76.47. Total city-gas supply

$$TS_{t}^{heat} = TQ_{t}^{heat}/\eta^{heat}$$

7.48. Total final energy demand

$$TQ_{t}^{fe} = TQ_{t}^{petro} + TQ_{t}^{elec} + TQ_{t}^{bcoal} + TQ_{t}^{cgas} + TQ_{t}^{acoal} + Q_{t}^{heat}$$

7.49. Total primary energy supply

$$TS_t^{pe} = TQ_t^{petro} + Q_{heat,t}^{petro} + Q_{cgas,t}^{petro} + Q_{elec,t}^{petro} + TQ_t^{bcoal} + Q_{elec,t}^{bcoal} + TQ_t^{acoal} + Q_{elec,t}^{acoal} + Q_{elec,t}^{nuc} + Q_{elec,t}^{LNG} + Q_t^{renew}$$

b) Prices

7.50. Bituminous coal price for non-power

$$\log(P_{np,t}^{bcoal}) = \underset{(0.002)}{2.212} + \underset{(0.333)}{0.039}\times\log(P_{np,t-1}^{bcoal}) + \underset{(0.000)}{0.784}\times\log(FP_t^{coal}) + \underset{(0.000)}{0.811}\times\log(ER_t)$$

$$+ \underset{(0.000)}{0.192}\times D_{05} - \underset{(0.000)}{0.139}\times D_{06}$$

$$\varepsilon_{i_t} = 0.759\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.996	$D.W.$	1.518	$\hat{\sigma}$	0.035	F	0.000
F_{Auto}	0.269	χ^2_{Norm}	0.687	F_{Reset}	0.182	F_{Hetero}	0.452

7.51. Bituminous coal price for power generation

$$\log(P_{pg,t}^{bcoal}) = -\underset{(0.828)}{0.704} + \underset{(0.322)}{0.215}\times\log(P_{pg,t-1}^{bcoal}) + \underset{(0.005)}{0.603}\times\log(FP_t^{coal}) + \underset{(0.057)}{1.031}\times\log(ER_t)$$

$\bar{R}^2$	0.944	$D.W.$	2.922	$\hat{\sigma}$	0.133	F	0.000
F_{Auto}	0.224	χ^2_{Norm}	0.674	F_{Reset}	0.783	F_{Hetero}	0.236

7.52. Aggregated petroleum price for industry

$$\log(P_{i,t}^{petro}) = \underset{(0.052)}{4.003} - \underset{(0.091)}{0.202}\times\log(P_{i,t-1}^{petro}) + \underset{(0.000)}{0.576}\times\log\left(FP_t^{oil}\right) + \underset{(0.000)}{0.682}\times\log(ER_t)$$

$$- \underset{(0.088)}{0.053}\times D_{92} - \underset{(0.000)}{0.171}\times D_{97} - \underset{(0.000)}{0.351}\times D_{98}$$

$$\varepsilon_{i_t} = 0.894\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.999	$D.W.$	2.244	$\hat{\sigma}$	0.037	F	0.000
F_{Auto}	0.668	χ^2_{Norm}	0.890	F_{Reset}	0.299	F_{Hetero}	0.289

7.53. Aggregated petroleum price for commerce and public

$$\log(P^{petro}_{cp,t}) = \underset{(0.035)}{6.591} - \underset{(0.976)}{0.005}\times\log(P^{petro}_{cp,t-1}) + \underset{(0.000)}{0.523}\times\log\left(FP^{oil}_{t}\right) + \underset{(0.000)}{0.785}\times\log(ER_t) - \underset{(0.007)}{0.215}\times D_{98}$$

$$\varepsilon_{i_t} = 0.910\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.996	$D.W.$	2.018	$\hat{\sigma}$	0.050	F	0.000
F_{Auto}	0.575	χ^2_{Norm}	0.725	F_{Reset}	0.319	F_{Hetero}	0.250

7.54. Aggregated petroleum price for households

$$\log(P^{petro}_{h,t}) = \underset{(0.073)}{3.004} - \underset{(0.757)}{0.041}\times\log(P^{petro}_{h,t-1}) + \underset{(0.000)}{0.644}\times\log\left(FP^{oil}_{t}\right) + \underset{(0.000)}{1.257}\times\log(ER_t)$$

$$\varepsilon_{i_t} = 0.673\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.988	$D.W.$	1.746	$\hat{\sigma}$	0.071	F	0.000
F_{Auto}	0.839	χ^2_{Norm}	0.495	F_{Reset}	0.887	F_{Hetero}	0.857

7.55. Gasoline price

$$\log(P^{gasoline}_{t}) = \underset{(0.817)}{0.289} - \underset{(0.000)}{0.593}\times\log(P^{gasoline}_{t-1}) + \underset{(0.001)}{0.191}\times\log\left(FP^{oil}_{t}\right) + \underset{(0.000)}{0.693}\times\log(ER_t)$$

$$+\underset{(0.006)}{0.150}\times D_{98} - \underset{(0.020)}{0.132}\times D_{09}$$

$$\varepsilon_{i_t} = 0.617\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.989	$D.W.$	1.279	$\hat{\sigma}$	0.059	F	0.000
F_{Auto}	0.107	χ^2_{Norm}	0.749	F_{Reset}	0.209	F_{Hetero}	0.686

7.56. Diesel price

$$\log(P_t^{diesel}) = -1.400 - 0.539\times\log(P_{t-1}^{diesel}) + 0.353\times\log\left(FP_t^{oil}\right) + 0.925\times\log(ER_t)$$
$$(0.324)(0.000) \qquad (0.000) \qquad (0.000)$$

$$- 0.208\times D_{09}$$
$$(0.000)$$

$$\varepsilon_{i_t} = 0.730\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.992	$D.W.$	2.083	$\hat{\sigma}$	0.079	F	0.000
F_{Auto}	0.585	χ^2_{Norm}	0.279	F_{Reset}	0.137	F_{Hetero}	0.662

7.57. Heavy-oil price for non-power

$$\log(P_{np,t}^{heavyo}) = -2.079 - 0.594\times\log(P_{np,t-1}^{heavyo}) + 0.384\times\log\left(FP_t^{oil}\right) + 0.854\times\log(ER_t)$$
$$(0.324)\ (0.000) \qquad (0.000) \qquad (0.000)$$

$$- 0.208\times D_{95} - 0.208\times D_{97}$$
$$(0.000) \qquad (0.000)$$

$\bar{R}^2$	0.990	$D.W.$	2.096	$\hat{\sigma}$	0.082	F	0.000
F_{Auto}	0.439	χ^2_{Norm}	0.171	F_{Reset}	0.118	F_{Hetero}	0.367

7.58. Heavy-oil price for power generation

$$\log(P_{pg,t}^{heavyo}) = -1.303 - 0.149\times\log(P_{pg,t-1}^{heavyo}) + 0.843\times\log\left(FP_t^{oil}\right) + 1.282\times\log(ER_t)$$
$$(0.441)\ (0.269) \qquad (0.000) \qquad (0.005)$$

$\bar{R}^2$	0.988	$D.W.$	2.314	$\hat{\sigma}$	0.062	F	0.000
F_{Auto}	0.625	χ^2_{Norm}	0.618	F_{Reset}	0.208	F_{Hetero}	0.937

7.59. LPG price

$$\log(P_t^{butane}) = -0.606 + 0.699\times\log(P_{t-1}^{butane}) + 0.229\times\log\left(FP_t^{oil}\right) + 0.569\times\log(ER_t)$$
$$(0.001)\ (0.000) \qquad (0.000) \qquad (0.005)$$

$$- 0.322\times D_{09} - 0.603\times D_{11}$$
$$(0.017) \qquad (0.000)$$

$\bar{R}^2$	0.974	$D.W.$	2.114	$\hat{\sigma}$	0.069	F	0.000
F_{Auto}	0.892	χ^2_{Norm}	0.992	F_{Reset}	0.350	F_{Hetero}	0.277

7.60. JA price

$$\log(P_t^{ja}) = \text{-}1.980 + 0.576\times\log(P_{t-1}^{ja}) + 0.444\times\log\left(FP_t^{oil}\right) + 0.332\times\log(ER_t) \text{ - } 0.385\times D_{09}$$
$$\quad(0.004)\ (0.000) \qquad\qquad (0.000) \qquad\qquad (0.002) \qquad\qquad (0.003)$$

$\bar{R}^2$	0.976	$D.W.$	2.591	$\hat{\sigma}$	0.099	F	0.000
F_{Auto}	0.380	χ^2_{Norm}	0.729	F_{Reset}	0.580	F_{Hetero}	0.420

7.61. Non-energy petroleum price

$$\log(P_t^{npetro}) = \text{-}6.774 + 0.553\times\log(P_{t-1}^{npetro}) + 0.428\times\log\left(FP_t^{oil}\right) + 1.054\times\log(ER_t)$$
$$\quad(0.000)\ (0.000) \qquad\qquad (0.000) \qquad\qquad (0.000)$$

$$+ 0.368\times D_{85}$$
$$(0.000)$$

$\bar{R}^2$	0.991	$D.W.$	1.570	$\hat{\sigma}$	0.084	F	0.000
F_{Auto}	0.317	χ^2_{Norm}	0.207	F_{Reset}	0.774	F_{Hetero}	0.864

7.62. LNG price for non-power

$$\log(P_{np,t}^{LNG}) = 3.840 \text{ - } 0.482\times\log(P_{np,t-1}^{LNG}) + 0.238\times\log\left(FP_t^{oil}\right) + 0.287\times\log(ER_t)$$
$$\quad(0.005)\ (0.016) \qquad\qquad (0.002) \qquad\qquad (0.175)$$

$$\text{- } 0.383\times D_{98} \text{ - } 0.136\times D_{01}$$
$$(0.003) \qquad (0.211)$$

$\bar{R}^2$	0.960	$D.W.$	2.248	$\hat{\sigma}$	0.0.83	F	0.000
F_{Auto}	0.163	χ^2_{Norm}	0.365	F_{Reset}	0.750	F_{Hetero}	0.545

7.63. LNG price for power generation

$$\log(P_{pg,t}^{LNG}) = 2.548 \text{ - } 0.111\times\log(P_{pg,t-1}^{LNG}) + 0.610\times\log\left(FP_t^{oil}\right) + 0.939\times\log(ER_t)$$
$$\quad(0.108)(0.449) \qquad\qquad (0.000) \qquad\qquad (0.015)$$

$\bar{R}^2$	0.981	$D.W.$	1.866	$\hat{\sigma}$	0.054	F	0.000
F_{Auto}	0.930	χ^2_{Norm}	0.566	F_{Reset}	0.422	F_{Hetero}	0.549

7.64. City-gas price for industry

$$\log(P_{i,t}^{cgas}) = -\ 3.017 + 0.573\times\log(P_{i,t-1}^{cgas}) + 0.660\times\log\left(P_{np,t}^{LNG}\right) -\ 0.353\times D_{90} -\ 0.321\times D_{99}$$
$$(0.001)\quad(0.000)\qquad\qquad(0.000)\qquad\qquad(0.010)\qquad(0.290)$$

$$-\ 0.321\times D_{02}$$
$$(0.001)$$

$$\varepsilon_{i_t} = 0.521\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.994	$D.W.$	1.505	$\hat{\sigma}$	0.042	F	0.000
F_{Auto}	0.260	χ^2_{Norm}	0.372	F_{Reset}	0.459	F_{Hetero}	0.976

7.65. City-gas price for commerce and public

$$\log(P_{cp,t}^{cgas}) = 0.116 + 0.508\times\log(P_{cp,t-1}^{cgas}) + 0.490\times\log\left(P_{np,t}^{LNG}\right) -\ 0.180\times D_{98} -\ 0.355\times D_{99}$$
$$(0.711)\quad(0.000)\qquad\qquad(0.000)\qquad\qquad(0.000)\qquad(0.000)$$

$$-\ 0.111\times D_{02}$$
$$(0.006)$$

$\bar{R}^2$	0.992	$D.W.$	1.553	$\hat{\sigma}$	0.034	F	0.000
F_{Auto}	0.352	χ^2_{Norm}	0.885	F_{Reset}	0.892	F_{Hetero}	0.180

7.66. City-gas price for households

$$\log(P_{h,t}^{cgas}) = 1.110 + 0.131\times\log(P_{h,t-1}^{cgas}) + 0.771\times\log\left(P_{np,t}^{LNG}\right) -\ 0.758\times D_{89} -\ 0.296\times D_{0011}$$
$$(0.000)\quad(0.000)\qquad\qquad(0.000)\qquad\qquad(0.000)\qquad(0.000)$$

$\bar{R}^2$	0.999	$D.W.$	2.431	$\hat{\sigma}$	0.018	F	0.000
F_{Auto}	0.341	χ^2_{Norm}	0.938	F_{Reset}	0.378	F_{Hetero}	0.224

7.67. Electricity price for industry

$$\log(P_{i,t}^{elec}) = 5.524 + 0.418\times\log(P_{i,t-1}^{elec}) + 0.078\times\log(TC_t^{elec}) -\ 0.055\times D_{01} -\ 0.084\times D_{0911}$$
$$(0.028)\quad(0.042)\qquad\qquad(0.009)\qquad\qquad(0.035)\qquad(0.016)$$

$\bar{R}^2$	0.985	$D.W.$	2.554	$\hat{\sigma}$	0.017	F	0.000
F_{Auto}	0.409	χ^2_{Norm}	0.630	F_{Reset}	0.218	F_{Hetero}	0.693

7.68. Electricity price for commerce and public

$$\log(P^{elec}_{cp,t}) = 4.203 + 0.638\times\log(P^{elec}_{cp,t-1}) + 0.028\times\log(TC^{elec}_{t}) + 0.089\times D_{01} - 0.037\times D_{09}$$
$$(0.153)\quad(0.012)\qquad\qquad(0.042)\qquad\qquad(0.037)\qquad(0.087)$$

$$\varepsilon_{i_t} = -0.305\times\varepsilon_{i_{t-1}} + \upsilon_t$$

$\bar{R}^2$	0.909	$D.W.$	2.644	$\hat{\sigma}$	0.016	F	0.000
F_{Auto}	0.257	χ^2_{Norm}	0.867	F_{Reset}	0.467	F_{Hetero}	0.151

7.69. Electricity price for households

$$\log(P^{elec}_{h,t}) = 5.106 + 0.490\times\log(P^{elec}_{h,t-1}) + 0.067\times\log(TC^{elec}_{t}) - 0.032\times D_{02} - 0.025\times D_{09}$$
$$(0.012)\quad(0.007)\qquad\qquad(0.002)\qquad\qquad(0.056)\qquad(0.091)$$

$\bar{R}^2$	0.980	$D.W.$	2.365	$\hat{\sigma}$	0.011	F	0.000
F_{Auto}	0.605	χ^2_{Norm}	0.881	F_{Reset}	0.559	F_{Hetero}	0.653

7.70. Total main energy cost by industry

$$TC^{e}_{i,t} = P^{e}_{i,t} \times TQ^{e}_{i,t}$$

7.71. Total main energy cost by commerce and public

$$TC^{e}_{cp,t} = P^{e}_{cp,t} \times TQ^{e}_{cp,t}$$

7.72. Total main energy cost by households

$$TC^{e}_{h,t} = P^{e}_{h,t} \times TQ^{e}_{h,t}$$

7.73. Aggregated energy price for industry

$$P^{e}_{i,t} = \frac{1}{TQ^{e}_{i}}(Q^{petro}_{i} \times P^{petro}_{i,t} + Q^{cgas}_{i} \times P^{cgas}_{i,t} + Q^{elec}_{i} \times P^{elec}_{i,t} + Q^{bcoal}_{i} \times P^{bocal}_{np,t})$$

7.74. Aggregated energy price for commerce and public

$$P^{e}_{cp,t} = \frac{1}{TQ^{e}_{cp}}(Q^{petro}_{cp} \times P^{petro}_{cp,t} + Q^{cgas}_{cp} \times P^{cgas}_{cp,t} + Q^{elec}_{cp} \times P^{elec}_{cp,t})$$

7.75. Aggregated energy price for households

$$P_{h,t}^{e} = \frac{1}{TQ_h^e}(Q_h^{petro} \times P_{h,t}^{petro} + Q_h^{cgas} \times P_{h,t}^{cgas} + Q_h^{elec} \times P_{h,t}^{elec} + Q_h^{acoal} \times P_{h,t}^{briq})$$

7.76. Cost share log ratio of petroleum to bituminous coal in industry

$$\begin{aligned} lnsr1_{i,t} = {} & 0.288 - (-0.013 \times w_{i,t}^{cgas} - 0.821 \times w_{i,t}^{elec} - 1.015 \times (w_{i,t}^{petro} + w_{i,t}^{bcoal})) \\ & \times \log(\frac{P_{i,t}^{petro}}{P_{np,t}^{bcoal}}) + (-0.013 - 1.000) \times w_{i,t}^{cgas} \times \log(\frac{P_{i,t}^{cgas}}{P_{np,t}^{bcoal}}) + (-0.821 - 1.000) \\ & \times w_{i,t}^{elec} \times \log(\frac{P_{i,t}^{elec}}{P_{np,t}^{bcoal}}) + 0.802 \times \log(\frac{Q_{i,t-1}^{petro}}{Q_{i,t-1}^{bcoal}}) \end{aligned}$$

7.77. Cost share log ratio of city-gas to bituminous coal in industry

$$\begin{aligned} lnsr2_{i,t} = {} & -0.103 - (-0.013 \times w_{i,t}^{petro} - 0.928 \times w_{i,t}^{elec} - 1.000 \times (w_{i,t}^{cgas} + w_{i,t}^{bcoal})) \\ & \times \log(\frac{P_{i,t}^{cgas}}{P_{np,t}^{bcoal}}) + (-0.013 - 1.015) \times w_{i,t}^{elec} \times \log(\frac{P_{i,t}^{petro}}{P_{np,t}^{bcoal}}) + (-0.928 - 0.857) \\ & \times w_{i,t}^{elec} \times \log(\frac{P_{i,t}^{elec}}{P_{np,t}^{bcoal}}) + 0.802 \times \log(\frac{Q_{i,t-1}^{cgas}}{Q_{i,t-1}^{bcoal}}) \end{aligned}$$

7.78. Cost share log ratio of electricity to bituminous coal in industry

$$\begin{aligned} lnsr3_{i,t} = {} & 0.355 - (-0.821 \times w_{i,t}^{petro} - 0.928 \times w_{i,t}^{cgas} - 0.857 \times (w_{i,t}^{elec} + w_{i,t}^{bcoal})) \\ & \times \log(\frac{P_{i,t}^{elec}}{P_{np,t}^{bcoal}}) + (-0.821 - 1.015) \times w_{i,t}^{petro} \times \log(\frac{P_{i,t}^{petro}}{P_{np,t}^{bcoal}}) + (-0.928 - 1.000) \\ & \times w_{i,t}^{cgas} \times \log(\frac{P_{i,t}^{cgas}}{P_{np,t}^{bcoal}}) + 0.802 \times \log(\frac{Q_{i,t-1}^{elec}}{Q_{i,t-1}^{bcoal}}) \end{aligned}$$

7.79. Cost share log ratio of petroleum to electricity in commerce and pubic

$$\begin{aligned} lnsr1_{cp,t} = {} & -0.293 - (-0.674 \times w_{cp,t}^{cgas} - 0.776 \times (w_{cp,t}^{petro} + w_{cp,t}^{elec})) \times \log(\frac{P_{cp,t}^{petro}}{P_{cp,t}^{elec}}) \\ & +(-0.776 - 0.661) \times w_{i,t}^{cgas} \times \log(\frac{P_{cp,t}^{cgas}}{P_{cp,t}^{elec}}) + 0.833 \times \log(\frac{Q_{cp,t-1}^{petro}}{Q_{cp,t-1}^{elec}}) \end{aligned}$$

7.80. Cost share log ratio of city-gas to electricity in commerce and pubic

$$\begin{aligned} lnsr2_{cp,t} = {} & 0.504 - (-0.674 \times w_{cp,t}^{petro} - 0.776 \times (w_{cp,t}^{cgas} + w_{cp,t}^{elec})) \times \log(\frac{P_{cp,t}^{cgas}}{P_{cp,t}^{elec}}) \\ & +(-0.674 - 0.776) \times w_{i,t}^{elec} \times \log(\frac{P_{cp,t}^{petro}}{P_{cp,t}^{elec}}) + 0.833 \times \log(\frac{Q_{cp,t-1}^{petro}}{Q_{cp,t-1}^{elec}}) \end{aligned}$$

7.81. Cost share log ratio of petroleum to anthracite coal in households

$$lnsr1_{h,t} = 1.280 - (-0.899 \times w_{h,t}^{cgas} - 0.829 \times w_{h,t}^{elec} - 0.483 \times \left(w_{h,t}^{petro} + w_{h,t}^{acoal}\right)) \times \log(\frac{P_{h,t}^{petro}}{P_{t}^{briq}}) + (-0.899 - 0.230) \times w_{h,t}^{cgas} \times \log(\frac{P_{h,t}^{cgas}}{P_{t}^{briq}}) + (-0.829 - 0.301) \times w_{h,t}^{elec} \times \log(\frac{P_{h,t}^{elec}}{P_{t}^{briq}}) + 0.889 \times \log(\frac{Q_{h,t-1}^{petro}}{Q_{h,t-1}^{acoal}})$$

7.82. Cost share log ratio of city-gas to anthracite coal in households

$$lnsr2_{h,t} = 1.342 - (-0.899 \times w_{h,t}^{petro} - 0.834 \times w_{h,t}^{elec} - 0.230 \times \left(w_{h,t}^{cgas} + w_{h,t}^{acoal}\right)) \times \log(\frac{P_{h,t}^{petro}}{P_{t}^{briq}}) + (-0.899 - 0.483) \times w_{h,t}^{petro} \times \log(\frac{P_{h,t}^{petro}}{P_{t}^{briq}}) + (-0.834 - 0.301) \times w_{h,t}^{elec} \times \log(\frac{P_{h,t}^{elec}}{P_{t}^{briq}}) + 0.889 \times \log(\frac{Q_{h,t-1}^{cgas}}{Q_{h,t-1}^{acoal}})$$

7.83. Cost share log ratio of electricity to anthracite coal in households

$$lnsr3_{h,t} = 1.385 - (-0.829 \times w_{h,t}^{petro} - 0.834 \times w_{h,t}^{cgas} - 0.301 \times \left(w_{h,t}^{elec} + w_{h,t}^{acoal}\right)) \times \log(\frac{P_{h,t}^{elec}}{P_{t}^{briq}}) + (-0.829 - 0.483) \times w_{h,t}^{petro} \times \log(\frac{P_{h,t}^{petro}}{P_{t}^{briq}}) + (-0.834 - 0.232) \times w_{h,t}^{cgas} \times \log(\frac{P_{h,t}^{cgas}}{P_{t}^{briq}}) + 0.889 \times \log(\frac{Q_{h,t-1}^{elec}}{Q_{h,t-1}^{acoal}})$$

7.84. Cost share of petroleum in industry

$$w_{i,t}^{petro} = \exp(\frac{lnsr1_{i,t}}{\exp\left(lnsr1_{i,t}\right) + \exp\left(lnsr2_{i,t}\right) + \exp(lnsr3_{i,t}) + 1})$$

7.85. Cost share of city-gas industry

$$w_{i,t}^{cgas} = \exp(\frac{lnsr2_{i,t}}{\exp\left(lnsr1_{i,t}\right) + \exp\left(lnsr2_{i,t}\right) + \exp(lnsr3_{i,t}) + 1})$$

7.86. Cost share of electricity industry

$$w_{i,t}^{elec} = \exp(\frac{lnsr3_{i,t}}{\exp\left(lnsr1_{i,t}\right) + \exp\left(lnsr2_{i,t}\right) + \exp(lnsr3_{i,t}) + 1})$$

7.87. Cost share of bituminous industry

$$w_{i,t}^{bcoal} = 1 - w_{i,t}^{petro} - w_{i,t}^{cgas} - w_{i,t}^{elec}$$

7.88. Cost share of petroleum in commerce and public

$$w_{cp,t}^{petro} = \exp\left(\frac{lnsr1_{cp,t}}{\exp(lnsr1_{cp,t}) + \exp(lnsr2_{cp,t}) + 1}\right)$$

7.89. Cost share of city-gas in commerce and public

$$w_{cp,t}^{cgas} = \exp\left(\frac{lnsr2_{cp,t}}{\exp(lnsr1_{cp,t}) + \exp(lnsr2_{cp,t}) + 1}\right)$$

7.90. Cost share of electricity in commerce and public

$$w_{cp,t}^{elec} = 1 - w_{cp,t}^{petro} - w_{cp,t}^{cgas}$$

7.91. Cost share of petroleum in households

$$w_{h,t}^{petro} = \exp\left(\frac{lnsr1_{h,t}}{\exp(lnsr1_{h,t}) + \exp(lnsr2_{h,t}) + \exp(lnsr3_{h,t}) + 1}\right)$$

7.92. Cost share of city-gas in households

$$w_{h,t}^{cgas} = \exp\left(\frac{lnsr2_{h,t}}{\exp(lnsr1_{h,t}) + \exp(lnsr2_{h,t}) + \exp(lnsr3_{h,t}) + 1}\right)$$

7.93. Cost share of electricity in households

$$w_{h,t}^{elec} = \exp\left(\frac{lnsr3_{h,t}}{\exp(lnsr1_{h,t}) + \exp(lnsr2_{h,t}) + \exp(lnsr3_{h,t}) + 1}\right)$$

7.94. Cost share of anthracite coal in households

$$w_{h,t}^{acoal} = 1 - w_{h,t}^{petro} - w_{h,t}^{cgas} - w_{h,t}^{elec}$$

c) Environment

7.95. CO_2 Emissions by petroleum products

$$\begin{aligned} CO2_t^{petro} = {} & Q_{i,t}^{petro} \times \beta_i^{petro} + Q_{i,t}^{npetro} \times \beta^{naphtha} + Q_{cp,t}^{petro} \times \beta_{cp}^{petro} + Q_{cp,t}^{npetro} \times \beta^{naphtha} + \\ & Q_{h,t}^{petro} \times \beta_h^{petro} + Q_{h,t}^{npetro} \times \beta^{naphtha} + Q_{cp,t}^{petro} \times \beta_{cp}^{petro} + Q_{cp,t}^{npetro} \times \beta^{naphtha} + \\ & Q_t^{ja} \times \beta^{ja} + Q_t^{avig} \times \beta^{avig} + Q_{tr,t}^{gasoline} \times \beta^{gasoline} + Q_{tr,t}^{diesel} \times \beta^{diesel} + \\ & Q_{tr,t}^{heavyo} \times \beta^{heavyo} + Q_{tr,t}^{LPG} \times \beta^{LPG} + Q_{heat,t}^{petro} \times \beta^{heavyo} + Q_{cgas,t}^{petro} \times \beta^{LPG} \end{aligned}$$

7.96. CO_2 Emissions by bituminous coal

$$CO2_t^{coal} = TQ_t^{bcoal} \times \beta^{bcoal} + TQ_t^{acoal} \times \beta^{acoal}$$

7.97. CO_2 Emissions by natural gas

$$CO2_t^{gas} = Q_t^{cgas} \times \beta^{cgas} + Q_{heat,t}^{LNG} \times \beta^{LNG}$$

7.98. Total CO_2 Emissions

$$CO2_t = CO2_t^{petro} + CO2_t^{coal} + CO2_t^{gas} + CO2_t^{elec}$$

7.99~119. Carbon pricing

$$PC_{np,t}^{acoal} = P_{np,t}^{acoal} + (CTAX \times \beta^{acoal})$$

$$PC_{pg,t}^{acoal} = P_{pg,t}^{acoal} + \left(CTAX \times \beta^{acoal}\right)$$

$$PC_{np,t}^{bcoal} = P_{np,t}^{bcoal} + (CTAX \times \beta^{bcoal})$$

$$PC_{pg,t}^{bcoal} = P_{pg,t}^{acoal} + \left(CTAX \times \beta^{bcoal}\right)$$

$$PC_t^{briq} = P_t^{briq} + (CTAX \times \beta^{briq})$$

$$PC_t^{gasoline} = P_t^{gasoline} + \left(CTAX \times \beta^{gasoline}\right)$$

$$PC_t^{diesel} = P_t^{diesel} + (CTAX \times \beta^{diesel})$$

$$PC_{np,t}^{heavyo} = P_{np,t}^{heavyo} + (CTAX \times \beta^{heavyo})$$

$$PC_{pg,t}^{heavyo} = P_{pg,t}^{heavyo} + (CTAX \times \beta^{heavyo})$$

$$PC_{tr,t}^{LPG} = P_{tr,t}^{LPG} + (CTAX \times \beta^{LPG})$$

$$PC_{i,t}^{petro} = P_{i,t}^{petro} + (CTAX \times \beta_i^{petro})$$

$$PC_{cp,t}^{petro} = P_{cp,t}^{petro} + (CTAX \times \beta_{cp}^{petro})$$

$$PC_{h,t}^{petro} = P_{h,t}^{petro} + (CTAX \times \beta_h^{petro})$$

$$PC_t^{ja} = P_t^{ja} \times (PC_{np,t}^{heavyo} / P_{np,t}^{heavyo})$$

$$PC_t^{npetro} = P_t^{npetro} \times (PC_{i,t}^{petro} / P_{i,t}^{petro})$$

$$PC_{np,t}^{LNG} = P_{np,t}^{LNG} + (CTAX \times \beta^{LNG})$$

$$PC_{pg,t}^{LNG} = P_{pg,t}^{LNG} + (CTAX \times \beta^{LNG})$$

$$PC_{i,t}^{cgas} = P_{i,t}^{cgas} + (CTAX \times \beta^{cgas})$$

$$PC_{cp,t}^{cgas} = P_{cp,t}^{cgas} + (CTAX \times \beta^{LNG})$$

$$PC_{h,t}^{cgas} = P_{h,t}^{cgas} + (CTAX \times \beta^{LNG})$$

$$PC_{tr,t}^{cgas} = P_{tr,t}^{cgas} + (CTAX \times \beta^{LNG})$$

A.3.3. CARBON EMISSION FACTORS

Table A.3.2. Carbon emission factors

`			Carbon Emission Factor	
			C kg/GJ	C Ton/TOE
Liquid Fossil	Primary fuels	Crude oil	20.00	0.829
		Natural Gas Liquids	17.20	0.630
	Secondary fuels	Gasoline	18.90	0.783
		Avi-gasoline	18.90	0.783
		Other Keroseone	19.50	0.812
		Jet Kerosene	19.60	0.808
		Diesel Oil	20.20	0.837
		Heavy Oil	21.10	0.875
		LPG	17.20	0.713
		Naphtha	20.00	0.829
		Bitumen	22.00	0.912
		Lubricants	20.00	0.829
		Petroleum Coke	27.50	1.140
		Refinery Feedstock	20.00	0.829
Soild Fossil	Primary fuels	Anthracite	26.80	1.100
		Cocking coal	25.80	1.059
		Other Bituminous Coal	25.80	1.059
		Lignite	27.60	1.132
		Peat	28.90	1.186
	Secondary fuels	BKB & Patent Fuel	25.80	1.059
		Coke Oven	29.50	1.210
Gaseous Fossil		Natural Gas (Dry)	15.30	0.637
Biomass		Solid Biomass	29.90	1.252
		Liquild Biomass	20.00	0.837
		Gas Biomass	30.60	1.281

Source: IPCC (1996)

A.3.4. RESULT OF THE EX-POST SIMULATION

Table A.3.3. Ex-post simulation errors

Notation	MAPE	Notation	MAPE	Notation	MAPE
CG	1.04	P^{ja}	4.79	TAX	2.34
CP	1.11	P_{np}^{LNG}	5.50	TC_{cp}	2.14
ER	5.70	P_{pg}^{LNG}	5.87	TC_h	1.62
EX	3.26	P^{npetro}	5.64	TC_i	1.06
I	2.42	P_{cp}^{petro}	4.70	TQ^{acoal}	3.41
IM	3.09	P_h^{petro}	5.38	TQ^{bcoal}	5.44
K	0.91	P_i^{petro}	4.57	TQ^{cgas}	2.57
L	0.36	P^w	0.84	TQ_h^e	1.40
L^*	0.36	PY	1.17	TQ_i^e	0.96
$LNSR1_{cp}$	7.08	Q_{cp}^{acoal}	0.00	TQ_{cp}^e	2.36
$LNSR1_h$	4.08	Q_h^{acoal}	15.72	TQ^{elec}	1.75
$LNSR1_i$	6.24	Q_i^{acoal}	3.94	TQ^{fe}	1.52
$LNSR2_{cp}$	4.05	Q_{nh}^{acoal}	5.59	TQ^{petro}	1.40
$LNSR2_h$	3.63	Q^{avig}	6.54	TQ_{cp}^{petro}	6.58
$LNSR2_i$	12.43	Q^{coke}	3.60	TQ_h^{petro}	6.35
$LNSR3_h$	3.74	Q_i^{bcoal}	5.73	TQ_i^{petro}	1.44
$LNSR3_i$	4.90	Q_{cp}^{cgas}	5.66	TQ_{tr}^{petro}	1.37
$M3$	1.45	Q_{heat}^{cgas}	2.07	TS^{cgas}	4.68
P_{np}^{bcoal}	4.70	Q_h^{cgas}	2.38	TS^{elec}	1.99
P_{pg}^{bcoal}	6.79	Q_i^{cgas}	2.59	TS^{heat}	5.60
P_t^{butane}	5.10	Q_{tr}^{cgas}	2.54	TS^{pe}	0.88
P^c	0.52	Q_{cp}^{elec}	2.38	W	2.23
P_{cp}^{cgas}	4.27	Q_h^{elec}	2.59	w_h^{acoal}	12.66
P_h^{cgas}	4.04	Q_i^{elec}	2.54	w_i^{bcoal}	14.44
P_i^{cgas}	6.43	Q_{tr}^{elec}	2.84	w_{cp}^{elec}	2.04
P^d	1.43	$Q_{tr}^{gasoline}$	2.13	w_{cp}^{cgas}	8.26
P^{diesel}	4.14	Q_{tr}^{heavyo}	2.34	w_h^{cgas}	4.28
P_{cp}^{elec}	0.86	Q^{heat}	3.11	w_i^{cgas}	6.19
P_h^{elec}	0.77	Q^{ja}	2.05	w_h^{elec}	3.52
P_i^{elec}	1.00	Q_{cp}^{ja}	2.05	w_i^{elec}	2.52
P^{ex}	0.33	Q_{tr}^{ja}	2.05	w_{cp}^{petro}	7.39
P_{cp}^e	0.52	Q_{tr}^{LPG}	1.35	w_h^{petro}	5.13
P_h^e	0.50	Q^{npetro}	2.49	w_i^{petro}	3.79
P_i^e	3.53	Q_{cp}^{npetro}	2.49	u	13.32
$P^{gasoline}$	4.94	Q_h^{npetro}	2.49	Y	0.96
P_{np}^{heavyo}	5.42	Q_i^{npetro}	2.49	YCB	5.16
P_{pg}^{heavyo}	7.45	Q_{cp}^{petro}	8.30	YD	1.40
P^i	1.51	Q_h^{petro}	6.42	YP	1.92
P^{im}	4.29	Q_i^{petro}	4.41	ρ	1.98

CHAPTER 4

THE EFFECT OF RESTRUCTURING THE CURRENT ENERGY TAXES AND ELECTRICITY PRICING SYSTEM WITH THE CARBON TAX POLICY ON THE ECONOMY

4.1. INTRODUCTION

As the Korean government set a national goal to reduce greenhouse gases (GHG) emissions by 30 per cent compared to Business As Usual (BAU) by 2020, introducing a carbon tax has been considered as a cost-effective policy, since the carbon tax internalizes the externality of GHG emissions of fossil fuels through levying taxes on the carbon contents of fossil fuels and the government takes new revenue from the carbon tax which can be re-distributed in various ways. In particular, the revenue can be used to reduce pre-existing distortionary taxes[50].

However, the concern has been raised as to whether the carbon tax policy would put a heavier burden on the economy through pushing up products' prices, thereby weakening industrial competiveness in a highly carbon-emitting country. Therefore, a number of studies have attempted to explore the effects of the carbon policy on the economy using general

[50] While the carbon tax will encourage firms and consumers to use more efficient and consume less carbon intensive products and the carbon tax raises revenues that can be redistributed in several ways such as subsidising green technology or reducing existing taxes, the cost of administrating the tax may be expensive and it is difficult to estimate the level of external cost and how much the carbon tax should be charged.

equilibrium models in recent years. In particular, they have paid attention to the effects of various carbon tax recycling methods. But, fewer studies have attempted to examine the effects of restructuring current inefficient taxes on energy products and the regulated electricity pricing structure when a carbon tax is introduced.

Hoeller and Coppel (1992a, b) point out that distortions in pre-existing taxes on energy would be worsened when a country adopts a carbon tax policy without adjustment. Their simulation results confirm that reforming pre-existing energy taxes reduce the economic costs of the carbon tax.

The current tax system of Korea has been imposed on energy products to obtain revenues regardless of managing the externality of environmental pollution caused from consuming the energy products. For example, while relatively high taxes are imposed on kerosene, LPG, and LNG compared to their social costs, no taxes are levied on coal which is a carbon-intensive fuel. Besides, existing electricity tariffs have been managed from the government's intervention to remain at lower levels than costs to promote industrial competitiveness and price stabilization. It is generally agreed that these current taxes and electricity pricing system resulted in inefficient resource allocation.

The unreasonable energy consumption structure caused by the existing systems would be worsened when the carbon tax policy is introduced if the relative prices are further distorted by the carbon tax. As a consequence, adding the carbon tax without rearranging the current energy tax and pricing systems is likely to be a relatively inefficient policy.

Therefore, these concerns over the current taxes on energy products and electricity price issues motivate us to analyse the effect of improving the energy tax and electricity price system when the carbon tax is introduced. We use the integrated model that couples the macro-econometric model with the MCP electricity market model described in the previous Chapter Three. Four scenarios: no carbon taxation (Business As Usual, BAU); 50,000 won per tonne of carbon (won/Cton); 50,000 won/Cton with energy taxes reform; and 50,000 won/Cton with energy taxes and electricity price reforms; will be simulated in order to compare the quantitative effects of the different scenarios on the economy. The carbon tax rate refers to existing studies Kim, 2012; and Park and Kim, 2012) and the case of a European country, Denmark, in which the carbon tax has been operated since 1996. The result shows that restructuring energy taxes and the electricity pricing system play an important role on determining economic costs of the carbon tax and emissions. Overall, the restructuring cases are shown to be more cost-effective than the case without restructuring.

The rest of this chapter is organized as follows. Section two reviews the theories of the carbon tax and previous literature on the effects of the carbon tax policies. Section three describes the current status of energy taxes and electricity pricing system in Korea. Section four performs the simulations of the carbon tax scenarios. Section five concludes this chapter.

4.2. LITERATURE REVIEW

A carbon tax is a type of Pigovian tax (Pigou, 1920) that internalises a negative externality (for example, global warming) by imposing a tax per unit of emissions which is equal to the marginal social cost in order to prevent the market failure incurred from the externality. The carbon tax is imposed on the carbon content of fossil fuels such as petroleum products, coal, and city-gas. The combustion of those products releases CO_2 into the atmosphere which is one of the greenhouse gases (GHG) causing global warming.

The carbon tax creates an economic incentive for agents to abate emissions by the following factors; firstly, raising the prices of fossil fuels decreases real income, and thus reduces consumption of the fuels in the short-run. Secondly, the changes in relative prices among the fuels prompt agents to substitute less carbon-intensive fuels for carbon intensive ones in the short-run. Lastly, high energy prices facilitate investment in energy-saving technology and development of GHG intensity-reducing technology. In addition to the incentive, the carbon tax generates revenue which can be re-distributed in various ways. In particular, the government can use the revenue to reduce existing distortionary taxes such as labour income and capital taxes. For those reasons, the carbon tax is regarded as one of the most efficient policies to reduce GHG emissions.

The effect of a carbon tax has already been reported in an extensive international and domestic literature; Orlov et al. (2013) provides a survey of theoretical studies and empirical research on the impact of a carbon tax, mainly the possibility of double dividend – both reduce GHG emissions and lower the costs of a tax system. Tol (2013) collects statistics of empirical studies on the economic impact of climate change and the marginal damage costs. Goulder (2013) and Donald and Toder (2014) summarise the issues of a carbon tax in terms from the point of view of a public finance.

Given the purpose of this thesis, the literature review focuses on the problem of distortions in energy taxes and the electricity pricing system and on domestic studies of the effects of a carbon tax on the economy.

It is also worth briefly mentioning notable studies analysing interaction with the other taxes. Bovenberg and Mooij (1994); Goulder (1995); and Wissema and Dellink (2007), focus on assessing the double dividend hypothesis (i.e. improvement in both the environment and the economy) by reducing distorting pre-existing taxes such as capital and labour taxes through the carbon tax revenue recycling. A recent paper, Goulder (2013), reviews this literature from the point of view of how climate change policies and environmental policies interact with the fiscal system including pre-existing taxes. The paper points out that a tax on energy is an implicit tax on factors of production. For example, if a carbon tax is introduced, the implicit tax on labour increases the labour supply curve further compared to the case of pre-existing tax on labour. Therefore, this leads to a further reduction in labour supply which is an additional efficiency loss, termed the tax-interaction effect. Goulder (2013) specifies necessary conditions for the double dividend in real world economies; (i) the initial tax system must be inefficient along some non-environmental dimension, and (ii) the revenue-neutral tax reform reduces this non-environmental inefficiency.

On the other hand, Kopp and Pizer (2007) and Ismer and Neuhoff (2007) argued the importance of imposing border tax adjustments (BTAs) for economic efficiency in carbon emission abatement among countries. Other studies, Goh (2004), Demailly and Quirion (2006), Babiker and Rutherfod (2005), Metcalf and Weisbach (2009), and Metcalf (2013) point out the necessity of the BTAs for preventing carbon leakage defined as increase in GHG emissions by shifting production or investment from high-tax countries to low-tax countries.

Earlier Korean studies in the late 1990s have focused on the effects of a carbon tax on economic growth and reduction in emissions. Kang (1998) compared the effects of a carbon tax, ad valorem tax, and unit tax on energy on the main macroeconomic variables and on emissions reduction using a CGE model. He found that the carbon tax is the most cost-effective policy for emission mitigation. Kang (1999) investigated the effects of the carbon tax, domestic emission trading, and international emission trading policies on the economy with a CGE model. The results show that domestic policies would cause a heavy burden on the economy because of the high marginal abatement cost, so that introducing international emission trading is needed to achieve the emission target cost effectively. Shin (2000) compared imperfect competition with economies of scale and with constant returns to scale (CRTS) with perfect competition by adopting the CGE model. He concludes that the CRTS case may underestimate the economic cost of the carbon tax. Bu (2002, 2003) built up a macro-econometric model which consists of macroeconomic, energy, and environmental modules. The model is applied to analyse the impact of the carbon tax policy on the economy. He found that reinvestment into energy efficiency and renewable energy from the tax revenue can reduce the economic loss caused by the carbon tax policy.

While earlier studies simply assumed that the carbon tax revenue is re-distributed to households as a lump-sum transfer, later works paid attention to the role of the carbon revenue recycling methods. Oh and Cho (2001) analysed the different impacts of the carbon tax when the revenue is used in one of several possible ways; reduction in income tax, pay-roll tax, or corporate income tax using an overlapping general equilibrium model. The study cautiously concludes that carbon tax recycling by reducing the corporate income tax may increase GDP despite the reduction of emissions. Ryu and Cho (2004) analysed the cost of a carbon tax, performance standard, mandated technology, and fuel tax, given the pre-existing distortions from income tax, corporate tax, and value added tax exist using a CGE model. The results confirm that the GDP loss was the smallest in the carbon tax case among the policies. Lim and Kim (2010) have focused on the payroll and corporate tax reduction. Shin et al. (2010) have compared the lump-sum transfer and pay-roll tax reduction. The two studies (Lim and Kim, 2010; Shin et al., 2010) using the CGE model point out that employment can be improved if the carbon tax revenue is recycled to reduce the payroll tax.

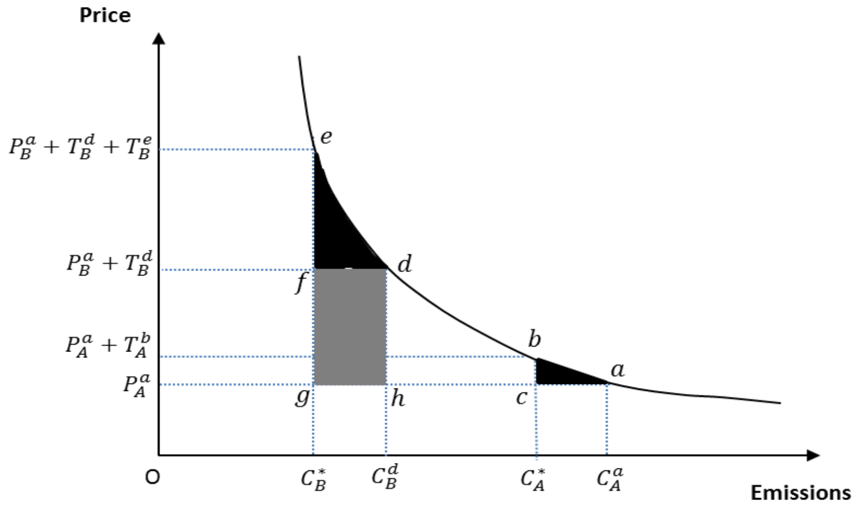

Figure 4.1. Marginal and average cost of carbon taxes

Source: Holeller and Coppel (1992b)

However, these works have shed little light on the effects of reforming pre-existing taxes on energy products and energy pricing system when the carbon tax is introduced. Hoeller and Coppel (1992a, b) give convincing answers to these questions with the illustrative Figure 4.1.above;

Assume that there are two countries (A and B), they have the same fuel and the demand function satisfying the law of diminishing marginal utility, no tax exists in country *A*, and the fuel is taxed at T_B^d in country *B*. Thus, the prices of the fuel are determined at P_A^a in country *A* and $P_B^a + T_B^d$ in country *B*, which leads to emissions C_A^a and C_B^d respectively. If both governments in two countries decide the same reduction target (i.e. $C_A^a - C_A^* = C_B^d - C_B^*$), different levels of the carbon tax are required: T_A^b in country *A* and T_B^e in country *B*. Therefore, the cost measured by loss in consumer surplus is the triangle area, $\boldsymbol{abc}$ in country *A*. In the case of country *B*, the cost calculated by the difference between total loss, the triangle area, $\boldsymbol{ega}$ and the loss from the pre-existing tax, the triangle area, $\boldsymbol{adh}$ is the trapezoid area, $\boldsymbol{degh}$. For any demand functions; linear or hyperbolic curves (the cost in the linear case is larger than in the hyperbolic one), the area $\boldsymbol{degh}$ is larger than $\boldsymbol{abc}$. Therefore, a pre-existing tax enlarges the cost incurred by introducing the carbon tax. However, it is important to note that if the tax is set at the right level to internalise externalities such as congestion costs, the economic cost is equal to the area of triangle $\boldsymbol{def}$, since the remaining part of costs, $\boldsymbol{fdhg}$ would be offset through recycling the revenue for improvement in social welfare. If carbon-intensive fossil fuels such as coal and heavy-oil are untaxed or lightly taxed compared to their social costs, the economic cost is larger than the area of $\boldsymbol{def}$. Thus, the optimum level of the pre-existing tax determines the economic cost which has a range between $\boldsymbol{def}$ and $\boldsymbol{fdhg}$. Practically, Hoeller and Coppel (1992a,b)'s simulation results using a partial equilibrium model advocate that both economic cost and emissions could be reduced through rearranging the existing taxes to reflect the externalities of fossil-fuel consumption. Burniaux et al. (1992) also find that pricing energy efficiently and then imposing a carbon tax leads to cutting CO_2 emissions more cost-effectively through energy conservation and substitutions. Paltsev et al. (2005) analysed the effects of a carbon tax exemption for transportation fuels on the economy in U.S. and European countries via a general equilibrium model. They point out that a pre-existing tax affects the policy cost; if the pre-existing tax is distorted, it increases the cost.

Recently, growing recognition of the necessity of reforming the existing energy tax system before introducing a carbon tax has been reflected in quantitative simulation studies. Jung and Park (2010) estimated the inefficiency of energy consumption caused from current abnormal electricity prices using a logit cost share model. The result shows that a cost reflective price is able to produce net benefits through saving fuel and imports for power generation. Park and Kim (2012) analysed the effect of taxation of electricity consumption and coal for power generation and CO_2 emissions using a CGE model. Lastly, Kim (2012) examined the influence of existing energy taxes on the economy when a carbon tax is introduced using a CGE model. Tax recycling methods such as a lump-sum transfer and payroll tax reduction are considered. They suggest that reforming the pre-existing tax system can lessen costs for reducing emissions. This research directs our attention to reforming the pre-existing energy tax system, as in Kim (2012). But, our approach can be distinguished in that we analyse the current electricity price system, together with the energy taxes, and adopt the integrated model combining a macro-econometric model and an MCP electricity market model which allows analysing the current electricity pricing system.

This integrated model has advantages over the CGE model that the earlier studies adopted. While the CGE model has limitations to capture the electricity's sector, regarded as the most influential sector to determine the carbon cost, due to simplified supply functions, the integrated model has the most suitable method to represent the demand pattern for electricity and technical properties of power plant precisely by building up a specialized module for the electricity sector. Furthermore, CGE models borrow the value of parameters from outside rather than using direct estimation. On the other hand, all behavioural equations in the integrated model are set up after econometric justification. Consequently, the integrated model can be expected to provide a more accurate method to examine the effect of a carbon policy on the economy.

It is also worth mentioning that CGE studies over a long-term period can be used to examine the effects of technical progress scenarios on carbon costs. This routine is subject to criticism; Herm (2003) point out the assumption for technical progress should be robustly scrutinised as the assumption will lower costs of energy supply or efficiency, and explain the reason why past predictions of falling costs have not realised. Therefore, we employ a dynamic linear logit-model derived from Tradeway (1971)'s optimal path to adjustment process theory which is able to capture gradual changes in energy demand over the long-run due to technological elements empirically (see literature review on section 3.2.3.2(b) in chapter 3), rather than matching exogenous assumptions for technical progress.

4.3. CURRENT ENERGY TAXES AND PRICING SYSTEM IN KOREA[51]

4.3.1. Energy taxes

A wide variety of energy taxes are used around the world; the International Energy Agency produces regular reports (see particularly, IEA statistics, 2013). This section, however, concentrates on the taxes and levies imposed on energy products in Korea.

Various taxes and levies have been imposed on petroleum products in Korea. For example, there are the transportation tax, individual consumption tax, education tax, local motor fuel tax, value added tax, customs, import and sales levy, safety management levy, and quality management levy. The individual consumption tax on gasoline and diesel was replaced by the transportation tax as a temporary measure from 1994 to 2006. The term, 'transportation tax' has been changed to 'transportation-energy-environment tax' since 2007. Objects of the taxation are gasoline, diesel, and similar substitute fuels for petroleum. The transportation-energy-environment tax is a flexible tariff system with basic tax rate of 30%. The education tax has been imposed at 15% of the transportation-energy-environment tax or individual consumption tax, which is used for expenditure related to education business. The tax rate on local motor fuel introduced in January, 2000 increased from 26.5% of the transportation tax to 32.5% of the transportation-energy-environment tax in July, 2007, which is mainly spent for subsidising transportation. In addition to these taxes, the import and sales

[51] This section refers to Jung and Park (2010) who conduct a study analysing problems of the existing energy tax and price system.

levy has been introduced since 2001 for demand management and price stabilization. This tax system for petroleum products has been transformed from an ad valorem tax to a unit tax since 1996 in order to gain revenues steadily in spite of volatile international oil prices and raise foreseeability. In the case of city-gas and electricity, value added tax, individual consumption tax, duties and several levies are imposed on the city-gas tariff. But only value added tax and electric power industry basis fund are levied on the electricity tariff (see Table A.4.1 in appendix for current energy taxation system).

As explained above, these taxes have been introduced mainly for securing tax revenue and financing transportation infrastructure expenditure. However, these complex taxes on petroleum products are far apart from the purpose that induces end users to save energy consumption and reduce environmental pollution through raising prices by taxation so as to reflect social costs of externalities. Even worse, the government levies a different tax rate on each energy product without a clear standard, which contradicts the principle of equal taxation. Jung and Park (2010) assess the structure of energy prices and analyse its problems in Korea. They compare the taxes rates on energy products with social costs which include traffic congestion costs and environmental costs. They point out that excessive tax rates and additional charges on kerosene and propane should be reduced, while the tax rate on heavy-oil and diesel should be increased.

Figure 4.2 compares social costs and taxes of energy products. As mentioned in Jung and Park (2010), overall, the current tax system does not reflect social costs correctly, even though various taxes are imposed on petroleum products. And the inequalities in tax burdens bring distortions in energy consumption, which will be explained later.

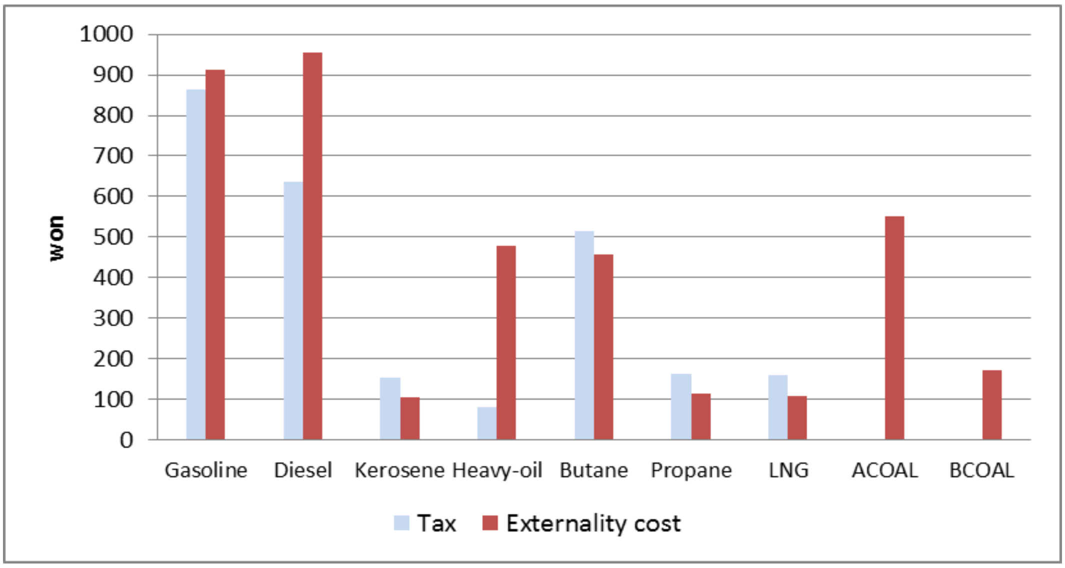

Figure 4.2. Energy product's externality cost and tax

Source: Jung and Park (2010)

Note: the externality cost consists of air pollution, GHG emission, and traffic congestion. Their monetary value refers to European Commission Directorate General Environment (2005); EU-ETS emissions permit price, 25 EUR/tCO_2, and the Cho et al. (2007) respectively.

ACOAL and BCOAL represent anthracite and bituminous coal respectively.

4.3.2. Energy prices

While petroleum products prices have been determined by the price mechanism in a competitive market as the government has introduced price liberalization since 1997, the tariffs of network energy such as city-gas and electricity have been regulated by Rate of Return Regulation (RORR) by the government.

It is generally agreed that the biggest problem the network energy pricing system facing is for electricity. The electricity tariff system is primarily divided by end user classification and then further subdivided into groups according to voltage and contracts. Different prices are charged to each type of end-users. The relatively higher tariffs have been imposed on residential and general users to guide saving energy, whereas lower tariffs have been levied on the industrial and agriculture sectors to enhance industrial competiveness, because electricity is regarded as one of the important input factors for production in Korea. These different compensation rates lead to cross-price subsidy systems.

Overall, the electricity tariffs for all customers are too low to cover supply costs. The Korea Electric Power Corporation, (KEPCO) which is a monopolistic supplier has never gained the desired level of RORR since 2003 by the government's intervention. Table 4.1 shows the current average electricity cost and price in Korea. Although the fuel costs for power generation have risen significantly since the mid-2000s, the increase in electricity tariff has stayed at a lower level than the rise in the cost, due to the government regulation. The government planned to introduce a "linking the electricity tariff with fuel procurement expenses" system in July, 2011 in order to readjust the electricity prices to a realistic level. But, the government postponed the effective date of the regulation, owing to concerns over a rise in inflation. Thus, the average selling price has been consistently lower than the average cost, as seen in Table 4.1.

Table 4.1. Average electricity costs and price in Korea (unit: won/kWh)

	2005	2006	2007	2008	2009	2010	2011
Average cost	75.88	80.48	82.95	102.00	92.06	96.27	103.31
Average selling price	74.39	76.45	77.71	79.24	84.23	86.80	90.32
Compensation Rate (%)	98.00	95.00	93.70	77.70	91.50	90.20	87.40

Source: Jung and Park (2010)

4.3.3. Distortion in energy consumption

Aforementioned, the inequalities in tax assessments and the government's network price regulations cause relative energy price distortions and an unreasonable energy consumption structure. In particular, the electricity prices became significantly lower than some petroleum products, because fuel costs for power generation were not reflected accurately in the electricity tariffs at the right time and relatively high taxes are imposed on petroleum produces. Table 4.2 compares the two petroleum products for heating and electricity prices.

Table 4.2. Petroleum and Electricity prices (unit: thousand won/TOE)

	Petroleum		Electricity			
	Kerosene	Propane	Households	Public	Industry	Agriculture
2005	1,004	943	1,059	1,107	701	485
2006	1,076	1,036	1,090	1,138	720	500
2007	1,046	1,104	1,102	1,135	751	494
2008	1,384	1,485	1,135	1,108	770	493
2009	1,091	1,309	1,140	1,145	857	490
2010	1,201	1,504	1,202	1,150	891	495
2011	1,476	1,688	1,222	1,182	945	495

Source: Author's calibration based on Korean Energy Economic Institute (2012)

Thus, the customers lean excessively toward electricity for heating. In view of energy conversion and transmission efficiency, the position of current electricity consumption contradicts the optimal allocation of resources[52].

Figure 4.3 illustrates changes in the fuel mix of final energy demands from 1990 to 2010. We exclude coking coal and petroleum products for non-energy use to focus on pure-energy use by end-users. The share of electricity in final energy rose from 13.6% in 1990 to 30.6% in 2010. On the other hand, the share of petroleum in final energy, which accounts for the largest share, 70.8% in 1995, decreased to 43.8% in 2010. As LNG has been imported

[52] Note that Korea has not experienced supply interruptions so far. Besides, fossil fuels for power are also imported from other countries. Thus, it cannot be seen that security of supply concerns restricted the current excessive demand for electricity.

from 1986, the share of city-gas also steadily increases to 17.3% in 2010 from 1.7% in 1990. The share of coal, which occupied 20.3% in 1990, sharply decreases to 8.3% of final energy demands.

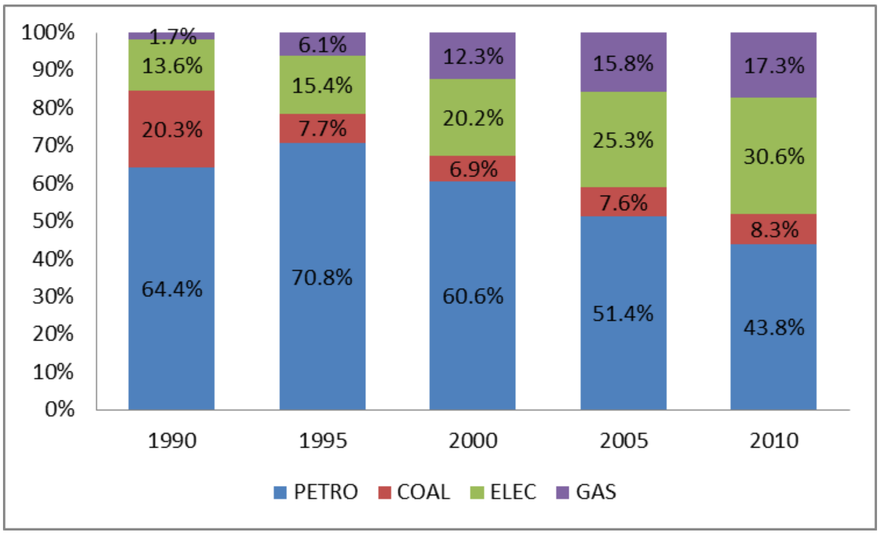

Figure 4.3. The change in final energy demands from 1990 to 2010

As seen from the share of electricity and petroleum, the low electricity tariff with the tax system drives out oil-stoves and promotes the installation of electric heaters, and consequently the demand for electricity goes on rapidly growing. This excessive demand for electricity gives rise to concern over lack of reserve supplies at peak times in summer and winter. To crown all, a temporary blackout took place on September 15th, 2011 due to a surge in demand caused by unseasonably hot Fall weather, together with reduced capacity because of regular maintenance.

Furthermore, the abnormal energy pricing system incurred excessive electricity demands in Korea where coal is the dominant technology in generation (bituminous and anthracite coals represent 40 per cent in total generation in 2010) and it is hard to reduce GHG emissions from coal power plants given the limited abatement options for coal fired power.

There are, overall, three types of abatement technology; energy saving, fuel-switching (oil-gas), and Carbon Capture and Storage (CCS), although its feasibility is uncertain at this time. The government also pays attention to a new technology; an Integrated Gasification Combined Cycle (IGCC) power plant that reduces emissions significantly through coal gasification, but its cost is much higher than the traditional coal power plant at this stage. Dealing with emissions from coal fired power plant is a key factor to help mitigate GHG emissions in Korea.

To sum up, the price stabilization and industrial competiveness from the electricity price intervention is an offset to the inadequate energy consumption structure and aggravated environmental externalities.

4.4. METHODOLOGY AND SIMULATION

4.4.1. Methodology

Carbon tax policy simulations are conducted using the integrated model combining the macro-econometric model and the MCP electricity model presented in the second and third chapters. The model has advantages over existing studies in that the electricity sector which is the largest source of emissions is modelled more accurately by employing the bottom-up method and fuel-switching effects in the non-electricity sector are examined empirically by adopting the cost logit model which is an econometric model of inter-fuel substitution. Besides, the parameters on agent's behavioural equations verified by econometric methods capture the current pricing system; adopting the partial adjustment model is able to explain the relatively slow adjustment of the price level. Thus, the model is expected to provide realistic quantified results for the carbon tax policy's effects on the economy.

We run an ex-post dynamic simulation given exogenous variables such as foreign countries' GDP, CPI, interest rate, and international price indices over the period from 2005 to 2011. A policy experiment requires at least two simulations; a controlled simulation which produces a reference case solution and a policy disturbed simulation which provides a new solution which reacts to the impact of changing parameter values or exogenous variables by setting a policy scenario. Macro-econometric studies usually measure a percentage change in an endogenous variable corresponding to different carbon tax scenarios in order to examine the impacts of a policy on the economy.

It is worth defining the multiplier. The difference between the reference case and the policy solution give a multiplier[53] which is normally measured by a percentage change in an endogenous variable to correspond to an increase in a policy variable of 1. For example, increase a policy variable, *G* by 2, and then a multiplier is obtained by taking the changes in a endogenous variable *Y* and dividing the changes in *Y* by the size of the change in *G*, 2 which is corresponds to an increase in *G* of 1 (For details, see page 422 in Pindyck and Rubinfeld, 1997). Thus, the multiplier can be regarded as an index adjusted by the scale of the change in a policy variable in order to evaluate the extent to which a change in one variable affects other variables. Finally, the policy effects on the economy can be figured out by looking at the multipliers of the endogenous variable.

[53] A dynamic model which has lagged variables yields a sequence of multipliers. An impact multiplier (or short-term multiplier) is the change in the initial first-period and the total long-run multiplier is obtained by summing up all the dynamic multipliers over the simulation period (Pindyck and Rubinfeld, 1997).

4.4.2. Scenarios

In view of existing literature (Kim, 2012; Park and Kim, 2012) analysing the effects of the carbon tax rate on the Korean economy and Denmark in which the carbon tax rate, 16.4 U.S. dollars per tonne of CO_2[54] has been uniformly imposed on all fossil fuels in 2007 (Kim, 2012), a carbon tax of 50,000 won/CTon[55] is adopted for simulation. The carbon tax is imposed on coal (anthracite coal and bituminous coal), petroleum goods (gasoline, kerosene, diesel, heavy oil, propane, butane, and non-energy oil), and LNG.

As explained in section 4.3, several petroleum products such as kerosene, LPG, and city-gas are already highly taxed compared to their social costs and the electricity supplier receives tariffs which are lower than its costs due to government intervention. Therefore, we examine the effects of restructuring the existing electricity pricing and tax systems on energy products on the economy, emissions reduction, and the energy mix when the carbon tax is introduced by setting the following four cases;

(1) No carbon taxation, Business as usual (BAU) case

(2) Maintaining the current electricity pricing system and energy taxes, and introducing a carbon tax of 50,000won/Cton along with passing carbon tax costs in power generation on to customers slowly by the electricity pricing equation (3.81) (CTAX50)

(3) Restructuring the pre-existing energy tax system in which the carbon tax, 50,000won/Cton is imposed on fossil fuels except for kerosene, LPG, and city-gas, along with the same slow adjustment of electricity price as in case (2) (CTAX+RT)

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[54] 1 tonne of Carbon is equivalent to 44/12 tonnes of CO_2.

[55] 50,000 Won is equivalent to 13.5 U.S. Dollar in April, 2014.

(4) Restructuring the pre-existing energy tax system as in the CTAX+RT case and introducing a reformed electricity pricing system in which an electricity supplier receives a 100% cost compensation rate from all sectors (industry, commerce and public, and households)[56] and passing the full additional costs incurred from the carbon tax in power generation directly on to customers as well as introducing the carbon tax of 50,000won/Cton using the following equation (CTAX50+RTRP)

(4.1) $P_{j,t}^{elec} = P_{j,t}^{nelec} + C_{w,t}^{elec}$

where, $P_{j,t}^{elec}$ denotes electricity prices by sector j, $P_{j,t}^{nelec}$ the normal electricity price in which the supplier receives 100% cost compensation rate, and $C_{w,t}^{elec}$ the carbon tax cost in power generation sector.

It is important to note that fundamentally, the revenues from the carbon tax are re-distributed to households as a lump-sum transfer in all cases under the revenue-neutral assumption. Besides, we assume that the electricity supplier issues a bond to finance the deficit caused from the low electricity tariff in cases 1~3. Therefore, any increase in this deficit raises the yield of corporate bonds in the macro-econometric module. The estimation result for the corporate bond yield equation shows that the elasticity of yield with respect to the deficit adjusted by GDP deflator is 0.35, although it is not statistically significant. The coefficient is assumed to hold for the simulations in this study.

[56] Note that due to data availability, we apply the compensation rate in 2011 to the simulation period. The data in 2011 is provided in Table 4.3.

Table 4.3. Average electricity costs and price in 2011

	Average cost (won/kWh)	Average selling price (won/kWh)	Compensation rate (%)
Residence	135.87	119.99	88.3
General	109.69	101.61	92.6
Industry	92.88	81.23	87.5
Total	103.31	90.32	87.4

In addition, it is worth mentioning that simulation scenarios adopted in this study are carefully chosen based on a revenue neutrality assumption adopted in the existing simulation studies in which the government imposes one tax and lightens another. One would think of simply reforming the existing taxes as a scenario, but it needs the revenue neutrality assumption to compare with the other cases fairly. In our case, the simple reform case, just giving exemptions to kerosene, LPG, and LNG is very likely to incur a budget deficit problem in a nation. The results cannot be fairly compared with the other cases due to a different finance situation. Alternatively, the CTAX50+RT case provides a suitable method to examine pre-existing taxes

4.5. RESULTS

This section summarises the main effects of the carbon tax policy on energy prices, the energy mix of final energy demands and power generation, and macroeconomic indicators such as GDP, consumption, investment, export, the unemployment rate, the consumer price and producer price index, and emission reductions[57].

4.5.1. Energy prices

Given the carbon tax scenarios, average annual increases for specific energy products are provided in Table 4.4. The high carbon emission factor of energy causes higher energy

[57] Emission reductions can bring primary benefits and secondary benefits. According to Ayers and Walter (1991), the primary benefit is defined as the avoided direct damage such as loss of economic activity and other consequences environmental changes. The secondary benefit includes reducing fossil fuels consumption per unit of economic activity (energy conservation) and substitution between lower carbon energy for carbon-intensive energy (carbon substitution). However, the benefit cannot be directly measured due to difficulties of estimating their monetary values (see next section 4.5.2.). Therefore, this study focuses on the effects of the carbon tax on GDP and reduction of emissions.

prices; compared to the BAU case, bituminous coal has the highest average increase, 35.64%, followed by anthracite coal, 33.49%, under all carbon tax scenarios. The currently high prices of energy forms such as aggregated oil and clean energy sources such as city-gas imply relatively lesser increases of 3.34% and 5.36% respectively in the CTAX50 case in which the tax of 50,000 won per tonne of carbon is imposed on all fuel products. However, the price of aggregated oil increases by only 1.81% and the price of city-gas remains as the BAU case in CTAX50+RT and CTAX+RTRP cases, as kerosene, LPG, and LNG are exempted from the carbon tax in these cases.

As for electricity prices in the cases, given the current pricing system regulated by the government, the carbon tax pushes the electricity price up by 5.38% and 5.39% in the CTAX50 and CTAX50+RT cases. The CTAX50+RTRP case has the highest electricity price; when the electricity pricing system was reformed and the carbon tax introduced, the electricity price rises by 31.53%.

Table 4.4. Carbon tax and price increase rate

Fuel	Price increase rate (%)		
	CTAX50	CTAX50+RT	CTAX50+RTRP
Anthracite coal	33.49	33.49	33.49
Bituminous coal	35.64	35.64	35.64
Aggregated oil	3.34	1.81	1.81
City-gas	5.36	0.00	0.00
Electricity	5.38	5.39	31.53

4.5.2. Macroeconomic indicators and emission reduction

Table 4.5 compares the change in major macroeconomic indicators, total primary energy demands and emissions in the carbon tax scenarios. Overall, the carbon tax policy decreases the GDP even though the revenue from the carbon tax is re-distributed to consumers as a lump-sum. As the carbon tax is introduced, the carbon tax increases the producer prices, which raises export prices and consumer prices in turn. Therefore, GDP falls by at least 0.24% on yearly average in the CTAX50+RT and at most by 0.49% on yearly average in the CTAX50+RTRP.

As seen in Table 4.5, depending on the pre-existing taxes on energy and electricity pricing system, the carbon tax policy's effects on the economy and emissions yield different results. We found that restructuring the pre-existing taxes on energy in the CTAX50+RT case is able to reduce the GDP losses by 0.24% compared to the BAU case. The most notable decrease in emissions is found when the electricity price system is reformed in the CTAX50+RTRP case, which reduces emissions by 11.51% compared to the BAU case. However, the significant rise in the price indices such as CPI and PPI coming from the electricity price increase brought the largest losses, -0.49% in GDP.

We define economic cost as GDP loss per tonne of carbon saved relative to BAU[58]. Note that the social cost of carbon (SCC) is not offset against this economic cost, given the monetary valuation of SCC is complicated by the wide range of SCC values in literature and the large uncertainty involved in estimating the potential economic impacts and related costs of climate change (Tol, 2013)[59]. Welfare comparisons are vulnerable to sensitivity to the valuation of SCC, as the ranking of policy options can be easily manipulated by adopting a

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[58] The economic cost is calculated by

$$(4.2) \qquad \sum_{t=0}^{N} \frac{1}{(1+r)^t} \times \left(\frac{GDP_{BAU,t} - GDP_{Case,t}}{Emission_{BAU,t} - Emission_{Case,t}}\right)$$

where t represents the initial year, N the last year, and r a discount factor; 0.05

[59] There are 75 studies with 588 estimates based on different models in his survey. The mean social cost of carbon was $196 per ton with a standard deviation of $322 in 2010 dollars. The large divergence is partially due to the use of different discount rate. However, controlling for difference does not eliminate uncertainty about the social cost of carbon; at a 3 percent real discount rate, the mean social cost was $25 with a standard deviation of $22.

wide range of values of SCC. On the other hand, the economic cost defined above can provide a robust ranking result in terms of the cost per tonne of carbon reduction. The reader could then compare these figures to their own preferred value for the social cost of carbon, or use that value to obtain a change in overall welfare. Therefore, this thesis intends to focus on analysing the effects of a carbon tax on the macroeconomic variables purely as most literature did, so that we distinguish the carbon cost from GDP loss per tonne of carbon reduction by using a terminology on economic cost that is consistent with Hoeller and Coppel (1992a).

Table 4.5. Annual average change in variables and economic cost

	CTAX50	CTAX50+RT	CTAX50+RTRP
GDP	-0.27%	-0.24%	-0.49%
Private Consumption	-0.39%	-0.36%	-0.88%
Investment	-0.08%	-0.08%	-0.16%
Export	-0.29%	-0.27%	-0.44%
Imports	-0.25%	-0.23%	-0.48%
Unemployment rate	1.53%p	1.39%p	2.27%p
CPI	0.35%	0.24%	0.87%
PPI	0.36%	0.32%	1.21%
Total primary energy supply (TPES)	-3.60%	-3.19%	-7.65%
Emissions (CO_2)	-5.79%	-6.10%	-11.51%
Economic cost (Won/Cton)	263,946	230,940	246,898

Note: the change in total primary energy does not consider hydro and renewable energy, as they are treated exogeously in the model.

The economic cost described in the last row in Table 5 shows that if reforming the energy tax (CTAX50+RT) or both energy tax and electricity pricing (CTAX50+RTRP) the economic costs are lower than in the CTAX50 case. It implies that well-designed restructuring of the pre-existing energy taxes and the electricity pricing system can reduce emissions more cost-effectively. The reason that CTAX+RTRP is the second in the economic cost can be explained by the country's economic structure; as seen Table 4.5, the highest change in PPI caused the biggest drop in exports despite the largest reduction of emissions. The problem here is an example of the theory of the second best, in that when only some taxes are reformed, welfare may not increase. Taxes in Korea have been reformed, but if other countries do not impose a carbon tax, this will encourage production of carbon-intensive products to shift to lower-carbon tax jurisdictions, making Korea's exports less competitive and also encourage Korean customers to purchase the carbon-intensive products from lower-carbon intensive jurisdictions. One solution to this is to adopt border tax adjustments to offset the impact on exporters (Metcalf and Weisbach 2009; Metcalf 2013).

It is also worth noting the total primary energy supply (TPES) in the CTAX50+RT case. The carbon taxation with reforms to existing taxes achieved the lowest economic cost among all cases, despite the smallest decrease in TPES among all cases. It can be interpreted that emissions can be reduced cost-effectively by optimal allocation of energy brought about by internalising the social cost of energy into its price rather than restraining energy consumption through simple taxation. The following section describes the results of the changes in energy mix.

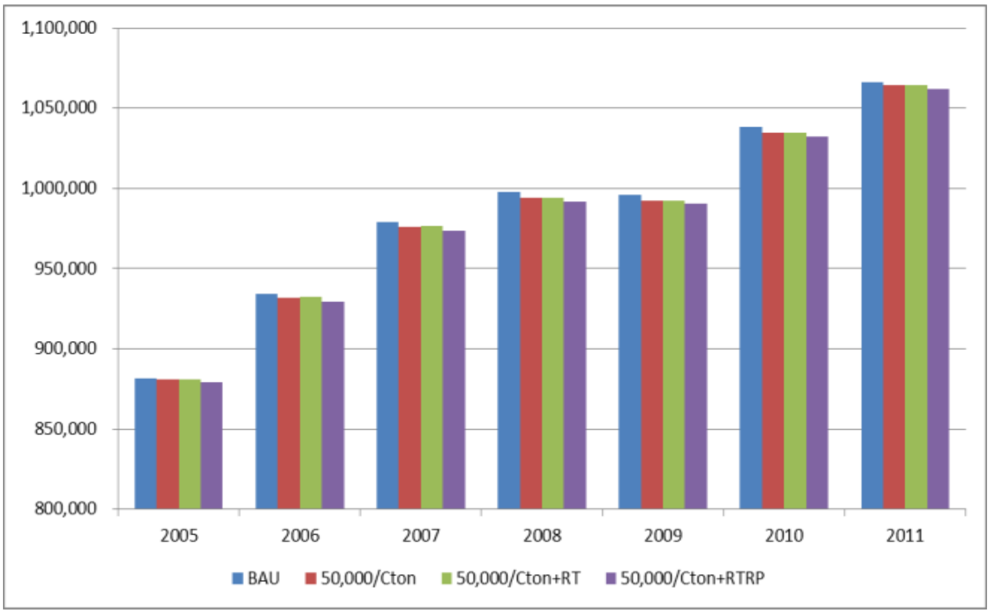

Figure 4.4. Results for GDP (Billion Won)

Figures 4.4 and 4.5 depict GDP and emissions respectively. GDP in 2011 is expected to reach 1,062 trillion won at least in the CTAX50+RTRP and at most 1,066 trillion won in the BAU case. Emissions in the BAU and the CTAX50+RTRP are recorded at 694 and 622 million tonnes of CO_2 respectively in 2011.

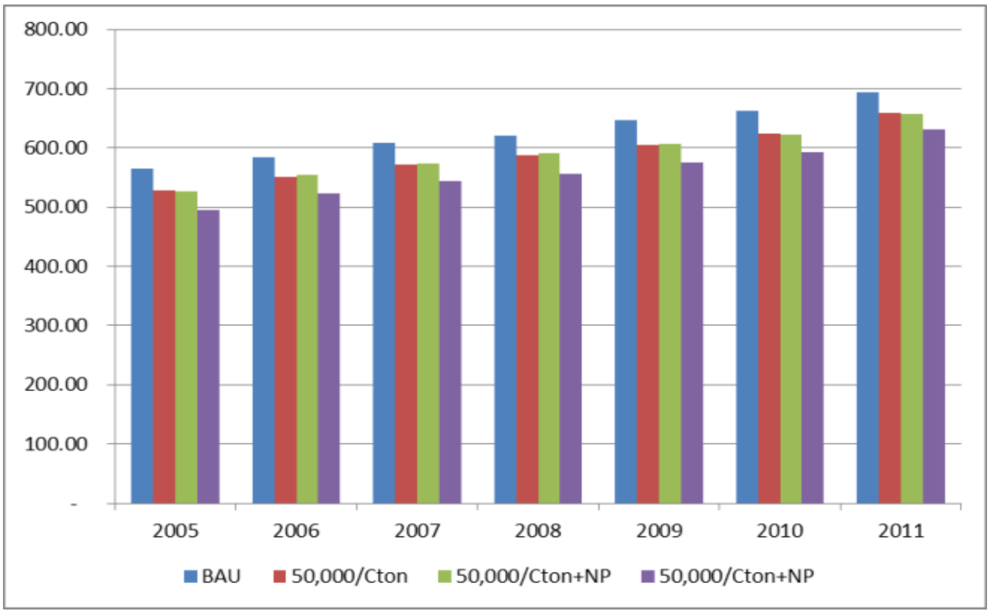

Figure 4.5. Results for emissions (CO_2 million tonnes)

4.5.3. Energy mix of final energy demands and power generation

The reduction in emissions is attributed to two factors, the decrease in energy consumption and fuel shifting to less carbon intensive fuels. Consequently, the fuel-switching behaviour affects changes in the energy mix.

Table 4.6 describes the changes in final energy demands and primary energy for power generation. As seen in Table 6, the carbon taxation decreases the TPES in the three carbon tax cases, because rising fuel prices reduce the real income of agents. In terms of changes in the demand for specific energy products in the CTAX50, the demand for coal which has the highest carbon content significantly declines by 7.89% on yearly average. The demand for petroleum products for energy-use shows a relatively small decrease, by 2.79%. Electricity and city-gas demands reduce by 6.21% and 6.13% respectively, since the carbon tax raises the cost of input sources such as bituminous coal and LNG for the final energy products.

In the case of restructuring pre-existing taxes on energy (CTAX50+RT), the demand for city-gas which is a less carbon-intensive energy decreases only by 1.79%. The largest decline in the electricity demand is found in the CTAX+RTRP, since the reformed electricity tariff considered as the right level of price reflecting the supplier's cost rises almost by 30%, compared to the BAU case. As a result, the amount of input energy for power generation significantly decreases.

Table 4.6. Results of changes in final energy and primary energy for power generation

	CTAX50	CTAX50+RT	CTAX50+RTRP
Final energy demands			
. Petroleum	-2.79%	-2.45%	-2.32%
. Coal	-7.89%	-7.60%	-7.57%
. Electricity	-6.21%	-5.95%	-19.48%
. City-gas	-6.13%	-1.79%	-4.33%
Power generation			
. Nuclear	0.00%	0.00%	0.00%
. Coal	-9.84%	-17.60%	-33.12%
. HEAVY-OIL	-37.95%	-37.95%	-52.58%
. CCGT	-12.82%	-1.32%	-10.18%

Figures 4.6 and 4.7 depict the final energy and power generation mixes. It appears that the CTAX50 and CTAX50+RT cases do not make significant changes in electricity's share in

final energy demands, as the electricity tariffs still remain at a lower level than the costs. Adding the carbon tax without restructuring the electricity pricing system cannot improve much the pre-existing distortions in relative energy prices. Thus, it can be interpreted that these policies have only a limited ability to improve efficient resource allocation. However, the CTAX50+RTRP case makes certain changes in the energy mix; the share of electricity falls by 3.8% and the share of city-gas and petroleum for energy use increases by 0.8% and 2.9% respectively in 2011 when the right level of electricity tariff is imposed on customers.

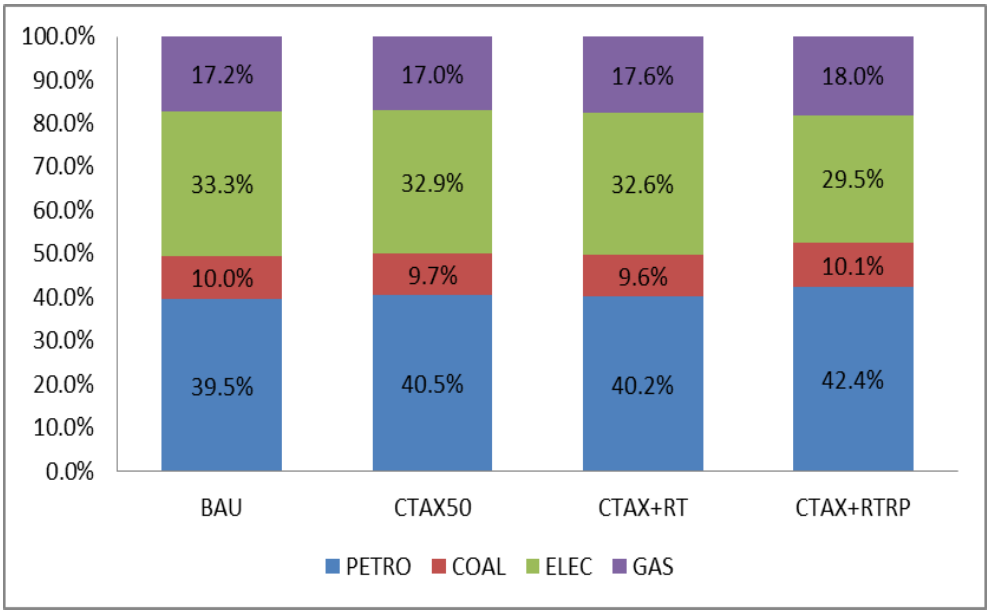

Figure 4.6. Final energy mix in 2011

As for the power generation mix indicated in Figure 4.7, base load technology (nuclear and coal power plants) are still cost-effective in merit order when the carbon tax of 50,000won/Cton is imposed, so that they represent approximately at least 70% of output in all cases. Notable changes in the proportion of LNG are found in the CTAX+RT and CTAX+RTRP cases; the share of LNG in power generation rises by about 2%. It is important to note that the share of coal considerably decreases from 40.9% to 33.0% via the decreased demand for electricity in the CTAX50+RTRP case. Nuclear power keeps the same amount of output as in the BAU case, thereby occupying the largest share, 38.2%.

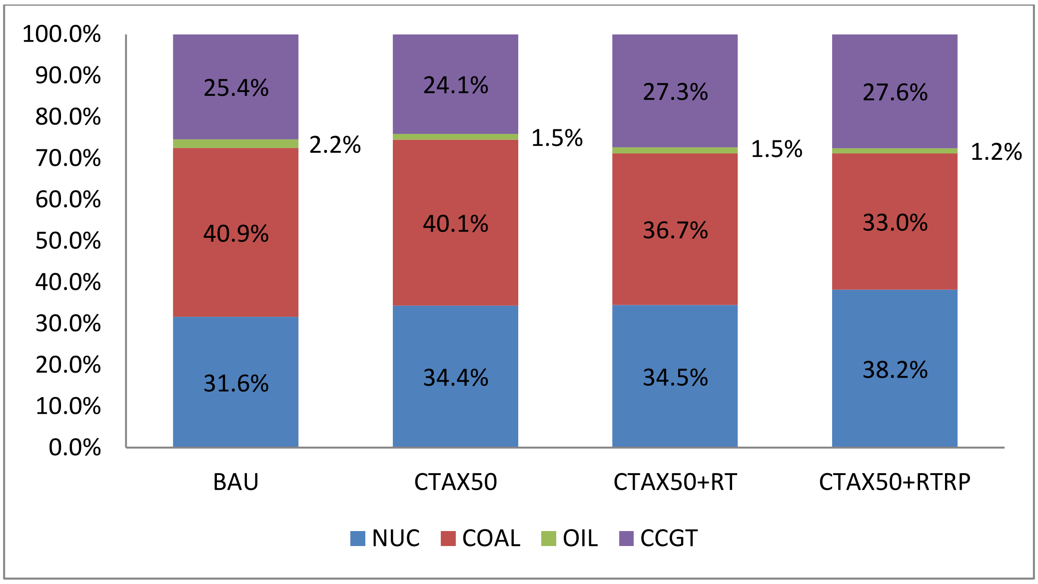

Figure 4.7. Power generation mix in 2011

To sum-up, the carbon tax policy with restructuring of pre-existing energy taxes and electricity pricing system induces energy prices to reflect the social cost fairly, and then allocate resources efficiently by shifting from high to low-carbon energy.

4.6. CONCLUSION

We examine the effects of the current energy taxes and electricity pricing system on the Korean economy when a carbon tax policy is introduced using an integrated model which combines the macro-econometric model and the MCP electricity market model developed earlier. Four scenario simulations are implemented to measure the magnitude of the effects of current systems on the economy; 1) no carbon taxation (BAU), 2) imposing a carbon tax of 50,000 won per tonne of carbon on energy products (CTAX50), 3) imposing the same carbon tax rate and reforming pre-existing energy taxes through exempting kerosene, LPG, and LNG from the carbon taxation (CTAX+RT), and 4) imposing the same carbon tax rate with the same tax reform and a new electricity pricing system in which the electricity supplier charges cost-reflective prices (CTAX+RTRP). The revenues from the carbon tax are assumed to be re-distributed to households as a lump-sum transfer.

The CTAX+RTRP case's results show that while the GDP shrinks by 0.49% on annual average, emissions decrease by 11.51%, compared to the BAU case. This case makes the electricity tariff reflect the social cost accurately without delay or disturbance from the government intervention. Besides, the tax burden in fuel prices is exactly proportional to their carbon content in the case of reforming the taxes on energy. As a result, the share of lower-carbon energy rises and the decreased demand for electricity lowers the demand for coal which has the highest carbon content. This contributes to the largest reduction in emissions. It is also worth mentioning a decrease in expenditure on imported energy for this energy-import dependent country[60]. As seen in Table 4.5, the CTAX+RTRP case is likely to bring a considerable decrease in imports, having the most reduced total primary energy supply among the carbon tax cases. While this case reduces the economic cost, which is defined as the GDP loss per tonnes of carbon saved relative to BAU in this study, compared to the CTAX50 case, a sudden change in the electricity pricing system incurs the highest increase in the CPI and PPI, thereby resulting in the largest GDP losses among the carbon tax cases. In particular, the PPI directly affects the export prices, so that concerns over industrial competiveness would be raised by export-centred industry.

The result of CTAX50+RT case indicates that it is the most cost effective policy; the smallest losses in GDP and relatively larger reduction in emissions than the CTAX50 case can

[60] Approximately 96% of demands for fossil fuels were met by imports in 2011.

be expected, since the low carbon energy sources such as LPG and LNG are exempted from the carbon taxation. However, by only reforming the current tax system, CTAX+RT is not able to provide a remedy for the root of the trouble resulting from the low electricity prices. Figure 4.6 show that the share of electricity in final energy demands remains at a high level as in the BAU case, which is far from the optimal allocation of energy from the viewpoint of energy efficiency. The excessive electricity use also would worsen the deficit problems of the electricity supplier originating from the current low electricity tariffs and at some point, this kind of deficit has to be sorted out[61].

As for the CTAX case, the result confirms that implementing the carbon tax policy without restructuring the current energy tax or electricity pricing system leads to the largest economic cost in that the carbon tax extends the distortions in relative energy prices in the pre-existing tax and pricing systems. Thus, the distortion restricts the effects of the fuel switching from high to low carbon energy. As a consequence, neither the energy mix nor the electricity supplier’s deficit problems can be significantly lessened. In this case, the reduction in emissions is mainly achieved by the decreased real income.

These results confirm that well-designed reform of pre-existing energy taxes and pricing system lessens the economic costs of CO_2 reduction when climate change policies are introduced into a nation. It implies that internalising the social cost of energy to its price via taxation and the regulated pricing system is able to provide a more cost-effective way to reduce CO_2 emissions. Therefore, the current complicated energy taxes need to be converted to an environmental taxation system. In addition, a normalisation of electricity prices is also necessary to restrain further distortions in energy consumption before the carbon tax is

[61] As for recent accounting treatment for the deficit, the electricity supplier, KEPCO treated the accumulated uncollected amount, approximately 1.9 trillion won, incurred from delay in implementation of linking the electricity tariff with fuel procurement expenses as non-operating losses in March, 2013.

introduced. However, considering the effect of the electricity price on industrial competiveness, gradual reforms rather than drastic changes in the current electricity pricing system would be recommended in order to soften the burden imposed by the carbon tax on the economy.

However, modelling the carbon tax policy is a continuous process, since the current simulation is done on the assumption that the carbon tax revenue is recycled to households through a lump-sum transfer. The assumption is inevitable because of the unavailability of time-series data for income, payroll, and corporate tax rates. The availability of such data will contribute to the development of modelling the effects of the various revenue recycling methods on the economy. Moreover, modelling the recycling through investment in energy efficiency and GHG reduction technology by adopting an engineering sub-model for important demand and supply side sectors would provide a policymaker with more practical guidelines for deciding an optimal carbon tax rate. The model can also be improved by modifying the foreign trade block which currently uses aggregated import data. It can be extended by modelling individual imported energy demands to quantify the effects of the energy policy on the rate of dependence on imports and analyse the effects of energy substitution on energy imports in more detail. In addition, the model needs to introduce agents' expectations into the empirical framework to respond to the Lucas critique in terms of the econometric policy evaluation. Lastly, the welfare analysis can be implemented by obtaining universal information for valuation of the social cost of carbon emissions in order to measure benefits of reducing emissions, but this remains for future studies.

APPENDIX 4

A.4.1. Energy taxation system

Table A.4.1. Energy taxation in Korea (2012.6)

		Gasoline (won/ℓ)	Kerosene (won/ℓ)	Diesel (won/ℓ)	Heavy-oil (won/ℓ)	LPG (won/kg)		LNG (won/m^3)	Briquette (won/EA)	Electricity for households (won/kWh)	Heat for households (won/10kcal)
						Propane	Butane				
Customs Tax	General	3%				3%		3%	-	-	-
	Quota (Provisional)	Crude Oil for LPG and Naphtha: 0% Product: 0%				Crude Oil: 0% Product: 0%		2%	-	-	-
Individual Cons. Tax	General	-	90	-	17	20	252	60	-	-	-
	Flexibility	-	-	-	-	-	275	-	-	-	-
Transportation Energy Environment Tax	General	475	-	340	-	-	-	-	-	-	-
	Flexibility	529	-	375	-	-	-	-	-	-	-
Education Tax		79.35	13.5	56.25	2.55	-	41.25	-	-	-	-
Local Drive Tax		137.54	-	97.50	-	-	-	-	-	-	-
VAT		160.82	102.86	146.07	-	-	-	80.8	-	11.8	79.3
Import Fee		16	16	16	16	-	-	24.2	-	-	-
Quality Examination Fee		0.469	0.469	0.469	0.469	0.027	0.027	-	-	-	-
Safety Management Levy		-	-	-	-	5.0	5.0	4.4	-	-	-
Sales Levy		36 (High)	-	-	-	-	62.28	-	-	-	-
Electric Power Industry Basis Fund		-	-	-	-	-	-	-	-	4.4	-
Total Tax Amount	Amount	923.2	232.8	691.3	36.0	25.0	383.6	169.4	-	16.2	79.3
	Price Share Ratio	**46.9%**	**16.1%**	**38.9%**	**3.2%**	**1.2%**	**15.9%**	**19.1%**	**0.0%**	**12.0%**	**9.1%**
Consumption Price (2012,6)		1,968.8	1,387.1	1,777.2	1,125.2	2,172.4	2,412.1	889.2	371.3	134.6	872.1

Source: Kim (2012)

A.4.2. Results of the carbon tax policy simulation

Table A.4.2. Aggregated petroleum price for industry (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	772,590	813,515	5.30%	802,100	3.68%	802,100	3.68%
2006	921,802	962,727	4.44%	951,312	3.10%	951,312	3.10%
2007	1,013,203	1,054,128	4.04%	1,042,713	2.83%	1,042,713	2.83%
2008	1,437,693	1,478,618	2.85%	1,467,203	2.01%	1,467,203	2.01%
2009	1,211,915	1,252,840	3.38%	1,241,425	2.38%	1,241,425	2.38%
2010	1,302,588	1,343,513	3.14%	1,332,098	2.22%	1,332,098	2.22%
2011	1,525,532	1,566,457	2.68%	1,555,042	1.90%	1,555,042	1.90%

Table A.4.3. Aggregated petroleum price for commerce and public (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	1,037,219	1,014,913	-2.15%	1,051,154	1.33%	1,051,154	1.33%
2006	1,175,606	1,103,268	-6.15%	1,189,541	1.17%	1,189,541	1.17%
2007	1,239,956	1,140,374	-8.03%	1,253,891	1.11%	1,253,891	1.11%
2008	1,643,559	1,558,028	-5.20%	1,657,494	0.84%	1,657,494	0.84%
2009	1,320,607	1,193,707	-9.61%	1,334,542	1.04%	1,334,542	1.04%
2010	1,438,864	1,402,607	-2.52%	1,452,799	0.96%	1,452,799	0.96%
2011	1,657,224	1,543,692	-6.85%	1,671,159	0.83%	1,671,159	0.83%

Table A.4.4. Aggregated petroleum price for households (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	973,573	1,076,589	10.58%	996,263	2.28%	996,263	2.28%
2006	1,061,928	1,214,976	14.41%	1,084,618	2.09%	1,084,618	2.09%
2007	1,099,034	1,279,326	16.40%	1,121,724	2.02%	1,121,724	2.02%
2008	1,516,688	1,682,929	10.96%	1,539,378	1.47%	1,539,378	1.47%
2009	1,152,367	1,359,977	18.02%	1,175,057	1.93%	1,175,057	1.93%
2010	1,361,267	1,478,234	8.59%	1,383,957	1.64%	1,383,957	1.64%
2011	1,502,352	1,696,594	12.93%	1,525,042	1.49%	1,525,042	1.49%

Table A.4.5. City-gas price for industry (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	401,935	433,785	7.92%	401,935	0.00%	401,935	0.00%
2006	476,145	507,995	6.69%	476,145	0.00%	476,145	0.00%
2007	545,600	577,450	5.84%	545,600	0.00%	545,600	0.00%
2008	617,255	649,105	5.16%	617,255	0.00%	617,255	0.00%
2009	637,744	669,594	4.99%	637,744	0.00%	637,744	0.00%
2010	654,982	686,832	4.86%	654,982	0.00%	654,982	0.00%
2011	678,215	710,065	4.70%	678,215	0.00%	678,215	0.00%

Table A.4.6. City-gas price for commerce and public (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	481,328	513,178	6.62%	481,328	0.00%	481,328	0.00%
2006	562,903	594,753	5.66%	562,903	0.00%	562,903	0.00%
2007	621,163	653,013	5.13%	621,163	0.00%	621,163	0.00%
2008	673,109	704,959	4.73%	673,109	0.00%	673,109	0.00%
2009	664,923	696,773	4.79%	664,923	0.00%	664,923	0.00%
2010	664,339	696,189	4.79%	664,339	0.00%	664,339	0.00%
2011	675,715	707,565	4.71%	675,715	0.00%	675,715	0.00%

Table A.4.7. City-gas price for households (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	483,937	515,787	6.58%	483,937	0.00%	483,937	0.00%
2006	548,756	580,606	5.80%	548,756	0.00%	548,756	0.00%
2007	608,581	640,431	5.23%	608,581	0.00%	608,581	0.00%
2008	670,602	702,452	4.75%	670,602	0.00%	670,602	0.00%
2009	659,402	691,252	4.83%	659,402	0.00%	659,402	0.00%
2010	695,961	727,811	4.58%	695,961	0.00%	695,961	0.00%
2011	715,247	747,097	4.45%	715,247	0.00%	715,247	0.00%

Table A.4.8. Electricity price for industry (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	705,761	732,419	3.78%	732,875	3.70%	984,056	28.28%
2006	718,911	767,009	6.69%	767,903	6.38%	1,017,791	29.37%
2007	735,096	801,819	9.08%	803,169	8.48%	994,545	26.09%
2008	771,043	854,349	10.80%	855,498	9.87%	1,125,558	31.50%
2009	866,924	966,179	11.45%	967,068	10.36%	1,225,335	29.25%
2010	908,895	1,021,129	12.35%	1,020,605	10.95%	1,256,063	27.64%
2011	955,915	1,077,253	12.69%	1,074,930	11.07%	1,310,576	27.06%

Table A.4.9. Electricity price for commerce and public (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	1,122,286	1,141,178	1.68%	1,141,498	1.68%	1,379,333	18.64%
2006	1,125,760	1,154,220	2.53%	1,154,745	2.51%	1,424,403	20.97%
2007	1,131,008	1,164,471	2.96%	1,165,148	2.93%	1,363,185	17.03%
2008	1,105,620	1,139,408	3.06%	1,139,754	2.99%	1,442,067	23.33%
2009	1,140,619	1,171,929	2.75%	1,172,014	2.68%	1,482,828	23.08%
2010	1,164,983	1,196,263	2.69%	1,195,605	2.56%	1,479,998	21.28%
2011	1,185,275	1,214,459	2.46%	1,213,106	2.29%	1,508,043	21.40%

Table A.4.10. Electricity price for households (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	1,068,253	1,112,549	4.15%	1,113,309	4.05%	1,382,659	22.74%
2006	1,087,428	1,149,053	5.67%	1,150,216	5.46%	1,428,836	23.89%
2007	1,104,207	1,172,209	6.16%	1,173,634	5.92%	1,384,728	20.26%
2008	1,147,374	1,215,789	5.96%	1,216,331	5.67%	1,530,395	25.03%
2009	1,160,007	1,217,299	4.94%	1,217,214	4.70%	1,537,448	24.55%
2010	1,200,532	1,257,874	4.78%	1,256,008	4.42%	1,599,018	24.92%
2011	1,232,773	1,285,013	4.24%	1,281,678	3.82%	1,615,395	23.69%

Table A.4.11. Bituminous coal price for non-power (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	114,028	166,978	46.44%	166,978	31.71%	166,978	31.71%
2006	101,582	154,532	52.13%	154,532	34.26%	154,532	34.26%
2007	108,596	161,546	48.76%	161,546	32.78%	161,546	32.78%
2008	225,052	278,002	23.53%	278,002	19.05%	278,002	19.05%
2009	180,125	233,075	29.40%	233,075	22.72%	233,075	22.72%
2010	197,492	250,442	26.81%	250,442	21.14%	250,442	21.14%
2011	236,096	289,046	22.43%	289,046	18.32%	289,046	18.32%

Table A.4.12. Briquette price (unit: won.TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	126,125	181,125	43.61%	181,125	30.37%	181,125	30.37%
2006	126,250	181,250	43.56%	181,250	30.34%	181,250	30.34%
2007	126,125	181,125	43.61%	181,125	30.37%	181,125	30.37%
2008	176,833	231,833	31.10%	231,833	23.72%	231,833	23.72%
2009	199,615	254,615	27.55%	254,615	21.60%	254,615	21.60%
2010	244,563	299,563	22.49%	299,563	18.36%	299,563	18.36%
2011	244,563	299,563	22.49%	299,563	18.36%	299,563	18.36%

Table A.4.13. GDP (unit: billion won)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	881,562	880,829	-0.08%	880,887	-0.08%	879,046	-0.29%
2006	933,975	932,072	-0.20%	932,208	-0.19%	929,511	-0.48%
2007	979,078	976,099	-0.30%	976,305	-0.28%	973,409	-0.58%
2008	997,831	994,016	-0.38%	994,264	-0.36%	991,660	-0.62%
2009	995,990	992,146	-0.39%	992,416	-0.36%	990,258	-0.58%
2010	1,038,141	1,034,642	-0.34%	1,034,927	-0.31%	1,032,550	-0.54%
2011	1,066,100	1,064,325	-0.17%	1,064,621	-0.14%	1,062,120	-0.37%

Table 4.A.14. Private consumption (unit: billion won)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	473,525	472,961	-0.12%	473,006.5	-0.11%	470,899	-0.55%
2006	500,796	499,250	-0.31%	499,355.0	-0.29%	496,184	-0.92%
2007	524,958	522,544	-0.46%	522,703.3	-0.43%	519,188	-1.10%
2008	538,391	535,350	-0.56%	535,538.4	-0.53%	532,376	-1.12%
2009	541,505	538,551	-0.55%	538,751.5	-0.51%	536,358	-0.95%
2010	555,133	552,561	-0.46%	552,762.6	-0.43%	550,277	-0.87%
2011	567,552	566,082	-0.26%	566,271.1	-0.23%	563,787	-0.66%

Table 4.A.15. Investment (unit: billion won)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	254,341	254,372	0.01%	254,369	0.01%	254,319	-0.01%
2006	262,784	262,791	0.00%	262,789	0.00%	262,655	-0.05%
2007	270,264	270,179	-0.03%	270,178	-0.03%	269,958	-0.11%
2008	265,047	264,855	-0.07%	264,855	-0.07%	264,582	-0.18%
2009	270,860	270,534	-0.12%	270,532	-0.12%	270,229	-0.23%
2010	276,113	275,691	-0.15%	275,688	-0.15%	275,357	-0.27%
2011	280,576	280,105	-0.17%	280,099	-0.17%	279,752	-0.29%

Table 4.A.16. Export (unit: billion won)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	354,174	353,896	-0.08%	353,918	-0.07%	353,761	-0.12%
2006	396,560	395,839	-0.18%	395,893	-0.17%	395,512	-0.26%
2007	441,531	440,278	-0.28%	440,367	-0.26%	439,781	-0.40%
2008	471,839	470,028	-0.38%	470,144	-0.36%	469,333	-0.53%
2009	451,141	449,202	-0.43%	449,325	-0.40%	448,387	-0.61%
2010	490,093	487,985	-0.43%	488,123	-0.40%	486,970	-0.64%
2011	526,336	524,884	-0.28%	525,029	-0.25%	523,682	-0.50%

Table 4.A.17. Import (unit: billion won)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	327,294	327,214	-0.02%	327,221	-0.02%	326,920	-0.11%
2006	361,660	361,296	-0.10%	361,320	-0.09%	360,628	-0.29%
2007	395,871	395,084	-0.20%	395,136	-0.19%	394,092	-0.45%
2008	424,547	423,289	-0.30%	423,369	-0.28%	422,130	-0.57%
2009	389,887	388,467	-0.36%	388,558	-0.34%	387,437	-0.63%
2010	429,330	427,661	-0.39%	427,772	-0.36%	426,525	-0.65%
2011	464,489	462,796	-0.36%	462,920	-0.34%	461,554	-0.63%

Table 4.A.18. Consumer price index (unit: index, 2005=100)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	100.77	100.95	0.18%	100.87	0.11%	101.21	0.44%
2006	103.84	104.15	0.30%	104.04	0.19%	104.58	0.71%
2007	106.56	106.95	0.37%	106.82	0.24%	107.40	0.79%
2008	111.47	111.92	0.40%	111.78	0.27%	112.51	0.93%
2009	113.56	114.01	0.40%	113.88	0.28%	114.73	1.04%
2010	116.27	116.74	0.40%	116.61	0.29%	117.53	1.08%
2011	119.86	120.33	0.39%	120.22	0.29%	121.17	1.09%

Table 4.A.19. Producer price index (unit: index, 2005=100)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	100.73	101.00	0.27%	100.93	0.20%	101.82	1.08%
2006	101.09	101.43	0.33%	101.36	0.27%	102.35	1.25%
2007	102.61	103.00	0.37%	102.94	0.32%	103.72	1.08%
2008	112.18	112.60	0.37%	112.56	0.33%	113.62	1.28%
2009	112.38	112.81	0.39%	112.78	0.36%	113.85	1.31%
2010	116.70	117.17	0.41%	117.15	0.39%	118.15	1.25%
2011	120.49	120.98	0.40%	120.97	0.40%	121.98	1.23%

Table 4.A.20. Total primary energy supply (unit: thousand TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	228,945	217,848	-4.85%	219,084	-4.31%	208,490	-8.93%
2006	234,013	225,111	-3.80%	226,404	-3.25%	215,460	-7.93%
2007	236,185	226,462	-4.12%	227,783	-3.56%	217,294	-8.00%
2008	239,664	231,614	-3.36%	232,559	-2.96%	220,439	-8.02%
2009	243,912	237,868	-2.48%	238,830	-2.08%	227,704	-6.65%
2010	254,300	245,394	-3.50%	246,068	-3.24%	235,075	-7.56%
2011	271,105	262,687	-3.10%	263,115	-2.95%	253,619	-6.45%

Table A.21. Total CO_2 emissions (unit: million tCO_2)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	564.58	528.26	-6.43%	523.20	-7.33%	490.42	-13.14%
2006	583.95	551.25	-5.60%	552.85	-5.33%	519.40	-11.05%
2007	607.93	572.09	-5.89%	573.11	-5.73%	541.10	-10.99%
2008	620.39	588.13	-5.20%	588.71	-5.11%	552.48	-10.95%
2009	646.46	604.10	-6.55%	602.57	-6.79%	567.58	-12.20%
2010	662.30	624.29	-5.74%	618.81	-6.57%	583.46	-11.90%
2011	694.04	658.34	-5.14%	653.35	-5.86%	622.13	-10.36%

Table A.22. Total final energy demand of petroleum products (unit: thousand TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	95,889	94,630	-1.31%	94,941	-0.99%	93,352	-2.65%
2006	97,423	95,865	-1.60%	96,143	-1.31%	94,949	-2.54%
2007	98,388	96,620	-1.80%	96,882	-1.53%	96,292	-2.13%
2008	95,884	94,206	-1.75%	94,430	-1.52%	93,756	-2.22%
2009	96,814	94,935	-1.94%	95,193	-1.67%	94,736	-2.15%
2010	98,218	96,239	-2.01%	96,507	-1.74%	96,281	-1.97%
2011	98,473	96,546	-1.96%	96,833	-1.67%	96,735	-1.76%

Table A.23. Total final energy demand of coal products (unit: MWh)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	8,801	8,293	-5.77%	8,349	-5.14%	7,959	-9.57%
2006	9,488	8,724	-8.05%	8,770	-7.57%	8,520	-10.20%
2007	10,201	9,203	-9.78%	9,241	-9.41%	9,164	-10.16%
2008	10,286	9,325	-9.35%	9,354	-9.07%	9,241	-10.16%
2009	10,939	9,917	-9.34%	9,949	-9.06%	9,896	-9.53%
2010	11,665	10,655	-8.66%	10,690	-8.36%	10,683	-8.42%
2011	12,269	11,301	-7.89%	11,337	-7.60%	11,341	-7.57%

Table A.24. Total final energy demand of electricity (unit: thousand TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	28,228	27,228	-3.54%	27,468	-2.69%	23,668	-16.15%
2006	30,535	29,240	-4.24%	29,413	-3.67%	24,667	-19.22%
2007	32,521	30,916	-4.93%	31,034	-4.57%	25,790	-20.70%
2008	33,910	32,170	-5.13%	32,240	-4.92%	27,783	-18.07%
2009	36,378	34,285	-5.75%	34,360	-5.55%	30,250	-16.85%
2010	38,885	36,496	-6.14%	36,581	-5.93%	31,628	-18.66%
2011	40,962	38,421	-6.21%	38,523	-5.95%	32,985	-19.48%

Table A.25. Total final energy demand of City-gas (unit: thousand TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	16,979	16,199	-4.59%	16,690	-1.70%	15,380	-9.42%
2006	17,756	16,792	-5.43%	17,437	-1.80%	16,151	-9.04%
2007	18,202	17,132	-5.87%	17,866	-1.84%	17,007	-6.56%
2008	18,759	17,652	-5.90%	18,438	-1.71%	17,317	-7.69%
2009	19,495	18,292	-6.17%	19,151	-1.76%	18,194	-6.67%
2010	20,262	19,008	-6.19%	19,898	-1.80%	19,169	-5.39%
2011	21,089	19,796	-6.13%	20,712	-1.79%	20,175	-4.33%

Table A.26. Nuclear power plant's output (unit: GWh)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	34,918	34,918	0.00%	34,918	0.00%	34,918	0.00%
2006	34,918	34,918	0.00%	34,918	0.00%	34,918	0.00%
2007	30,030	30,030	0.00%	30,030	0.00%	30,030	0.00%
2008	30,030	30,030	0.00%	30,030	0.00%	30,030	0.00%
2009	30,030	30,030	0.00%	30,030	0.00%	30,030	0.00%
2010	30,030	30,030	0.00%	30,030	0.00%	30,030	0.00%
2011	31,724	31,724	0.00%	31,724	0.00%	31,724	0.00%

Table A.27. Bituminous coal power plant's output (unit: GWh)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	131,744	102,829	-21.95%	87,520	-33.57%	65,572	-50.23%
2006	136,196	122,283	-10.22%	120,937	-11.20%	100,705	-26.06%
2007	152,170	143,744	-5.54%	137,979	-9.33%	116,871	-23.20%
2008	176,380	155,975	-11.57%	154,976	-12.13%	128,523	-27.13%
2009	178,658	147,373	-17.51%	146,587	-17.95%	117,771	-34.08%
2010	181,722	154,589	-14.93%	142,270	-21.71%	110,461	-39.21%
2011	181,433	163,047	-10.13%	148,245	-18.29%	118,650	-34.60%

Table A.28. Heavy-oil plant's output (unit: GWh)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	13,357	4,565	-65.83%	4,733	-64.57%	4,126	-69.11%
2006	10,187	5,440	-46.60%	5,496	-46.05%	4,196	-58.81%
2007	10,701	5,398	-49.56%	5,427	-49.29%	4,284	-59.97%
2008	8,660	4,912	-43.27%	4,895	-43.48%	4,284	-50.53%
2009	10,200	6,227	-38.95%	6,191	-39.31%	4,275	-58.09%
2010	9,827	6,227	-36.64%	6,227	-36.64%	4,463	-54.59%
2011	9,346	6,227	-33.37%	6,227	-33.37%	4,759	-49.08%

Table A.29. CCGT power plant's output (unit: thousand TOE)

	BAU	50,000/Cton	% Change	50,000/Cton+RT	% Change	50,000/Cton+RTRP	% Change
2005	55,435	54,558	-1.58%	78,595	41.78%	66,957	20.78%
2006	59,755	52,959	-11.37%	56,744	-5.04%	42,373	-29.09%
2007	61,136	44,561	-27.11%	55,042	-9.97%	38,938	-36.31%
2008	58,708	62,608	6.64%	63,288	7.80%	41,320	-29.62%
2009	67,056	97,398	45.25%	97,403	45.26%	82,070	22.39%
2010	96,155	106,878	11.15%	119,152	23.92%	105,734	9.96%
2011	98,423	101,699	3.33%	115,783	17.64%	105,464	7.15%

CHAPTER 5 CONCLUSION

5.1. SUMMARY OF MAIN FINDINGS

The main purpose of this thesis was to examine the effects of climate change policies on the Korean economy in order to draw policy implications. We have paid attention to two promising economic instruments; a cap and trade system and carbon tax policies. In particular, we focus on recently emerging issues, the initial permit allocation rules in the electricity sector and restructuring the current energy tax and electricity pricing systems with a carbon tax policy. These issues are important factors to determine the economic costs of GHG mitigation.

In order to perform quantitative simulation analysis, this thesis builds two models; one is the electricity market model based on the MCP framework which is able to incorporate operation, investment, and emission trade decisions in the deregulated electricity market in order to provide more realistic results. In particular, the allocation rules to new entrants are modelled explicitly in this study. The second model is an integrated model linking the MCP electricity market model and a macro-econometric model which has advantages over a single model for analysing the effects of climate change policies on the economy in that the integrated model is capable of representing the electricity sector's technological constraints by adopting a bottom-up approach and macroeconomic interactions between variables by employing a top-down approach at the same time. Furthermore, the soft-link integration method adopted in this model provides the highest degree of detailed modelling of the electricity sector's properties; power output decisions for multiple periods and demand response to changes in fuel and energy prices.

The main findings of each chapter are summarized as follows;

1. Chapter two quantifies the impacts of different initial allocation rules on emissions, capacity mix, emission allowance prices, electricity prices, and social welfare. We examine typical allocation rules such as auctioning to all power plants, a free allocation based on a uniform benchmark to all power plants, free allocation based on a fuel-specific benchmark to existing power plants and a uniform benchmark to new entrants, and a fuel-specific benchmark to all power plants.

1) The fuel-specific benchmark allocation method to existing and new entrants ranks the highest in social welfare through prompting more new investment in an imperfectly competitive industry, thereby resulting in lower electricity prices. But, the method raises the cost of achieving the emission reduction target by highly incentivizing investment in new coal power plants. Given the long economic life span of the plant, the high allowance prices would remain a burden on the economy in the long-run. Therefore, the government should recognise the trade-off relationship between the low electricity price and the high carbon cost when they choose the allocation method.

2) The second highest welfare is in the auction case, which is the most powerful policy to reduce emissions in the electricity sector. Although this allocation method has several merits; preventing distortion in investment decisions and giving the biggest amount of revenue, the auction is likely to face political

resistance from industries due to concerns over the highest increase in electricity prices which incurs the largest consumer welfare loss in the model. In this case, it is worthwhile to consider that a part of the auction revenue could be redistributed to subsidise customers.

3) According to the Coase theorem, the uniform benchmark to all power plants and fuel-specific benchmark to existing power plants along with the uniform benchmark to new entrants have same effects on the market. Although they brought down the highest social costs equally, the latter case would be more helpful to reduce resistance from the power industry by allowing more permits to only existing power plants in the initial period.

2. Chapter 3 provides an integrated model that combines the MCP electricity market model (bottom-up approach) built in chapter two and a macro-econometric model (top-down approach) in order to analyse the effect of a carbon policy on the economy. The macro-econometric model consists of seven blocks; final demand, labour and supply, price and wage, fiscal and monetary, finance, foreign trade, and energy and environment blocks. The total number of equations is 148 in which 57 behavioural equations and 91 identities exist. In terms of variables, there are 148 endogenous variables and 58 exogenous variables.

1) The energy module in the macro-econometric model estimates own-price and cross-price elasticities of petroleum, coal, electricity, and city-gas in industry, commerce and public, and households sectors using the elaborate inter-fuel substitution econometric method, the cost share logit model (Considine and

Mount, 1984). The result shows that all energy products have negative own-price elasticities. Estimated parameters for the cross-price elasticities indicate that relatively low substitution possibilities from carbon intensive energy to less intensive one are found in the industry sector, but there is a higher replacement possibility in the household sector.

2) We perform in-sample simulation to test the predictive ability of the model as a simultaneous system. Statistical measures based on MAPE suggest that the overall performance of the model is reliable.

3. Chapter 4 analyses the effects of the current energy taxes and electricity pricing system on the Korean economy when the carbon tax policy is introduced using the integrated model provided in chapter three. Currently, relatively high taxes are imposed on kerosene, LPG, and LNG compared to their social costs, and the government keeps low electricity tariffs for industrial competiveness and price stabilization, which raise a concern over inefficiency and possible side-effects if the carbon tax is imposed without adjustment.

   The model performs four scenario simulations for the period from 2005 to 2011: (1) no carbon taxation (BAU); (2) maintaining the current energy taxes and electricity pricing system and introducing a carbon tax of 50,000 won per tonne of carbon on energy products (CTAX50); (3) introducing the carbon tax and reforming pre-existing energy taxes in which kerosene, LPG, and LNG are exempted from the carbon taxation (CTAX+RT); and (4) restructuring the electricity pricing system in which a cost reflective electricity tariff is charged to customers (CTAX+RTRP). The carbon tax revenue is assumed to be recycled to households as a lump-sum transfer in all carbon tax cases.

(1) The results of the CTAX case show that it incurs the largest mitigation cost per reduced CO_2 tonne among the cases; it reduces GDP by 0.27% on annual average and emissions by 5.79% in the last year, since simply adding the carbon tax into the current energy tax and electricity pricing system without adjustment worsens further the distortions in relative prices, so that it limits the fuel switching effects. As a consequence, this case becomes the least cost-effective policy.

(2) The result of CTAX50+RT case indicates that it is the most cost-effective policy; it yields the smallest losses in GDP, by 0.24% and a relatively larger reduction in emissions, by 6.10%, because energy prices are rearranged to reflect social costs more accurately by reforming the pre-existing energy taxes. However, this case has a limited ability to reduce chronic excessive electricity consumption caused from the low electricity tariff from the government intervention, which in turn still needs a large amount of coal for power generation in the merit order system and worsens the electricity supplier's deficit problems.

(3) The CTAX + RTRP case's result is the most powerful policy to reduce emissions, by 11.51%, but leads to the largest loss in GDP, by 0.49%. This is, however, still more cost-effective than the CTAX case, since the electricity prices are adjusted to reflect the social cost accurately without the government intervention. In addition, the carbon tax is imposed in proportion to their carbon contents by reforming the taxes on energy. These lead to a lower cost per unit of reduced emissions by changing the final energy demand mix. However, a rapid change in

the electricity pricing system would worsen industrial competiveness of export-centred industry.

To sum up, restructuring pre-existing energy taxes and the electricity pricing system can lessen the economic cost of the carbon tax. However, we suggest gradually reforming the current electricity pricing system in order to minimize the negative effect on the industrial competiveness in the Korean economy.

5.2. FUTURE EXTENSIONS

This study can be regarded as a keystone that can be extended in order to provide more detailed and realistic results for climate change policies in the Korean economy. There are several possibilities for further developments towards the sophisticated model based on the integration approach;

1. The macro-econometric model can be extended to a macro-econometric and input-output model which incorporates inter-industry linkages. Given the input-output table and disaggregated data on macroeconomic indicators and energy consumption by sector, the model can conduct analysis on the effects of the climate change policies on the different sectors' output. Furthermore, imports of energy products can modelled individually, which allows the model to examine the effects of changes in the energy mix on imports of the corresponding energy products. In addition, the econometric method needs to introduce rational expectations in order to reinforce the validity of policy simulation results.
2. Important energy supply sectors such as the petroleum supply chain and energy intensive industries, for example, iron, cement, steel and chemicals could be modelled

in detail using the bottom-up approach that captures technical properties of input energy demands and marginal abatement curves. Also, new technology options for GHG reduction can be simulated to examine their contributions.

3. The model can examine the effects of carbon tax revenue recycling methods provided that time-series data of income and corporate tax rates are obtained. Besides, modelling re-investment from a carbon tax or auction revenue into energy efficiency and other GHG reduction technology is expected to provide useful guidance to policy makers for the recycling policy.

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