From Partial to Total Economic Analysis: Five Applications to Environmental and Energy Economics

Von der
Carl von Ossietzky Universität
– Fakultät II Informatik, Wirtschafts- und Rechtswissenschaften –
zur Erlangung des Grades eines

Doktors der Wirtschaftswissenschaften (Dr. rer. pol.)

genehmigte Dissertation

von:

Herrn Tim Hoffmann
Kaiserring 22
68161 Mannheim

geboren am 14.12.1970 in Mannheim

Referent: Prof. Dr. Heinz Welsch

Koreferent: Prof. Dr. Christoph Böhringer

Tag der Disputation: 04.05.2006

Zusammenfassung in deutscher Sprache

Die im Rahmen dieser Arbeit vorgestellten Studien betrachten umwelt- und energiepolitisch motivierte Regulierungsmaßnahmen und simulieren deren Auswirkungen mittels computergestützen numerischen Modellen. Dies geschieht auf unterschiedlichen wirtschaftlichen Aggregationsstufen. Zunächst liegt der Schwerpunkt der Analyse auf Unternehmensebene. Die Ergebnisse beziehen sich somit auf einzelne, klar abgegrenzte Wirtschaftssubjekte – z.B. auf einzelne Stromversorgungs- unternehmen in Deutschland. In Folge werden Fragestellungen – z.B. die Abschätzung von Effizienzwirkungen des europäischen Emissionshandels – auf multi-sektoraler sowie multinationaler Ebene untersucht, wobei nach wie vor nur ein einzelner Markt betrachtet wird. Anschließend werden die Analysen – z.B. die Bewertung von Fördermechanismen für erneuerbare Energien – um Wechselwirkungen zwischen verschiedenen Märkten ergänzt. Den Abschluss der Arbeit bildet eine Totalanalyse zur Abschätung makroökonomischer Effekte eines EU-weiten Ausstiegs aus der Kernenergie unter Berücksichtigung sämtlicher gesamtwirtschaftlichen Zusammenhänge sowohl auf nationaler als auch auf internationaler Ebene

Die im Rahmen der Arbeit betrachteten Fragestellungen werden mittels modellgestützten numerischen Analysen bearbeitet. Ausgehend von dem zu untersuchenden Problem kommen Optimierungsmodelle und sogenannte gemischte Komplementaritätsprobleme (mixed complementarity problems – MCP) zum Ansatz, wobei letztere den methodischen Schwerpunkt der Arbeit bilden (Kapitel 3 - 6). Ein wichtiger Grund für das Interesse an gemischten Komplementaritätsproblemen in der angewandten Wirtschaftforschung ist die Gleichheit des Konzepts von Komplementarität mit dem der Beschreibung von Systemgleichgewichten. Der Ausgleich von Angebot und Nachfrage – zentraler Bestandteil ökonomischer Systeme – wird mathematisch häufig als komplementäre Beziehung zweier Mengen von Systemvariablen beschrieben. Wettbewerbsgleichgewichte in Tauschökonomien lssen sich beispielsweise mittels der Komplementarität von Preis und (Überschuss-) Nachfrage beschreiben: Im Falle eines positiven Preises kann kein Nachfrageüberschuss existieren; ebenso muss der Preis eines Gutes gleich null sein, sofern ein positiver Angebotsüberschuss besteht. Das Prinzip des komplementären Schlupfs in der linearen und nichtlinearen Programmierung verdeutlicht darüber hinaus die Wichtigkeit von Komplementarität in durch Nebenbedingungen beschränkten Optimierungsmodellen.

Die Arbeit gliedert sich in einen einführenden methodischen Teil (Kapitel 1) und einen Teil mit fünf illustrativen Anwendungen (Kapitel 2 - 6). Die einzelnen Kapitel der Arbeit werden nachfolgend kurz vorgestellt:

Zunächst erfolgt eine umfassende Beschreibung des (gemischten) Komplementaritätsproblems. Neben der allgemeinen Definition des MCP-Ansatzes werden verschiedene Spezialfälle von Komplementaritätsproblemen – wie z.B. lineare und nichtlineare Komplementaritätsprobleme – abgeleitet. Ferner wird die Anwendung des MCP Ansatzes in der angewandten Wirtschaftforschung motiviert.

Die erste im Rahmen der Arbeit vorgestellte Studie (Kapitel 2) befasst sich mit der Frage, welchen Einfluss unterschiedliche Regelungen bezüglich des Ausstiegs aus der Kernenergie in Deutschland (z.B. Vorgabe von Restlaufzeiten oder Begrenzung von Reststrommengen) auf Höhe und Verteilung möglicher dadurch hervorgerufener Kosten nehmen. Mittels eines dynamischen Optimierungsmodells für den deutschen Stromsektor erfolgt einerseits die Quantifizierung der gesamten Ausstiegskosten, andererseits wird die Verteilung dieser Kosten auf die Stromkonzerne berechnet. Das Modell minimiert die Kosten, die zur Schließung der durch vorzeitigen Ersatz ausscheidender Kernkraftwerke entstehenden Versorgungslücke. Es wird verdeutlicht, dass verschiedene Ausstiegsregeln große Kostenunterschiede und Wettbewerbsverzerrungen bedingen können, auch wenn diese Regeln zum gleichen Ausstiegsdatum führen.

Die beiden folgenden Studien (Kapitel 3 und 4) behandeln einen der Kernbestandteile europäischer Klimapolitik: die am 1.1.2005 vollzogene Einführung eines EU-weiten Emissionshandelssystems. Der Emissionshandel betrifft jedoch nicht alle Wirtschaftssektoren. Mittels der sogenannten Nationalen Allokationspläne (NAP) bestimmen EU-Mitgliedsstaaten den Teil ihres gesamten, im EU Lastenteilungsabkommen festgelegten, Emissionsbudgets, der auf die am Handel teilnehmenden Sektoren entfällt. Zur Erreichung des Emissionsziels müssen demnach die nicht vom Handel betroffenen Sektoren ergänzenden Politikmaßnahmen (z.B. Emissionssteuern) unterworfen werden. Die durch mögliche ineffiziente Zuweisung der Emissionsbudgets hervorgerufenenn Zusatzkosten sind Gegenstand der Untersuchung in Kapitel 3. Es erfolgt zunächst eine stilisierte Analyse der Effizienzwirkungen der segmentierten Emissionsregulierung. Anschließend kommt ein partiales Gleichgewichtsmodell zur Abbildung des europäischen Markts für Emissionsrechte zum Ansatz. Das Modell basiert auf Grenzvermeidungskosten-Kurven am Handel teilnehmender und nicht am Handel teilnehmender Sektoren. Anhand der aktuellen Nationalen Allokationspläne wird verdeutlicht, dass ein segmentiertes System in den Mitgliedsstaaten substanzielle Zusatzkosten im Vergleich zu einem alle Wirtschaftssektoren umfassenden Handelssystem hervorrufen kann, da ein Abweichen von der effizienten Allokation unweigerlich zu einer Verschiebung der Vermeidungslast hin zu vergleichsweise teuren Vermeidungsoptionen führt.

Kapitel 4 betrachtet das europäische Emissionshandelssystem aus Sicht einer kleinen offenen Volkswirtschaft am Beispiel Deutschlands. Die angesprochene Segmentierung der Emissionsregulierung führt hierbei zu einem grundsätzlichen Informationsproblem für die nationale Regulierung: Zur effizienten Ausgestaltung des Nationalen Allokationsplans müssen sowohl der zukünftige internationale Preis für Emissionsrechte, als auch die Kosten der heimischen Emissionsvermeidungsoptionen bekannt sein. Das europäische Emissionshandelssystem verliert dadurch eine grundlegende Eigenschaft marktbasierter Regulierung, nämlich die umfassende Nutzung dezentraler Marktmechanismen. Eine numerische Analyse am Beispiel Deutschlands zeigt einerseits auf, dass Fehleinschätzungen dieser Größen zu beträchtlichen Zusatzkosten führen können. Die Ergebnisse weisen jedoch auch darauf hin, dass Zusatzkosten eher durch Lobby-Aktivität einflussreicher am Handel teilnehmender Wirtschaftssektoren erklärt werden können.

Kapitel 5 dieser Arbeit befasst sich mit den ökonomischen Konsequenzen verschiedener politischer Instrumente zur Förderung erneuerbarer Energien. Neben der Einführung eines Emissionshandelssystems kommt der beschleunigten Marktdurchdringung von Technologien zur Stromerzeugung auf Basis erneuerbarer Energien in Europa eine große umwelt- und energiepolitische Bedeutung zu. Als übergeordnetes Ziel wird auf europäischer Ebene bis zum Jahr 2010 fast eine Verdopplung des Anteils erneuerbarer Energien am gesamten Stromverbrauch der EU angestrebt. Jedoch im Gegensatz zu der auf europäischer Ebene weitgehend harmonisierten Emissionsregulierung ist die Förderung von erneuerbaren Energien in Europa nach wie vor sehr heterogen. Neben fiskalischen Instrumenten und reinen Investitionszuschüssen nutzt die Mehrzahl der Mitgliedsstaaten Quotenhandelsmodelle und fixe Einspeisetarife. Letztere weisen häufig technologiespezifische Vergütungssätze auf, die meist mit der Möglichkeit zur gezielten Förderung von Technologien mit unterschiedlichen Reifegraden begründet werden, häufig aber auch durch strategische Überlegungen (wie der Förderung bestimmter heimischer Industrien) motiviert sind. Die technologiespezifische Förderung birgt jedoch die Gefahr erheblicher Zusatzkosten durch die potenzielle Überförderung ineffizienter Technologien.

Zur Abschätzung dieser Zusatzkosten kommt ein numerisches Modell zur Abbildung des (unvollkommenen) Wettbewerbs auf europäischen Strommärkten zum Ansatz. Anhand illustrativer Politikszenarien zeigt sich, dass technologiespezifische Einspeisetarife die Zielerreichung gegenüber einheitlichen Tarifen oder gar gegenüber eines EU-weiten Quotenhandelssystems beträchtlich verteuern.

Die letzte vorgestellte Studie (Kapitel 6) befasst sich wiederum mit dem Kernenergieausstieg. Im Vergleich zur Untersuchung in Kapitel 2 erfolgt die Analyse nun auf europäischer Ebene. Neben Deutschland haben weitere europäische Staaten den zukünftigen Ausbau nuklearer Kapazitäten ausgeschlossen oder streben gar einen beschleunigten Ausstieg aus der Kernenergie an.

Zentrales Element der kontrovers geführten Diskussion um die Zukunft der Kernenergie auf europäischer Ebene sind die induzierten makroökonomischen Effekte und – speziell vor dem Hintergrund europäischer Klimaschutzstrategien – die Emissionswirkungen, die von einem zukünftigen Verzicht auf Kernenergie hervorgerufen werden. Zur Abschätzung dieser Effekte kommt ein berechenbares allgemeines Gleichgewichtsmodell für die Europäische Union zum Ansatz. Das (Hybrid-) Modell beinhaltet eine aktivitätsanalytische Darstellung verschiedener Stromerzeugungsoptionen (-technologien). Die Modellergebnisse verdeutlichen, dass ein Ausstieg aus der Kernenergie zu deutlichen Anpassungskosten und einem erheblichen Anstieg der Emissionen in Europa führen kann.

Contents

List of Figures

List of Tables

Part 1

Introduction

CHAPTER 1

Introduction

1.1. Executive Summary

The studies presented in this thesis address the consequences of market distortions of governmental policies – predominantly in the area of environmental and energy policy. The studies cover different economic aggregation levels: The first study aims at investigating firm-level effects. Thus, the results refer only to a small number of well-defined economic entities, e.g. electricity supply companies in Germany. Subsequently, issues – such as the evaluation of efficiency effects of the European Emissons Trading system – are addressed on a multi-sectoral and multi-regional level, but still only one market is considered. Thereupon, the scope of investigation is broadened by interactions of different markets – e.g. as in the case of the economic evaluation of renewable energy promotion strategies. Finally, a general equilibrium analysis of a European nuclear phase-out scenario covers all economic feed-backs on the national and international level.

The five studies presented in Part 2 are based on applied numerical models of economic and/or energy systems. Depending on the particular issue either pure optimization models are employed or models are formulated as so-called mixed complementarity problems (MCP), where the latter approach is used in four of the five applications (Chapters 3 - 6), and hence, represents the methodological focus of this thesis.

The structure of this thesis is as follows: Chapter 1 introduces and motivates the mixed complementarity problem and exemplifies its application in applied economics. Chapters 2 - 6 provide five studies applied to the area of environmental and energy economics. The remainder of this section briefly sketches these applications:

The first study (Chapter 2) addresses the question of how alternative phase-out regulations for nuclear power in Germany affect both the magnitude of total economic costs and its distribution across competing companies. The study is based on a dynamic linear programming model of German electricity supply. It is designed to investigate the additional costs associated with an accelerated phase-out of existing nuclear power plants as compared to a baseline scenario. The model minimizes the costs of covering the supply gap, which is caused by the premature phase-out of nuclear capacities. It is shown that alternative regulations leading to the same phase-out date exhibit large differences in total costs which are mainly associated with the respective differences in permissible cumulative nuclear power

production. The cost differences diminish to a large extent when authorities prescribe the same cumulative threshold for nuclear power production instead of the phase-out year. Furthermore, the distribution of phase-out costs across companies changes considerably for the various regulation schemes.

The next two studies (Chapters 3 and 4) analyze the European Emissions Trading Scheme (EU-ETS). As of 1 January 2005 the European Union has launched the first large-scale international carbon emissions trading program. Implementation of an EU-wide emissions trading system by means of National Allocation Plans is at the core of the European environmental policy agenda. EU Member States must allocate their national emission budgets under the EU Burden Sharing Agreement between energy-intensive sectors that are eligible for European emissions trading (referred to as *DIR* sectors) and the remaining segments of their economies that will be subject to complementary domestic emission regulation (referred to as *NDIR* sectors). As the EU-ETS covers only part of domestic carbon emissions, it implies a segmented environmental regulation scheme which may lead to non-negligible efficiency costs. In order to quantify the allocative inefficiencies and compliance costs associated with the segmented emission regulation at the EU level (in Chapter 3), a numerical partial equilibrium model of the EU carbon market is employed. The model is based on marginal abatement cost curves for *DIR* and *NDIR* sectors in the EU-15 that are calibrated to empirical data. A result of the analysis is that such hybrid emission regulation may lead to substantial excess costs compared to a comprehensive emissions trading system covering all segments of the European economy. Furthermore, the hybrid system associated with the current design of National Allocation Plans is likely to discriminate against sectors that are not part of the emissions trading scheme.

The segmentation of the emission market into multiple domestic markets and a single international market creates an information problem for environmental regulation on the Member State level (see Chapter 4): Given such a segmented regulation scheme, the domestic regulator must have perfect information on the international price of tradable emission allowances and the marginal abatement costs across all domestic emission sources that are not covered by the EU-ETS in order to implement the cost-minimizing National Allocation Plan. Hence, segmented emission regulation discards a key element of market-based regulation, i.e. the consequent use of decentralized market mechanisms. The quantitative analysis in Chapter 4 highlights the generic problems of segmented carbon regulation in terms of information requirements for international carbon prices and domestic abatement costs of sectors outside the EU-ETS. Based on numerical simulations for Germany, the excess costs of segmented carbon regulation are quantified. An important conclusion of the simulation is that inefficiencies can be much better explained by lobbying of influential EU-ETS sectors than by information problems.

The fourth application (see Chapter 5) focuses on the economic consequences of another important goal of the European Union, i.e. the increased market penetration of electricity produced from renewable energy sources (RES-E). The indicative objective of the EU is almost a doubling of the share of renewable energy in Europe's gross energy consumption until 2010. Member States employ various RES-E promotion schemes in order to contribute to this ambitious goal. Most commonly applied to date are feed-in tariff schemes and quota obligation systems. Based on a large-scale partial equilibrium model of the liberalized EU electricity market it can be shown that regionally fragmented feed-in tariff schemes incur substantial excess cost compared to an EU-wide tradable green quota. The excess costs are even more pronounced, when countries employ technology-specific feed-in tariffs in order to pursuit additional targets of strategic and regional policy interest.

The last application deals with the future role of nuclear power in Europe's electricity supply (Chapter 6). Besides Germany, several other governments of EU Member States have recently started initiatives for a moratorium or even a premature phase-out of nuclear power. Central subjects surrounding the controversial policy debate of phase-out initiatives are the induced macroeconomic and environmental impacts. To address these issues a hybrid computable general equilibrium (CGE) model for the European Union is used. The model features an activity analysis representation of discrete electricity supply options for EU-15 Member States. We find that an accelerated dismantling of nuclear power imposes non-negligible adjustment costs that reflect the foregone use of existing cost-efficient nuclear capacities for electricity generation. Moreover, carbon emissions will increase substantially since carbon-free nuclear power will be replaced to a larger extent by fossil fuel technologies.

1.2. Background – The mixed complementarity problem (MCP)

1.2.1. Motivation of mixed complementarity problems. A mixed complementarity problem (MCP) is a system of simultaneous conditions that can include (weak) inequalities associated with bounded variables (Rutherford 1995). In such a system, any of the given inequalities has a complementary slack relationship with a specific bounded variable. The problem is referred to as mixed because it accommodates combinations of equalities as well as inequalities. The equality conditions imply that the variable associated with an equality is unbounded (or free). As shown in the following section, the special case that all of the equations are equalities simply transforms into a simultaneous system of nonlinear equations. The most familiar complementarity problem that arises in economics is the system of Karush-Kuhn-Tucker conditions that form the solution to a constrained nonlinear optimization problem where constraints are characterized by inequalities (Karush 1939, Kuhn & Tucker 1951).

The MCP, however, has many applications to equilibrium problems in which (i) integration to a single underlying optimization problem is not possible or where (ii)

the notion of equilibrium does not explicitly condition an objective being optimized (Ferris & Pang 1997, Harker & Pang 1990). For instance, economic equilibrium has a natural formulation as a complementarity system when complementarity conditions embody behavioral statements about the heterogeneous agents.[1] In the first case these "non-integrabilities" refer to quite common situations in economic modelling where e.g. ad-valorem taxes or marginal cost pricing in regulated markets would implicitly constrain dual variables (here the price) in optimization of economic surplus (see e.g. Mathiesen 1977), or where equilibrium is characterized by non-symmetric actions of heterogeneous agents, i.e. when cross-price elasticities are non-symmetric or dominant firms exert market power via mark-ups on their marginal costs. Such equilibria could be computed by solving a sequence of (nonlinear) optimization problems but formulated as complementarity problems the models are much better accessible and more transparent (Rutherford 1992, Rutherford 1995).

In the recent past, the formulation of equilibrium problems as a system of nonlinear inequalities has been advocated (Cottle *et al.* 1992) and successfully applied to large-scale models taking advantage of the availability of commercial software for model formulation and robust solution algorithms (Rutherford 1995, Dirkse & Ferris 1995*b*). Consequently, an increasing number of economic applications makes use of the ameliorated manageability of numerical models.

The following section briefly introduces the mixed complementarity problem and its basic application to economic modelling.

1.2.2. Types of complementarity problems. Complementarity problems may arise in different types. This section gives an overview of different problems that can be considered as complementary problems (CP). Four out of the five applications in Part 2 of this thesis address problems of naturally occurring complementary forms and the algebraic description of these problems maintains the so-called complementarity format. Beginning with a general definition of the complementarity problem a number of special cases will be derived. The general definition of a **mixed complementarity problem (MCP)** reads as follows (Rutherford 1995):

$$
\begin{aligned}
\text{(1.2.1)} \qquad \text{Given:} \quad & F : R^N \longrightarrow R^N, \quad l, u \in R^N \qquad (MCP) \\
\text{Find:} \quad & z, w, v \in R^N \\
\text{s.t.} \quad & F(z) - w + v = 0 \\
& l \leq z \leq u, \;\; w \geq 0, \;\; v \geq 0 \\
& w^T(z - l) = 0, \quad v^T(u - z) = 0 \\
\text{in which:} \quad & -\infty \leq l \leq u \leq +\infty
\end{aligned}
$$

[1]See e.g. the Walrasian law of competitive equilibria of exchange economies or the Wardrop principle in traffic theory (Walras 1954, Wardrop 1952).

The first special case of the MCP is a **linear system of equations (LSYS)** which can be represented as a CP by letting $l = -\infty$, $u = +\infty$, $z = x$, and letting $F(z) = Ax - b$. In order to satisfy the equations $w^T(x - l) = 0$, $v^T(u - x) = 0$, clearly w and v must be zero (with $-\infty \leq x \leq +\infty$). If now $w = 0$ and $v = 0$, the linear system of equations then reads as follows:

$$\begin{aligned} \text{Given:} \quad & A \in R^{n \times n}, \quad b \in R^N \qquad (LSYS) \\ \text{Find:} \quad & x \in R^n \\ \text{s.t.} \quad & Ax = b \end{aligned} \tag{1.2.2}$$

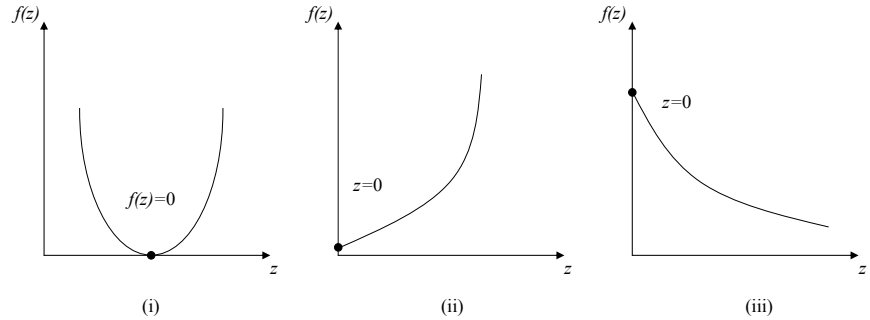
Accordingly, the CP format also incorporates the **nonlinear system of equations (NLSYS)** as a special case. Again let $l = -\infty$, $u = +\infty$ and $z = x$. Then, if a nonlinear function $f(z)$ is introduced (letting $F(z) = f(z)$), the same rationale as above leads to the following nonlinear system of equations:

$$\begin{aligned} \text{Given:} \quad & f : R^n \longrightarrow R^n, \quad b \in R^n \qquad (NLSYS) \\ \text{Find:} \quad & x \in R^n \\ \text{s.t.} \quad & f(x) = 0 \end{aligned} \tag{1.2.3}$$

So far, neither the linear nor the nonlinear system of equations featured complementarity. This changes when a lower bound is imposed on the variable z. Readressing the general MCP definition from above and letting $l = 0$, $u = +\infty$ and $F(z) = q + Mz$ the *MCP* corresponds to a **linear complementary problem (LCP)**. Again, from $v^T(u - z) = 0$ and $0 \leq z \leq +\infty$ directly follows that $v = 0$. Now, if $l = 0$ then $w^T(z - l) = 0$ directly transforms into $w^T z = 0$. Clearly, this equation only holds if either w or z is zero. Two cases may be now be differentiated: In the first case, if $w = 0$ then z can be greater than or equal to zero ($z \geq 0$). In this case – with $w = 0$ – from the general expression $F(z) - w = 0$ directly follows that the equality $q + Mz = 0$ must hold. Accordingly, if – in the latter case – the weak inequality $w^T \geq 0$ and the equality $w = 0$ apply, the possibility is given that $(q + Mz) \geq 0$. This case differentiation reveals the concept of complementarity between the function $F(z)$ and the variable z. It states that either z or $F(z)$ must be zero, hence one of the (weak) inequalities is satisfied as an equality. Consequently, not only $q + Mz \geq 0$ and $z \geq 0$ must hold, but also $z^T(q + Mz) = 0$. As shown later in a more general example, the resulting LCP corresponds to the optimality conditions of a constrained linear optimization problem.

Summarizing, the linear complementarity problem reads as follows:

FIGURE 1.2.1. Complementarity between $f(z)$ and z



$$
\begin{array}{rll}
\text{Given:} & M \in R^{n\times n}, \quad q \in R^n & (LCP) \\
\text{Find:} & z \in R^n & \\
\text{s.t.} & 0 \leq z \quad \perp \quad (q + Mz) \geq 0 &
\end{array}
\tag{1.2.4}
$$

where the orthogonality symbol ($\perp$) expresses that the inner product of $F(z)$ and z is zero, thus $z^T(q + Mz) = 0$.

With the same assumptions as above ($l = 0$ and $u = +\infty$) and the introduction of a nonlinear function $f(z)$ (letting $F(z) = f(z)$), the MCP corresponds to the (more general) **nonlinear complementary problem (NCP)**:[2]

$$
\begin{array}{rll}
\text{Given:} & f : R^n \longrightarrow R^n & (NCP) \\
\text{Find:} & z \in R^n & \\
\text{s.t.} & 0 \leq z \quad \perp \quad f(z) \geq 0 &
\end{array}
\tag{1.2.5}
$$

In other terms: this NCP corresponds to the problem of solving the nonsmooth equation $\min[z, F(z)] = 0$ where the min operation is taken component-wise (Ferris & Pang 1997). Figure 1.2.1 illustrates the concept of complementarity between a function and a variable in the context of an NCP. As shown in section 1.2.3 this form of complementarity arises as the first-order conditions of a constrained nonlinear optimization problem. In this regard, the solution described in Figure 1.2.1.i. represents a global maximum of a function $H(z)$ if $f(z) = \bigtriangledown H(z)$.

So far, the focus has been on situations, where variables are either unbounded or were non-negativity is assumed. In practice, many problems have lower and/or upper bounds on the variables, instead of the nonnegativity assumption leading

[2]Again the orthogonality symbol expresses the complementarity between the variable and the nonlinear function so that the following holds: $f(z) \geq 0, \;\; z \geq 0, \;\; z^T f(z) = 0$

to LCP or NCP. More generally, a problem may have lower and upper bounds on some variables, only lower or upper bounds on other variables, and no bounds at all on the remaining variables. Many applications exhibit both conditions expressed as a system of linear or nonlinear equations and complementarity conditions. The mixed complementarity problem allows for both of these conditions.[3]

Let a problem be characterized by a set of Q variables and Q equations (with $q = 1, ..., Q$) where a subset I ($I \in Q$) of the variables are free ($-\infty \leq z_I \leq +\infty$); then – as shown in the case of NLSYS above – there is a set of I nonlinear equations $f_I(z) = 0$. If the remaining J ($J \in Q$) variables are constrained by non-negativity ($0 \leq z_J \leq +\infty$) then there is a set of J (nonlinear) complementarity conditions – as shown in the case of NCP.

The resulting mixed complementarity problem (MCP) reads as follows:

$$
\begin{aligned}
\text{Given:} \quad & f_I : R^n \longrightarrow R^n, \quad f_J : R^n \longrightarrow R^n \qquad (MCP) \\
\text{Find:} \quad & z \in R^n \\
s.t. \quad & f_I(z) = 0 \\
& 0 \leq z_J \quad \perp \quad f_J(z) \geq 0 \\
& -\infty \leq z_I \leq +\infty, \quad 0 \leq z_J \leq +\infty
\end{aligned} \tag{1.2.6}
$$

1.2.3. Complementarity and optimization problems. Many economic problems are formulated as linear or nonlinear optimization problems (Ferris & Kanzow 2002, Ferris *et al.* 2001, Ferris & Pang 1997, Dirkse & Ferris 1995*a*). As already noted in the previous section complementarity problems are closely connected to optimization problems. The attribute of complementarity is a central element of all constrained optimization problems (Mangasarian 1969). The well known complementary slackness property in linear- and nonlinear programming points up the fundamental role of complementarity in optimization. Complementary slackness arises from the possibility to reformulate each so-called primal optimization problem as an equivalent dual optimization problem.

For example: Let $f(x) = ax$ and $g(x) = bx + c$, then the optimization problem:

$$
\begin{aligned}
\text{maximize:} \quad & ax \\
\text{s.t.} \quad & bx \leq c
\end{aligned} \tag{1.2.7}
$$

can be transformed into the minimization problem:

[3]Where the term "mixed" reflects the distinction between complementarity conditions and equality conditions.

$$\begin{aligned} \text{minimize:} \quad & \lambda_g^T c \\ \text{s.t.} \quad & \lambda_g^T b \geq a \end{aligned} \tag{1.2.8}$$

with x as the primal and λ_g as the dual variable. Concerning the optimal primal-dual solution $x^*$and λ_g^* complementary slackness states that the optimum is found if both $\lambda_g^{*T}(bx^* - c) = 0$ and $x^*(\lambda_g^{*T} b - a) = 0$ hold. In other words, whenever there is positive slackness in one of the constraints, the associated dual variable must be zero, i.e. whenever a constraint is not binding.

The close relation between constrained optimization and complementarity suggests that, in principle, any nonlinear program (NLP) can be formulated as an MCP (Ferris & Sinapiromsaran 2000). Employing the notation above, the following constrained NLP will exemplify the equivalence of NLP and MCP:[4]

$$\begin{aligned} \text{maximize} \quad & f(x) \\ \text{s.t.} \quad & g(x) \leq 0 \\ & h(x) = 0 \\ & 0 \leq x \leq +\infty \end{aligned} \tag{1.2.9}$$

Introducing λ_g and λ_h as the Lagrange multipliers (or dual variables) of the constraints $g(x) \leq 0$ and $h(x) = 0$, the Lagrangian of the problem reads as follows:

$$\mathcal{L} = f(x) - \lambda_g^T g(x) - \lambda_h^T h(x) \tag{1.2.10}$$

Differentiating for x, λ_g and $\lambda_h$leads to the well known first-order conditions – or Karush-Kuhn-Tucker (KKT) conditions (Karush 1939, Kuhn & Tucker 1951):

[4] $f(x)$ is assumed to be convex and continuously differentiable and $g(x)$ is assumed to be concave and also continuously differentiable.

$$\frac{\partial \mathcal{L}}{\partial x} = \nabla f(x) - \lambda_g^T \nabla g(x) - \lambda_h^T \nabla h(x) \geq 0 \tag{1.2.11}$$

$$\frac{\partial \mathcal{L}}{\partial \lambda_g} = -g(x) \geq 0 \tag{1.2.12}$$

$$\frac{\partial \mathcal{L}}{\partial \lambda_h} = -h(x) = 0 \tag{1.2.13}$$

$$x \geq 0 \tag{1.2.14}$$

$$\lambda_g \geq 0 \tag{1.2.15}$$

$$\lambda_h \geq -\infty \tag{1.2.16}$$

$$x^T \left(\nabla f(x) - \lambda_g^T \nabla g(x) - \lambda_h^T \nabla h(x)\right) = 0 \tag{1.2.17}$$

$$\lambda_g^T g(x) = 0 \tag{1.2.18}$$

Recalling the general definition of a complementarity problem from the previous section the KKT conditions can be transformed into a mixed complementarity problem by letting:

$$z = \begin{pmatrix} x \\ \lambda_g \\ \lambda_h \end{pmatrix}, \quad l = \begin{pmatrix} 0 \\ 0 \\ -\infty \end{pmatrix}, \quad u = \begin{pmatrix} +\infty \\ +\infty \\ +\infty \end{pmatrix},$$

$$F(z) = \begin{cases} \nabla f(x) - \lambda_g^T \nabla g(x) - \lambda_h^T \nabla h(x) \\ -g(x) \\ -h(x) \end{cases}.$$

Employing the case differentiations as described previously in the context of the LCP (NCP), the KKT conditions translate into the MCP:

$$\begin{aligned} \text{Given:} \quad & f : R^n \longrightarrow R, \;\; g : R^n \longrightarrow R^m, \;\; h : R^n \longrightarrow R^m \\ \text{Find:} \quad & x, \lambda_g, \lambda_h \in R^n \\ \text{s.t.} \quad & 0 \leq x \quad \perp \quad \nabla f(x) - \lambda_g^T \nabla g(x) - \lambda_h^T \nabla h(x) \geq 0 \\ & 0 \leq \lambda_g \quad \perp \quad -g(x) \geq 0 \\ & h(x) = 0 \\ & 0 \leq x \leq +\infty, \\ & 0 \leq \lambda_g \leq +\infty, \quad -\infty \leq \lambda_g \leq +\infty \end{aligned} \tag{1.2.19}$$

Looking at the resulting MCP (and of course the KKT conditions) the familiar notion of complementary slackness directly leads to important economic implications.

E.g., if in the example above $f(x)$ represents a profit function and $g(x)$ describes an upper bound on the availability of a scarce resource, the shadow price λ_g determines the value of resource use. In this context the complementary slackness conditions (i.e. the KKT conditions $x^T[\nabla f(x) - \lambda_g \nabla g(x) - \lambda_h \nabla h(x)]$ and $\lambda_g^T g(x)$) state that in optimality either a positive amount of resource is used if marginal profits equal the marginal costs of resource use, or resource use is equal to zero which implies that marginal costs are greater or equal marginal profits. Whenever the constraint on the availability of the resource becomes binding, the use of the resource has a positive value (or shadow price). In this case the marginal profits determine the optimal use. If the resource is not used up to the limit of its availability there is de facto no scarcity of the resource which implies that the resource has no positive price.

1.2.4. Market equilibrium and complementarity. An important reason why complementarity problems play an important role in applied economics is because the concept of complementarity is synonymous with the specification of system equilibrium. Balancing supply and demand is a central aspect in economic systems. Mathematically this fundamental balance can be described by a complementary relation between two sets of decision variables – namely prices and activity levels. For instance the classical Walrasian law of competitive equilibria of exchange economies can be formulated as a nonlinear complementarity problem in the price and excess demand variables. The complementarity condition for this problem expresses that whenever the price for a commodity is positive, the excess demand of a commodity must be zero. Vice versa, the price of the commodity must be zero if there is positive excess supply.

As a more comprehensive example: If a competitive (Arrow Debreu) economy consists of n commodities (including production factors), m production activities (sectors) and h households, then a competitive market equilibrium is determined by (Böhringer & Rutherford 2006, Ferris & Pang 1997, Mathiesen 1985):

- a non-negative vector of commodity prices p (with index $j = 1, ...n$),
- a non-negative vector of sectoral production activity levels y (with index $j = 1, ...m$) and
- a non-negative vector of household income levels M (with index $h = , 1, ..., k$),

such that the following statements hold:

(1) Each sector maximizes its profit. If sectoral production is characterized by constant returns to scale the statement translates into the statement that none of the sectors makes excess profits. If $\Pi_j(p)$ denotes the profit function of production activity j (the difference between revenue and production costs) the zero-profit condition reads as:

$$-\Pi_j(p) = -a_j^T(p)p \geq 0 \tag{1.2.20}$$

where $a_j(p)$ is the technology vector for activity j (derived by Hotelling's Lemma as the partial derivative $\nabla\Pi_j(p)$).

(2) Supply exceeds demand (market clearance condition), i.e. excess supply is non-negative for all commodities. If, on the other hand, excess demand would exist for a commodity, producers would increase production of this commodity until supply equals demand. If w_h denotes the initial endowment of houshold h and $d_h(p, M_h)$ the utility maximizing demand vector of houshold h, the market clearance condition can be stated as follows:

$$\sum_j y_j \nabla\Pi_j(p) + \sum_h w_h \geq \sum_h d_h(p, M_h) \tag{1.2.21}$$

(1) Total expenditures for consumption do not exceed the income generated by the trading of commodities (budget constraint) such that:

$$M_h = p^T d_h \geq -p^T d_h(p, M_h) \tag{1.2.22}$$

Using Walras' law the equilibrium conditions (1.2.20) - (1.2.22) can be transformed into:

$$y_j \Pi_j(p) = 0 \tag{1.2.23}$$

$$p\left[\left(\sum_j y_j \nabla\Pi_j(p) + \sum_h w_h\right) - \sum_h d_h(p, M_h)\right] = 0 \tag{1.2.24}$$

$$M_h\left(M_h = p^T w_h\right) = 0 \tag{1.2.25}$$

it is easy to see that complementarity between the equilibrium conditions and the equilibrium variables is an evident feature of the economic equilibrium as stated above:

(1) The zero-profit condition implies that activities will be operated as long as revenues cover the costs, otherwise production activities are shut down.
(2) The market clearance condition implies that positive market prices lead to market clearance, otherwise commodities are in excess supply and the respective prices fall to zero.

(3) The budget constraint links income variables to income budget constraints.

The complementarity features of the general market equilibrium problem, thus, motivate the formulation of the general equilibrium conditions as a complementarity problem. Again, recalling the definition of a complementarity problem in section 1.2.2 the equilibrium can be formulated as a nonlinear complementarity problem by letting:

$$z = \begin{pmatrix} y \\ p \\ M \end{pmatrix}, \quad l = \begin{pmatrix} 0 \\ 0 \\ 0 \end{pmatrix}, \quad u = \begin{pmatrix} +\infty \\ +\infty \\ +\infty \end{pmatrix} \qquad \text{and}$$

$$F(z) = \begin{cases} -\Pi_j(p) \\ \sum_j y_j \nabla \Pi_j(p) + \sum_h w_h - \sum_h d_h(p, M_h) \\ M_h - p^T w_h(p, M_h) \end{cases} .$$

where z represents the equilibrium variables and $F(z)$ depicts the equilibrium conditions (1.2.20) - (1.2.22).

Part 2

Five Selected Applications

CHAPTER 2

The Nuclear Phase-Out in Germany[1]

2.1. Introduction

Since they have taken over political power in 1998, the coalition of Social-Democrats and the Green party have pursued the rapid phase-out of nuclear power in Germany. A critical issue in the design of phase-out policies has been the operating time for existing nuclear power plants, because it provides the basis for potential compensation claims of power companies, offsetting their opportunity costs induced by an accelerated phase-out. While the power companies insisted on an operating time of 40 full-load years in order to minimize these opportunity costs, the government offered a ceiling of 30 calendar years (Maier-Mannhart 2000). Hence, the proposals not only differ with respect to the nominal number of years, but also with respect to the reference point for the operating time. Adopting calendar years as the reference point implies that power plants are taken off the grid as soon as the given number of calendar years has passed since their initial start-up. In contrast, the full-load-year approach only considers the effective use of power plants, i.e., downtime due to fuel make-up, routine or unscheduled repair work is not accounted for. Both approaches provide runtime operating rules at the plant level. Another policy-relevant approach would be to administer a target year in which the last existing power plant must go off the grid.

A dynamic partial equilibrium model of electric power supply options is used to quantify how these alternative phase-out regulations affect both the magnitude of economic costs and the distribution of these costs across power companies. The analysis identifies large costs savings of the target-year approach as compared to calendar-year or full-load-year regulation because the former provides a higher capacity for nuclear power generation at any given point in time. Comparing the calendar-year approach and the full-load-year approach, regulation based on full-load years yields a significant cost decrease even when it is tailored to achieve the same phase-out date of the last nuclear power plant. The reason is that several plants with low historical utilization can be used longer than would be permissible under the calendar-year regulation. The quantitative simulations indicate substantial changes in the cost incidence across power companies depending on the

[1] This chapter is based on the article:

Böhringer, C., Hoffmann, T. & Vögele, S. (2002), 'The Cost of Phasing Out Nuclear Power: A Quantitative Assessment of Alternative Scenarios for Germany', *Energy Economics* 24(5), p.469-490.

regulatory approach which reveal an important equity dimension of phase-out policies. There have been several studies on the economic costs of phasing out nuclear power in Germany (Horn & Ziesing 1997, Pfaffenberger & Gerdey 1998, Schade & Weimer-Jehle 1999, Schmitt 1999, Welsch & Ochsen 2001). In contrast to these studies, which focus only on the total costs for a very narrow set of phase-out scenarios, we quantify the phase-out costs of alternative regulations as a function over time. Moreover, we compute how the total costs are distributed across power companies and may affect competitiveness.

Our quantitative results refer to Germany with its specific plant structure as well as plant-ownership by companies. However, the underlying issues as well as the methodology in use are potentially relevant for other countries which contemplate similar regulations for an accelerated nuclear phase-out (e.g. Sweden, Switzerland or Belgium).

The remainder of the chapter is organized as follows. Section 2.2 provides background information on the electricity supply options and the role of nuclear power in Germany. Section 2.3 summarizes the analytical framework and its parametrization. Section 2.4 defines the scenarios and discusses our results. Section 2.5 concludes.

2.2. Background

2.2.1. Options for closing the nuclear gap. At present, 19 nuclear power plants are operating in Germany, which produced around 160 billion kWh in 2000. Nuclear power has covered roughly a third of Germany's electricity demand over the last years. An administered accelerated phase-out of nuclear power would induce a supply-side gap that can be reduced or closed using, in principle, four options:

(1) reduction of energy demand,
(2) increased utilization of existing power plants,
(3) increased electricity imports, or
(4) construction of new non-nuclear power plants.

A decline in electricity demand for Germany is unrealistic given unisonous expert analysis (Prognos / EWI 1999, European Commission 1999*b*, EIA 2000). Increasing the degree of utilization in the middle and peak load as well as load shifting may cover only a small fraction of the base-load gap caused by a nuclear phase-out, because these measures are rather costly and limited in overall scope.[2]

Thus, two major options remain for closing the power supply gap: increased electricity imports or the construction and operation of new non-nuclear power plants.

[2]The high cost pressure among competing power companies on the liberalized European electricity markets has already significantly reduced stand-by power. According to recent studies (Siemens AG 1999, DVG 1999) the bulk of stand-by capacity in Germany (ca. 23 GW) consists of older oil- and gas power plants with low efficiencies, i.e. high variable costs. In fact, the variable cost for most of these power plants are higher than the total cost per kWh of a new power plant.

Table 2.2.1. “Consumed” calendar years and full-load years in 1999

	“Consumed” calendar years (A)	“Consumed” full-load years (B)	Average degree of utilization (B/A)
Obrigheim	30	24	80%
Stade	27	23	84%
Biblis A	24	17	71%
Neckarwestheim 1	23	18	80%
Biblis B	22	16	74%
Brunsbüttel	22	13	57%
Unterweser	20	16	80%
Isar 1	20	16	78%
Philippsburg 1	19	14	75%
Grafenrheinfeld	17	14	85%
Gundremmingen B	15	13	87%
Krümmel	15	12	83%
Grohnde	14	13	91%
Philippsburg 2	14	12	89%
Gundremmingen C	14	12	86%
Brokdorf	13	11	87%
Emsland	11	10	93%
Isar 2	11	10	89%
Neckarwestheim 2	10	9	93%
Average	17	14	82%

In both cases, companies will face additional costs which are driven by the difference between the unrestricted economic operating time of their plants and the concrete utilization constraint imposed by the respective phase-out regulation.

2.2.2. Age Pattern of Nuclear Power Plants. Table 2.2.1 provides an overview of the age pattern for Germany’s nuclear power plants in regard to "consumed" calendar years and full-load years, respectively. The difference ranges up to 9 years for the case of Brunsbüttel. In the past, the average availability, which is measured as the ratio between "consumed" full-load years and "consumed" calendar years, has been lowest for Brunsbüttel, Biblis-A and Biblis-B. These power plants have operated on average less than 6500 full-load hours per year. On the other end, there are Grohnde, Emsland and Neckarwestheim-2, which have operated for more than 7800 full-load hours per year. As mentioned above, in the case of a full-load year regulation, downtime does not reduce the effective operation time, i.e. past times of no-use delay the shut-down of the power plants in the future. The historical differences in "consumed" calendar years and "consumed" full-load years play a key role in explaining the disproportionate cost incidence of calendar-year regulation versus full-load regulation as reported in Section 2.4 below.

TABLE 2.3.1. Development of international fossil fuel prices. Source: FEES (1999).

Fuel	Unit	1995	2000	2005	2010	2020	2030
Hard coal	DM95/GJ	2.58	3.00	3.41	3.59	3.96	4.37
Crude oil	DM95/GJ	4.36	5.11	5.85	6.47	7.71	9.68
Light heating oil	DM95/GJ	5.31	6.25	7.18	7.85	9.20	11.46
Heavy heating oil	DM95/GJ	3.52	4.14	4.75	5.23	6.18	7.74
Natural gas	DM95/GJ	4.06	4.37	4.68	5.31	6.56	8.58

2.2.3. Ownership of Nuclear Power Plants. In order to calculate the incidence of the nuclear phase-out at the company level (see Section 2.4.2), information on the ownership of plants is needed, which is given in Figure 2.2.1.

It is evident that several companies hold multiple ownership in plants. After the calculation of the cost incidence of alternative regulation schemes at the plant level, the implied cost for the companies can be determined by distributing the cost at the plant level across companies, according to their respective shares in plants.

2.3. Analytical Framework and Parametrization

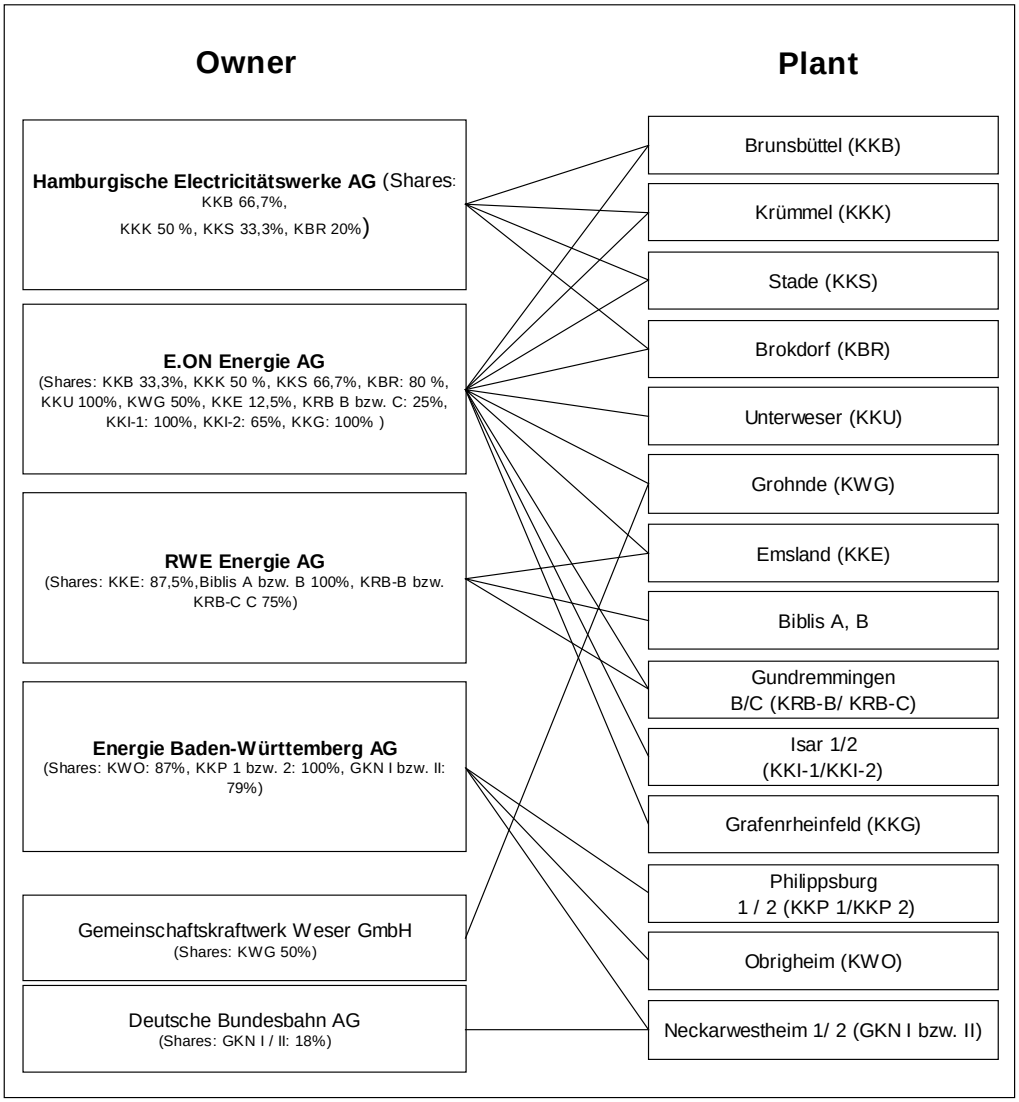
2.3.1. Analytical Framework. The dynamic linear programming model is designed to investigate the additional costs associated with an accelerated phase-out of existing nuclear power plants as compared to a baseline scenario where these plants can be used until the end of their economic lifetime. The model minimizes the costs of covering the supply gap, which is caused by the retirement of nuclear power plants subject to technological as well as policy constraints (Vögele 2000). It includes detailed technological information (efficiency factor, capacity limits, etc.) and economic data (fixed and variable costs, investment costs, etc.) on existing nuclear power plants as well as current and future non-nuclear plant types for electricity generation (KFA 1994). Appendix A.1 provides an algebraic model summary.

2.3.2. Parametrization. Data on operating, maintenance and investment costs as well as technical information on power plants stem from IKARUS (KFA 1994), a comprehensive techno-economic data base that has been developed for the German Ministry for Technology and Research over the last years. A brief overview of non-nuclear power plants underlying the calculations is given in Table 2.3.2.

The analysis is based on exogenous data on energy demand, international energy prices, and upper limits on electricity imports throughout the time horizon. The projections on world market prices for fossil fuels, as given in Table 2.3.1, are based on FEES (1999) .

With respect to additional electricity imports to replace nuclear power, an upper capacity bound of 2 TWh at an average import price of 0.06 DM_{95} is assumed, including transmission costs. The interest rate is set to 7.5%, which reflects the

FIGURE 2.2.1. Ownership of German nuclear power plants



Note:
Energie Baden-Württemberg AG is a merger of the former companies Badenwerk AG and Energie-Versorgung Schwaben AG (including Neckarwerke Stuttgart AG).
RWE Energie AG is a merger of former companies RWE Energie AG and Vereinigte Elektrizitätswerke Westfalen AG.
E.ON Energie AG is a merger of former companies Bayernwerk AG (including Isar-Amperwerke AG) and Preußen-Elektra AG.

Note:
For the sake of transparency we omit a number of small shareholders such as Energieversorgung Ostbayern (KKI-2: 10 %), Stadtwerke München (KKI-2: 25 %), Zementwerke Lauffen – Elektrizitätswerk Heilbronn (GKNI/II: 3 %); 12 % of shares in KWO are held by nine further companies.

Table 2.3.2. Overview of Non-Nuclear Power Technologies

	Type of technology	available in	Investment costs mill. DM/kW	Efficiency %	Fixed costs mill. DM/kW	Variable costs DM/kWh
f1	Hard coal (suspension firing)	1989	2476.85	41.08	137	0.014
f10	Compound (hard coal, natural gas)	1989	2354.14	40.57	88	0.017
f11	Hard coal CHP	1989	3343.92	35.67	172	0.028
f12	Hard coal CHP	1989	2481.74	37.51	100	0.014
f16	CCGT (hard coal gasification)	2005	3200.52	45.50	117	0.011
f17	CCGT (brown coal gasification)	2005	3178.89	48.10	152	0.015
f18	CCGT (hard coal gasification)	2005	2790.06	48.50	100	0.010
f20	Compound (hard coal, natural gas)	2005	2760.20	48.36	162	0.013
f21	CCGT (oil)	1989	1454.30	46.90	50	0.007
f22	Hard coal	2005	2595.00	45.47	98	0.010
f3	Brown coal (suspension firing)	1989	2318.69	40.11	88	0.011
f4	Hard coal (fluidized-bed combustion)	1989	2282.41	41.02	132	0.017
f5_1	Natural Gas (gas turbine)	1989	558.22	33.26	15	0.012
f5_2	Oil	1989	649.68	31.28	17	0.014
f6	Hard coal CHP (fluidized-bed combustion)	1989	2640.88	44.91	150	0.027
f7	CCGT (natural gas)	1989	1483.70	52.42	67	0.004
f9	CCGT CHP (natural gas)	1989	1931.95	47.50	81	0.005

market price of borrowed capital. The technical lifetime of nuclear power plants is set to 40 full-load years (Majewski 1999, Nuclear Energy Agency 1992). The utilization factor of nuclear power plants in the core simulations amounts to 85.6%, i.e. the nuclear power plants are effectively operated over 10.27 months per year.

2.4. Scenarios and Results

2.4.1. Scenario Definition. In the simulations, three scenarios are distinguished with respect to the operating time of nuclear power plants:

- *CAY* – calendar years: The phase-out regulation is based on calendar years.
- *FLY* – full-load years: The phase-out regulation is based on full-load years. The effective runtime in calendar years is obtained when historical and future degrees of utilization are taken into account.

- *TAY* – target year: Instead of administrating plant-specific operating times (either in terms of full-load years or in terms of calendar years), the government sets a target year by which all power plants must be shut down.

The costs of the nuclear phase-out are measured with respect to a baseline scenario in which existing nuclear power plants are assumed to run until the end of their economic lifetime. The baseline already excludes the construction of new nuclear power plants reflecting rather persistent social preferences in Germany. Accounting for the historical degree of utilization, the remaining plant-specific operating time for each nuclear power plant is calculated according to the following rule: First, the number of consumed full-load years is subtracted from the upper limit of 40 full-load years, which yields the remaining lifetime in terms of full-load years. The latter is then divided by the assumed future degree of utilization, i.e. 85.6%, to obtain the effective operating time in calendar years. In the baseline, the last nuclear power plant (Neckarwestheim-2) will thus be shut down in 2034. For the calculation of phase-out costs of alternative regulations schemes as a function over time (see Figures 2.4.1 A-C), we assume that a ceiling of 30 calendar years provides a lower bound for the feasible operating time of power plants. This means that no existing nuclear power plant will be shut down before 2005.

2.4.2. Simulation Results. Figure 2.4.1 visualizes the phase-out costs as a function of the runtime for *CAY*, *FLY* and *TAY*. By definition, *FLY* coincides with the baseline scenario for a runtime of 40 full-load years. Thus, the additional costs in that specific case are zero. A runtime of 40 full-load years based on *FLY* is equivalent to a maximal runtime of 53 calendar years based on *CAY*, after accounting for past and future downtimes of power plants.[3]

Not surprisingly, the costs of a phase-out for all scenarios become higher the shorter the permitted operating time is compared to the baseline case, because the foregone utilization of competitive power generating capacities is increasing. When comparing across different regulation schemes, *TAY* provides the cheapest way for a phase-out at a given date, followed by *FLY* and then *CAY*. The simple reason is that at any point in time, competitive nuclear capacities are higher under *TAY* as compared to *FLY*, and higher in *FLY* as compared to *CAY*. *TAY*, then, implies the lowest foregone profits with respect to the baseline.

Let us consider the scenario in more detail, where the government concedes 30 calendar years for the permissible operating time of existing power plants. As can be seen from the final row in Table 2.2.1, this scenario (*CAY-30*) imposes phase-out costs of roughly 28 billion DM; the last nuclear power plant (Neckarwestheim-2) will be shut down in 2019. When we allow, instead, for 30 full-load years (*FLY-30*), the costs of the phase-out decline by roughly the half to 15 billion DM. However,

[3]The maximum of 53 years is achieved by Brunsbüttel, which had very high historical downtimes.

FIGURE 2.4.1. Phase-out costs under calendar-year regulation (CAY), full-load year regulation (FLY) and target-year regulation (TAY)

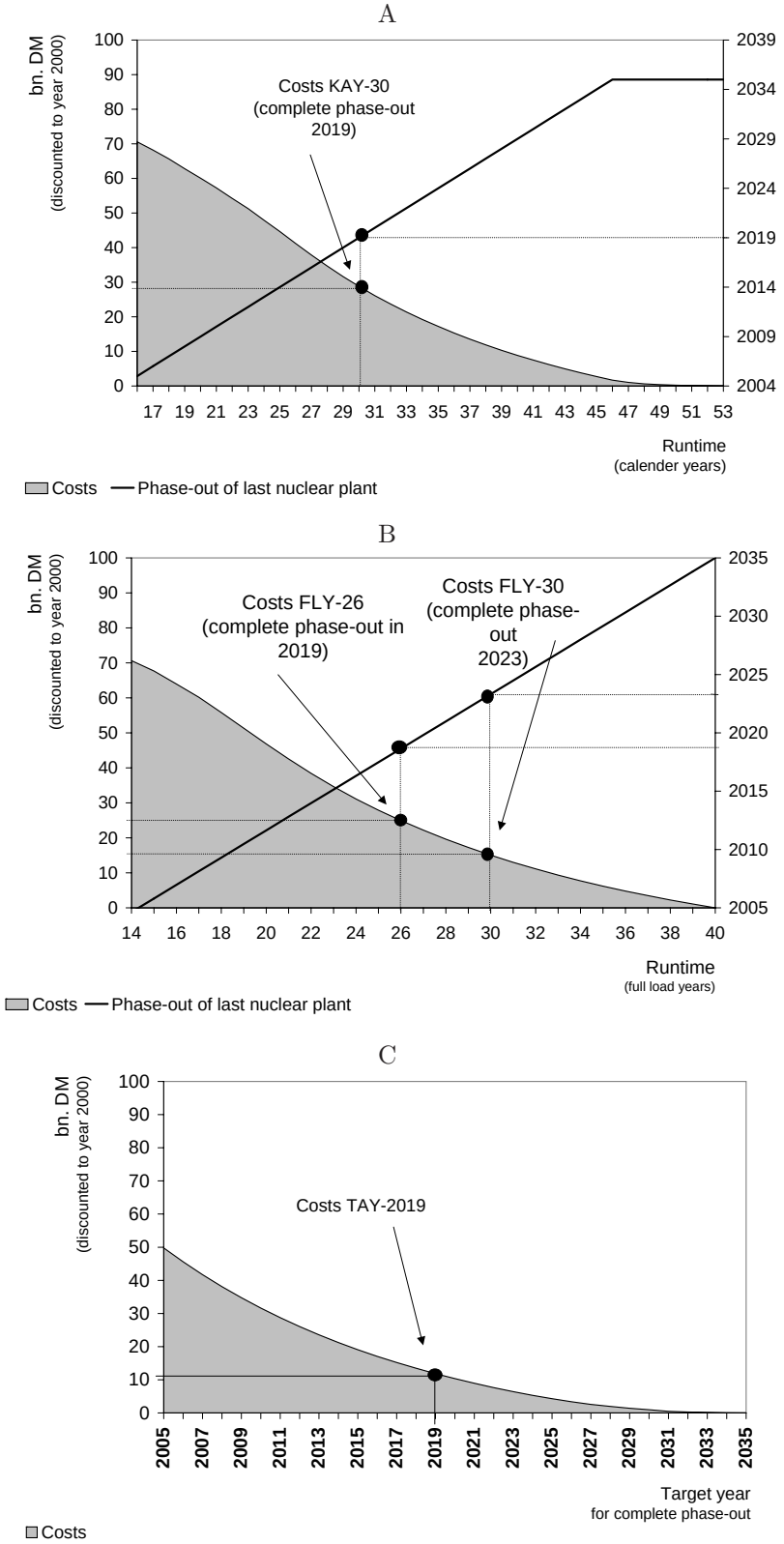
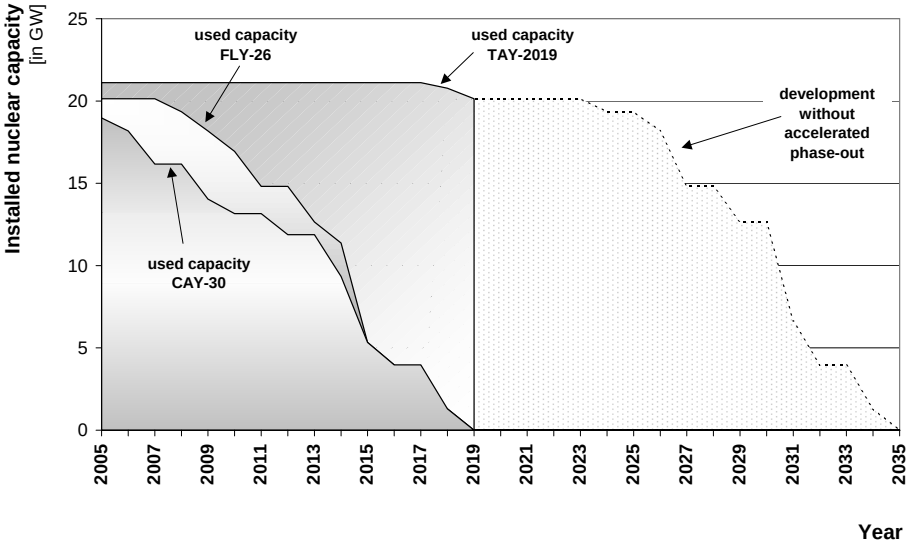


FIGURE 2.4.2. Development of installed nuclear capacities under *TAY-2019*, *CAY-30* and *FLY-26* regulation



the reduction in costs comes along with delaying the ultimate phase-out of nuclear power by four calendar years (when Isar-2 and Neckarwestheim-2 will be taken off the grid). On the other hand, the government could achieve the ultimate phase-out of nuclear power in 2019 under *FLY* when it sets the permissible operating time in terms of full-load years to 26 (*FLY-26*). Though *FLY-26* achieves the same date for the ultimate phase-out as *CAY-30*, it saves 3.5 billion DM. The reason is that some power plants can be operated longer than 30 calendar years under *FLY-26* depending on their specific degrees of utilization.[4] Finally, *TAY-2019*, which also assures an ultimate phase-out of nuclear power in 2019, imposes by far the smallest aggregate costs. As indicated above, this is due to the additional capacity available. Figure 2.4.2 illustrates the reason for this cost ranking with respect to the concrete regulations *CAY-30*, *FLY-26* and *TAY-2019*. When the government postulates the same calendar year for an ultimate phase-out, the quantitative differences in total costs between *TAY* and plant-specific approaches *CAY* and *FLY* become more pronounced – ceteris paribus – the larger the age differences across power plants are. The major differences between *CAY* and *FLY* stem from different historical degrees of utilization for the specific plants.

The cross-comparison of scenarios so far has focused on the cost differences with respect to a given date for the shut-down of the last nuclear power plant in Germany. It must be noted, however, that the cost differences across alternative regulatory regimes which lead to the same phase-out date are mainly caused by the respective differences in cumulative nuclear power production. The cost differences diminish to

[4]Brunsbüttel, for example, will be shut down in 2007 under *CAY-30*, but only in 2014 under *FLY-26*. Due to a low utilization of some power plants in the past, the operating time under *FLY-26* is longer by 1.5 calendar years as compared to *CAY-30* (i.e. 31.5 calendar years instead of 30 calendar years).

a large extent when authorities prescribe the same cumulative threshold for nuclear power production instead of the phase-out year. This means that the alternative regulation schemes converge in cost-effectiveness as we select the risk from nuclear power operation (measured in terms of produced PWh) as a decision criterion rather than the phase-out date. Figures 2.4.3 and 2.4.4 illustrate this reasoning.

Given an ultimate phase-out of nuclear power in 2019 (see Figure 2.4.3), *CAY-30* allows only for a total electricity production of 2.0 PWh (additional costs: 28 billion DM), whereas *FLY-26* concedes 2.1 PWh (additional costs: 24 billion DM) and *TAY-2019* accommodates 3 PWh (additional costs: 10.5 billion DM). If the government, instead, restricts the cumulative electricity production to 2.0 PWh, which corresponds to the *CAY-30*, the equivalent *FLY* regulation would then save only about 1.8 billion DM (Figure 2.4.4) and the equivalent target-year regulation – *TAY-2012* – another 3.7 billion DM.[5]

Tables 2.4.1 and 2.4.2 split up the total costs at the plant level. Alternative regulatory approaches not only significantly affect the total costs, but also the distribution of costs across the different nuclear power plants. As with total costs, the plant-specific costs decline when regulation is switched from *CAY-30* to *FLY-26* and then *TAY-2019*. However, the changes in costs at the plant level are not uniform. The *TAY* regulation does not account for differences across plants with respect to their operating time so far.[6] While *TAY* is most attractive from an overall cost point of view, it is potentially most distortionary with respect to the relative cost incidence at the plant level because it favors rather old plants.

A switch to the plant-specific regulation schemes *CAY* and *FLY*, implies a more even distribution of costs at the plant level. As to *CAY*, this only applies when historical downtimes of plants are roughly of the same magnitude. *FLY*, in turn, guarantees an equal treatment across plants as it especially accounts for downtime differences in the past. An illustration of of these points along some concrete plants: *TAY-2019* postulates a phase-out date that is later than the final lifetime year of Obrigheim and Stade. Therefore, these plants do not induce any excess costs with respect to the baseline scenario. On the other hand, *CAY-30* and *FLY-26*, both of which achieve the same ultimate phase-out date, impose specific excess costs of 0.8 million DM/KW in the case of Obrigheim and 1.8 million DM/KW in the case of Stade.

In order to calculate the cost incidence for the concrete policy scenario at the owner level above, the results shown in Tables 2.4.1 and 2.4.2 must be combined with the owner-plant-relationships given in Figure 2.2.1. Table 2.4.3, then, summarizes the cost incidence at the company level. Obviously, the total costs for a company depend on the number of plants in which it holds stakes, the magnitude of its

[5]Note that in this case *FLY* phases out nuclear power one year earlier as compared to *CAY* whereas *TAY* abbreviates the phase-out for an additional 6 years.

[6]In fact, *TAY* does not distinguish between a young power plant that just went into operation and an old power plant that is at the end of its lifetime.

FIGURE 2.4.3. Costs and cumulated electricity production for different phase-out regulations designed to lead to the same phase-out year

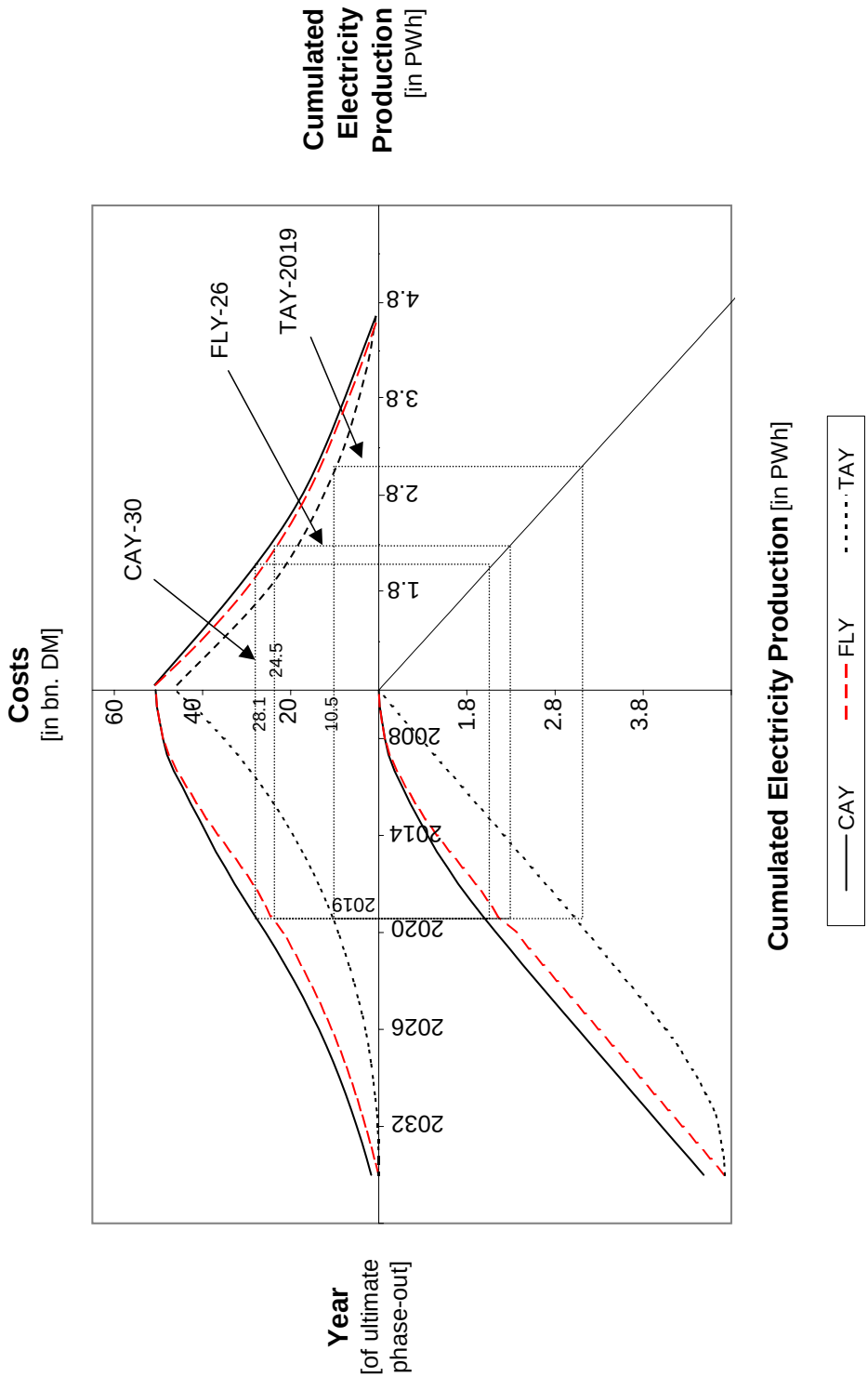


FIGURE 2.4.4. Costs and cumulated electricity production for different phase-out regulations designed to lead to the same cumulated electricity production

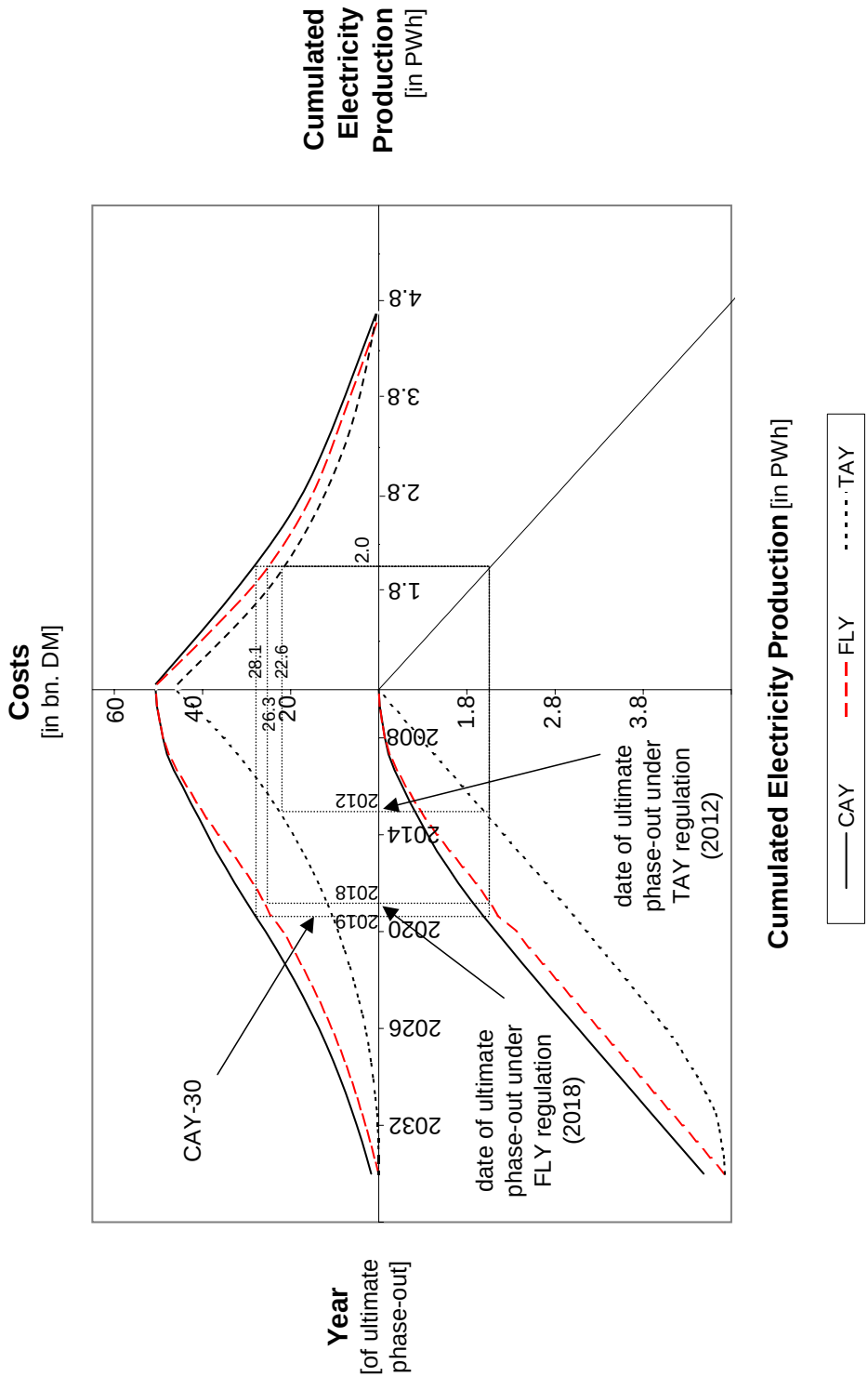


TABLE 2.4.1. Cost comparisons of alternative phase-out scenarios at plant level – scenarios *CAY-30* and *FLY-30* (discounted to 2000)

Scenarios CAY-30 and FLY-30

	Period of phasing out*	Additional costs to baseline scenario in bn.DM	Specific costs in mill. DM/KW	Years	bn. DM (%)
	Scenario CAY-30				
Obrigheim	2005	0,31	0,9		
Stade	2005	1,15	1,7		
Biblis A	2005	2,62	2,2		
Neckarwestheim 1	2006	1,56	1,9		
Biblis B	2007	2,44	1,9		
Brunsbüttel	2007	1,66	2,1		
Unterweser	2009	2,06	1,6		
Isar 1	2009	1,43	1,6		
Philippsburg 1	2010	1,37	1,5		
Grafenrheinfeld	2012	1,68	1,3		
Gundremmingen B	2014	1,45	1,1		
Krümmel	2014	1,47	1,1		
Grohnde	2015	1,40	1,0		
Philippsburg 2	2015	1,41	1,0		
Gundremmingen C	2015	1,37	1,0		
Brokdorf	2016	1,32	0,9		
Emsland	2018	1,12	0,8		
Isar 2	2018	1,17	0,9		
Neckarwestheim 2	2019	1,08	0,8		
Sum		28,06	Ø 1,3		
	Scenario FLY-30			Difference to CAY-30	
Obrigheim	2006	0,27	0,8	+1	0 (-15%)
Stade	2007	0,88	1,3	+2	-0,3 (-23%)
Biblis A	2013	1,03	0,9	+8	-1,6 (-61%)
Neckarwestheim 1	2012	0,80	1,0	+6	-0,8 (-48%)
Biblis B	2015	1,05	0,8	+8	-1,4 (-57%)
Brunsbüttel	2018	0,51	0,6	+11	-1,1 (-69%)
Unterweser	2015	1,06	0,8	+6	-1 (-48%)
Isar 1	2015	0,74	0,8	+6	-0,7 (-48%)
Philippsburg 1	2017	0,65	0,7	+7	-0,7 (-53%)
Grafenrheinfeld	2017	0,95	0,7	+5	-0,7 (-43%)
Gundremmingen B	2019	0,82	0,6	+5	-0,6 (-43%)
Krümmel	2019	0,84	0,6	+5	-0,6 (-43%)
Grohnde	2019	0,87	0,6	+4	-0,5 (-37%)
Philippsburg 2	2020	0,88	0,6	+5	-0,5 (-37%)
Gundremmingen C	2020	0,78	0,6	+5	-0,6 (-43%)
Brokdorf	2021	0,83	0,6	+5	-0,5 (-37%)
Emsland	2022	0,71	0,5	+4	-0,4 (-37%)
Isar 2	2023	0,74	0,5	+5	-0,4 (-37%)
Neckarwestheim 2	2023	0,68	0,5	+4	-0,4 (-37%)
Sum		15,09	Ø 0,7		-13 (-46%)

TABLE 2.4.2. Cost comparisons of alternative phase-out scenarios at plant level – scenarios *CAY-26* and *TAY-2019* (discounted to 2000)

Scenarios CAY-26 and TAY-2019

	Period of phasing out*	Additional costs to baseline scenario in bn.DM	Specific costs in mill. DM/KW	Years	bn. DM (%)
	Scenario FLY-26			Difference to CAY-30	
Obrigheim	2005	0,31	0,9	+0	0 (0%)
Stade	2005	1,15	1,7	+0	0 (0%)
Biblis A	2009	1,71	1,4	+4	-0,9 (-35%)
Neckarwestheim 1	2008	1,33	1,6	+2	-0,2 (-15%)
Biblis B	2010	1,74	1,4	+3	-0,7 (-29%)
Brunsbüttel	2014	0,85	1,0	+7	-0,8 (-49%)
Unterweser	2010	1,76	1,3	+1	-0,3 (-15%)
Isar 1	2011	1,22	1,3	+2	-0,2 (-15%)
Philippsburg 1	2012	1,07	1,2	+2	-0,3 (-22%)
Grafenrheinfeld	2013	1,57	1,2	+1	-0,1 (-6%)
Gundremmingen B	2014	1,36	1,0	+0	-0,1 (-6%)
Krümmel	2015	1,38	1,0	+1	-0,1 (-6%)
Grohnde	2015	1,45	1,0	+0	0,1 (4%)
Philippsburg 2	2015	1,46	1,0	+0	0,1 (4%)
Gundremmingen C	2015	1,29	1,0	+0	-0,08 (-6%)
Brokdorf	2016	1,37	1,0	+0	0,05 (4%)
Emsland	2018	1,16	0,9	+0	0,04 (4%)
Isar 2	2018	1,22	0,9	+0	0,04 (4%)
Neckarwestheim 2	2019	1,12	0,8	+0	0,04 (4%)
Sum		24,51	Ø 1,1		-3,5 (-13%)
	Scenario TAY-2019			Difference to CAY-30	
Obrigheim	2017	0,00	0,0	+12	-0,3 (-100%)
Stade	2018	0,00	0,0	+13	-1,2 (-100%)
Biblis A	2019	0,43	0,4	+14	-2,2 (-84%)
Neckarwestheim 1	2019	0,22	0,3	+13	-1,3 (-86%)
Biblis B	2019	0,51	0,4	+12	-1,9 (-79%)
Brunsbüttel	2019	0,43	0,5	+12	-1,2 (-74%)
Unterweser	2019	0,52	0,4	+10	-1,5 (-75%)
Isar 1	2019	0,36	0,4	+10	-1,1 (-75%)
Philippsburg 1	2019	0,42	0,5	+9	-0,9 (-69%)
Grafenrheinfeld	2019	0,62	0,5	+7	-1,1 (-63%)
Gundremmingen B	2019	0,70	0,5	+5	-0,8 (-52%)
Krümmel	2019	0,71	0,5	+5	-0,8 (-52%)
Grohnde	2019	0,74	0,5	+4	-0,7 (-47%)
Philippsburg 2	2019	0,75	0,5	+4	-0,7 (-47%)
Gundremmingen C	2019	0,74	0,6	+4	-0,6 (-46%)
Brokdorf	2019	0,79	0,6	+3	-0,5 (-40%)
Emsland	2019	0,83	0,6	+1	-0,3 (-26%)
Isar 2	2019	0,87	0,6	+1	-0,3 (-26%)
Neckarwestheim 2	2019	0,88	0,7	+0	-0,2 (-18%)
Sum		10,53	Ø 0,4		-17,5 (-62%)

Table 2.4.3. Cost incidence at the company level (discounted to 2000)

	bn. DM	Pf/kWh	Relative cost incidence
	CAY-30		
Energie Baden-Württemberg AG	5,09	0,77	1,53
Hamburgische Electricitätswerke AG	2,49	1,40	2,79
E.ON Energie AG	10,58	0,55	1,09
RWE Energie AG	8,15	0,50	1,00
Sum	28,06		
	FLY-30		
Energie Baden-Württemberg AG	2,88	0,44	1,81
Hamburgische Electricitätswerke AG	1,22	0,69	2,85
E.ON Energie AG	5,99	0,31	1,29
RWE Energie AG	3,90	0,24	1,00
Sum	15.09		
	FLY-26		
Energie Baden-Württemberg AG	4,69	0,71	1,78
Hamburgische Electricitätswerke AG	1,91	1,08	2,71
E.ON Energie AG	9,71	0,50	1,27
RWE Energie AG	6,45	0,40	1,00
Sum	24.51		
	TAY-2019		
Energie Baden-Württemberg AG	2,06	0,31	1,83
Hamburgische Electricitätswerke AG	0,80	0,45	2,66
E.ON Energie AG	4,03	0,21	1,23
RWE Energie AG	2,75	0,17	1,00
Sum	10.53		

shares and the plant-specific phase-out costs. Evidently, in absolute monetary terms, E.ON Energie AG will be most affected by the phase-out for all regulation schemes. This company holds stakes in several nuclear power plants with relatively high specific phase-out costs.

However, absolute cost figures are a misleading indicator for the potential market distortions induced by the phase-out because they do not incorporate information on the respective basis of the total cost incidence. The implied increase in costs per kWh at the company level represents a more appropriate measure for the competitive effects of alternative phase-out regulations. The latter is calculated under the assumption that the excess costs of the phase-out are uniformly shifted on the supplied electricity over the next 20 years.[7]

Employing the specific cost measure, Table 2.4.3 indicates that *CAY-30* imposes the highest cost pressure on Hamburgische Electricitätswerke AG, followed by Energie Baden-Württemberg AG, E.ON Energie AG and RWE Energie AG. When *FLY-26* is adopted, specific costs are reduced but the cost ranking is rather robust. Differences in specific costs become less pronounced, which can be interpreted as a

[7]Given the increasing competition on European electricity markets, a total shift of additional costs to the consumer side seems unrealistic. Yet, the measure indicates the additional cost pressure at the firm level that emerges from alternative regulations.

TABLE 2.4.4. Sensitivity analysis results for phase-out costs

Variation	Description	Difference from baseline (%)		
		CAY-30	FLY-26	TAY-2019
Baseline (bn. DM)	**See section 2.3.2**	**28.1**	**24.5**	**10.5**
1. Operating time	Max. operating time: 40 calendar years instead of 40 full-load years	-32	-39	-56
2. Interest rate	5 % instead of 7.5 %	+30	+35	+45
	10 % instead of 7.5 %	-24	-27	-32
3. Import capacity	6 TWh at 0.06 DM/kWh instead of 2 TWh at 0.06 DM/kWh	-2	-2	0
4. Gas price	Price for natural gas at a level of 70% of the initial values	-11	-9	-4

reduction in the distortionary effects of the regulation (see columns "relative cost incidence" in Table 2.4.3). At the company level, *TAY-2019* not only provides a further reduction in specific costs, but also minimizes the differences in relative costs. Although *TAY-2019* produces the most distinct cost differences at the plant level, the specific owner-plant-relationships reverse this effect. The explanation behind this is that the vintage structures of plants belonging to the respective companies are rather similar.[8]

2.4.3. Sensitivity Analysis. Table 2.4.4 summarizes the robustness of the results with respect to changes in key parameters. For the sake of brevity and transparency, the sensitivity analysis focuses on those regulation scenarios that lead to an ultimate phase-out in the year 2019. The qualitative findings remain robust for changes in key parameters. The ranking of the different regulation approaches is always the same: For a given ultimate phase-out year, *TAY* causes the lowest phase-out costs followed by *FLY* and then *CAY*. Also, the conclusions with respect to the competitive effects remain robust.

Not surprisingly, the assumption about the lifetime of the plants plays a major role for the costs of phasing out nuclear power generation. The longer the lifetime in the baseline, the more costly it gets ceteris paribus to phase out nuclear power. If nuclear plants are expected to run only 40 calendar years (i.e. 34.2 full-load years) the costs of *CAY-30* and *FLY-26* are roughly 30% and 40% lower than those of the respective scenarios in the core simulations. For *TAY-2019*, the costs drop by more than 50%.

In the core simulations, the interest rate for discounting future monetary flows has been set to 7.5%. When a lower interest rate of 5% is assumed, the effective costs of a phase-out are less discounted and therefore increase. The opposite holds for a higher discount rate (here: 10%).

[8]Note that the incidence analysis is based on the current owner-plant relationships assuming constant market shares of companies.

The ongoing liberalization of energy markets may lead to higher electricity import capacities. In the sensitivity analysis, import capacities have been tripled as compared to the assumptions in the baseline and the core simulations. Increased imports reduce total costs only by 2% for *CAY* and *FLY*. For *TAY-2019* an increase in import capacities does not save any additional costs compared to the baseline scenario because in *TAY-2019* (like in the baseline) all imports are used to replace those power plants (here: Obrigheim and Stade) which are not affected, anyway, from a phase-out regulation under *TAY-2019*.[9]

Finally, the world market prices of natural gas are assumed to be 30% below the initial level. This implies that gas power plants get more competitive as compared to coal power plants, which reduces total costs by roughly 10% for scenarios *CAY* and *FLY* and by 4% for *TAY*.

2.5. Conclusions

The analysis in this chapter quantified how alternative regulation schemes for an accelerated phase-out of existing nuclear power plants in Germany affect the magnitude of total adjustment costs and the distribution of these costs across competing companies. The cost differences have been evaluated as a function of the ultimate phase-out time, i.e. the date of shutting down the last operating nuclear power plant. The results show that plant-specific regulation based on full-load years will be significantly cheaper as compared to the calendar-year regulation for the same phase-out date, because the former allows several plants with low historical utilization to be used longer than would be permissible under the calendar-year regulation. In comparison with the plant-specific regulation schemes, a target-year approach always causes less costs for the same date of an ultimate phase-out because, at any given point in time, it provides a higher capacity for nuclear power generation. Not surprisingly, the cost differences between alternative regulation schemes diminish to a large extent when we compare the phase-out scenarios with respect to the cumulative nuclear power production. In other words: The alternative regulation schemes converge in cost-effectiveness when we select the risk from nuclear power operation (measured in terms of produced PWh) as a decision criterion rather than the phase-out date.

The simulations reveal large changes in the cost incidence across power companies, depending on the regulatory approach. This suggests that the various companies have different stakes in the negotiations with the government on alternative regulation schemes. The government, in turn, is not only challenged with overall efficiency considerations but also with equity concerns.

[9]Under *TAY-2019* Obrigheim and Stade reach the end of their lifetime before the administered phase-out year (see Table 2.4.2). Import capacities get fully exhausted, both for *TAY-2019* as well as for the baseline, from the same point in time onwards.

The simulations have omitted several issues that are potentially important for a comprehensive analysis of the economic implications induced by a nuclear phase-out. The partial-analytical framework does not consider spill-over and feed-back effects between the electricity supply market and other markets. Competitive behavior of electricity suppliers is assumed in the context of liberalizing European electricity markets, thereby strategic behavior by companies that might be large enough to exert market power is ignored. Given the high level of uncertainty on the external costs of operating nuclear power plants as well as nuclear waste disposal, the analysis has not accounted for the benefits of phase-out policies. A further topic not considered in the analysis is how the costs of carbon abatement strategies will be affected when nuclear power, as a carbon-free energy supply option, is abandoned.

CHAPTER 3

Assessing Emission Regulation in Europe[1]

3.1. Introduction

In January 2005, an EU-wide carbon emissions trading scheme has come into force. The key objective of the trading scheme is to promote cost-efficiency in reaching the emission reduction commitments of Member States: In principle, emission reductions shall take place where it is cheapest, implying equalized marginal abatement costs across all emission sources within the EU. However, the EU trading system as prescribed in the EU Directive for Emission Allowance Trading (Commission 2003) only covers energy-intensive installations in some sectors while the remaining segments of EU economies are subject to complementary domestic abatement policies that must balance the countries overall emission budgets.

This chapter focuses on this hybrid nature of the EU emission regulation approach. It discusses inefficiencies which result from restricting international trade in emission allowances to only a part of the economy: Inefficiencies arise because the allowance price for sectors that participate in trading (thereafter referred to as *DIR* sectors) may differ from the country-specific shadow prices for emissions associated with complementary domestic abatement policies for sectors outside the trading system (thereafter *NDIR* sectors). In addition to these inefficiencies, the hybrid emission regulation might lead to a rather uneven cost incidence between *DIR* and *NDIR* polluters not only within one country but across Member States since each EU Member State can decide on the number of allowances for *DIR* sectors and the procedure for allocating them.

The quantitative assessment of the current EU emission regulation scheme confirms theoretical concerns on inefficiencies and discriminatory treatment between *DIR* and *NDIR* sectors. Compared to the overall cost-efficient solution, EU Member States have allocated too many emission allowances to politically influential energy-intensive industries covered by the EU trading scheme. This induces total costs that are drastically higher than the aggregate costs for an efficient trading

[1] This chapter is based on the articles:

Böhringer, C., Hoffmann, T., Lange, A., Löschel, A. & Moslener, U. (2005), 'Assessing Emission Regulation in Europe: An Interactive Simulation Approach', *The Energy Journal* 26(4), p.1-21.

Hoffmann, T., Löschel, A. & Moslener, U. (2006), 'Harmonizing Emission Allocation: What are the Equity Consequences for the Sectors in and outside the EU-Trading Scheme', in De Miguel, C., Labandeira, X. & Manzano, B. ed., Economic Modelling of Energy and Climate Change Policies, Edward Elgar, Cheltenham, in press.

scheme and even higher than purely domestic abatement action (without European emissions trading). Compliance costs for NDIR sectors increase substantially vis-à-vis efficient regulation while the respective costs for *DIR* sectors fall to zero. These efficiency drawbacks of the European hybrid regulation scheme can be relaxed when EU Member States are allowed to purchase cheap emission credits from outside the EU, e.g., via project-based mechanisms such as the Clean Development Mechanism (CDM) under the Kyoto Protocol (UNFCCC 1997). In this case, emissions within the EU will exceed its Kyoto target which is only met by the use of flexible instruments.

The numerical results presented in this chapter are based on an interactive simulation model featuring marginal abatement cost functions for energy-intensive sectors that are eligible for international emissions trading as well as for those sectors subject to complementary domestic emission regulation. The interested reader can access the model through a web-interface (http://brw.zew.de/simac/), specify abatement cost functions, set up user-defined emission regulation policies, and calculate the associated economic implications.

The remainder of the chapter is structured as follows. Section 3.2 summarizes key features of the EU emissions trading system. These features feed into a simple partial equilibrium model of Section 3.3 to illustrate problems of allocative inefficiencies and sectoral burden shifting under hybrid emission regulation. In Section 3.4, a presentation of the numerical model designed for the economic assessment of hybrid emission control strategies follows. In Sections 3.5 and 3.6, this model is used for evaluating the EU emissions trading system. Section 3.7 concludes.

3.2. EU Carbon Emission Regulation

Under the Kyoto Protocol, the European Union committed itself to reduce EU-wide greenhouse gas emissions by 8% vis-à-vis 1990 emission levels during 2008-2012. This aggregate EU reduction requirement has been redistributed among individual Member States according to an EU-internal Burden Sharing Agreement (European Commission 1999*a*). The resulting reduction requirements with respect to historic and future projected carbon emissions across EU Member States are summarized in Table 3.2.1.

The left-hand part of Table 3.2.1 lists the carbon emissions for 1990 (the reference year of the reduction commitments under Kyoto and the EU Burden Sharing Agreement) and projected emissions for 2005 (the base-year for our model simulations on the EU trading system) as well as for 2010 (the central year for which the final Kyoto commitment applies).[2]

[2]We apply the EU Burden Sharing Agreement covering all greenhouse gases to CO_2 only which is by far the most important greenhouse gas within the EU.

TABLE 3.2.1. CO_2 emissions and reduction requirements

	CO_2 emissions (in Mt)			Reduction requirements (in %)		
	1990	2005	2010	1990	2005	2010
Austria	55.1	60.3	60.7	13.0	20.5	21.0
Belgium	106.3	113.6	112.2	7.5	13.4	12.4
Denmark	52.8	48.4	46.6	21.0	13.8	10.5
Finland	53.2	55.4	51.4	0.0	4.0	-3.5
France	354.1	389.9	406.4	0.0	9.2	12.9
Germany	943.0	815.6	823.6	21.0	8.7	9.5
Greece	71.1	97.8	105.6	-25.0	9.1	15.8
Ireland	29.7	44.6	46.5	-13.0	24.8	27.8
Italy	390.8	416.7	422.2	6.5	12.3	13.5
Netherlands	152.9	164.6	174.0	6.0	12.7	17.4
Portugal	39.0	61.2	67.9	-27.0	19.1	27.1
Spain	203.8	292.6	302.6	-15.0	19.9	22.5
Sweden	50.6	52.6	54.0	-4.0	0.0	2.5
U.K.	569.1	526.9	519.4	12.5	5.5	4.1
EU (total)	3071.5	3140.2	3193.1	8.6	10.6	12.1

Source: (European Commission 2003*b*, Commission 2003)

As can be seen from the right-hand part of Table 3.2.1, the effective reduction targets under the Burden Sharing Agreement may change dramatically along the baseline (business-as-usual) development. While Germany, for example, starts out with a rather stringent reduction target of 21% with respect to 1990, the effective reduction target halves with respect to projected business-as-usual emission levels in 2005 or 2010. Spain, in turn, had been attributed an emission budget of 15% in excess of its 1990 emissions but due to economic growth faces an effective reduction of around 20% in 2005 which rises up to nearly 23% in 2010.

To allow for cost-efficient EU-wide emission reduction in view of the different economic developments, the European Commission launched a Directive for a pan-European carbon trading system which was approved by the European Parliament in July 2003 and became legally binding by January 2005 (European Commission 2003*b*). The envisaged trading scheme consists of several temporal stages: a first phase from 2005 until 2007, a second one from 2008 until 2012, coinciding with the Kyoto commitment period, and subsequent five-year-periods covering potential Post-Kyoto commitment periods. In its initial stage, the trading system only applies to energy-intensive (downstream) sectors that include all major CO_2 producing sites such as power, heat and steam generation, oil refineries, coke ovens in iron and steel production, mineral industries (e.g., glass, cement), or pulp and paper plants. The most important sectors not covered by the European trading system are transport and households. According to Article 9 of the Directive, each

Member State had to develop a National Allocation Plan (NAP) until March 2004 that (i) specifies an overall cap on emission allowances for installations (sectors) included in the trading scheme, and (ii) prescribes in detail how these allowances will be allocated to installations.

Here, free allowance allocation has been a necessary condition for the EU emissions trading scheme to be accepted by politically influential carbon-intensive industries.[3]

Table 3.2.2 contains a condensed characterization of National Allocation Plans across the EU-15 Member States mainly based on a most recent screening by Gilbert *et al.* (2004). The column labeled "$\overline{E}_r$" in Table 3.2.2 indicates the overall emission budget (following directly from Table 3.2.1) for each Member State r. The subsequent column provides the emission cap $\overline{E}_r^{DIR}$ for (*DIR*) sectors that are covered by the EU Directive (reflecting the NAP). The residual $\overline{E}_r - \overline{E}_r^{DIR}$ yields the implicit emission constraint $\overline{E}_r^{NDIR}$ for (*NDIR*) sectors that are not covered by the emissions trading system. Depending on the projected baseline emissions for *DIR* sectors in our reference year ($\overline{E}_{r,2005}^{DIR}$), the final column of Table 3.2.2 reports the so-called fulfillment factor $\lambda_r = \overline{E}_r^{DIR}/\overline{E}_{r,2005}^{DIR}$, i.e., the fraction of baseline emissions that are freely allocated as allowances. We see that fulfillment factors vary across regions which may create legal problems of competition distortions or state aid: Financial transfers that are implicit to the free (static) allocation of allowances differ across firms having the same characteristics but operating in different EU regions.[4]

3.3. Analytical Framework

A stylized partial model can be set up in order to demonstrate the inefficiencies that are likely to occur from the practical implementation of National Allocation Plans. R regions (r=1,...,R) are considered. Each region is constrained by an aggregate emission budget $\bar{E}_r$ (as given for EU Member States by the Burden Sharing Agreement). In designing the National Allocation Plan, a Member State has to consider the abatement costs in *DIR* sectors, $C_r^{DIR}(e)$, and likewise in *NDIR* sectors, $C_r^{NDIR}(e)$, (both decreasing, convex, differentiable in e), where e denotes emissions. Total abatement costs as the sum of $C_r^{DIR}(e_r^{DIR})$ and $C_r^{NDIR}(e_r^{NDIR})$ are represented by $C_r(E_r)$.

The cost-efficient allocation depends on whether the EU system is closed to the world market ($\sum e_r^{DIR} + \sum e_r^{NDIR} = \sum \bar{E}_r^{DIR} + \sum \bar{E}_r^{NDIR} = \sum \bar{E}_r$) or it is

[3]Member States must allocate 95% of emission allowances dedicated to the emissions trading sectors for free in the so-called warm-up phase from 2005 to 2007 (Article 10, EU, 2003a). In the next phase from 2008 to 2012 this threshold can be reduced to 90%, whereas the rules for later phases have not yet been decided upon.

[4]Böhringer and Lange (2005) investigate the issue of competition distortions. They show that any harmonization of fulfillment factors to preserve competition neutrality either implies partial auctioning of emission allowances to energy-intensive installations or adjustments of country-specific emission caps for *DIR* sectors.

TABLE 3.2.2. Segmentation of emission budgets under National Allocation Plans for EU-15 (Gilbert et al., 2004)

	$\overline{E}_r$	$\overline{E}_r^{DIR}$	$\overline{E}_r^{NDIR}$	$\overline{E}_{r,2005}^{DIR}$	λ_r
	(in Mt CO_2)			(in Mt CO_2)	
Austria	47.9	22.1	25.8	23.5	0.940
Belgium	98.3	61.6	36.7	59.1	1.042
Denmark	41.7	20.6	21.1	24.2	0.850
Finland	53.2	33.7	19.5	34.4	0.980
France	354.1	85.3	268.8	85.8	0.995
Germany	745.0	481.2	263.8	481.2	1.000
Greece	88.9	58.7	30.2	58.7	1.000
Ireland	33.6	13.8	19.8	14.3	0.970
Italy	365.4	228.2	137.2	212.5	1.074
Netherlands	143.7	89.8	53.9	87.2	1.030
Portugal	49.5	27.2	22.3	26.3	1.035
Spain	234.4	111.4	123.0	118.5	0.940
Sweden	52.6	15.3	37.3	15.3	1.000
U.K.	498.0	240.7	257.3	242.4	0.993
EU-15 (total)	**2806.3**	**1489.6**	**1316.7**	**1483.4**	**1.004**

Key:

$\overline{E}_r$	:	total emission budget under the EU Burden Sharing Agreement
$\overline{E}_r^{DIR}$	:	emission budget to DIR sectors under the National Allocation Plans
$\overline{E}_r^{NDIR} = \overline{E}_r - \overline{E}_r^{DIR}$	:	emission budget to NDIR sectors under the National Allocation Plans
$\overline{E}_{r,2005}^{DIR}$	:	projected business-as-usual emissions for the DIR sectors in 2005
$\lambda_r = \overline{E}_r^{DIR} / \overline{E}_{r,2005}^{DIR}$	:	fulfillment factor

possible to use credits obtained from CDM projects or other countries. In the latter case, it is assumed that the world market price is given by $\sigma = \sigma^{WM}$.[5]

For the closed system, minimization of total abatement costs across all EU regions requires

$$\min_{e_r^{DIR} e_r^{NDIR}} \quad \sum_r \left[C_r^{DIR}\left(e_r^{DIR}\right) + C_r^{NDIR}\left(e_r^{NDIR}\right) \right] \tag{3.3.1}$$

$$s.t. \sum \left(e_r^{DIR} + e_r^{NDIR}\right) = \sum e_r^{DIR} + \sum e_r^{NDIR} = \sum \bar{E}_r^{DIR} + \sum \bar{E}_r{}^{NDIR} = \sum \bar{E}_r$$

For the open system, the optimization is given by:

[5]Here, we assume that import supply for emission allowances from outside the EU is fully elastic.

(3.3.2)
$$\min_{e_r^{DIR} e_r^{NDIR}} \sum_r \left[C_r^{DIR}\left(e_r^{DIR}\right) + C_r^{NDIR}\left(e_r^{NDIR}\right) + \sigma^{WM}\left(e_r^{NDIR} + e_r^{DIR} - \bar{E}_r\right)\right]$$

In both cases, differentiating with respect to e_r^{DIR} and e_r^{NDIR}, yields the well-known first-order condition of equalized marginal abatement costs across all emission sources:

$$\sigma = -\frac{\partial C_r^{DIR}}{\partial e_r^{DIR}} = -\frac{\partial C_r^{NDIR}}{\partial e_r^{NDIR}} = -\frac{\partial C_r}{\partial \left(e_r^{NDIR} + e_r^{DIR}\right)} \tag{3.3.3}$$

where the Lagrange multiplier σ stands for the endogenous European emission price or the world market price ($\sigma = \sigma^{WM}$), respectively. Optimal emissions follow as E_r^*, $e_r^{DIR^*}$, $e_r^{NDIR^*}$ where $E_r^* = e_r^{DIR^*} + e_r^{NDIR^*}$. The difference between the exogenous total emission budget $\bar{E}_r$ and aggregate optimal emissions E_r^*, i.e., $\bar{E}_r - E_r^*$, yields the optimal trade volume in emission allowances.

From the perspective of an (EU-) social planner, the efficient solution could be decentralized by imposing uniform emission taxes at the optimal rate σ on the *NDIR* sectors. The remaining emission budget, $\bar{E}_r - e_r^{NDIR^*}$, would then be given as initial endowment to the *DIR* sectors eligible for international emissions trading. The optimal region-specific fulfillment factor for DIR sectors is thus given by $\lambda_r = \left(\bar{E}_r - e_r^{NDIR^*}\right) / \overline{E}_{r,2005}^{DIR}$.

In the hybrid regulation regime, implementation of the efficient solution requires central planners information on both the emerging international price of emission allowances and the specific abatement costs curves. Such information is typically not available for decision makers; furthermore, in policy practice the segmentation of the overall emission budget $\bar{E}_r$ has been driven by compensation motives to energy-intensive industries rather than by pure efficiency considerations. Apart from free allocation of emissions allowances to energy-intensive industries, which has been a conditio-sine-qua-non for the legal approval of the trading initiative by the EU Parliament, these sectors have successfully lobbied for generous endowments with allowances.

Any deviation from the optimal solution sketched above clearly implies efficiency losses. If energy-intensive industries are given too many allowances and the import of additional credits from clean development mechanism or similar flexible instruments is not possible, *NDIR* sectors have to abate more given that both segments of the economy together are only endowed with a fixed national emission budget $\bar{E}_r$. In case the credits can be imported from the world market, a too generous allocation to *DIR*-sectors results in a European emissions price for these sectors which is below the world market price, σ^{WM}. The remaining sectors have either to

abate more or to import a larger than optimal number of credits, both leading to welfare losses.

Consequently, *NDIR* sectors will be subject to more stringent complementary domestic policies with higher marginal as well as inframarginal economic costs whether allowing the import of credits or not. Thus, *NDIR* sectors might be discriminated vis-à-vis *DIR* sectors in two respects: Firstly, they do not receive emission allowances for free. Secondly, with shadow prices for emissions in *NDIR* being higher than the European allowance price for *DIR* sectors, *NDIR* sectors will also bear higher costs per unit of emission use.

3.4. Numerical Framework

In order to quantify the allocative inefficiencies and compliance costs associated with hybrid emission regulation, a simple numerical partial equilibrium model of the EU carbon market is employed. The model is based on marginal abatement cost curves for *DIR* and *NDIR* sectors in the EU-15 that are calibrated to empirical data. The algebraic model formulation is given in Appendix A.2.

The reader can access the model via a web-based interface (http://brw.zew.de/simac/). This interface allows for user-defined specification of hybrid regulation schemes. The user can (i) define the segmentation of the regional emission budgets between *DIR* and *NDIR* sectors, (ii) choose alternative historic and base-year emission levels, (iii) use alternative abatement cost functions at the country level for *DIR* and *NDIR* sectors separately, and (iv) specify whether a scenario should be run without or with the CDM option. In the latter case, he can also enter the desired international carbon price.

In this way, a flexible non-technical framework for a comprehensive economic assessment of the forthcoming EU emissions trading system is provided. Instructions for the use of the interface are given on the web-site.[6] The interface further allows the user to replicate our simulation results reported in section 3.5.

3.4.1. Model Parametrization. Marginal costs of emission abatement may vary considerably across countries and sectors due to differences in carbon intensity, initial energy price levels, or the ease of carbon substitution possibilities. Continuous marginal abatement cost curves for the *DIR* and *NDIR* sectors in EU countries can be derived from a sufficiently large number of discrete observations for marginal abatement costs and the associated emission reductions in the *DIR* and *NDIR* sectors. In applied research these values are often generated by partial equilibrium models of the energy system (such as the POLES model (Criqui & Mima 2001) or

[6]Numerically, the model is implemented in GAMS (Brooke et al., 1987) using PATH (Dirkse and Ferris, 1995) as a solver. The GAMS file and the EXCEL reporting sheet can be downloaded from the web-site.

the PRIMES model (Capros *et al.* 1998) that embody a detailed bottom-up description of technological options. Another possibility is to derive marginal abatement cost curves from computable general equilibrium (CGE) models (see e.g., Eyckmans *et al.* (2001)). For this analysis the latter approach is adopted. A reduced form of complex CGE interactions in terms of marginal abatement cost curves have been generated that are directly accessible to the non-CGE specialist. In order to obtain such marginal abatement cost curves for the *DIR* and *NDIR* sectors across EU countries, the PACE model has been used – a standard multi-region, multi-sector CGE model for the EU economy (for a detailed algebraic exposition see Böhringer (2002)) which is based on recent consistent accounts of EU Member States production and consumption, bilateral trade and energy flows for 1997 (as provided by the GTAP5-E database see Dimaranan and McDougall (2002)).

With respect to the analysis of carbon abatement policies, the sectors in the model have been carefully selected to keep the most carbon-intensive sectors in the available data as separate as possible. The energy goods identified in the model include primary carriers (coal, natural gas, crude oil) and secondary energy carriers (refined oil products and electricity). Furthermore, the model features three additional energy-intensive non-energy sectors (iron and steel; paper, pulp and printing; non-ferrous metals) whose installations in addition to the secondary energy branches (refined oil products and electricity) are subject to the EU emissions trading system. The remaining manufacturers and services are aggregated to a composite industry that produces a non-energy-intensive macro good, which together with final demand captures the activities (*NDIR* segments) that are not included in the EU trading system.

To generate the reduced form model, a sequence of carbon tax scenarios for each region is performed where uniform carbon taxes (starting from 0 € to 200 € per ton of carbon in steps of 1 €) are imposed. The model thereby generates a large number of marginal abatement costs, i.e., carbon taxes, and the associated emission reductions in *DIR* and *NDIR* sectors. The final step involves a fit to the set of observations. Various types of functional forms could be employed. Common forms include iso-elastic exponential functions (of the type $C'(e) = a \cdot (e_0 - e)^b$), quadratic or more elaborate polynomial functions ($C'(e) = a \cdot (e_0 - e) + a \cdot (e_0 - e)^2 + ...$) as well as exponential functions ($C'(e) = a \cdot \exp\left(b \cdot (e_0 - e) / e_0\right)$) (see e.g., Böhringer and Löschel (2003)).[7] For the numerical framework, a least-square fit by a polynomial of third degree is applied which provides sufficient flexibility. The functional form of the marginal abatement cost curves in region r for the *DIR* and *NDIR* sectors is, thus, given by:

[7]Baseline emission levels e_0 do not impose a binding emission reduction – hence, the associated marginal abatement costs for emission use at the baseline level are zero. Clearly, zero marginal abatement costs also hold for emission levels $e > e_0$.

(3.4.1)
$$-C'_{ir}(e_{ir}) = a_{1,ir}(e_{0_{ir}} - e_{ir}) + a_{2,ir}(e_{0_{ri}} - e_{ir})^2 + a_{3,ir}(e_{0_{ir}} - e_{ir})^3 \qquad i \in \{DIR, NDIR\}$$

Table 3.4.1 lists the associated least-square estimates for the coefficients of marginal abatement cost curves across regions based on our simulated top-down CGE "observations".

TABLE 3.4.1. Coefficients for marginal abatement cost functions

	Directive Sectors (DIR)			**Non-Directive Sectors (NDIR)**		
	$a_{1,DIR,r}$	$a_{2,DIR,r}$	$a_{3,DIE,r}$	$a_{1,NDIR,r}$	$a_{2,NDIR,r}$	$a_{3,NDIR,r}$
Austria	33.90	6.24	9.39	153.68	11.28	34.90
Belgium	13.60	-0.49	0.99	32.68	2.28	0.35
Denmark	8.57	-1.82	0.46	94.97	29.05	-0.78
Finland	26.44	3.41	1.01	104.07	30.23	16.55
France	11.27	0.59	0.25	8.86	0.24	0.00
Germany	1.60	0.00	0.00	5.77	0.08	0.00
Greece	19.52	-1.08	0.45	61.59	2.87	2.36
Ireland	8.55	19.52	15.70	169.53	61.00	41.43
Italy	4.41	0.10	0.01	12.78	-0.40	0.11
Netherlands	3.61	1.22	0.08	18.22	0.52	0.07
Portugal	29.20	-1.44	9.85	83.66	28.48	-1.27
Spain	6.29	-0.01	0.07	18.32	0.78	0.01
Sweden	49.51	0.32	38.26	104.01	14.25	-0.06
U.K.	4.08	0.08	0.01	6.97	0.12	0.00

Obviously, (marginal) abatement cost curves together with the effective reduction requirements for *DIR* and *NDIR* sectors are critical elements for the concrete quantitative simulation results. For this reason, the flexible web-based interface allows the user to enter different parametrization of cost curves as well as different information on effective reduction requirements (depending on projected baseline emissions) whenever alternative data is available.

3.4.2. Partial versus General Equilibrium Analysis. The reduced form representation of economy-wide adjustment to emission regulation provides a transparent and easy access to numerical analysis. A potential drawback of this simplifying approach is the neglect of market interaction and spillover effects. There are several articles illustrating the importance of such indirect effects (Böhringer 2002, Böhringer & Rutherford 2002, Bernard *et al.* 2003, Klepper & Peterson 2002). In the context of carbon abatement policies, induced terms-of-trade effects on fossil fuel markets may substantially alter the direct costs of abatement. Depending on the magnitude of global cuts in fossil fuel demand and the level of fossil fuel supply

elasticities, a drop in international fuel prices provides secondary benefits for fossil fuel importers while it hurts fossil fuel exporters.

Against this background, the crucial question regarding the robustness of partial equilibrium results based on marginal abatement cost curves is whether terms-of-trade effects are sufficiently small. For the policy issue in this analysis, the omission of terms-of-trade effects can be justified: On the one hand, when determining the impact of different National Allocation Plans, policies outside the EU can be taken as exogenous. On the other hand, changes in the allocation rules in EU countries do not affect the overall European reduction target, which after all has a negligible impact on world prices as EU emission cutback amounts only to a very small share in global carbon emissions.[8]

Apart from terms-of-trade effects, other potentially important general equilibrium interactions concern revenue-recycling. It is well-known that the manner in which revenues from environmental regulation are recycled to the economy can have a larger impact on the gross costs of environmental policy (Goulder 1995, Bovenberg 1999). Within the National Allocation Plans, a larger part of emission allowances, i.e., scarcity rents, is handed lump-sum to energy-intensive industries. Thus, omission of alternative recycling strategies can be justified.[9]

3.5. Policy Scenarios and Results

3.5.1. Policy Scenarios. The primary objective of emissions trading is to achieve potential efficiency gains vis-à-vis purely domestic abatement policies. So-called where-flexibility assures that emissions will be abated where it is cheapest across all emitting sources. Full where-flexibility implies flexibility across countries say regional flexibility and flexibility across the sectors of the economy say sectoral flexibility. Under the EU Directive sectoral flexibility is restricted to energy-intensive industries (*DIR* sectors). For the complementary domestic abatement policies in *NDIR* sectors, implementation at the single-country level is assumed to be cost-efficient.

The policy relevance of allocative inefficiencies and burden shifting between *DIR* and *NDIR* sectors for the hybrid EU regulation scheme is illustrated along three policy scenarios: *NoTrade*, *NAP_ Opt*, and *NAP*.

The first two scenarios *NoTrade* and *NAP_ Opt* reflect the two extremes regarding potential efficiency gains from where-flexibility. Under *NoTrade*, EU Member States meet the emission reduction target as prescribed by the Burden Sharing Agreement through cost-efficient domestic action only, for example by setting an appropriate

[8]The cutback in emissions under the EU Burden Sharing Agreement amounts to 1% of projected global carbon use in 2005 and 0.9% of projected global carbon use in 2010 with negligible impacts on international fossil fuel prices.

[9]A crude shortcut to an explicit representation of tax interaction effects is the use of estimates for marginal costs of public funds that may be applied ex-post in order to assess the "double dividend" of revenue recycling for cuts in distortionary taxes (Böhringer & Rutherford 2002).

TABLE 3.5.1. Overview of scenario characteristics

Scenario	Regulation Scheme		European Emissions Trading	Fulfillment Factor
	DIR sectors	*NDIR* sectors		
NoTrade	CO_2 tax	CO_2 tax	No	None
NAP_Opt	Allowances	CO_2 tax	Yes (in *DIR* sectors)	Endogenous
NAP	Allowances	CO_2 tax	Yes (in *DIR* sectors)	Exogenous

domestic carbon tax.[10] In scenario *NAP_Opt*, National Allocation Plans are coordinated to exploit the full potential of efficiency gains from where-flexibility in emission abatement across EU Member States. This implies that the partitioning of national emission budgets between *DIR* and *NDIR* sectors is endogenous (and so are the country-specific fulfillment factors) in order to assure equalization of marginal abatement costs across all carbon emitters. In technical terms, the cost-efficient design of National Allocation Plans can be derived from unrestricted emissions trading across all sectors and EU Member States. Emissions of *NDIR* sectors for the cost-efficient solution then determine the remaining budget of emission allowances for the *DIR* sectors (equal to the difference between the national emission budgets and the *NDIR* emissions).[11]

The third scenario *NAP* mimics the actual segmentation of regional emission budgets as suggested by the individual National Allocation Plans of EU Member States (Gilbert *et al.* 2004). Here, the free allocation of emission allowances to *DIR* sectors is exogenous and so are the associated fulfillment factors (see Table 3.5.1). Sectoral flexibility between *DIR* and *NDIR* is restricted but there is full regional flexibility within the *DIR* sectors of EU Member States.

As a default assumption, EU Member States cannot trade emissions with regions outside the EU. However, there might be the opportunity to make use of project-based emission-crediting under the Clean Development Mechanism (see EU Linking Directive (European Commission 2004)). For this reason, additional simulations for *NAP_Opt* and *NAP* (see end of section 3.5.2) are provided under the assumption that EU regions can import emission credits in infinite amounts at a given international price.[12]

Table 3.5.1 provides a summary of our central case assumptions across the three scenarios.

[10]This is equivalent to a setting where domestic governments auction off their national emission budget to domestic emitters, i.e., a situation with full sectoral flexibility but without any regional flexibility.

[11]After initializing the hybrid regulation scheme with the efficient partitioning of the national budget, restriction of sectoral where-flexibility under *NAP_Opt* does not induce any efficiency losses since the emission caps for *NDIR* sectors are set to their EU-wide efficient levels.

[12]Note that the user of our interactive interface can specify whether a scenario should be run without or with the CDM option. In the latter case, he can also enter the desired international carbon price.

3.5.2. Results. Table 3.5.2 reports quantitative scenario results for the base-year 2005 on marginal abatement costs as well as total abatement costs differentiated by *DIR* and *NDIR* sectors. Under *NoTrade*, the marginal abatement costs are equivalent to the domestic carbon tax which EU Member States must levy in order to achieve their respective emission reduction target under the Burden Sharing Agreement. A key determinant for the magnitude of marginal abatement costs is the effective cutback requirement. Ceteris paribus, the more emissions a country has to reduce, the more costly it is at the margin to substitute away from carbon in production and consumption. The high marginal abatement costs for regions such as Austria of Ireland reflect large reduction requirements vis-à-vis countries such as the U.K. or Finland that have low marginal costs along with small abatement targets. Clearly, countries that do not face any binding emission target in our case: Sweden have marginal abatement costs of zero. Apart from the magnitude of emission reduction requirements, other important determinants of marginal abatement costs include initial energy prices, carbon intensities, or the ease of carbon substitution in production and consumption that are reflected in the slope and curvature of sectoral marginal abatement cost curves. These additional determinants explain why a country (e.g., France) may need higher carbon taxes than another country (e.g., Netherlands) although its effective percentage reduction target is smaller. The pronounced differences in marginal abatement costs across EU countries for the *NoTrade* case result from the lack of regional flexibility. They indicate the potential for efficiency gains from cross-country emissions trading. An efficient implementation of hybrid regulation as captured by scenario *NAP_ Opt* would imply equalized marginal abatement costs of 13.9 € per ton of CO_2 which represents the price of traded emission allowances in the *DIR* sectors as well as the tax rate to be levied on CO_2 emissions in *NDIR* sectors.

The pattern of allowance trade emerges from the magnitude of marginal abatement costs under *NoTrade* vis-à-vis the equalized marginal abatement costs for the case of tradable emission allowances. Countries whose marginal abatement costs under *NoTrade* are below the uniform allowance price will sell emission allowances and abate more emissions. In turn, countries whose marginal abatement costs are above the uniform allowance price will buy emission allowances and abate less.

Imposition of exogenous fulfillment factors under scenario *NAP* implies an effective reduction requirement of zero for *NDIR* sectors: On average, EU Member States have allocated more emission allowances to *DIR* sectors than are actually needed to keep energy-intensive industries on their business-as-usual path in our base-year 2005. As a consequence, the marginal value of carbon in the EU emissions trading system falls to zero. All the abatement is shifted to *NDIR* sectors which are excluded from international emissions trading. The hybrid regulation then leads to extremely high marginal abatement costs in the *NDIR* sectors for several EU Member States.

TABLE 3.5.2. Marginal abatement costs and total compliance costs for base-year 2005

	Marginal abatement costs in €$_{2002}$ per ton of CO_2				Compliance cost (in million €$_{2002}$)								
	NoTrade	*NAP_Opt*	*NAP*		*NoTrade*			*NAP_Opt*			*NAP*		
			DIR	*NDIR*	Total	*DIR*	*NDIR*	Total	*DIR*	*NDIR*	Total	*DIR*	*NDIR*
Austria	73.5	13.9	0	489.9	343.6	215.4	128.2	138.6	132.1	6.6	1781.8	0.0	1781.8
Belgium	17.6	13.9	0	83.3	118.0	73.3	44.8	113.7	84.9	28.7	627.8	0.0	627.8
Denmark	3.8	13.9	0	32.7	13.5	12.6	0.8	-50.9	-60.7	9.7	46.8	0.0	46.8
Finland	4.5	13.9	0	16.3	4.7	3.8	1.0	-13.9	-22.7	8.7	11.8	0.0	11.8
France	20.9	13.9	0	36.7	340.4	121.4	218.9	306.0	202.9	103.1	596.1	0.0	596.1
Germany	8.7	13.9	0	49.2	296.0	229.6	66.4	202.8	40.8	162.1	1578.7	0.0	1578.7
Greece	11.8	13.9	0	66.4	52.3	40.4	11.9	50.8	34.6	16.3	262.7	0.0	262.7
Ireland	80.4	13.9	0	661.6	299.9	182.2	117.7	113.9	108.3	5.6	2331.3	0.0	2331.3
Italy	20.3	13.9	0	259.1	464.8	301.2	163.6	425.0	342.2	82.8	5390.9	0.0	5390.9
Netherlands	12.0	13.9	0	52.0	105.0	65.0	40.0	103.1	50.5	52.6	546.0	0.0	546.0
Portugal	44.2	13.9	0	188.7	202.3	116.4	85.9	119.0	108.3	10.7	1007.4	0.0	1007.4
Spain	45.0	13.9	0	147.5	1050.8	606.7	444.1	606.6	554.9	51.7	3178.1	0.0	3178.1
Sweden	0.0	13.9	0	0.0	0.0	0.0	0.0	-28.1	-37.7	9.6	0.0	0.0	0.0
U.K.	7.4	13.9	0	19.5	103.5	62.7	40.8	35.4	-99.0	134.4	254.5	0.0	254.5
EU-15			?	?	3394.8	2030.8	1364.0	2122.0	1439.5	682.6	17613.9	0.0	17613.9

The differences in marginal abatement costs across scenarios are reflected in the differences of aggregate EU abatement costs under the Burden Sharing Agreement. Total compliance costs amount to nearly 3.4 billion € for the *NoTrade* case. These costs can be substantially reduced via implementation of an overall efficient EU emissions trading scheme. In this case, the cost savings equal more than a third of the *NoTrade* compliance costs. All countries are better off under efficient trading as compared to purely domestic action. In a partial equilibrium framework where terms-of-trade and income effects are neglected this result does not come as a surprise: Comprehensive where-flexibility must be Pareto-superior.

Ceteris paribus the gains from unconstrained where-flexibility for a specific county increase with the deviation of its autarky marginal abatement costs from the efficient international allowance price. For example, the efficiency gains under *NAP_ Opt* for the Netherlands compared to the *NoTrade* case are very small (ca. 2%) because its autarky carbon value is very close to the international allowance price. In contrast, Spain gains more than 40% from efficient trading as its *NoTrade* marginal abatement costs are about three times the international allowance price.

Countries which do not face a binding emission constraint under *NoTrade* unambiguously will have negative costs under *NAP_ Opt* as compared to the business-as-usual, i.e., they will be better off with EU-wide carbon regulation than without because their revenues from allowance sales exceed the domestic abatement costs (here: Sweden). Likewise countries with relatively low abatement targets (or low marginal abatement costs) may more than offset overall abatement costs with revenues from allowance sales (here: Denmark and Finland).

As soon as where-flexibility is restricted at the sectoral level and efficient partitioning of national budgets is not guaranteed, efficiency implications of carbon trade may be quite different. It is no longer clear that neither the EU as a whole nor individual Member States will benefit vis-à-vis domestic abatement policies (in this case uniform carbon taxes where part of tax revenues could be recycled lump-sum to energy-intensive industries for compensation purposes).

Scenario *NAP* provides evidence on the policy relevance of efficiency losses through hybrid regulation: Under *NAP* aggregate costs are eight times higher than under an efficient trading scheme and five times higher than for purely domestic (efficient) abatement action. In this case, there are no efficiency gains that could be exploited in *DIR* sectors through regional flexibility because the implied carbon price is zero. All abatement is shifted to the *NDIR* sectors and must be achieved by domestic policies. Countries, thus, can not take advantage of sectoral flexibility ending up with higher marginal abatement costs for the *NDIR* sectors compared to the *NoTrade* scenario and zero marginal costs for the *DIR* sectors. As a consequence, there occur substantial excess costs even compared to the *NoTrade* scenario where

one assures at least equalization of marginal abatement costs across sectors within the domestic economy.

This leads to another central insight from the simulation analysis. Hybrid regulation may not only deteriorate efficiency in a drastic way but also induce politically delicate burden shifting between *DIR* and *NDIR* sectors. Generous compensations to *DIR* sectors are directly at the expense of *NDIR* sectors with potentially large increases in marginal and inframarginal costs (see e.g., Austria, Ireland, Italy, Portugal, or Spain). The *NDIR* sectors which do not receive any compensation from scarcity rents in the first place then bear the additional burden of diluting the polluter-pays-principle for *DIR* sectors.

Table 3.5.3 shows the large differences in endogenous fulfillment factors for the efficient *NAP_Opt* scenario: Fulfillment factors range from 0.285 for Ireland up to 1.09 for Sweden. These results highlight the implicit tension with competition neutrality if the EU will stick to free allocation of emission allowances to *DIR* sectors while seeking overall efficiency of the hybrid regulation scheme (for a detailed discussion of this issue see Böhringer and Lange 2005).

Table 3.5.3 furthermore reports the induced percentage emission reductions at the regional and sectoral level. By definition, the aggregate regions emission reduction must comply with the EU Burden Sharing Agreement for the *NoTrade* scenario. Within regions, the *DIR* sectors will contribute relatively more to the reduction requirement which reflects that carbon abatement options in energy-intensive industries through fuel shifting or energy savings is relatively cheaper than in the *NDIR* sectors.

For efficient carbon regulation under *NAP_Opt* the direction and magnitude of changes in autarky emission reductions are driven by the differences between the autarky carbon value and the international allowance price (the qualitative movements for *DIR* and *NDIR* sectors within a single region are obviously the same). Under *NAP*, total emission reduction at the regional level will be the same as under *NoTrade* because regional flexibility across *DIR* sectors has not any effect given an effective overall reduction requirement of zero for these sectors. The implied shifts at the sectoral level are, however, dramatic: Under *NAP* the *NDIR* sectors have to deliver the overall regional abatement duties implying very high *NDIR* percentage reduction for several EU countries which results in very high marginal abatement costs.

In view of the extreme results under *NAP*, linkage of the EU regulation scheme to abatement options outside the EU via the Clean Development Mechanism (European Commission 2004) may become very important. For illustration, we assume a CDM world market price for CO_2 emissions of 10 € per ton. Furthermore, it is assumed that emission credits from CDM will be imported into *DIR* and *NDIR* sectors as long as they are cheaper than the respective (shadow) prices. Welfare losses from inefficient allocation within the EU can then be substantially reduced: For the *NAP*

TABLE 3.5.3. Fulfillment factors and emission reductions for base-year 2005

	Fulfillment factor λ^*		Emission reduction (in % vis-à-vis 2005 projected base-year emissions)								
	NAP_Opt	NAP	NoTrade			NAP_Opt			NAP		
			Total	DIR	NDIR	Total	DIR	NDIR	Total	DIR	NDIR
Austria	0.516	0.940	20.5	35.7	10.7	7.0	13.9	2,6	18.1	0.0	29,7
Belgium	0.814	1.042	13.4	16.9	9.7	11.3	14.5	7.9	15.6	0.0	32.6
Denmark	0.783	0.850	13.8	25.8	1.8	36.4	66.8	6	6.3	0.0	12.6
Finland	0.974	0.980	4.0	5.1	2.2	10.9	13.7	6.2	2.7	0.0	7.2
France	0.763	0.995	9.2	15.9	7.3	6.6	12.0	5.1	9.1	0.0	11.6
Germany	0.903	1.000	8.7	11.4	4.7	13.0	17.0	7.2	8.7	0.0	21.1
Greece	0.889	1.000	9.1	11.7	5.2	10.6	13.6	6.1	9.1	0.0	22.8
Ireland	0.285	0.970	24.8	53.4	11.2	9.9	25.2	2.7	23.8	0.0	34.9
Italy	0.816	1.074	12.3	16.2	8.3	9.2	12.4	5.9	16.1	0.0	32.8
Netherlands	0.850	1.030	12.7	16.1	8.8	14.0	17.5	10.1	14.3	0.0	30.4
Portugal	0.618	1.035	19.1	28.1	12.2	9.0	15.0	4.6	20.5	0.0	36.1
Spain	0.573	0.940	19.9	31.1	12.3	9.1	15.9	4.4	17.5	0.0	29.4
Sweden	1.092	1.000	0.0	0.0	0	7.1	15.4	3.8	0.0	0.0	0
U.K.	0.963	0.993	5.5	7.3	3.9	9.4	12.2	7	5.2	0.0	9.6

scenario the total compliance cost in this illustrative policy setting amount to about 3 billion €. This is less than one fifth of the compliance cost without CDM linkage and about 12% less than for domestically efficient abatement policies (*NoTrade*).

3.6. A closer Look at Harmonization

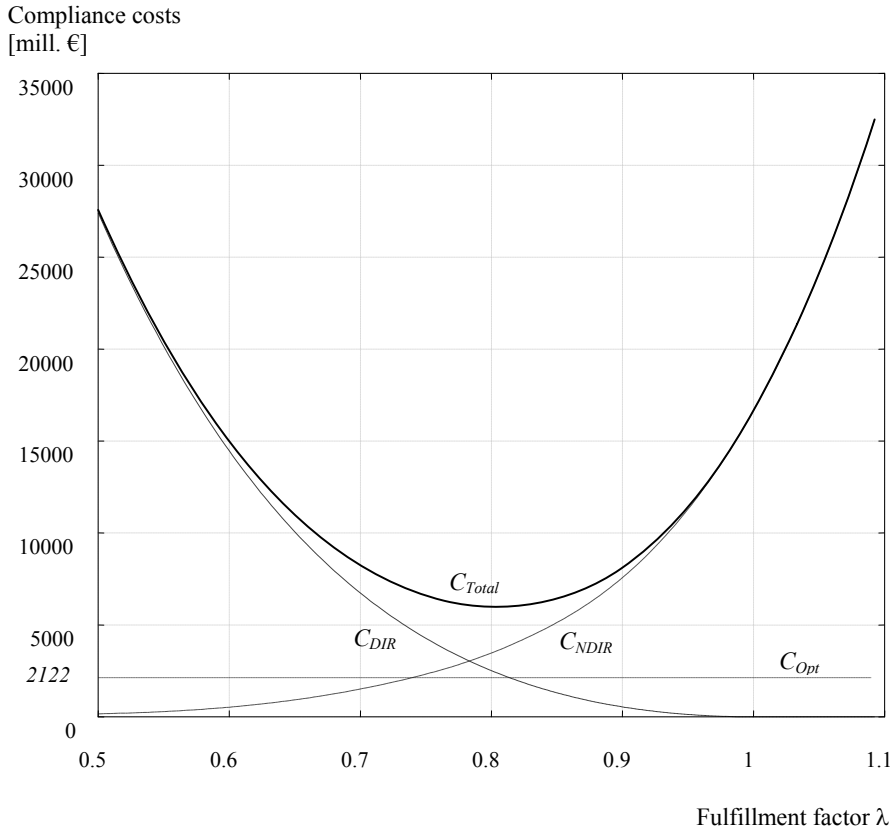
3.6.1. Harmonizing the fulfillment factor. Given the fixed, but differentiated commitments under the EU BSA, allocating the efficient emission budgets of *NAP_ Opt* will leave the *DIR* sectors with very different shares of their previous emissions allocated for free. This will potentially lead to competitive disadvantages of *DIR* sectors in countries where the national emissions budget is comparatively small compared to their actual emissions. Thus, the states face the question, how to distribute permits to the different sectors when they (i) aim at minimizing their nationwide (and also European) compliance cost, and (ii) when they account for potential competitive disadvantages of domestic sectors within as well as outside the trading scheme caused by higher relative reduction requirements compared to their international competitors. Auctioning a larger fraction of the permits would contribute to solving the problem at least with respect to competitors within the European Union. Related to these concerns about competitiveness is the debate on harmonizing the allocation process. The cost burden which may lead to competitive disadvantages of a sector is determined by the sectoral emissions budget, by the set of abatement options, but also by the overall emission intensity of the sector. Abstracting from the two latter, i.e., considering only the reduction requirement, some requests for a harmonization of the fulfillment factor were brought up.

As our analysis has revealed so far, deviating from efficient fulfillment factors inefficiently shifts the burden of emission reduction. Therefore, using an identical fulfillment factor comes at economic costs as compared to an efficient allocation. We assess the magnitude of these costs by calculating a sequence of scenarios with harmonized fulfillment factors (ranging from $\lambda = 0.5$ to $\lambda = 1.1$).

3.6.2. Efficient versus harmonized fulfillment factors. First we demonstrate the efficiency losses that result from a harmonization of the fulfillment factor for *DIR* sectors. Figure 3.6.1 displays the total compliance costs (C_{Total}) for the whole EU-15 as well as the compliance costs of the *DIR* (C_{DIR}) and the *NDIR* (C_{NDIR}) sectors if fulfillment factors are harmonized at different levels. It is obvious that the cost burden of the *DIR* sectors decreases in rising fulfillment factors since higher λ directly translate into reduced emission abatement obligations.

Given an overall emission constraint a reduction of relative abatement requirements in the *DIR* sectors inevitably shifts the burden towards the *NDIR* sectors where increasing abatement costs can be observed. Total compliance costs reach an overall cost minimum at a harmonized λ of 0.8. Figure 3.6.1 also depicts the total compliance costs (C_{Opt}) for the case of efficient but country-specific (non-harmonized)

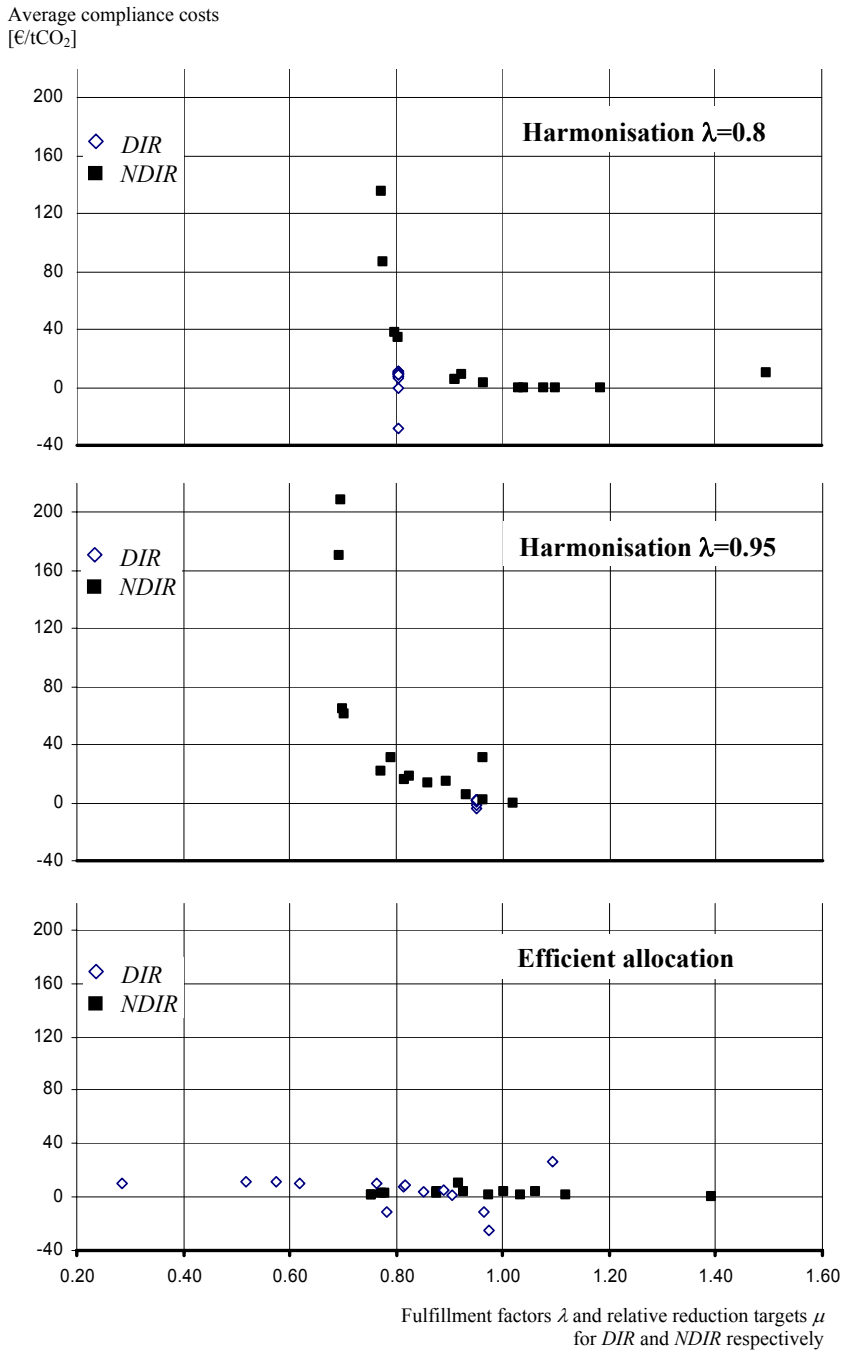
FIGURE 3.6.1. Compliance costs for the EU-15 for efficient but country specific fulfillment factors (horizontal line) and for harmonized factors (u-shaped curve)



fulfillment factors. In this illustration, an efficient distribution of country-specific emission budgets across *DIR* and *NDIR* sectors would reduce overall compliance costs to less than 50 percent as compared to the harmonized case. Furthermore, the additional costs of harmonization are distributed across *DIR* and *NDIR* sectors. While harmonization increases costs in *DIR* sectors by approximately 50%, additional costs for the *NDIR* sectors are more than five times higher than in the efficient case. It is also evident that a harmonization of fulfillment factors for *DIR* sectors affects relative reduction requirements of the *NDIR* sectors (μ). Figure 3.6.2 indicates the correlation between the relative reduction targets of *DIR* and *NDIR* sectors (λ and μ) in each Member State and the corresponding average compliance costs per ton of CO_2 in the respective sectors and countries.

By definition, harmonizing the fulfillment factors of *DIR* sectors eliminates their variance compared to the efficient case shown in the lower part of Figure 3.6.2 where country-specific fulfillment factors for *DIR* sectors range from 0.29 up to 1.09. Given this spread it is not surprising that there are concerns in some sectors whether they might be disadvantaged relative to their competitors in other EU

FIGURE 3.6.2. Average compliance cost of individual countries in the DIR and NDIR sectors and their fulfillment factor.



Note: The three scenarios are (i) the harmonized fulfillment factor at the second best level (λ=0.8), (ii) a harmonized factor which leads to over-allocation (λ=0.95), and (iii) the efficient allocation

Member States. Relative reduction targets of *NDIR* sectors vary between 0.75 and 1.39. Surprisingly, the overall reduction requirements of the Member States as stated in the BSA vary a lot less: if compared to the projected emissions in 2005 (European Commission 2003*b*) the available relative budget for the first Kyoto phase ranges from approximately 1 (Sweden) to about 0.75 (Ireland). In the efficient case average compliance costs of the *DIR* sectors composed of sectoral abatement costs and costs or revenues for buying or selling permits on the international market range from -25 up to almost 27 €/tCO_2. Average compliance costs of the *NDIR* sectors only composed of abatement costs range from less than 1 to 10 €/tCO_2. As can be seen in the upper part of Figure 3.6.2 applying a harmonized λ of 0.8 does not substantially inflate the variance of the relative reduction requirements of the *NDIR* sectors (between 0.77 and 1.49). But this harmonization has a strong effect on the variance of the average compliance cost per ton of CO_2.

While the spread of average abatement costs of the *DIR* sectors slightly decreases as well as they have an upper bound on their average compliance cost per ton of about 11€, the average costs for the individual *NDIR* sectors may reach more than 130 €/tCO_2 for harmonization at $\lambda = 0.8$. This spread increases even more when a higher harmonized λ is chosen. The middle part of Figure 3.6.2 depicts the results for a harmonized λ of 0.95 which reflects an over-allocation of *DIR* sectors in the EU-15. This situation can be considered similar to the allocation plans that have actually been designed by the Member States. Not surprisingly, compliance now becomes cheap for *DIR* sectors but the majority of *NDIR* sectors face substantially higher average compliance costs up to more than 200 €/tCO_2. This comes with a shift of the relative reduction requirements in the *NDIR* parts towards more severe targets. On the whole, the harmonization of the assignment in the *DIR* sectors does not seem to substantially inflate the variance of the relative emission assignments to the *NDIR* sectors. But it increases its average costs per ton of reduced emissions significantly in some cases drastically. Given that an (at least partly) harmonization seems to be the alternative that has been chosen in the political process, it seems obvious that this would come with significantly stricter requirements in the *NDIR* sectors especially in terms of average cost per abated ton of CO_2 of some countries.

3.7. Conclusions

The EU-wide carbon market established from 2005 onwards provides the first multi-jurisdictional emissions trading regime and constitutes the world-largest market for tradable emission allowances. The concrete implementation via National Allocation Plans entails a hybrid regulation where energy-intensive sectors are eligible for emissions trading and other segments of the economy must be constrained by complementary domestic policy instruments in order to comply with the EU Burden Sharing Agreement.

In this chapter, a simulation model has been used to demonstrate that such hybrid regulation may involve large allocative inefficiencies and a rather uneven cost incidence across differentially treated sectors. To some extent, these problems can be relaxed by importing CDM credits from the world market.

We have also analyzed the effects of harmonizing the fulfillment factors of the sectors included in the trading regime of the EU. The most significant result is that the harmonization under the auctioning restrictions although sometimes politically desirable will come at high efficiency costs. However, when striving for cost efficient emission reduction, the abatement requirements for the different countries in the sectors within as well as outside the directive vary a lot, even if compared to the national reduction requirements as laid down in the European Burden Sharing Agreement. Harmonization eliminates this variance in the *DIR* sectors and seems not to inflate it significantly in the other sectors.

It should be kept in mind that the relative emission requirement alone may not be a good measure for the influence of the allocation of the competitive disadvantages resulting from an allocation. The same holds for the average compliance cost per ton of abated CO_2. Our analysis at least accounts for different shapes of the abatement cost functions. For future analysis, aspects like the emission intensity of the output value which is inter alia influenced by historical climate policies or the exposure of sectors to the world market would have to be considered as well.

Our results highlight the importance of a gradual re-design of the EU emission regulation approach: The initial design featuring restricted where-flexibility and generous free allocation of emission allowances to energy-intensive industries may have been necessary to achieve political feasibility of market-based environmental regulation. In the medium-run, however, allocative inefficiencies should be avoided by equalizing emission allowance prices across all sectors, e.g., by a comprehensive upstream coverage of all carbon emitters. Furthermore, the equity conflict inherent to the current discriminatory treatment of sectors (polluters) could be resolved by a gradual transition to an auctioned allowance system. The latter simply implies the rigorous adoption of the polluter pays principle.

It should be stressed that our analysis is of interest beyond the scope of the current debate on National Allocation Plans within the EU. The derived insights may not only be useful for the re-design of Allocation Plans across EU Member States in future periods, but also with respect to the specification of any hybrid regulation regime where emissions trading for some sectors is combined with complementary regulation in other sectors.

CHAPTER 4

The Efficiency Costs of Separating Carbon Markets under the EU Emissions Trading Scheme[1]

4.1. Introduction

Since long, economists have advocated the efficiency advantages of market-based instruments, i.e., emission taxes or tradable emission allowances over command-and-control standards. The basic reasoning behind this is that taxes or tradable allowances can achieve the same marginal costs for each use of a given pollutant so that the economy as a whole will employ the cheapest abatement options. While a deliberate design of standards could in principle also achieve cost effective abatement, the fundamental advantage of market-based regulation is that cost efficiency can be obtained by decentralized market mechanisms: There are no information requirements for the regulator on the specific abatement options across different pollution sources to assure equalization of marginal abatement costs.

During the last decade, in particular emission taxes have played a growing role in domestic environmental policies of OECD countries – not at least because efficiency arguments promoted overall political feasibility (OECD 2001*b*). The most recent prominent example for the market-based course in environmental policy design is the European Unions Emissions Trading Scheme (EU-ETS) being in force since the first of January 2005 (Commission 2003). Its key objective is to foster cost-efficiency of carbon reduction under the EU Burden Sharing Agreement (EU-BSA) that entails specific emission reduction targets across EU Member States (European Commission 1999*a*) in line with the EU's overall reduction commitment under the Kyoto Protocol.[2]

Initially, the EU-ETS will only cover carbon dioxide (CO_2) emissions from selected energy intensive sectors including: production and processing of iron and steel;

[1] This chapter is based on the articles:

Böhringer, C., Hoffmann, T. & Manrique-de-Lara-Peñate, C. (2006), 'The efficiency costs of separating carbon markets under the EU emissions trading scheme: A quantitative assessment for Germany', *Energy Economics* 28(1), p.44-61.

Hoffmann, T. (2005), 'Effizienzkosten hybrider CO_2 Regulierung in Deutschland: Eine kritische Betrachtung der EU-Emissionshandelsrichtlinie', *Zeitschrift für Energiewirtschaft* 28(4), p.255-262.

[2] Under the Kyoto Protocol the EU is committed to cut its annual greenhouse gas emissions during 2008-2012 by 8% on average as compared to 1990 emission levels (UNFCCC 1997).

production of cement, glass, or ceramic; energy transformation (electricity generation and oil refineries). According to Article 10 of the EU-ETS-Directive, emission allowances to these sectors will be grandfathered, i.e. given for free.[3] Each Member State is obligated to set up a National Allocation Plan (NAP) where it defines the cap on emission allowances for sectors (installations) included in the trading scheme and the specific allocation rule for grandfathering. The NAPs for the first trading period from 2005 - 2007 had to be submitted to the EU Commission by April 2004 for official review and approval.

As the EU-ETS covers only a part of CO_2 emission sources, it implies a segmented environmental regulation scheme. Each Member State must complement the EU-ETS with specific domestic abatement policies for the sectors outside the EU-ETS in order to meet the country's total emissions budget under the EU-BSA. The segmentation of the emission market into multiple domestic markets and a single international market creates a fundamental information problem for environmental regulation that seems to be widely ignored in the public policy debate: Under a segmented scheme, the domestic regulator must have perfect information on the international price of tradable emission allowances and the marginal abatement cost curves across all domestic emission sources that are not included in the emissions trading scheme in order to implement the (single) cost-minimizing NAP. Hence, segmented emission regulation as implied by the EU-ETS discards a key element of marketbased regulation, i.e. the rigorous use of decentralized market mechanisms.

In this chapter, an investigation of the potential efficiency costs of segmented carbon emission regulation is presented. It starts with a simple analytical partial equilibrium framework to demonstrate the fundamental information problems of segmented regulation. Then the potential excess costs of segmented regulation for Germany are quantified using marginal carbon abatement cost curves based on empirical data. The simulation results suggest that the inefficiencies of the actual German NAP can be better explained by lobbying of influential sectors within the EUETS than by information problems of regulatory authorities.

The analysis complements more recent research on the economic impacts of the EU-ETS and complementary environmental policy measures. Johnstone (2002) as well as Sorrell and Sijm (2003) investigate the interaction between the EU-ETS and existing policy instruments such as energy taxes, subsidies to renewable energies, or energy efficiency standards. In their qualitative analysis, they conclude that the rationale for sticking to the existing policy instruments must rely on their contribution to overcome market barriers and market failures (other than carbon externalities) or in contributing to social objectives other than economic efficiency. Klepper and Peterson (2004) use a computable general equilibrium model for the

[3]More specifically, Member States must allocate at least 95% of emission allowances for free in the warm-up phase from 2005 to 2007. In the next phase – from 2008 to 2012 – this threshold can be reduced to 90%, whereas the ceilings for later phases have been not yet decided upon.

European Union to quantify the economic impacts for a range of likely implementations of NAPs. Although their analysis implicitly captures inefficiencies due to diverging marginal abatement costs between sectors inside and outside the EU-ETS, the focus is on the role of accession countries for alleviating overall compliance costs and adverse competitiveness effects. Another strand of the literature emphasizes the distortionary effects of dynamic (updating) allocation rules (see e.g. Böhringer and Lange (2005)) or competitive distortions between similar energy-intensive firms across EU Member States (see e.g. Böhringer and Lange (2005)).

4.2. Stylized Analysis

Under the EU-BSA, a Member State must comply with a country-specific emissions budget $\overline{E}$. With international emissions trading, efficient national regulation comes down to minimizing compliance costs as the sum of abatement costs $C_i(e_i)$ across all domestic sectors i and the costs of buying emission allowances from the international market at an exogenous price $\overline{p}$:[4]

$$\min_{e_i} \sum_i C_i(e_i) + \overline{p}\left(\sum_i e_i - \overline{E}\right) \tag{4.2.1}$$

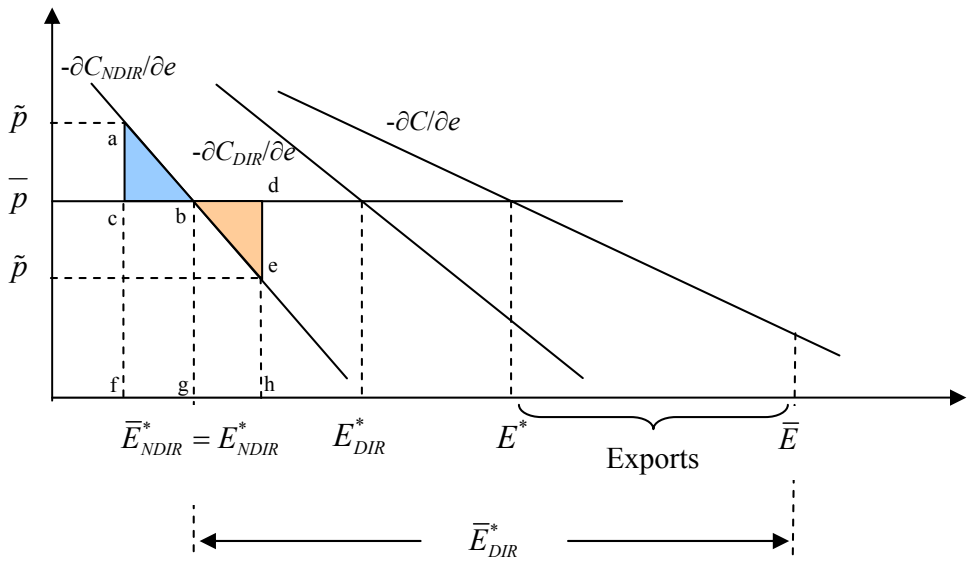
The associated first-order condition states that marginal abatement costs are equalized across all sectors at the international emissions price:

$$\overline{p} = -\frac{\partial C_i}{\partial e_i} \tag{4.2.2}$$

From the perspective of the national regulator, the efficient solution can be decentralized by implementing an open emissions trading scheme where the national emissions budget $\overline{E}$ is auctioned or grandfathered lump-sum. In this way, the national authority does neither require any information on domestic abatement technologies (i.e., the marginal costs of domestic abatement options) nor on the international emissions price: The efficient abatement across sectors together with exports or imports of emission allowances are implicitly determined by decentralized market mechanisms. For segmented emission regulation under the EU-ETS, however, the national regulator must know both – the international carbon value $\overline{p}$ as well as (marginal) abatement cost curves for domestic emission sources that are not included in the international emissions trading scheme – in order to partition the national emissions budget $\overline{E}$ into efficient segments $\overline{E}^*_{DIR}$ for the EU-ETS sectors (thereafter referred to as *DIR* sectors that are covered by the EU-ETS Directive) and $\overline{E}^*_{NDIR} = \overline{E} - \overline{E}^*_{DIR}$ for the remaining sectors of the domestic economy

[4] As usual, $\partial C_i/\partial e_i$ and $\partial^2 C_i/\partial^2 e_i > 0$ where e_i denote emissions by sector i. Countries are assumed to be price takers on the international emission market.

FIGURE 4.2.1. Efficient emission budgets and efficient emission levels for *NDIR* and *DIR* sectors



(thereafter referred to as *NDIR* sectors outside the EU-ETS Directive). Furthermore, the segmented regulation reduces the flexibility for grandfathering policies even if perfect information would be available: $\overline{E}^*_{DIR}$ constitutes the upper bound at which emission allowances to EU-ETS sectors could be given for free (lump-sum) without reducing overall efficiency in the segmented system.[5]

Figure 4.2.1 illustrates the impending excess costs of segmented market regulation. The aggregate marginal abatement cost curve for *DIR* sectors is denoted by $\partial C_{DIR}/\partial e_i$and for *NDIR* sectors by $\partial C_{NDIR}/\partial e_i$ respectively; the two marginal cost curves add up to the overall marginal abatement cost curve $\partial C/\partial e_i$. The intersection of the international emissions price $\overline{p}$ with the marginal abatement cost curves determines the efficient partitioning of the overall emissions budget $\overline{E}$: *NDIR* sectors should comply with an emissions constraint $\overline{E}^*_{NDIR}$ whereas the remaining emissions budget $\overline{E}^*_{DIR} = \overline{E} - \overline{E}^*_{NDIR}$ should be allocated to the *DIR* sectors. If domestic marginal abatement costs to reach the overall emission target $\overline{E}$ are below the international emissions price, the region becomes an exporter of emission allowances (as sketched in Figure 4.2.1) with an efficient domestic emission level E^* below the mandated emissions budget $\overline{E}$; otherwise, the region becomes an importer. In Figure 4.2.1, E^*_{DIR} and E^*_{NDIR} denote the efficient levels of emissions for *DIR* and *NDIR* sectors.

[5]Under non-segmented carbon regulation (where all sectors are eligible for international emissions trading) the total budget $\overline{E}$ could be grandfathered lump-sum, i.e., the regulator would have more flexibility with respect to distributional objectives for *DIR* sectors.

The efficient solution could be decentralized by imposing uniform emission taxes at the international permit price $\overline{p}$ on the *NDIR* sectors that are not eligible for international emissions trading. The remaining emissions budget, $\overline{E} - \overline{E}^*_{NDIR}$, would be allocated to the *DIR* sectors that are eligible for international emissions trading. Depending on the business-as-usual emissions $\overline{E}^0_{DIR}$ for *DIR* sectors, the efficient allocation factor λ^* (which reports the fraction of business-as-usual emissions that are freely allocated as allowances) equals $\overline{E}^*_{DIR}/\overline{E}^0_{DIR}$. In policy practice, partitioning of $\overline{E}$ will generally deviate from efficient values λ^* due to inherent information problems or lobbying of interest groups. Figure 4.2.1 illustrates a situation where efficiency losses emerge from wrong assumptions of the national regulator on the international emissions price $\overline{p}$: If the national authority presumes a price $\widetilde{p}$ above the actual international price $\overline{p}$, domestic abatement by the *NDIR* sector exceeds the efficient level by $\overline{bc}$. The induced excess costs amounts to the shaded area *abc* which equals the difference between additional abatement costs *abgf* and the additional revenues *cbgf* from allowance exports $\overline{bc}$ via the *DIR* sectors to the international emissions market. Likewise, excess costs *bde* arise if the international emissions price $\widetilde{p}$ presumed by the national authority is below the actual international price $\overline{p}$. Clearly, the efficiency implications are the same if the deviations from efficient partitioning emerge from wrong assumptions on the marginal abatement cost curves in the *NDIR* sectors or are due to lobbying power.

4.3. Numeric Model Parametrization

In order to provide empirical estimates for the magnitude of efficiency losses induced by segmented carbon regulation, we transform our stylized analytical framework into a simple numerical model based on marginal abatement cost curves for Germany. These curves represent the marginal adjustment costs of reducing carbon emissions by different amounts within the German economy. Total (inframarginal) adjustment costs to emission constraints emerge as the integral of marginal abatement cost curves (see Figure 4.2.1).

Continuous marginal abatement cost curves for the *DIR* and *NDIR* sectors of the German economy are derived from a sufficiently large number of discrete observations for marginal abatement costs and the associated emission reductions in the respective sectors. These values are generated with PACE a standard multi-region, multi-sector computable general equilibrium (CGE) model for the EU economy (Böhringer 2002) which is based on recent consistent accounts of EU Member States production and consumption, bilateral trade and energy flows as provided by the GTAP5-E database (Dimaranan & McDougall 2002): Increasingly stricter carbon emission limits are imposed on the German economy. The CGE model then calculates the associated (uniform) marginal abatement costs together with the abatement contributions by *DIR* and *NDIR* sectors. In this way, a reduced form of complex CGE adjustment effects is created cast as marginal abatement cost curves

TABLE 4.3.1. Coefficients for sector-specific marginal abatement cost functions in Germany

Directive Sectors (DIR)			Non-Directive Sectors (NDIR)		
$a_{1,DIR}$	$a_{2,DIR}$	$a_{3,DIR}$	$a_{1,DIR}$	$a_{2,DIR}$	$a_{3,DIR}$
1.60372	0.00318	0.00042	5.76568	0.08324	0.00095

that are directly related to the stylized analysis of section 4.2 and easily accessible to non-CGE specialists.[6]

It should be noted that the marginal abatement cost functions provide a partial equilibrium approximation of general equilibrium effects. For instance, the reduced from representation via abatement cost functions does no longer explicitly account for endogenous market interactions such as indirect changes in factor prices due to exogenous emission constraints. Total abatement costs in the reduced form approach the integral of marginal abatement cost functions represent a local approximation of general equilibrium adjustment costs, i.e. the loss in money-metric utility (Hicksian equivalent variation in income) due to the policy-induced reallocation of resources.

For the concrete empirical specification of marginal abatement costs curves a flexible polynomial function of third degree is adopted:

(4.3.1)
$$-C_i^{'}(e_i) = a_{1,i}(e_{0_i} - e_i) + a_{2,i}(e_{0_i} - e_i)^2 + a_{3,i}(e_{0_i} - e_i)^3 \qquad i \in \{DIR, NDIR\}$$

where $C_i^{'}$ are the marginal costs of reducing carbon emissions in sector e_{0_i} are the business-as- usual emissions, and e_i are the actual emissions, i.e., $(e_{0_i} - e_i)$ denotes the level of abatement. A least-square fit to the CGE observations for marginal abatement costs and the associated emissions reductions determines the coefficients $a_{1,i}$,$a_{2,i}$ and $a_{3,i}$.[7] For the sake of transparency, the CGE results are aggregated on sector-specific emission reductions for given marginal abatement costs in only two composite sectors: one sector (*DIR*) that includes all segments of the economy eligible for international emissions trading and one sector (*NDIR*) that summarizes the remaining segments outside the emissions trading scheme.

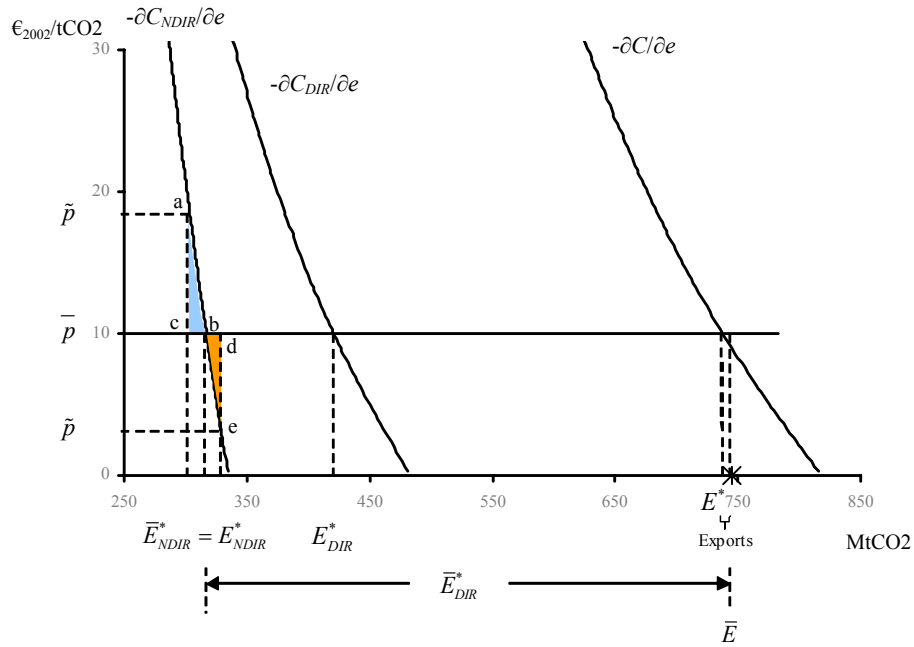
Table 4.3.1 provides a summary of least-square estimates for the coefficients of marginal abatement cost curves for *DIR* and *NDIR* sectors in Germany.[8] The marginal abatement costs curves for *DIR* and *NDIR* sectors are used in the simple

[6]Sensitivity analysis for the scenario simulations in section 4.4 (see Table 4.4.2) – based on the comprehensive CGE model – confirms robustness of the results derived from the reduced form partial equilibrium model.

[7]Note that the interested reader can easily employ alternative observations – e.g. based on mathematical programming models of the national energy system – to fit the coefficients of the functional forms.

[8]The units of coefficients for the marginal abatement cost curves are as follows: [a1,i]:= (\$97/tC)/MtC, [a2,i]:= (\$97/tC)/(MtC)^2 , and [a3,i]:= (\$97/tC)/(MtC)^3.

FIGURE 4.3.1. Efficient emission budgets and efficient emission levels for *NDIR* and *DIR* sectors



partial equilibrium model of segmented emission regulation as outlined in section 4.2 (see Appendix A.2 for the algebraic model description). The model is implemented numerically using GAMS (Brooke *et al.* 1996) and solved using PATH (Dirkse & Ferris 1995*b*).

Figure 4.3.1 substantiates the stylized analysis of section 4.2 with a concrete example based on the estimated marginal abatement cost functions for Germany: At an international emissions price $\overline{p} = 10$ €/t CO_2 the efficient segmentation of the overall emission budget $\overline{E}$ is characterized by $\overline{E}^*_{DIR}$ and $\overline{E}^*_{NDIR}$. Any deviation from this partitioning – either due to wrong expectations on the international emissions price or due to political economy (lobbying) reasons – will induce excess costs of regulation (here: shaded triangles *abc* or *bde*). In the graphical exposition of Figure 4.3.1 as well as in the subsequent numerical simulations of section 4.4, complementary regulation in the *NDIR* sectors is assumed to be efficient. In practice, however, *NDIR* sectors might be regulated by command-and-control approaches. Therefore, the overall inefficiency of the segmented system compared to a comprehensive trading system is likely to be even greater than stated in this analysis.

4.4. Scenarios and Results

Table 4.4.1 summarizes the evolution of emissions and emission reduction requirements for Germany vis-à-vis the EU average based on most recent business-as-usual

TABLE 4.4.1. CO_2 emissions and reduction requirements (EU 2003b)

	CO_2 emissions (in Mt)		**Reduction requirements (in %)**	
	1990	2005	1990	2005
Germany	943.0	815.6	21.0	8.7
EU 15 (total)	3071.5	3140.2	8.6	10.6

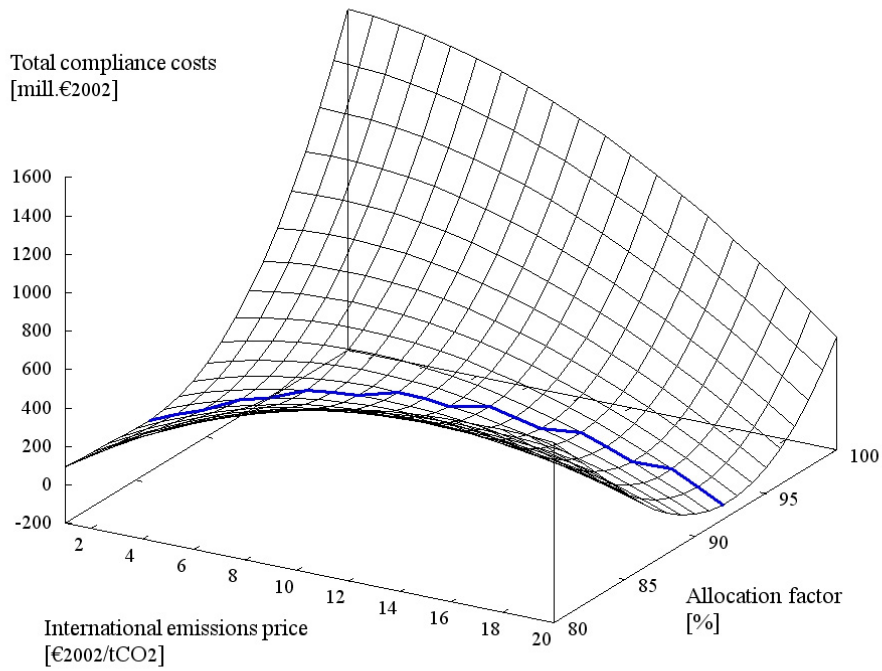
projections by the EU (European Commission 2003*b*). Obviously, the effective reduction targets under the EU-BSA can change dramatically along the business-as-usual development.[9]

Germany committed itself under the EU-BSA to an emissions reduction target of 21% compared to 1990 emission levels. Against business-as-usual emission levels in 2005, the effective reduction requirement only amounts to 8.7%.[10] In order to illustrate the excess costs for segmented carbon regulation, Germany's compliance costs are plotted as a function of the international emissions prices for CO_2 and the domestic allocation factor λ. The latter has been a central parameter of negotiations between the national regulatory authorities and the *DIR* sectors covered by the EU-ETS. Obviously, the *DIR* sectors had a strong incentive to lobby for large allocation factors in order to reduce effective reduction requirements vis-à-vis their business-as-usual emissions. A review of NAPs that have been approved so far by the EU Commission indicates rather generous allocation of emission allowances to the DIR sectors with λ being close or even beyond 1 (Gilbert *et al.* 2004). As to Germany, the allocation factor is 1, i.e., the *DIR* sectors are more or less endowed with their business-as-usual emissions. Figure 4.4.1 provides a contour plot of total compliance costs for Germany across a meaningful range of international CO_2 prices and allocation factors: (i) Reflecting broad consensus of carbon market analysts, international CO_2 prices will not exceed 20 € per ton of CO_2 in the initial phase of the EU-ETS, and (ii) allocation factors for Germany range between 0.8 and 1 covering efficient allocation factors (as an endogenous function of the international CO_2 price) as well as the negotiated allocation factor of 1. The marked solid line in Figure 4.4.1 reports the minimum compliance costs for Germany given alternative international CO_2 prices p and associated choices of the efficient allocation factor λ^*. At a given international CO_2 price, compliance costs become the higher, the more the national authority deviates from the efficient allocation factor – this explains the U-shaped hull around the minimum cost line. Total excess costs of

[9]We apply the EU Burden Sharing Agreement covering all greenhouse gases to CO_2 only which is by far the most important greenhouse gas within the EU. This explains why the EU average reduction requirement for CO_2 amounts to 8.6% relative to 1990 CO_2 emission levels (rather than yielding the official EU reduction target of 8% for all greenhouse gases).

[10]The major source for the decrease in emissions since 1990 can be traced back to so-called wall-fall profits in the context of Germany's reunification with a sharp decline in East German emission-intensive production together with more efficient energy transformation utilities.

FIGURE 4.4.1. Total compliance costs for Germany (mill. EUR)



inefficient choices for λ emerge as the difference between compliance costs for the respective λ and the minimum costs for λ^*.

Total compliance costs are composed of direct abatement costs for all sectors and the value of emission allowances that can be traded via the *DIR* sectors. Whenever λ deviates from λ^* the marginal abatement costs in *NDIR* sectors are no longer equalized with marginal abatement costs in *DIR* sectors the latter always coinciding with the international emissions price p. If λ is higher than λ^* at a given international emissions price (which is actually the case for Germany over the whole selected range of international emissions prices) the effective reduction burden for *NDIR* sectors becomes more stringent leading to higher marginal abatement costs than p and an increase in *NDIR* compliance costs. While the *DIR* sectors gain and may even achieve substantial net revenues from carbon exports, total compliance costs for *DIR* and *NDIR* sectors go up.[11]

Table 4.4.2 reports the efficient allocation factor λ^* as a function of the international emissions price together with the total compliance costs for λ^* and $\lambda = 1$, i.e. the

[11]The same logic applies, if λ is lower than λ^*: Here the marginal abatement costs for *NDIR* sectors drop below p, thereby reducing *NDIR* compliance costs at the expense of increasing compliance costs for *DIR* sectors.

TABLE 4.4.2. Excess costs of the German National Allocation Plan

Emissions price (in €$_{2002}$/tCO_2)	λ^*	Compliance costs* for λ^* (in mill. €$_{2002}$)	Compliance costs for $\lambda = 1$ (in mill. €$_{2002}$)	Absolute excess costs (in mill. €$_{2002}$)	Relative excess costs (as a factor of costs*)	
5	87.2	245.4	1494.3	1248.9	5.1	[5.6]´
6	87.6	269.5	1457.9	1188.4	4.4	[4.9]´
7	88.0	285.7	1415.5	1129.8	4.0	[4.4]´
8	88.3	294.5	1367.1	1072.6	3.6	[4.0]´
9	88.7	295.7	1313.0	1017.3	3.4	[3.8]´
10	89.0	289.7	1253.4	963.7	3.3	[3.6]´
11	89.4	276.6	1188.5	911.9	3.3	[3.5]´
12	89.7	256.8	1118.4	861.6	3.4	[3.5]´
13	90.1	230.4	1043.3	812.9	3.5	[3.6]´
14	90.4	197.5	963.4	765.9	3.9	[3.8]´
15	90.7	158.4	878.8	720.4	4.5	[4.2]´

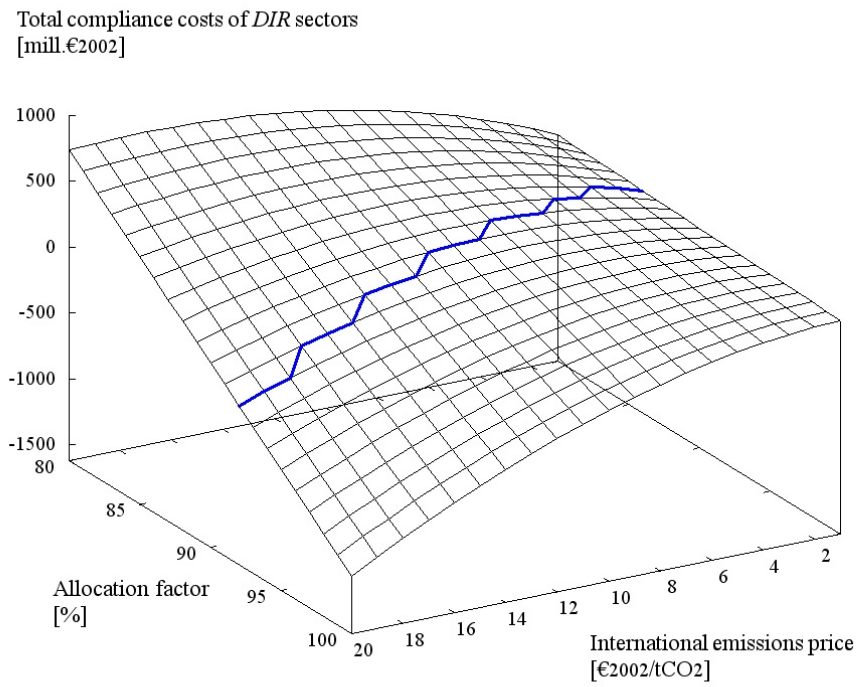
[] Computable general equilibrium (CGE) sensitivity analysis

actual policy choice. Furthermore, the associated excess costs in absolute and relative terms are listed. The final column of Table 4.4.2 includes in brackets the results of equivalent CGE simulations which confirm the robustness of findings based on the reduced form partial equilibrium representation via marginal abatement cost curves.

Figure 4.4.1 and Table 4.4.2 indicate that the choice of the efficient λ^* is relatively insensitive with respect to sensible assumptions on the international emissions price p. The actual choice of the allocation factor $\lambda = 1$ as implied in the German NAP may therefore not be reasonably explained by expectation errors on p but rather by successful lobbying efforts of *DIR* sectors for a generous λ. As a matter of fact, well organized and politically influential *DIR* sectors in Germany were able to negotiate the amount of free emission allowances with the national authorities whereas the *NDIR* sectors had not been involved in the implicit burden sharing debate at all. Figures 4.4.2 and 4.4.3 decompose the total compliance costs into the components for *DIR* and *NDIR* sectors.

In both figures, the minimum cost line for efficient NAPs is marked. Compliance costs for *NDIR* sectors are equal to the sum of direct abatement costs across these sectors, whereas compliance costs for *DIR* sectors in addition include the value of exported or imported CO2 allowances. The shape of *NDIR* compliance costs is straightforward: Independent of the international emissions price, abatement costs of *NDIR* sectors are determined by the effective reduction requirement associated with the choice of λ. *NDIR* compliance costs sharply increase in λ, thereby reflecting empirical evidence on costly abatement options in important segments of the domestic economy such as traffic and transportation outside the EU-ETS. In turn,

FIGURE 4.4.2. Compliance costs of DIR sectors in Germany (mill. 2002)

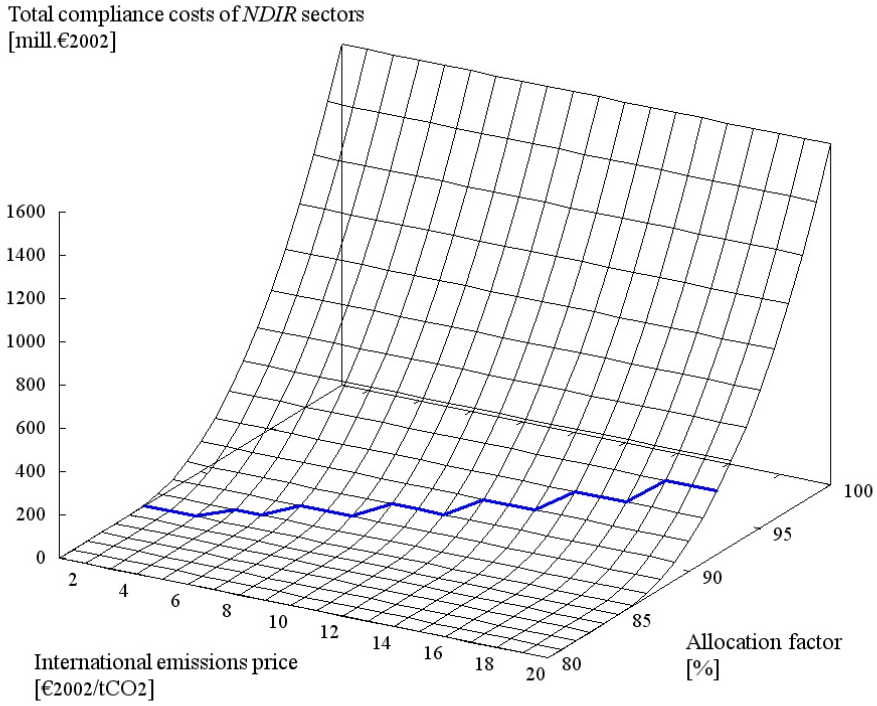


compliance costs in *DIR* sectors at a given international price decrease in λ rendering negative costs (or likewise net revenues) via permit exports if free allowance allocation is sufficiently high.

The value of allowance trade is illustrated in Figure 4.4.4. Whenever this value drops to zero, the associated allocation factor λ characterizes an autarky situation for the given international emissions price p.

The decomposition of compliance costs for *DIR* and *NDIR* sectors not only provides useful information on the sources of excess costs from segmented regulation but also de-masks an important equity dimension: A generous allocation of free emission allowances to *DIR* sectors may fully shift the burden of emission reduction under the EU-BSA to the *NDIR* sectors (see 3) whereas *DIR* sectors may be better off compared to business-as-usual. For concreteness, consider an international permit price of €10 per ton of CO2: With an efficient $\lambda^* = 0.89$, total compliance costs for Germany amount to 289.7 mill. $€_{2002}$ as the sum of *DIR* costs (204.1 mill. $€_{2002}$) and *NDIR* costs (85.6 mill. $€_{2002}$). If the allocation factor is chosen at 1, total compliance costs more than quadruple to 1253.4 mill. $€_{2002}$. Apart from the large

FIGURE 4.4.3. Compliance costs of NDIR sectors in Germany (mill. 2002)



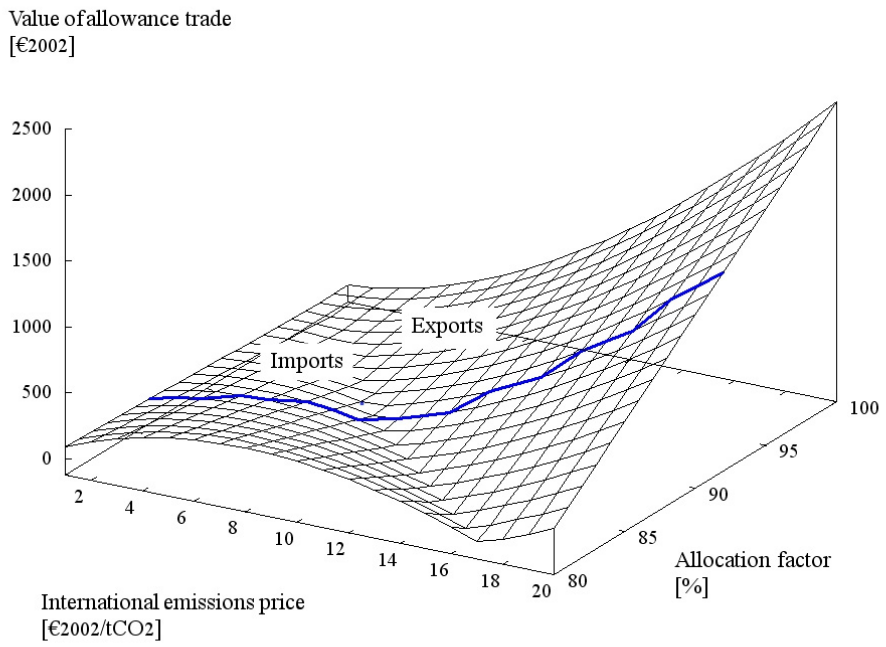
excess costs, the change in compliance costs between *DIR* and *NDIR* sectors vis-à-vis the efficient solution is dramatic: *NDIR* sectors have to bear a burden of 1578.7 mill. €$_{2002}$, whereas *DIR* sectors achieve profits of 325.3 mill. €$_{2002}$.

The graphical exposition does not only visualize the excess costs and distributional impacts of inefficient choices for λ, it also illustrates the impending excess costs of segmented regulation due to the lack of central planner information: Differences between various points on the minimum cost line provide information on the excess costs of segmented carbon regulation when the national regulatory assumes the wrong international emissions price for pursued efficient partitioning of the national emissions budget. If, e.g., the national regulator expects an international CO_2 price at 10 € per ton of CO_2 and the real market price should materialize at 15€ per ton of CO_2, the implied excess costs amount to 21.3 mill. €$_{2002}$ (i.e., a cost premium of 13.4% above the true cost minimum).

4.5. Conclusion

From 1 January 2005 onwards the European Union has launched the first large-scale international emissions trading program. The EU Emissions Trading Scheme

FIGURE 4.4.4. Value of allowance trade (mill. 2002)



(EU-ETS) in principle has the opportunity to advance the role of market-based policies in environmental regulation and to form the basis for future European and international climate policies.

This chapter has highlighted a central pitfall of the current EU-ETS that could seriously limit its efficiency thereby weakening arguments for a market-based regulation course. The EU-ETS under the European Burden Sharing Agreement implies a segmented regulation scheme as sectors of domestic economies that are not covered by the emissions trading scheme require complementary emission regulation. Under a segmented scheme, the domestic regulator must have perfect information on the international emissions price as well as the (marginal) abatement cost curves across all domestic emission sources that are not included in the international emissions trading scheme in order to implement the single cost-minimizing abatement policy. Therefore, the current EU policy design for emission abatement discards a central element of market-based regulation, i.e. decentralized markets that autonomously achieve efficient use of scarce resources.

The pitfall of segmented regulation becomes particularly policy-relevant when one accounts for distributional constraints or lobbying activities for the amount of

grandfathered emissions allowances: Under segmented regulation, the efficient partitioning of the national emission budget provides an upper bound to the amount of emission allowances that can be grandfathered lump-sum to EU-ETS sectors without efficiency trade-off. In policy practice, allocation of free emission allowances to EU-ETS sectors may exceed the efficient upper bound in order to achieve political feasibility.

The numerical simulations based on empirical data for Germany illustrate the relevance of political economy considerations: The quantitative results show that the choice of efficient allocation factors is rather insensitive with respect to sensible assumptions on the international emissions price. This, in turn, means that the actual implementation of the German NAP with generous allocation of free emission allowances to emission-intensive industries should be rather explained by lobbying efforts of these industries than by expectation errors of the regulation authorities on uncertain international emissions prices.

The deficiency of current EU emission regulation, however, should not be construed as an argument against emissions trading or market-based instruments per se. The informational requirements of achieving an efficient solution under the EU-ETS arise from segmented regulation that creates separate emission markets. Segmentation of carbon emission regulation – as implied by the current EU-ETS under the EU Burden Sharing Agreement – is also likely to foster lobbying success of emission-intensive industries that are covered by the trading scheme at the expense of sectors outside the EU-ETS: As a matter of fact, emission-intensive industries in Germany were able to negotiate generous allocation of free emissions allowances with the national authorities whereas the sectors outside the EU-ETS had not been involved in the implicit burden sharing debate.

As a consequence, the EU-ETS should be expanded in the future to include all domestic sectors of EU economies thereby creating a single emission market. A comprehensive market-based trading regime will avoid the information problems of the regulator and is likely to reduce lobbying power of emission-intensive industries as burden shifting between different affected parties becomes more explicit.

CHAPTER 5

Alternative Strategies for Promoting Renewable Energy in EU Electricity Markets

5.1. Introduction

Political support for renewable energy technologies has a history of over 30 years within the EU. Motives as well as favored policies and measures to promote the market penetration of electricity from renewable energy sources (RES-E) have differed largely.

The first major impetus for the promotion of renewable energies can be traced back to the oil crises in the early 70s and 80s: Renewable energy from EU-internal sources was seen as an appropriate long-term substitution to exhaustible and mainly imported fossil fuels in order to secure EU-wide energy supply. A second central push is linked to the negative environmental externalities associated with the combustion of fossil fuels. In the mid 80s environmental concerns were mainly related to local and regional problems of air quality and acidification. These problems were handled largely through end-of-pipe technologies for electricity production from coal but also provided additional political support to renewable energies. Much more substantial had been and still are the implications of anthropogenic carbon emissions from fossil fuel combustion for global warming turning out to be the most challenging problem for environmental policy over the next decades and maybe even centuries. Carbon-free energy supply technologies are considered as the central response to cope with the problem of global warming in the long run. More recently – and complementary to energy security as well as environmental objectives – "green" policy makers push renewable energy in order to create new jobs and strengthen competitiveness of the EU economy in terms of lead technologies that might be promoted on world markets.

As to policy measures for the promotion of renewable energies there had been a shift – as more generally in environmental policy design – from command-and-control policies to market-based instruments such as taxes, subsidies, and tradable quotas. In the context of renewable energy promotion, taxation of energy in many EU countries meanwhile comes along with tax breaks or tax exemptions to renewable energy working as implicit subsidies to correct relative prices with respect to energy security and environmental targets. In addition, direct subsidies for renewable energy are warranted – typically differentiated by the type of green energy, i.e.,

hydropower, wind, biomass, solar, etc. A relatively new strand of policy regulation is the use of tradable green quotas where energy suppliers are required to produce a certain share of energy services from renewable energy but are flexible to trade these shares between each other in order to exploit potential difference in specific compliance costs.

In this chapter, the economic consequences of promoting the increased market penetration of electricity produced from renewable energy sources within the EU are investigated. RES-E promotion strategies have been studied extensively. Based on theoretical efficiency considerations, Menanteau et al. (2003) highlight the potential benefits – in terms of efficiency – of tradable green certificates vs. feed-in tariff or tendering systems (see also Finon & Menanteau 2003 and Kühn 2000). Voogt et al. (2000) and Uyterlinde et al. (2003) confirm these benefits based on applied models of the European green electricity market, nevertheless, Uyterlinde et al. (2003) allude to the potential risk and transaction costs connected with tradable green certificates. Jensen & Skytte (2002) point up important interactions of green certificates and electricity markets based on a stylized model and find potential difficulties in the manageability of quota obligation schemes when a regulator has additional policy targets than just greening the electricity (for interactions with emission allowance trading see also Morthorst 2000a and 2001 as well as Madlener & Stangl 2000).

Our analysis complements recent studies by fully integrating green electricity into a liberalized European electricity market where firms compete for market shares in different regions and market segments. We focus on two alternative policy instruments which are central to the EU strategy for the promotion of RES-E: Feed-in tariffs, i.e. direct subsidies to electricity production from renewable energy, on the one hand; and quota obligation systems with tradable green certificates (TGC) on the other hand. Based on large-scale partial equilibrium model of the EU electricity market calibrated to empirical data, we find that differentiated feed-in tariffs (the most commonly applied to date) incur substantial excess cost compared to an EU-wide tradable green quota. In broader terms, this excess cost can be interpreted as the price tag that policy makers have to attach to other objectives than the pure greening of electricity. Such objectives might include pursuits to reduce additional market failures associated with market barriers to specific infant renewable technologies, knowledge spillovers from private R&D or aspects of strategic and regional policies.

The remainder of this chapter is as follows: Section 5.2 provides a brief summary of the EU policy initiatives for the promotion of renewable energy in electricity production and sketches obstacles to efficient RES-E promotion. Section 5.3 lays out the basic efficiency considerations for the design of promotion strategies. Section 5.4 describes the analytical framework and the database underlying our numerical

TABLE 5.2.1. Indicative RES-E targets in 2010 and national support schemes to achieve them

	RES-E target [in %]	National support schemes		
		Feed-in tariffs	Quota obligations / TGC	Other
Austria	78.1	yes		
Belgium	6.0		yes	Minimum price for renewables
Denmark	29.0	yes		Tender schemes for offshore wind
Finland	31.3			Tax exemptions and investment incentives
France	21.0	yes		
Germany	12.5	yes		
Greece	20.1	yes		Investment incentives
Ireland	13.2	yes (announced)		Tender schemes
Italy	25.0	yes (for PV)	yes	
Luxembourg	5.7	yes		
Netherlands	9.0	yes		
Portugal	39.0	yes		Investment incentives
Spain	29.4	yes		
Sweden	60.0		yes	
United Kingdom	10.0		yes	
European Union	*21.7*			

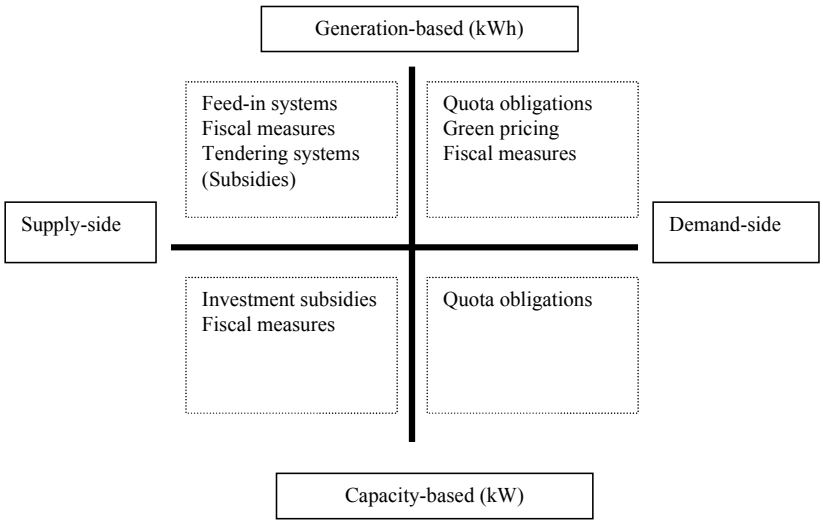
Source: EU 2005

analysis. Section 5.5 presents illustrative policy scenarios and discusses the results. Section 5.6 concludes.

5.2. Background: RES-E Promotion in Europe

The Directive on the Promotion of Electricity produced from Renewable Energy Sources (RES-E) in the internal electricity market, is the main legislation affecting RES-E at the EU level (European Commission 2001*a*). The Directive aims at facilitating a significant increase in RES-E production within the EU. The indicative objective of the Directive is a doubling of the share of renewable energy in Europe's gross energy consumption from approximately 6% in 1997 to 12% in 2010. The share of 12% of renewable energy in gross energy consumption has been translated into a specific share for consumption of RES-E, i.e. the consumption of electricity from renewable energy sources in final EU electricity consumption, of 22.1% in 2010 (as compared to 14% in 1997). This objective was set in the 1997 White Paper on renewable energy sources (European Commission 1997) and endorsed by the Energy Council in May 1998. The Directive also establishes indicative targets for the penetration of RES-E in each Member State (see column "RES-E target" in Table 5.2.1).

FIGURE 5.2.1. Classification of RES-E Policy Support Mechanisms



Source: Uytelinde et al. 2003

To date, Member States employ a myriad of support schemes. Some of them stimulate the supply of renewable electricity, while others directly affect the demand. Furthermore, support schemes can be distinguished according to the supported activity, i.e., either capacity installation is promoted or the generation of green electricity. Figure 5.2.1 classifies the support schemes regarding the dimension of support. A recent survey published by the European Commission (European Commission 2005*e*) shows that feed-in tariffs are the most common promotion measure (in seven out of the EU-15 Member States) followed by quota obligation systems with tradable green certificates (TGC) (in four out of the EU-15 Member States). In contrast, tender schemes, investment subsidies and fiscal measures only play a minor role (see also Table 5.2.1).

From an economist's point of view the promotion of RES-E – as well as other regulatory policies – must be justified by market failures, i.e. the inability of markets to capture all the social benefits and social costs associated with economic activities. These failures, typically referred to as externalities, require mandatory regulations for internalization in order to assure more efficient use of scarce resources. For policy making the identification of appropriate instruments to cure market failures is crucial. In simplistic terms, each externality can be addressed by one targeted policy instrument such as taxes, subsidies, definition of property rights, liability rules, etc. However, promotion of renewable energies obviously can contribute to ameliorate simultaneously various discrete externalities and serve strategic individual interests (such as the market penetration of specific infant renewable technologies, the creation of knowledge spillovers from private R&D or the consideration of strategic aspects of industrial and regional policies).

There are various obstacles to the design and implementation of efficient RES-E promotion policies. Obviously, there is imperfect information or uncertainty which can affect the appropriate choice of instruments. Assuming an exogenous target such as a minimum share of RES-E, a quota obligation will assure effectiveness whereas a feed-in tariff system would require to have perfect information on all technologies, their costs and potentials, price developments on the electricity market, consumer preferences, etc.[1] But feed-in tariffs allow for a differentiated treatment of alternative renewable technologies taking into account other objectives than just the greenness of the electricity system. In policy practice, feed-in tariff systems stand out for a large discrimination across different green technologies.[2] The consequence is that less efficient more costly technologies such as solar or geothermic energy are much more subsidized than more competitive renewables such as hydro- or windpower. If the policy objective was simply the greenness of energy production, such a differentiated feed-in tariff system is likely to create huge excess costs which may be interpreted as an additional premium that policy makers have to attach to other objectives than the pure greening of electricity.

In contrast, quota obligation systems with tradable green certificates (TGC) make use of decentralized market mechanisms in order to meet overall national (or EU-wide) targets in an efficient way.[3] The quota system implicitly assigns a scarcity price to the "greenness" of electricity (or *green value*) as an explicit policy objective. There is no differentiation between alternative renewable energies and the market will sort out which type and quantity of renewable energy will serve most efficiently the policy objective of green electricity. However, green certificates may pose a higher risk for investors and long-term, currently high cost technologies are not easily developed under such schemes.

On a supra-national level not only the choice of appropriate promotion schemes affects the efficiency but also the geographic scope. E.g. an EU-wide market for TGCs would allow for an increased regional flexibility and inevitably cut costs for meeting the overall EU target. Against the background of the development of a single European market for electricity – stipulated by the liberalization Directive (EU 2003) – the Renewable Energy Directive also provides a framework for the future harmonization of renewable energy support schemes within in the EU.[4] However, in

[1]Against this background it is not surprising, that – according to recent studies (e.g. Uyterlinde et al. 2003) most of the Member States who employ feed-in tariff systems will not reach their indicative targets until 2010.

[2]As an example: The German Renewable Energy Sources Act defines a premium for solar electricity which is roughly four times higher than for electricity produced from biomass (Deutscher Bundestag 2001).

[3]Such systems distinguish between the commodity (electricity) and the service of this commodity (the environmental friendliness or "greenness") and – in case of a tradable certificate system – create a secondary market for the service. The commodity is sold at respective power-market prices and the corresponding *greenness* of electricity can either be sold or purchased on the certificate market.

[4]The Directive announced a decision on a community framework for support schemes by the end of 2005, with a following transition period of at least 7 years where existing support schemes could be maintained for already installed capacity.

its communication from 7 December 2005 the European Commission concluded that at this stage a harmonized European system would not be appropriate (European Commission 2005*e*). The main reason against an EU-wide feed-in tariff system is the information problem as described above which would be even more challenging on a wider EU-level. A common TGC market is considered as problematic since uncertainties in the future development of the green value may lead to potentially high investment risk, and thus hinder the development of RES-E penetration in the future (European Commission 2005*e*, European Commission 2005*d*).

5.3. Analytical Framework

We set up a stylized partial equilibrium model of the electricity market that demonstrates the efficiency effects of the two most common RES-E promotion policies in Europe. i.e. feed-in tariff systems and quota obligations. Let a (competitive) electricity market be determined by the electricity price p, an isoelastic, nonlinear demand function $D(p) = \beta \cdot p^{-\sigma}$ with σ as the price elasticity of demand and β as the demand function share coefficient.[5]

Three different technologies are available – a conventional thermal technology c and two renewables technologies $r1$ and $r2$. They can be used to supply electricity at activity levels x_c, x_{r1} and x_{r2}.[6] Production costs are depicted by the cost-function $C(x_c, x_{r1}, x_{r2})$ where marginal costs of the non-renewable technology c are the lowest followed by $r1$ and $r2$, i.e. $0 \leq MC(x_c) \leq MC(x_{r1}) \leq MC(x_{r2}) \leq +\infty$.[7] Initially RES-E technologies are inactive (i.e. $MC(x_{r1}) > p$ and $MC(x_{r2}) > p$).

A central planner now seeks a market allocation that maximizes economic surplus – measured as the sum of producer and consumer surplus – subject to a minimum activity level of RES-E technologies. Three policy options are possible to achieve this goal: (i) a quota obligation system, (ii) a feed-in tariff system with a uniform feed-in tariff, and (iii) a feed-in tariff system with technology-specific or diversified tariffs.

Under a quota obligation system an explicit lower bound is imposed on the activity levels of $r1$ and $r2$, such that:

$$(x_{r1} + x_{r2}) \geq rq \cdot (x_c + x_{r1} + x_{r1}) \tag{5.3.1}$$

.

Economic surplus then is maximized by:[8]

[5] Where $\beta = D_0 \cdot p_0^{\sigma}$ with D_0 as the reference demand and p_0 as the reference demand.
[6] For the sake of simplicity, we omit capacity limits.
[7] And where $MC'(x_c) = MC'(x_{r1}) = MC'(x_{r2}) = 0$
[8] With $= \epsilon \frac{\sigma - 1}{\sigma}$ and $\varphi = \frac{1}{1+\sigma} \beta^{1/\sigma}$.

$$\text{maximize:} \quad \varphi D^{\epsilon} - C(x_c, x_{r1}, x_{r2}) \tag{5.3.2}$$

$$s.t. \quad (x_c + x_{r1} + x_{r1}) \geq D \tag{5.3.3}$$

$$(x_{r1} + x_{r2}) \geq rq \cdot (x_c + x_{r1} + x_{r1}) \tag{5.3.4}$$

$$x_c \geq 0,\ x_{r1} \geq 0,\ x_{r1} \geq 0,\ D \geq 0 \tag{5.3.5}$$

The nonlinear optimization problem can be interpreted as a market equilibrium problem where prices and quantities are defined using duality theory. With p and λ as the dual values on the market clearance condition and the quota obligation, the primal-dual solution of this problem translates into the market equilibrium problem:[9]

$$\begin{aligned} 0 \leq x_c, &\quad \perp \quad MC(x_c) + rq \cdot \lambda - p \geq 0 \\ 0 \leq x_{r1}, &\quad \perp \quad MC(x_{r1}) + rq \cdot \lambda - \lambda - p \geq 0 \\ 0 \leq x_{r2}, &\quad \perp \quad MC(x_{r2}) + rq \cdot \lambda - \lambda - p \geq 0 \\ 0 \leq p, &\quad \perp \quad (x_c + x_{r1} + x_{r1}) \geq \beta \cdot p^{-\sigma} \\ 0 \leq \lambda, &\quad \perp \quad x_{r1} + x_{r2} \geq rq \cdot (x_c + x_{r1} + x_{r1}) \end{aligned} \tag{5.3.6}$$

We mimic a feed-in tariff scheme by (i) granting a (per-unit) subsidy λ to RES-E production that ensures the minimum share of renewables in total electricity demand, and by (ii) imposing an ad-valorem tax ψ that allocates the overall magnitude of RES-E promotion to the customers. We substitute constraint (5.3.4) by:

$$x_{r1} + x_{r2} \geq rq \cdot \beta \cdot [p \cdot (1 + \psi)]^{-\sigma} \tag{5.3.7}$$

and add

$$p \cdot \psi \cdot \beta \cdot [p \cdot (1 + \psi)]^{-\sigma} \geq \lambda \cdot (x_{r1} + x_{r2}) \tag{5.3.8}$$

.

as an additional constraint.

Since we allow for technology-specific promotion, we transform the subsidy level λ into technology-specific premiums through the use of adjustment factors a_{r1} and a_{r2}. By letting $a_{r1} = 1$ and $a_{r2} = 1$ uniform feed-in tariffs are applied.

[9] Where the orthogonality symbol ($\perp$) expresses that the inner product of a variable and a function must be zero, e.g. when $0 \leq x_c \perp MC(x_c) - p \geq 0$ also $x_c\,(MC(x_c) - p) = 0$ must hold.

The central planner's maximization problem then translates into the market equilibrium problem:

$$
\begin{aligned}
0 \leq x_c &\perp MC(x_c) - p \geq 0 \\
0 \leq x_{r1} &\perp MC(x_{r1}) - a_{r1} \cdot \lambda - p \geq 0 \\
0 \leq x_{r2} &\perp MC(x_{r2}) - a_{r2} \cdot \lambda - p \geq 0 \\
0 \leq p &\perp (x_c + x_{r1} + x_{r1}) \geq \beta \cdot [p \cdot (1+\psi)]^{-\sigma} \\
0 \leq \lambda &\perp x_{r1} + x_{r2} \geq rq \cdot \beta \cdot [p \cdot (1+\psi)]^{-\sigma} \\
0 \leq \psi &\perp p \cdot \psi \cdot \beta \cdot [p \cdot (1+\psi)]^{-\sigma} \geq \lambda \cdot (x_{r1} + x_{r2})
\end{aligned}
\tag{5.3.9}
$$

Figure 5.3.1 displays our theoretical considerations. Figure 5.3.1 a) shows the effects of a feed-in tariff scheme with uniform premiums. When we assume perfectly competitive markets and full information the feed-in tariff system with uniform premiums is equivalent to a quota obligation scheme with trade in TGCs. In our stylized example only technology $r1$ is used to meet the target. The subsidy level λ^F for $r1$ under a feed-in tariff system equals the subsidy level λ^Q when we impose a quota obligation. Under both regulations the total RES-E production level x_r (i.e. $x_{r1} + x_{r2}$) accounts for the desired share of renewables in production respectively consumption. In case of a quota system, the higher costs of RES-E production (measured as $\lambda^Q \cdot x_r$) is distributed across all active technologies such that $\lambda^Q \cdot x_r = rq \cdot \lambda^Q \cdot x^{Q*}$. In other words, marginal costs of electricity supply rise by $rq \cdot \lambda^Q$. Clearly, higher costs of supply inevitably lead to higher electricity prices and, thus, to a lower electricity demand – in our simple example the price rises from p_0^* to $p_0^* + rq \cdot \lambda^Q = p^{Q*}$ and demand drops from x_0^* to x^{Q*}.

Under a feed-in tariff scheme the regulator re-finances the total magnitude of RES-E promotion or subsidies (measured as $\lambda^F \cdot x_r$) via an ad-valorem tax on the electricity consumption. The electricity tax ψ (in our example given as:[10] $\psi = \lambda^F \cdot rq/p_0^*$) increases the electricity price by $\psi \cdot p_0^* = \lambda^F \cdot rq$ to p^{F*} and, consequently decreases electricity demand from x_0^* to x^{F*}. Under both regulations the loss in economic surplus amounts to the shaded area *abc*.

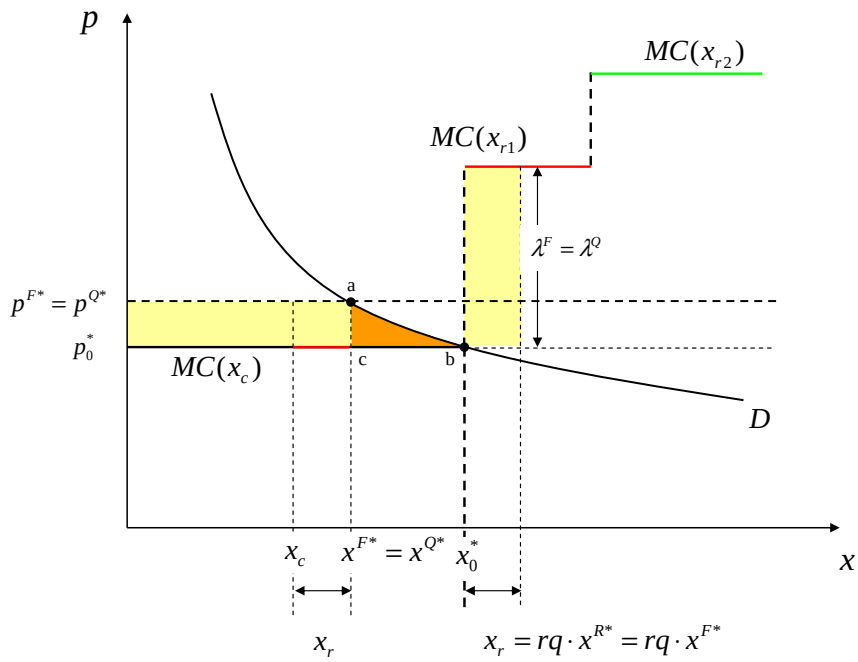
The results change when we allow for technology specific premiums (see Figure 5.3.1 b). Let us assume that the more costly technology $r2$ receives 110% and technology $r1$ only 50% of the total subsidies (i.e. $a_{r1} = 0.5$ and $a_{r2} = 1.1$).[11] Though higher than in the cases before, the shadow price λ^{AF} on the renewables constraint does not facilitate the deployment of – the initially cheaper – technology $r1$. Instead, technology $r2$ is solely used to meet the given RES-E target. Technology $r2$ now

[10] Derived from: $\psi = \frac{\lambda^F \cdot (x_{r1}+x_{r2})}{p_0^* \cdot D(p_0^*+(1\cdot\psi))}$ when we assume market clearance such that $D(p_0^*+(1\cdot\psi)) = (x_c + x_{r1} + x_{r2})$.

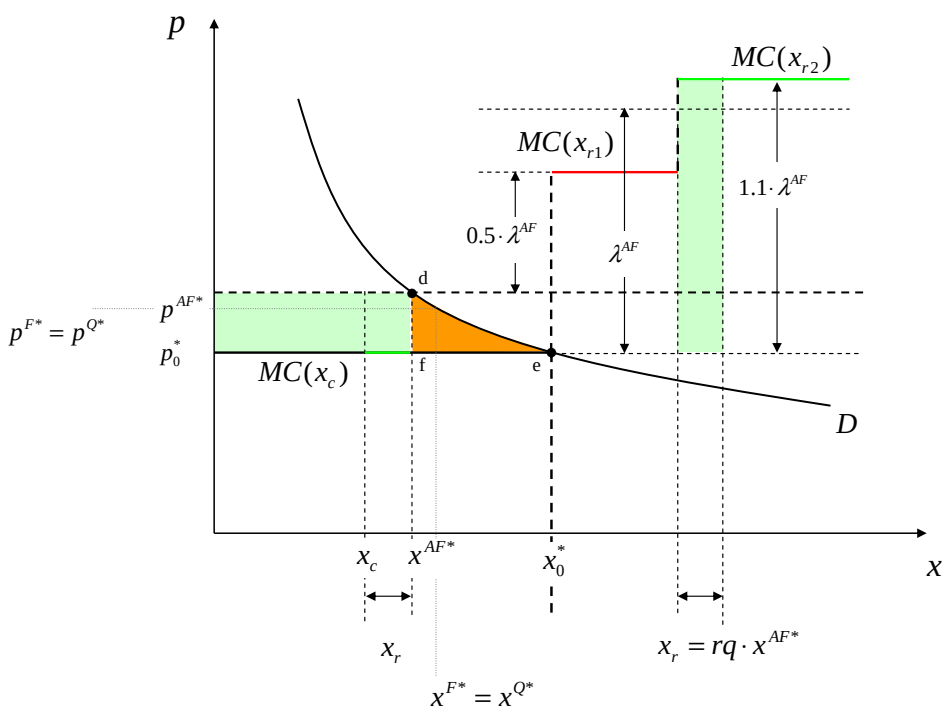
[11] Note that in this case the feed-in tariff for $r2$ effectively is 2.2 times higher than the tariff for technology $r1$.

FIGURE 5.3.1. Effects of feed-in systems and quota obligation

a) Feed-in tariff system with uniform tariff and quota obligation



b) Feed-in tariff system with technology-specific (adjusted) tariffs



receives an overall subsidy of $1.1 \cdot \lambda \cdot x_r$ which is considerably higher than in the case of a uniform tariff and, accordingly, leads to a higher electricity tax. We see that the adjustment leads to higher prices $p^{AF*} \geq p^{F*}$ and to lower electricity demand $x^{AF*} \geq x^{F*}$ as compared to uniform premiums. Consequently, the loss in economic surplus – depicted by the shaded area def in Figure 5.3.1 b – is also larger.

5.4. Numerical Framework

5.4.1. Model Summary. Our numerical analysis of different RES-E promotion strategies is based on a (static) large-scale partial equilibrium model of the European electricity sectors where a set of strategically acting firms competes for market shares on regional markets. In each region firms own a fixed stock of generation capacity that consists of a discrete set of different power plants characterized by specific generation technologies. Electricity markets in each of the regions are further segmented into markets for electricity supplied to residential and industrial customers. In addition, industrial customers face differentiated pricing over the load-curve which accommodates differentiated electricity products and, hence, mimics to some extent the existence of a spot market for electricity where industrial customers may buy electricity in the short term. In contrast, residential customers – who are usually supplied on basis of long-term power purchase contracts – pay a flat fee for electricity delivered at any point of the load-curve. Notwithstanding, residential customers demand electricity in base- and peak-load. For the sake of simplicity we introduce two load segments – one for demand in base-load and one for peak-load demand. The resulting regional demand segments are characterized by iso-elastic demand functions.

Firms supply domestic demand either by using their domestic generation capacities or by importing electricity from other regions as well as they might supply electricity to other regions. Cross-border electricity trade is thereby limited by the availability and the capacity constraints of inter-regional exchange points. Transmission and distribution of electricity is priced with (exogenous) grid charges. Costs for inter-regional electricity exchange also account for the scarcity of exchange capacities.

Electricity production and supply are subject to different technical and political constraints. Plant-specific capacity limits impose an upper bound on the electricity production and supply of each firm. Furthermore, suppliers are obliged to assure a certain level of reserve capacity (determined as a fraction of total electricity supply in a region). Suppliers may either be constrained by regional maximum emission (CO_2) levels or by emission taxes. Electricity markets are subject to minimum targets for the deployment of RES-E capacities and respective policies to reach them. RES-E supply options are captured by regional cost-potential curves. Feed-in tariff systems and quota obligations have been implemented as described in the previous section. In addition, we introduce a (secondary) international market for tradable green certificates. Regions can meet their RES-E target either by domestic

production or by importing TGCs. On the other hand, regions can produce more RES-E than they are obliged to and become exporters of TGCs.

Numerically, our model is formulated as a mixed complementarity problem (MCP). The algebraic formulation is implemented in GAMS (Brooke, Kendrick and Meeraus 1987) using PATH (Dirkse and Ferris 1995) as a solver. The algebraic description of the model can be found in the Appendix.

5.4.2. Parametrization. We parametrized the model for 23 regions (23 EU countries[12] representing the enlarged EU-25 without Malta and Cyprus). Regional reference electricity demand was obtained from recent UCTE (2005), NORDEL (2005) and IEA (2005) statistics. In order to facilitate the disaggregation of the overall regional demand figures into residential and industrial demand we used detailed energy balance data from IEA/OECD (2004). In addition, we employed detailed statistics on hourly load values provided by international associations (UCTE, NORDEL) and and several national grid operators in order to determine the load-specific demand for both demand segments in each region. Regional electricity prices were obtained from the 4th Benchmarking Report of the European Commission (European Commission 2005*a*). For regional demand and price figures see Appendix B.1

The supply side of the model covers over 1100 conventional thermal power plants. Each of the plants is owned by one of over 220 firms. Information on the installed capacity of each plant and on the ownership structure was obtained from an extensive power plant database that covers all 23 regions of the model (Meller *et al.* 2005). Technical and economic information on the power plants stem from IKARUS (KFA 1994), a comprehensive data base that has been developed for the German Ministry for Technology and Research. The database provides data on installation costs, operating and maintenance costs and the thermal efficiencies of the power plants. We carefully mapped the technologies provided in the power-plant database to a set of 11 selected IKARUS technologies (covering fossil fuel-fired and nuclear plants) and used a dynamic investment calculus in order to obtain technology-specific electricity production costs. Fuel prices and data on personnel costs needed for the calculation were obtained from recent European statistics (European Commission 2005*b*, European Commission 2005*c*, Eurostat 2005). Technology-specific carbon emission-coefficients also stem from IKARUS. The operating costs of conventional power plants are presented in Appendix B.1.

We introduced a set of 16 RES-E technologies. Cost and potential data stem from the ADMIRE-REBUS model, a large scale partial equilibrium model of the European renewable energy system (Uyterlinde *et al.* 2003, de Noord *et al.* 2004). Each renewables technology is further sub-divided into "technology-bands" in order

[12]Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, the Netherlands and the United Kingdom.

TABLE 5.5.1. Summary of policy scenarios

	Feed-in tariff schemes		Quota systems	
	FEED_D	*FEED_H*	*QUOTA_R*	*QUOTA_EU*
Promotion scheme	Regional and technology-specific feed-in tariffs	Harmonized feed-in tariff in all regions	Regional quota	Regional quotas and trade in TGCs
Financing of promotion	Through electricity tax	Through electricity tax	Through the electricity market	Through the electricity market and the TGC market
Harmonized green value	No	Yes (national/regional)	Yes (national/regional)	Yes (EU-wide)
Trade in TGC's	No	No	No	Yes

to account for different site qualities (e.g. different wind speed) and potentials or availability of renewable fuels (e.g. wood or other biomass). We attributed the available technology-specific potentials in each region to the firms according to their shares of conventional capacity in a region's total generation capacity. Information on inter-regional electricity trade and exchange capacity limits were obtained from recent statistics of system operators and associations (European Transmission System Operators – ETSO 2001*a*, European Transmission System Operators – ETSO 2001*b*, NORDEL 2005*a*, NORDEL 2005*b*, UCTE 2005).

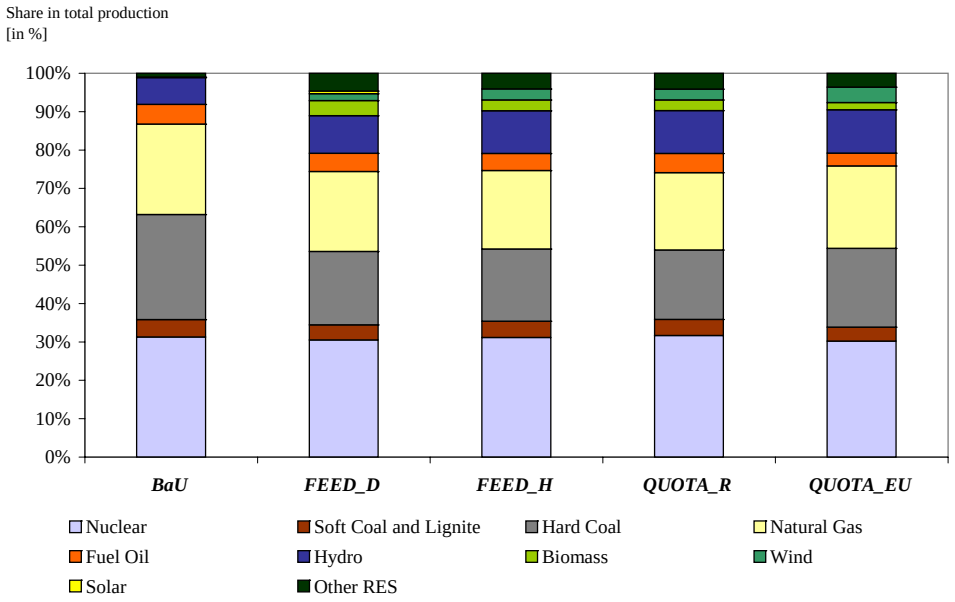
5.5. Policy Scenarios and Results

5.5.1. Policy Scenarios. We investigate the economic consequences of promoting the increased market penetration of RES-E along a business as usual development (scenario *BaU*) and four illustrative policy scenarios *FEED_D*, *FEED_H*, *QUOTA_R* and *QUOTA_EU*. Scenario *BaU* reflects an extreme situation where no political support is given to RES-E production.

Scenario *FEED_D* mimics the situation where Member States employ diversified support schemes for RES-E. Different technologies receive support at different levels. The induced diversity may imply an inefficient distribution of the overall support level of RES-E across different technologies. Member States achieve their indicative targets but possibly at high costs. This scenario reflects the present situation in most of the EU-15 Member States. Scenario *FEED_H* reflects a regulation where Member States employ harmonized feed-in tariffs in their region. In other words: Each technology receives the same premium. This tariff reflects the regional scarcity of RES-E options. According to the differences in regional potentials and costs of RES-E production these levels will vary across the EU Member States. Subsidization and re-financing is the same as in Scenario *FEED_D*.

In Scenario *QUOTA_R* Member States achieve their indicative RES-E targets by a quota system which obliges the supply side to ensure the regional targets. Firms

FIGURE 5.5.1. Technology mix of European electricity supply

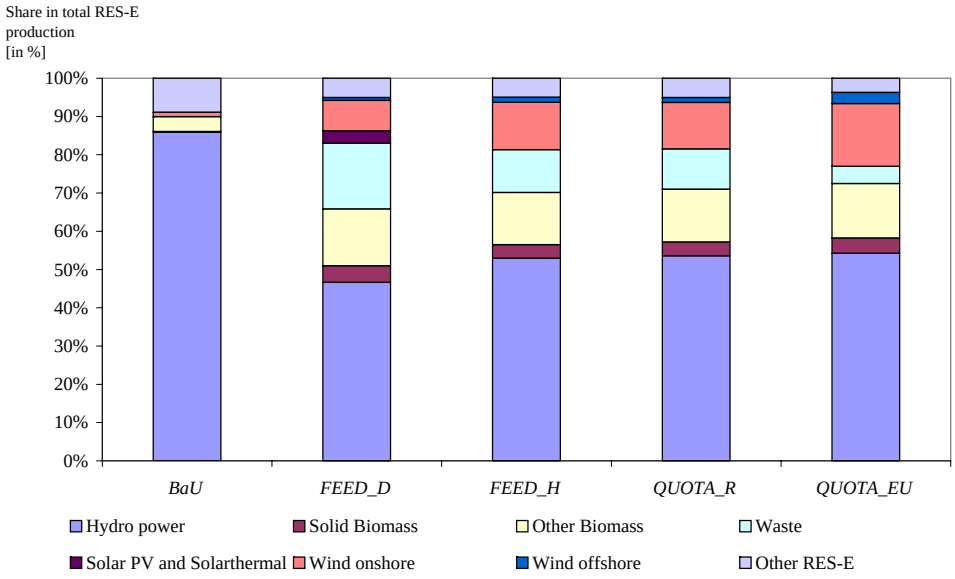


in the Member States produce the needed level of RES-E according to the national targets. The induced increase in the costs of electricity supply is transferred to the customers via potentially higher electricity prices. The scenario leads to a harmonized national/regional certificate price or green value.The results of this scenario should not considerably deviate from those of Scenario *FEED_H*. Notwithstanding, differences may occur due to cross-border electricity trade or market power of suppliers.

Finally, in Scenario *QUOTA_EU* a completely harmonized situation is simulated by introducing a common support framework (and level of support) across Europe. As in the case of regional quotas, market parties are obliged to meet national targets but, in addition, a market for tradable green certificates is introduced. Regional targets can either be met by production of RES-E or by importing TGCs. In addition, certificates may be sold at the market if domestic costs are lower than the international certificate price. Hence, this scenario provides a harmonized value of green electricity for all countries across Europe. The quota system for renewable electricity will ensure that the EU reaches its overall RES-E target of approximately 22% in a cost-efficient way.

5.5.2. Electricity Production and Technology Mix. Figure 5.5.1 displays the changes in the European electricity supply system. The administered market penetration of green electricity production inevitably affects the use of conventional thermal production capacity. Additional RES-E production mainly influences the use of coal (hard coal as well as soft coal and lignite) and fuel oil. In each of the scenarios the share of coal in total production of EU-15 countries

FIGURE 5.5.2. Technology mix of European green electricity supply



decreases by approximately 10% vs. *BaU*. Clearly, green production substitutes the most expensive technologies at first. Due to additional electricity taxes under *FEED_D* and *FEED_R* and higher overall production costs under *QUOTA_R* or *QUOTA_EU* expensive technologies become unprofitable. Nevertheless, nuclear capacities and coal plants still provide more than 50% of the total electricity supplied to customers.

Different promotion schemes explicitly influence the deployment of RES-E technologies. Figure 5.5.2 shows the shares of green technologies in total green electricity production (detailed regional RES-E production is given in B.2). In the *BaU* scenario hydropower accounts for over 85% of total RES-E production. Only a small fraction of electricity is produced from wind, the remaining 13% are produced from biomass and waste. When technology-specific feed-in tariffs are employed in scenario *FEED_D* hydropower still accounts for the major share of green production (45%), however, the RES-E-mix exhibits much more technological diversity. Biomass and waste constitute roughly 36% of green production. Even relatively costly solar potentials are utilized (approximately 3%).

Under *FEED_H* and *QUOTA_R* the diversity prevails, but especially windpower (onshore) profits from uniform regional green values at the expense of waste and biomass. This indicates a regional over-funding of biomass and waste under differentiated feed-in tariffs, whereas windpower receives insufficient support according to its relative profitability. Solar potentials are no longer employed as regional green values are not high enough for solar capacities to break even.

The described trend continues, when EU-15 countries are subject to a harmonized quota system with TGC trade. The equalization of marginal costs of RES-E production across all participating regions ensures that the most profitable potentials are used at first. Scenario *QUOTA_EU* facilitates the additional use of wind potentials in France, Greece (onshore) and the Nordic region (onshore and offshore) – but now almost solely at the expense of waste.

5.5.3. Impacts on the electricity markets. Table 5.5.2 shows the effects of RES-E promotion on the development of industrial (base- and peak-load) and residential electricity prices as well as the total electricity consumption in the regions. An administered increase of green production implicitly causes higher electricity prices. Not only primarily unprofitable capacities are phased-in; these capacities also substitute initially more profitable technologies. Consequently, most regions are subject to significantly increasing electricity prices. Under scenario *FEED_D* industrial base-load prices rise up to 17.3% (Nordic market) above their *BaU* level. Peak-load prices and prices for residential customers increase up to 28.9% and 19.5% vis-à-vis *BaU* in Spain and Portugal. Accordingly, the increase in electricity prices has a negative impact on electricity demand. Total electricity consumption decreases by 7.4%. Inter-regional electricity trade to some extent compensates these effects. Countries that are not subject to RES-E regulation may even face decreasing electricity prices. A switch to uniform feed-in tariffs (*FEED_H*) mitigates the decrease in electricity consumption on the EU-wide level (-6.2% vs. *BaU*). The increase in electricity prices is less pronounced than under *FFED_D*.

Table 5.5.3 displays the results of the four scenarios regarding green values λ (or the per-unit support level for renewables), induced electricity taxes ψ, the direct costs of RES-E promotion ($\lambda \cdot x_r$), and the efficiency costs (measured as the loss in economic surplus). Obviously, regional green values differ in each of the scenarios where inter-regional TGC trade is not possible, thereby reflecting each region's scarcity of RES-E production facilities. E.g. in scenario *FEED_A* green values range from 0 €/MWh in Greece to 108.4 €/MWh in Spain and Portugal. In comparison to *BaU* the Greek RES-E target does not induce an increase in the magnitude of RES-E production, although the share of RES-E production in the total electricity supply increases. Greece reaches its target by a slight decrease in electricity demand. The needed total support for renewables within the EU-15 amounts to approximately 19.6 bn.€ (see column "Direct costs" in Table 5.5.3). Re-financing these costs significantly affects consumer's electricity bills. In case of Scenario *FEED_D* the ad-valorem tax ranges from 2.8% in the BeNeLux region to 40.2% in Spain and Portugal – or to put it differently: in the latter case 40.2% of the total expenditures for electricity are used to re-finance RES-E promotion. But the magnitude of this share is not solely influenced by the total support for renewables in a region. The ad-valorem tax depends on the electricity price, the per-unit support paid to green electricity producers and the indicative RES-E target in

TABLE 5.5.2. Changes in electricity prices and electricity demand

	Changes in electricity price			Change in demand	Changes in electricity price			Change in demand
	Industrial		Residential	Total	Industrial		Residential	Total
	Base-load	Peak-load			Base-load	Peak-load		
	[in % vs. BaU]							
	FEED_D				*FEED_H*			
EEA*	-0.1	-1.1	0.0	0.2	0.0	-1.0	0.1	0.1
Austria	15.8	22.1	18.7	-16.5	14.2	20.0	16.9	-15.1
Czech Republic	0.0	-0.2	-0.5	0.2	0.2	-0.3	-0.5	0.1
France	8.7	7.2	7.2	-7.6	6.7	4.9	4.9	-5.5
Greece	0.5	-0.8	0.7	-0.3	0.5	-0.8	0.7	-0.3
Italy	8.3	10.7	8.7	-8.9	8.2	10.7	8.7	-8.9
Poland	0.5	-3.2	-0.9	0.7	0.1	-4.1	-1.2	1.2
Nordic region**	17.3	13.5	14.1	-14.4	12.1	10.4	11.0	-11.0
Baltic Region***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UK and Ireland	2.8	3.4	3.3	-3.2	1.6	2.1	2.0	-2.0
Germany	5.8	5.5	5.6	-5.8	5.0	2.6	3.7	-4.2
BeNeLux****	-0.1	3.2	1.2	-1.1	-1.4	2.6	0.1	0.0
Spain and Portugal	12.8	28.9	19.5	-16.4	13.5	27.5	19.5	-16.5
Total				**-7.4**				**-6.2**
	QUOTA_R				*QUOTA_EU*			
EEA*	0.1	0.3	0.2	-0.2	0.0	0.3	-0.4	0.1
Austria	15.1	18.9	16.9	-15.1	16.2	22.4	19.1	-16.7
Czech Republic	0.2	-0.3	0.1	-0.1	0.2	-0.4	0.1	-0.1
France	9.0	7.4	6.6	-7.4	9.9	7.3	7.3	-8.0
Greece	-0.7	2.7	0.8	-0.6	9.1	8.4	6.7	-8.1
Italy	10.8	7.5	8.7	-9.2	9.9	7.4	8.0	-8.6
Poland	-0.4	0.4	-0.3	0.3	-0.5	0.5	-0.2	0.2
Nordic region**	15.4	10.8	11.5	-12.4	22.7	15.9	16.5	-17.2
Baltic Region***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UK and Ireland	2.2	1.8	2.0	-2.2	2.4	2.9	3.1	-2.9
Germany	7.3	0.8	3.7	-4.8	5.9	1.7	3.6	-4.4
BeNeLux****	-1.1	2.4	0.1	-0.1	-0.4	2.5	0.7	-0.6
Spain and Portugal	19.3	22.5	20.4	-18.2	7.4	10.6	8.7	-8.4
Total				**-7.0**				**-6.4**

*Rest of Eastern European accession countries (Slovakia, Slovenia, Hungary)
** Finland, Sweden and Denmark
***Estonia, Latvia, Lithuania
**** Belgium, The Netherlands and Luxembourg

TABLE 5.5.3. Green values, induced electricity taxes and direct compliance costs

	Green Value λ [EUR/ MWh]	Electricity tax ψ [in % of electricity price]	Direct costs $\lambda \cdot x_r$ [mill. EUR]	Efficiency costs vs. BaU [mill. EUR]
Feed-in tariff systems		*FEED_D*		
Austria	40.3	27.5	748.9	769.6
France	49.0	7.2	1812.6	2312.0
Greece				15.5
Italy	60.1	10.7	2597.9	3250.4
Nordic Market*	37.1	20.2	2629.6	2480.6
UK and Ireland	45.9	4.8	1267.7	698.1
Germany	85.6	9.4	3691.9	3005.2
BeNeLux**	45.1	2.8	403.6	330.4
Spain and Portugal	108.4	40.2	6385.8	4993.7
Total EU-15			19537.9	17855.5
		FEED_H		
Austria	37.2	25,3	702.9	717.1
France	32.9	4,9	1245.5	1581.8
Greece				15.0
Italy	59.7	10,7	2584.3	3237.0
Nordic Market*	28.9	15,7	2127.2	1804.2
UK and Ireland	33.7	3,5	942.7	259.9
Germany	66.5	7,3	2915.0	2269.3
BeNeLux**	32.8	2,1	296.9	186.9
Spain and Portugal	104.0	38,0	6122.0	5027.8
Total EU-15			16936.4	15099.0
Quota systems		*QUOTA_R*		
Austria	38.7	-	731.5	798.0
France	32.9	-	1220.6	2383.6
Greece		-		26.5
Italy	59.7	-	2574.6	3016.0
Nordic Market*	28.9	-	2093.7	1820.3
UK and Ireland	33.8	-	943.2	227.0
Germany	66.5	-	2896.9	1807.4
BeNeLux**	33.0	-	298.5	187.6
Spain and Portugal	99.3	-	5728.0	4421.5
Total EU-15			16487.1	14687.9
		QUOTA_EU		
Austria	44.5	-	824.7	855.6
France	44.5	-	1639.7	2577.3
Greece	44.5	-	154.1	253.2
Italy	44.5	-	1931.0	2638.7
Nordic Market*	44.5	-	3050.7	2702.3
UK and Ireland	44.5	-	1233.1	497.7
Germany	44.5	-	1949.5	1830.0
BeNeLux**	44.5	-	400.7	298.3
Spain and Portugal	44.5	-	2873.7	2163.1
Total EU-15			14057.0	13816.3

* Finland, Sweden and Denmark

** Belgium, The Netherlands and Luxembourg

a region. In other words: the higher the obliged relative share of green electricity in the total supply to a region is, the higher is, ceteris paribus, the ad-valorem tax in this region. This is clearly reflected by our results. Regions like Austria, the Nordic market or Spain and Portugal with relatively high indicative targets of 78.1%, 46.6% and 30.9% face the highest taxation (27.5% for Austria, 20.2% for the Nordic market and 40.2% for Portugal and Spain), whereas the share of renewables promotion in total expenditures is relatively low in regions like BeNeLux or UK and Ireland (targets 7.6% and 10.2%, taxes of 2.8% and 4.8% respectively). In consideration of the adjustment effects on the electricity markets the technology-specific feed-in tariff finally leads to excess (or efficiency) costs of approximately 17.9 bn.€ vis-à-vis *BaU*.

When we switch to uniform feed-in tariffs in scenario *FEED_H* green values decrease – in some regions significantly – compared to *FEED_D*. The feed-in tariff now provides a premium that is oriented at the marginal costs of the RES-E supply options in each region. Countries like France (-21.8 €/MWh) and Germany (-19.1 €/MWh) exceedingly profit from a harmonization of green premiums. Accordingly, the total (EU-wide) magnitude of support decreases by approximately 2.6 bn.€ to 16.9 bn.€ caused by a more efficient distribution of support across technologies. In terms of loss in economic surplus *FEED_H* saves roughly 2.8 bn.€ compared to *FEED_D*.

A regional quota obligation as simulated in Scenario *QUOTA_R* leads to similar results as uniform regional feed-in tariff systems. Regional quota obligations further marginally lower the magnitude of support on the EU-15 level by approximately 500 mio.€. Differences to *FEED_H* arise from interactions with the electricity markets such as changes in inter-regional electricity trade. Especially Spain and Portugal would profit from the regional quota system. Their total support level would decrease by roughly 400 mio.€ to approximately 5.7 bn.€.

Trade in TGCs – facilitated under *QUOTA_EU* – further reduces EU-wide costs significantly. The overall support level can be decreased to 14.0 bn.€. The uniform green value amounts to 44.5 €/MWh. As mentioned before, the equalization of marginal costs across regions leads to the exploitation of the most profitable RES-E potentials which directly affects EU-wide adjustment costs for meeting the overall RES-E target. Under *QUOTA_EU* losses in economic surplus amount to 13.8 bn.€ and are, thus, approximately 23% lower than under *FEED_D*. Re-addressing our theoretical considerations in Section 5.3, our quantitative analysis confirms the potentially huge excess costs of differentiated support schemes versus harmonized systems.

5.6. Conclusions

The political support for electricity produced from renewable energy sources has a long history within the European Union. At present, Member States employ

a relatively wide range of support schemes. The most common are feed-in tariff systems, i.e. direct subsidies to electricity production from renewable energy, and quota obligations with tradable green certificates. In this chapter, the economic consequences of these two alternative policy instruments have been investigated.

Our theoretical considerations and numerical simulations based on a large-scale partial equilibrium model of the EU electricity market suggest that differentiated feed-in tariff schemes may incur substantial excess cost compared to regionally and EU-wide harmonized systems. If the "greening" of electricity was the only political objective, an EU-wide tradable green quota would reach the European RES-E target at 23% lower costs than independent national feed-in tariff systems with technology-specific premiums. The higher costs can be interpreted as the additional premium to serve other objectives than the pure greening of electricity.

As a consequence, policy makers must clearly lay out the multiple objectives and the respective weights that can justify discriminatory pricing across renewable energies. In order to evaluate the efficiency of renewable promotion strategies, policy has to be more concrete on the weights attached to the different policy objectives. Otherwise, it is not possible to appraise and trade off renewable promotion policies with a combination of direct single-targeted instruments.

A major concern in this context must be the potentially large inefficiencies due to co-existing overlapping policy strategies. One example on the field of climate policy is the parallel regulation of electricity industries within the EU via an EU emission quota system and multiple renewable policy initiatives at the Member State level. Given a certain ceiling of emissions (e.g. implied by the EU burden sharing agreement) a comprehensive market-based system of tradable emission quotas will endogenously determine the cost-efficient level of green energy within the EU and each Member State. Under pure emissions regulation there is no need for complementary green energy policies which at best have no effect but often may involve excess costs due to a deviation from cost-efficient allocation patterns.

CHAPTER 6

Dismantling Nuclear Power in Europe: Macroeconomic and Environmental Impacts[1]

6.1. Introduction

Several governments of EU member states have recently started initiatives for a premature phase-out of nuclear power. Central issues surrounding the controversial policy debate of phase-out initiatives are the induced (macro-)economic and environmental impacts that depend on the concrete shutdown schedule of power plants, the availability and costs of replacing technologies, etc.

The objective of this chapter is to provide quantitative insights into these issues by using a hybrid computable general equilibrium (CGE) model for the European Union that features an activity analysis representation of electricity supply options. The production possibilities in the electricity sector are represented by convex combinations of discrete technological options instead of top-down smooth constant-elasticity-of-substitution (CES) production functions usually employed within the CGE approach. The bottom-up description of technologies for the electricity sector, which is based on engineering data, provides a realistic picture of the endogenous adjustment to policy measures that are, particularly, targeted to the electricity sector as is the case for nuclear phase-out policies.

We examine an extreme phase-out scenario in which those five EU member states that do not consider nuclear power as a long-run supply option (i.e. Belgium, Germany, the Netherlands, Spain and Sweden) impose a linear decline of nuclear power from business-as-usual levels in 2000 to a complete phase-out in 2020. Based on simulations with our hybrid CGE model we find that the premature phase-out induces

(1) non-negligible macroeconomic adjustment costs ranging between 0.5% loss of GDP for Germany to more than 1% loss of GDP for Belgium or Sweden,
(2) substantial increases in electricity prices of phase-out countries depressing domestic electricity production and demand,
(3) an increase in fossil-fuel based gas and hard coal technologies to fill the supply gap,

[1] This chapter is published as:

Böhringer, C., Hoffmann, T. and Löschel, A. (2003), 'Dismantling Nuclear Power in Europe: Macroeconomic and Environmental Impacts', *ZEW Discussion Paper* **03-15**, Mannheim.

(4) a rise in carbon emissions vis-à-vis the business-as-usual between 2% (Germany) and more than 6% (Sweden),
(5) negligible spillover effects to other EU countries which maintain business-as-usual energy policies.

In comparison with previous studies on nuclear phase-out scenarios in EU countries (see e.g. Nordhaus (1997), Welsch and Ochsen (2001), Böhringer *et al.* (2002)), the contribution of the our analysis is twofold. Firstly, we consider simultaneously the phase-out policies of several EU countries within a multi-region, multi-sector model of the EU internal market. Secondly, by integrating bottom-up partial-analytical techniques into a top-down CGE model we employ a new hybrid methodology that accommodates consistent analysis of both the electricity-related and the general-economic issues.

The remainder of this chapter is organized as follows. Section 6.2 provides background information on nuclear energy in Europe. Section 6.3 gives a non-technical summary of the bottom-up specification for the electricity sector and the dynamic-recursive model setting. Section 6.4 lays out the policy scenario and the simulation results. Section 6.5 concludes.

6.2. Background Information: Nuclear Energy in Europe

In 2001, roughly 846TWh of electricity were produced by nuclear power plants within the European Union. This represents about one third of the total EU electricity generation (as an aside, note that roughly one third of the worlds total nuclear capacities in 2001 are located in the EU).

Nuclear power plants are currently operated in eight European countries: Belgium, Finland, France, Germany, the Netherlands, Spain, Sweden and the United Kingdom. The shares of nuclear power generation in domestic electricity production for these countries range from 4% in the Netherlands up to 90% in France. Table 6.2.1 provides an overview of the current role of nuclear power across EU member states.

The perception of nuclear power at the superordinate EU level is ambiguous which reflects the heterogeneous role that nuclear power plays across various EU countries. Drawing upon the European Commissions Green Paper Towards a European strategy for the security of energy supply the future role of nuclear power in Europe is uncertain. On the one hand, nuclear power is seen as a "less than perfect" supply option which applies to varying degrees also to fossil fuels (coal, oil, gas) as well as renewable energies. More specifically, nuclear power is classified as undesirable and referred to as a source of energy in doubt (as is the case for coal). On the other hand, nuclear power as a domestic carbon free energy carrier is seen as one of the elements in the debate on tackling climate change and energy autonomy (European Commission 2001*b*).

TABLE 6.2.1. Key figures of nuclear power generation in the European Union (Source: IEA 2002)

	Nuclear capacity (net) [MW]	Share in EU nuclear capacity	Electricity generation [TWh]	Share in EU nuclear generation	Share in total country's power generation
Belgium	5331	4,43%	43,7	5,16%	51,47%
Finland	2590	2,15%	21,9	2,59%	26,94%
France	60636	50,42%	401,3	47,43%	89,44%
Germany	21097	17,54%	162,1	19,16%	31,16%
Netherlands	449	0,37%	3,7	0,44%	3,52%
Spain	7749	6,44%	61,1	7,22%	28,33%
Sweden	9273	7,71%	69,3	8,19%	46,11%
United Kingdom	13133	10,92%	83,0	9,81%	22,58%
EU	120258	100,00%	846,1	100,00%	33,57%

Most member states of the EU seem to be rather concerned on the use of nuclear power. Among the eight "nuclear" EU countries, only France and Finland have decided not only to maintain nuclear capacities but also to extend nuclear power production by building new power plants. The British government has left open the possibility to extend the country's nuclear capacity with respect to energy supply security and greenhouse gas abatement requirements under the Kyoto Protocol. Five out of the eight countries that employ nuclear capacities (Belgium, Germany, the Netherlands, Spain and Sweden) have taken decisions towards a moratorium or yet towards the gradual phase-out of their nuclear power programs.

Although the current political attitude towards nuclear power across EU member countries is rather clear, it is hardly possible to make medium- to long-run predictions on the future role of nuclear power. Since major parties in EU member countries often have opposing views towards nuclear energy, its prospects can be strongly influenced by future election results.

6.3. Analytical Framework: A Hybrid CGE Model

The model used for our analysis is an extension of an earlier dynamic-recursive model designed to investigate the economic implications of energy-environmental strategies for the European Union. This section presents a non-technical summary of the standard model (see Appendix A in Böhringer *et al.* (2000) for a detailed algebraic description) and discusses the incorporation of activity analysis for the bottom-up representation of power generation technologies.

6.3.1. Non-technical model summary. The current model features 7 industries (coal, crude oil, natural gas, refined oil products, electricity, energy-intensive sectors, and other manufactures/services) and the 15 EU member states.

Nested constant elasticity of substitution (CES) functions characterize the use of inputs in production, and all production exhibits non-increasing returns to scale. Goods are produced with capital, labor, energy and materials, and all sectors produce a single good. Firms behave competitively and all markets are perfectly competitive.

A representative agent in each region is endowed with three primary factors: natural resources (used for fossil fuel production), labor, and initial stock of capital. Nested CES functions characterize consumption by the representative agent (final demand) and the representative agent has myopic expectations, i.e., he is not forward-looking. The supplies of labor and natural resources are exogenous, and labor can move freely across sectors within each region but cannot move between regions. Natural resources and capital are sector specific.

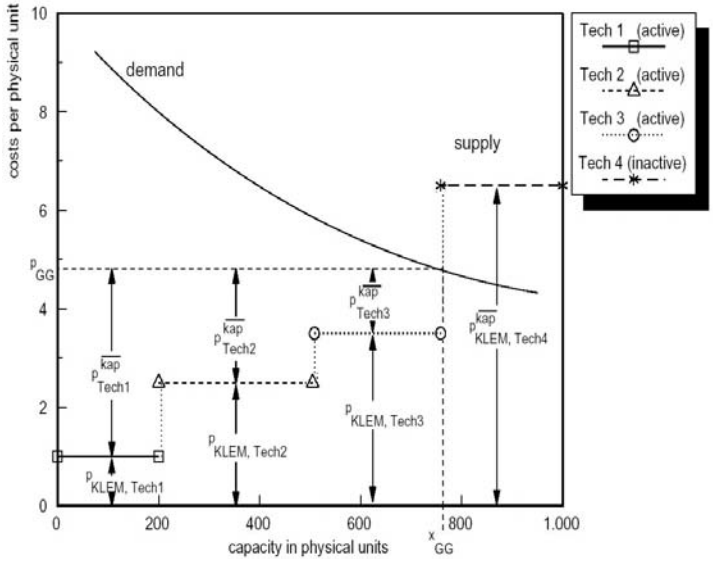
All goods, except for coal, crude oil and gas, are differentiated by region of origin. Constant elasticity of transformation functions characterize the differentiation of production between production for the domestic markets and the export markets. Regarding imports, nested CES functions characterize the choice between imported and domestic varieties of the same good (Armington 1969).

The rest of the world is represented with horizontal export demand and import supply schedules, i.e., the EU regions behave as a small open economy vis-à-vis the rest of the world. The balance of payments for each region with respect to the rest of the world is exogenous.

Analysis of the adjustment of physical capital stocks or production structures to policy constraints over time requires a dynamic framework. On the consumption side, dynamics involve the representation of the savings behavior of households. On the production side, dynamics involve the description of investment decisions of firms. The concrete specification of dynamic features rests on assumption on the degree of foresight of the economic agents, i.e. households and firms. For the current model version, we have adopted a dynamic-recursive approach where dynamics are restricted to the savings behavior of households under myopic expectations. In line with empirical evidence, the fraction of income devoted to savings is assumed to be constant (marginal propensity to save). Total investment equals the endogenous level of savings. The composition and allocation of investment goods across sectors is determined by economic considerations, i.e. investment is allocated to sectors and technologies with the highest returns to capital. This formulation still permits de-investment in technologies as soon as new vintage capital is smaller than depreciation.

In the dynamic-recursive set-up, the time path for the economy is a set of connected equilibria where the current period's savings (investment) provide new vintage capital for the next period. Sector and technology specific capital stocks are updated as an intermediate calculation between periods taking into account new vintage investment and depreciation.

FIGURE 6.3.1. Bottom-up representation of power generation options (Böhringer 1998)



As is customary in applied general equilibrium analysis, the model is based on economic transactions in a particular benchmark year (1997 in our case). Benchmark data determine parameters of the functional forms from a given set of benchmark quantities, prices, and elasticities. With respect to benchmark quantities and prices, we employ the GTAP-EG database as described in Rutherford and Paltsev (2000).

The economic impacts of energy policy interference such as an administered nuclear phase-out depend crucially on business-as-usual projections for GDP, fuel prices, energy efficiency improvements, etc. Our dynamic-recursive model is calibrated to the European Commissions (European Commission 1999*b*) business-as-usual assumptions on non-uniform growth rates for GDP as well as fossil fuel production and use (carbon emissions). Autonomous energy efficiency improvement factors are employed which scale energy demand functions in order to match GDP forecasts with the energy production and consumption projections. In addition, endogenous taxes and subsidies which reflect the regulatory framework for power production across EU member countries ensure the business-as-usual projections by the European Commission with respect to the production levels of the various electricity production technologies (see section 6.3.2 below). A detailed algebraic formulation of the model can be found in Appendix A.4.

6.3.2. Activity analysis representation of power generation. An innovative feature of our model is the elaborate treatment of power supply options by means of activity analysis. The standard description of power generation options in the electricity sector via nested CES functions is replaced with a bottom-up discrete representation of technologies.

Approaches to integrate bottom-up energy supply models into economy-wide CGE models date back to Alan Manne's (1977) ETA-Macro where the process analysis ETA-submodel of the U.S. energy system has been linked with a one-sector Macro-model of the U.S. economy in a non-linear optimization framework. The shortfall of Manne's optimization approach is the highly stylized representation of the non-energy economy in order to avoid "non-integrabilities" that can not be handled in the single optimization framework. "Non-integrabilities" refer to quite common situations where individual demand functions depend not only on prices but also on the initial endowments. In such cases, demand functions are typically not "integrable" into an economy-wide utility function (see e.g. Chipman 1974). Subsequent energy-economy models presented – among others – in Jorgenson (1982), Lundgren (1985) or Bergman and Lundgren (1990) – account for more sectoral details and economic features by accommodating "non-integrabilities". However, these models that are formulated as a square system of nonlinear equations are based on soft-links between top-down CGE modules for the non-energy economy and bottom-up linear programming modules for the energy system. Due to the heterogeneity in complexity and accounting methods across the submodules, the soft-link approach stands out for substantial problems in achieving overall consistency and convergence of iterative solution approaches. More recently, the formulation of equilibrium problems as a system of (weak) nonlinear inequalities in the so-called Mixed Complementarity Problem (MCP) format has been advocated (Cottle *et al.* 1992) and successfully applied to large-scale CGE models taking advantage of the availability of commercial software for model formulation and solution ((Rutherford 1995, Dirkse & Ferris 1995*b*)). As laid out by Böhringer (1998) in a static prototype model, the MCP approach provides a straightforward way for an integrated hybrid description of production possibilities in energy policy modeling. In the model used for the current analysis, we have adopted the MCP approach to energy-economy modeling within an intertemporal CGE framework. The bottom-up representation of major power supply options enhances the transparency and credibility of simulated technological responses in electricity production that are triggered by nuclear phase-out policies.

Power producers have discrete choices with respect to alternative technologies and combine these based on capacity constraints in order to meet electricity demand in a cost-minimizing way. Figure 6.3.1 illustrates the bottom-up description of power production by means of a step-wise supply function which emerges from specific capacity limits and cost shares of technologies.

In the model implementation, we can restrain ourselves to a few key technologies that are already sufficient to give an appropriate representation on the range of available technological options for power generation. Table 6.3.1 summarizes the set of discrete technologies incorporated in the electricity sub-module of the model.

Table 6.3.1. Summary of representative technologies for electricity generation

	Type of technology	Fuel type / source	Capacity (MW)	Utilization (h)
Conventional technologies:				
HCO	Suspension firing / fluidized-bed combustion	Hard coal	200	4400 - 7100
SCO	Suspension firing	Soft coal and lignite	800	7525
OIL	Gas turbine	Fuel oil	156	450
NGS	Gas turbine	Natural gas	145	450
NUC	Pressurized water / boilingwater	Nuclear		7900
Renewable technologies:				
BIO	Solid biomass	Solid biomass	1	2000
WND	Wind	Wind	1	2200
HYD	Hydro	Hydro	1	5800
SOL	Solar PV	Solar	1	900

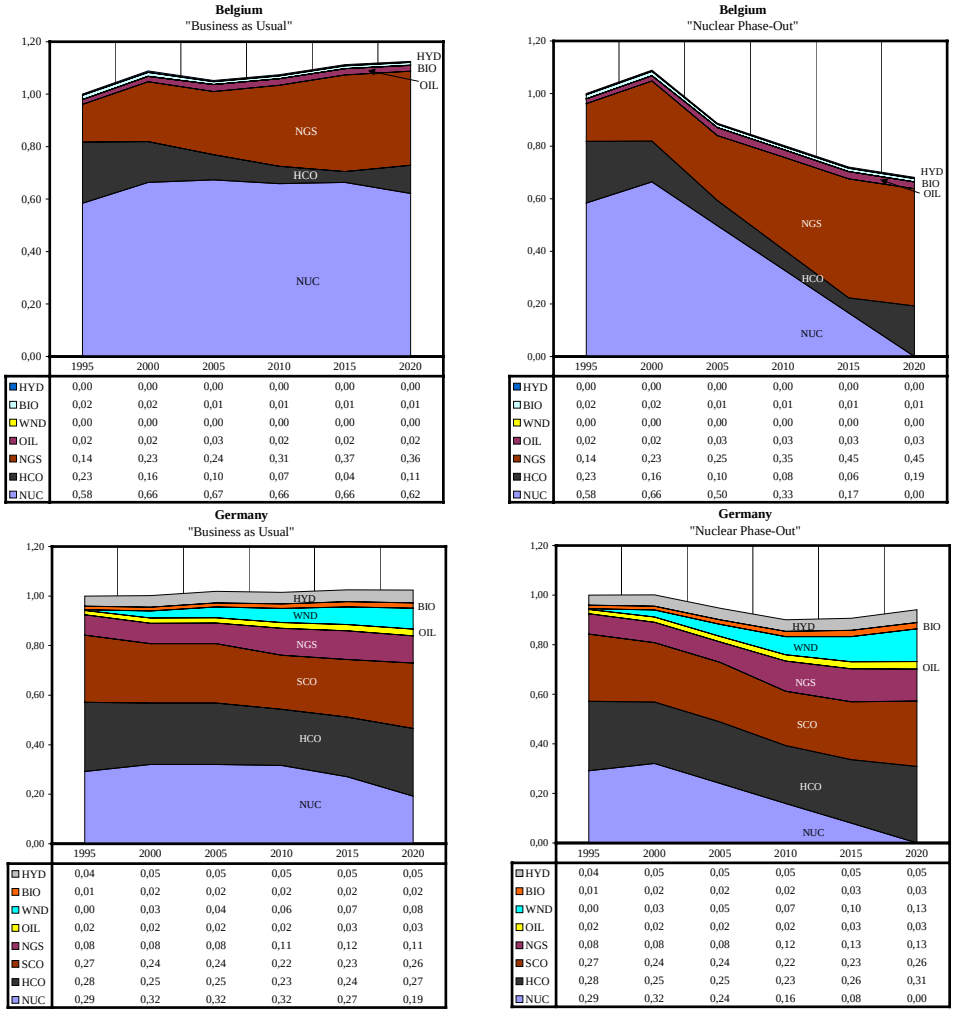
The different electricity generation technologies are characterized through specific cost structures, benchmark output shares and physical capacity constraints (incl. upper bounds on expansion rates). Cost shares for the different technologies in each EU region (see Appendix B.3) are calculated on the basis of dynamic investment analysis with techno-economic data from IKARUS (KFA 1994).

6.4. Phase-out Scenario and Results

We simulate a premature nuclear phase-out for those five EU member states that have been characterized in the past by strong public reservations against the use of nuclear power. More specifically, we assume that Belgium, Germany, the Netherlands, Spain and Sweden impose a linear decline of nuclear power from 2000 levels to zero production in 2020.

The premature phase-out of nuclear power induces a supply-side gap that can be filled, in principle, by four options: (i) reduction in energy demand (ii) increased utilization of existing power plants (iii) increased electricity imports, or (iv) construction of new non-nuclear power plants. Increasing the degree of utilization during medium and peak loads, as well as load shifting, may cover only a small fraction of the base-load gap caused by a nuclear phase-out, because these measures are rather costly and limited in overall scope. Thus, three major options remain for closing the power supply gap: decrease in electricity demand, increase in electricity imports and the construction and operation of new non-nuclear power plants.

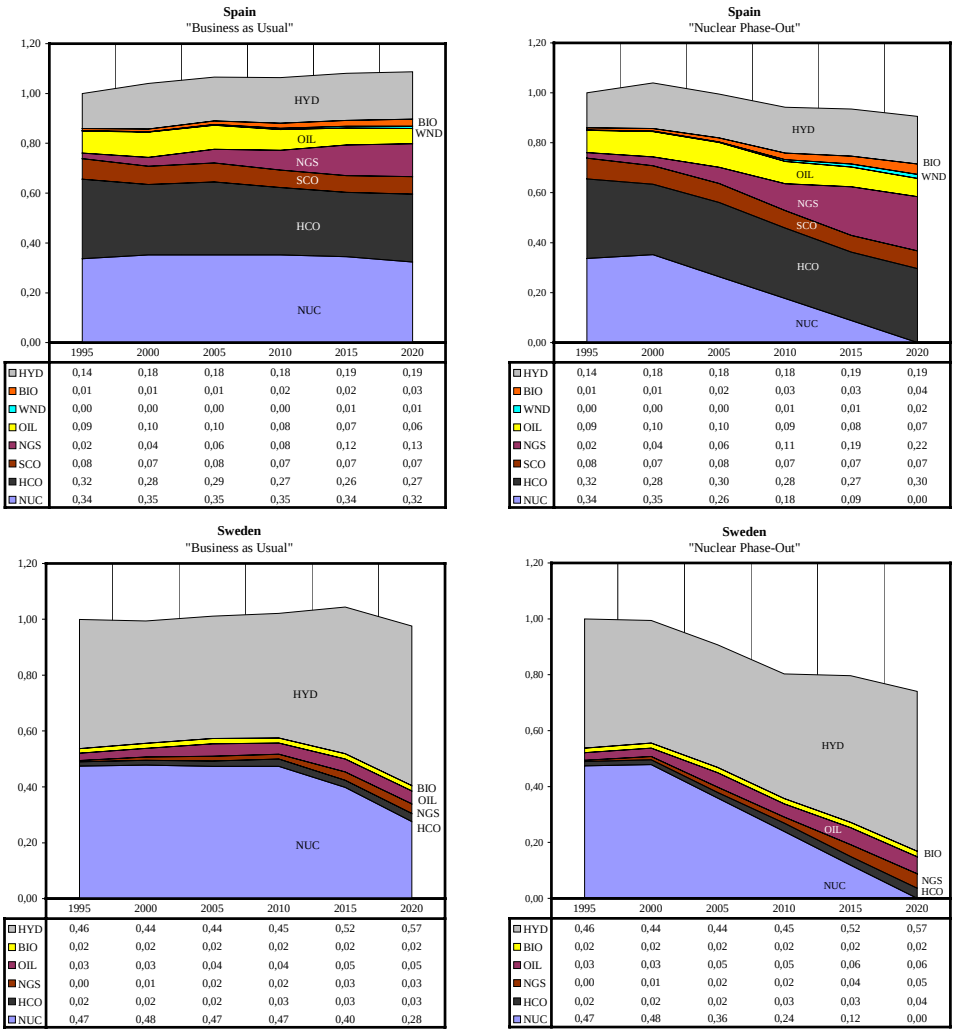
FIGURE 6.4.1. Electricity production in Belgium and Germany (Index 1995=1)



In our quantitative analysis, we measure the economic and environmental impacts of the premature nuclear phase-out with respect to the business-as-usual scenario. Results are only presented for Belgium, Germany, Spain and Sweden. As to Netherlands, the economic impacts are negligible since nuclear power constitutes only a very small fraction in power production up to 2010 under business and is phased-out thereafter. Likewise, we omit all remaining EU countries without nuclear capacities because the indirect spillovers from nuclear phase-out policies are very small.

Figures 6.4.1 and 6.4.2 visualize the level and structure of electricity production by the different energy supply technologies between the years 1995 and 2020. Under business as usual, electricity production increases by 12.5% in Belgium, by 2.4% in Germany, by 8.7% in Spain, and drops by 2.3% in Sweden. Belgium's electricity generation is based on natural gas and, particularly, on nuclear power; the main power technologies employed in Germany are nuclear, soft coal and hard coal; Spain

FIGURE 6.4.2. Electricity production in Spain and Sweden (Index 1995=1)



	1995	2000	2005	2010	2015	2020
HYD	0,14	0,18	0,18	0,18	0,19	0,19
BIO	0,01	0,01	0,01	0,02	0,02	0,03
WND	0,00	0,00	0,00	0,00	0,01	0,01
OIL	0,09	0,10	0,10	0,08	0,07	0,06
NGS	0,02	0,04	0,06	0,08	0,12	0,13
SCO	0,08	0,07	0,08	0,07	0,07	0,07
HCO	0,32	0,28	0,29	0,27	0,26	0,27
NUC	0,34	0,35	0,35	0,35	0,34	0,32

	1995	2000	2005	2010	2015	2020
HYD	0,14	0,18	0,18	0,18	0,19	0,19
BIO	0,01	0,01	0,02	0,03	0,03	0,04
WND	0,00	0,00	0,00	0,01	0,01	0,02
OIL	0,09	0,10	0,10	0,09	0,08	0,07
NGS	0,02	0,04	0,06	0,11	0,19	0,22
SCO	0,08	0,07	0,08	0,07	0,07	0,07
HCO	0,32	0,28	0,30	0,28	0,27	0,30
NUC	0,34	0,35	0,26	0,18	0,09	0,00

	1995	2000	2005	2010	2015	2020
HYD	0,46	0,44	0,44	0,45	0,52	0,57
BIO	0,02	0,02	0,02	0,02	0,02	0,02
OIL	0,03	0,03	0,04	0,04	0,05	0,05
NGS	0,00	0,01	0,02	0,02	0,03	0,03
HCO	0,02	0,02	0,02	0,03	0,03	0,03
NUC	0,47	0,48	0,47	0,47	0,40	0,28

	1995	2000	2005	2010	2015	2020
HYD	0,46	0,44	0,44	0,45	0,52	0,57
BIO	0,02	0,02	0,02	0,02	0,02	0,02
OIL	0,03	0,03	0,05	0,05	0,06	0,06
NGS	0,00	0,01	0,02	0,02	0,04	0,05
HCO	0,02	0,02	0,02	0,03	0,03	0,04
NUC	0,47	0,48	0,36	0,24	0,12	0,00

is producing electricity mainly through hard coal, nuclear and hydro; Sweden relies almost exclusively on hydro and nuclear.

The nuclear phase-out implies a loss of productive resources due to the foregone use of existing cost-efficient nuclear capacities for electricity generation. The premature investment in replacement technologies raises power production costs which in turn increases electricity prices as compared to the business as usual. Between 2000 and 2020 electricity production costs increase by 41.1% in Belgium, by 6.3% in Germany, by 21.9% in Spain, and by 21.9% in Sweden (see Figure 6.4.3).

The variation in cost changes across these countries reflect country-specific differences in the opportunity costs of a premature phase-out as captured by the magnitude of lost nuclear generation, the cost-potentials of replacement technologies (i.e. relative profitability of existing nuclear power plants vis-à-vis the back-up

FIGURE 6.4.3. Change in electricity production costs in the scenario Nuclear Phase-Out (in % relative to Business as Usual)

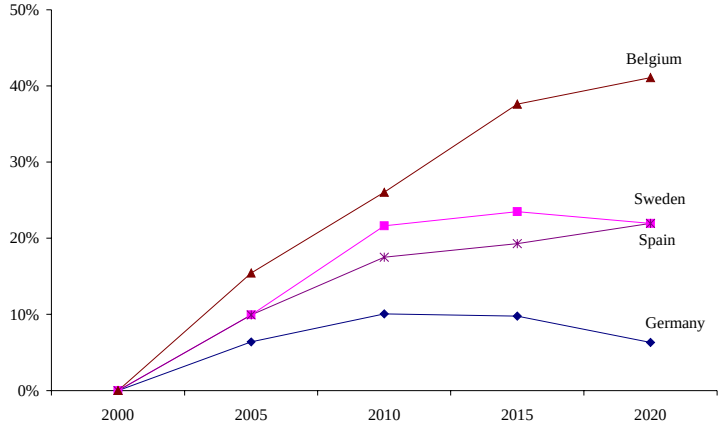


FIGURE 6.4.4. Change in electricity demand in the scenario Nuclear Phase-Out (in % relative to Business as Usual)

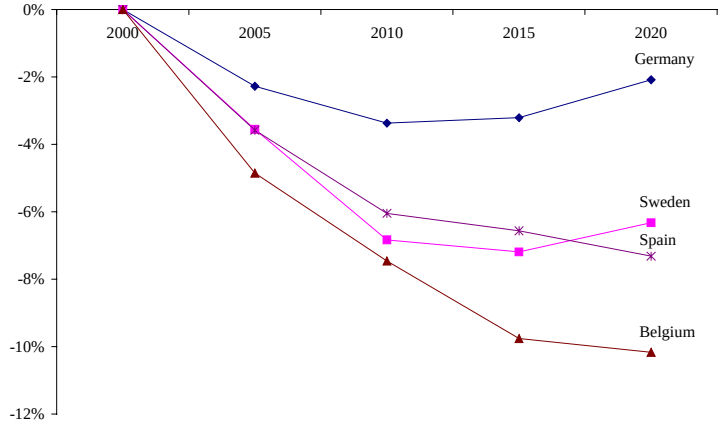


FIGURE 6.4.5. Change in electricity imports in the scenario Nuclear Phase-Out (in % relative to Business as Usual)

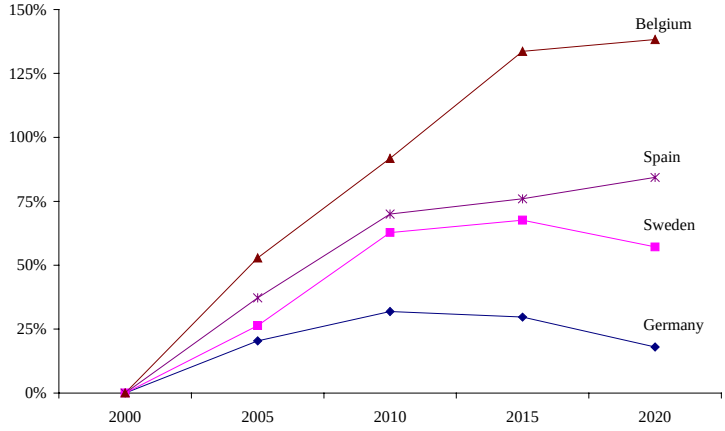
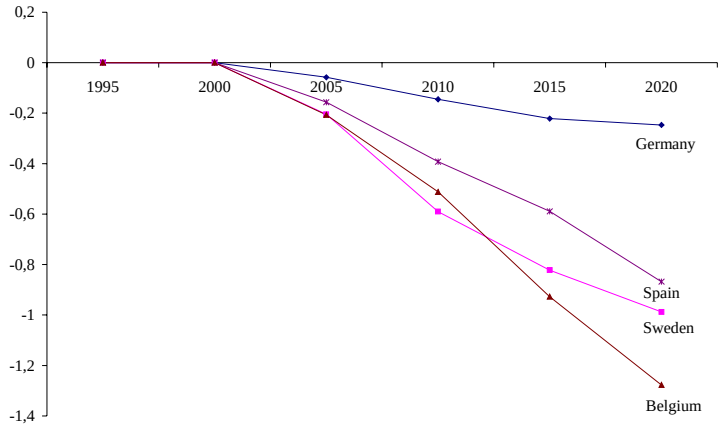


FIGURE 6.4.6. Welfare changes in the scenario Nuclear Phase-Out (in % relative to Business as Usual)



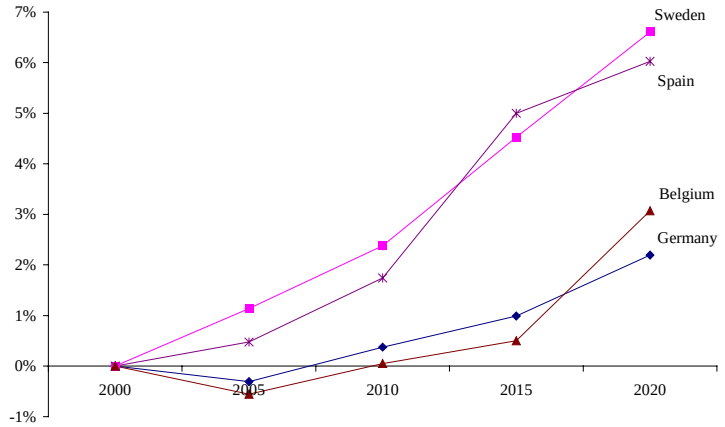
options) and the ease of economy-wide electricity savings. Not surprisingly, the increase in electricity prices has a negative impact on electricity demand. The higher the transitional increase in electricity prices the larger the decline in electricity demand. Figure 6.4.4 indicates that electricity demand is reduced by 10.2% in Belgium, by 2.1% in Germany, by 7.3% in Spain, and by 6.3% in Sweden between 2000 and 2020. As shown in Figures 6.4.1 and 6.4.2, the reductions in electricity supply between 2000 and 2020 are even larger: 31.9% in Belgium, 5.9% in Germany, 9.5% in Spain, and 25.8% in Sweden. To back nuclear capacities, Belgium mainly draws on hard coal and natural gas, as is the case for Germany which in addition increases power generation by wind. Spain compensates the loss in nuclear power through additional gas power plants. The remaining supply-side gap is closed through increased electricity imports (see Figure 6.4.5). Electricity imports increase by almost 140% in Belgium, by 18% in Germany, by 84% in Spain, and by 57% in Sweden up to 2020.

When we turn to the technology mix in power generation – measured as technology shares in overall production – we see significantly large increases in the share of natural gas for Belgium and hydro for Sweden (see Figure B.4.1 in appendix B.4). Note that the increase in the share does not necessarily imply an increase in absolute production of the specific technologies taking into account a policy-induced overall decline in electricity production.

The macroeconomic costs of the phase-out scenario are measured in Hicksian equivalent variation in income (HEV). Welfare losses for the phase-out regions are non-negligible (see Figure 6.4.6) ranging from 0.2% in 2020 for Germany up to 1.2% in 2020 for Belgium. The magnitude of GDP losses is closely related to the increase of electricity production costs associated with the premature nuclear phase-out.

A premature nuclear phase-out will increase carbon emissions in the respective countries as compared to the business as usual since carbon free nuclear power will

FIGURE 6.4.7. Changes in carbon emissions in the scenario Nuclear Phase-Out (in percent relative to Business as Usual)



be in part replaced by electricity from fossil fuel based technologies. Figure 6.4.7 indicates that carbon emissions increase between 2% (Germany) and more than 6% (Sweden) up to the year 2020.

6.5. Conclusions

We have investigated the economic and environmental implications of an accelerated simultaneous nuclear phase-out in five European countries (Belgium, Germany, the Netherlands, Spain and Sweden). Our quantitative results show that a premature nuclear phase-out imposes non-negligible adjustment costs to the respective economies that reflect the foregone use of existing cost-efficient nuclear capacities for electricity generation.

From a climate policy perspective, an accelerated nuclear phase-out induces substantially higher carbon emissions since carbon-free nuclear power will be replaced to a larger extent by fossil fuel technologies. Thus, the opportunity costs of phasing-out nuclear power can be significantly magnified if stringent carbon reduction targets as required by future climate protection policies will apply.

In our analysis, we have not accounted for the external costs of nuclear power due to the large uncertainties in the valuation of nuclear risks. Therefore, the adjustment costs presented in our analysis can not be interpreted as simple excess costs of energy policy interference, but must be viewed as the price tag for the risk reduction from nuclear power operation given additional constraints (preferences) on back-up technologies and carbon neutrality.

Bibliography

Armington P (1969). A Theory of Demand for Producers Distinguished by Place of Production, *IMF Staff Papers* **16**, 159–178.

Bergman L & Lundgren S (1990). General Equilibrium Approaches to Energy Policy Analysis in Sweden, *in* L. Bergman and D.W. Bergman and E. Zalai, ed., *General Equilibrium Modeling and Economic Policy Analysis*, Blackwell Publishing, pp. 351–382.

Bernard A, Paltsev S, Reilly J, Vielle M & Viguier L (2003). Russia's Role in the Kyoto Protocol, MIT Joint Program on the Science and Policy of Global Change, Report No. 98 Cambridge, MA.

Betge P (1998). *Investitionsplanung: Methoden – Modelle – Anwendungen, Wiesbaden*, Gabler.

Böhringer C (1998). The Synthesis of Bottom-Up and Top-Down in Energy Policy Modeling, *Energy Economics* **20(3)**, 234–248.

Böhringer C (2000). Cooling Down Hot Air – A Global CGE Analysis of Post-Kyoto Carbon Abatement Strategies, *Energy Policy* **28**, 779–789.

Böhringer C (2002). Industry-level Emission Trading between Power Producers in the EU, *Applied Economics* **34(4)**, 523–533.

Böhringer C, Hoffmann T & de Lara-Peñate C M (2006). The efficiency costs of separating carbon markets under the EU emissions trading scheme: A quantitative assessment for Germany, *Energy Economics* **28(1)**, 44–61.

Böhringer C, Hoffmann T, Lange A, Löschel A & Moslener U (2005). Assessing Emission Regulation in Europe: An Interactive Simulation Approach, *The Energy Journal* **26(4)**, 1–21.

Böhringer C, Hoffmann T & Löschel A (2003). Dismantling Nuclear Power in Europe: Macroeconomic and Environmental Impacts, *ZEW Discussion Paper* **03-15**.

Böhringer C, Hoffmann T & Vögele S (2002). The Cost of Phasing Out Nuclear Power: A Quantative Assessment of Alternative Scenarios for Germany, *Energy Economics* **24(5)**, 469–490.

Böhringer C, Jensen J & Rutherford T (2000). Energy Market Projections and Differentiated Carbon Abatement in the European Union, *in* C. Carraro, ed., *Efficiency and Equity of Climate Change Policy*, Kluwer Academic Publishers, pp. 199–220.

Böhringer C & Lange A (2005). Mission Impossible !? On the Harmonization of National Allocation Plans under the EU Emissions Trading Directive, *Journal of Regulatory Economics* **27(1)**, 81–94.

Böhringer C & Lange A (in press). On the Design of Optimal Grandfathering Schemes for Emission Allowances, *European Economic Review* .

Böhringer C & Löschel A (2002). Market power and hot air in international emissions trading: the impact of US withdrawal from the Kyoto Protocol, *Applied Economics* **35**, 651–663.

Böhringer C & Rutherford T F (2002). Carbon Abatement and International Spillovers, *Environmental and Resource Economics* **22(3)**, 391–417.

Böhringer C & Rutherford T F (2006). Combining Top-Down and Bottom-up in Energy Policy Analysis: A Decomposition Approach, *ZEW Discussion Paper No. 06-007* .

Bovenberg A L (1999). Green Tax Reforms and the Double Dividend: An Updated Reader's Guide, *International Tax and Public Finance* **6**, 421–443.

Brooke A, Kendrick D & Meeraus A (1996). *GAMS: A User´s Guide*, GAMS Development Corp.

Bundesregierung (1998). *Koalitionsvereinbarung zwischen der Sozialdemokratischen Partei Deutschlands und Bündnis 90 / Die Grünen.* http://www.spd.de/aktuell/ programmatisches/ vertrag.htm (19.10.1999).

Capros P, Mantzos L, Kolokotsas D, Ioannou N, Georgakopoulos T, Filippopoulitis A & Antoniou Y (1998). *The PRIMES Energy System Model – Reference Manual, National Technical University of Athens. Document as peer reviewed by the European Commission, Directorate General for Research.*

CENTREL (2005). *Annual Report 2004*, available at: http://www.centrel.org /Def AR Centrel 2004 PDF.pdf.

Chipman J (1974). Homothetic preferences and aggregation, *Journal of Economic Theory* **8**, 26–38.

Commission E (2003). Directive establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council directive 96/61/EC, European Commission, Brussels available at: http://europa.eu.int/comm/environment/climat/030723provisionaltext.pdf.

Cottle R W, Pang J S & Stone R E (1992). *The Linear Complementarity Problem*, Academic Press, San Diego, CA.

Criqui P & Mima S (2001). The European Greenhouse Gas Tradable Emission Permit System: Some Policy Issues Identified with the POLES-ASPEN Model, *ENER Bulletin* **23**, 51–55.

de Noord M, Beurskens L W M & d̃e Vries H J (2004), 'Potentials and costs for renewable electricity generation : A data overview '.

Deutscher Bundestag (2001). Gesetz für den Vorrang Erneuerbarer Energien, *Bundesgesetzblatt, Jg. 2004 Teil I Nr. 40* pp. 0033 – 0040.

Deutsches Atomforum, ed. (1999). *Kernenergie in Deutschland: Jahresbericht 1998*, Bonn.

Dimaranan B & McDougall R (2002). *Global Trade, Assistance and Production: The GTAP 5 Data Base*, West Lafayette: Center for Global Trade Analysis, Purdue University.

Dirkse S P & Ferris M C (1995*a*). MCPLIB: A collection of nonlinear mixed complementarity problems, *Optimization Methods and Software* **5**, 319–345.

Dirkse S P & Ferris M C (1995*b*). The PATH solver: A non-monotone stabilization scheme for mixed complementarity problems, *Optimization Methods and Software* **5**, 123–156.

Dirkse S P & Ferris M C (1995*c*). The PATH Solver: A Non-monotone Stabilization Scheme for Mixed Complementarity Problems, *Optimization Methods and Software* **5**, 123–156.

DVG (1999). *Entwicklung der allgemeinen (öffentlichen) Stromversorgung in Deutschland 1999 bis 2010*, Deutsche Verbundgesellschaft, Heidelberg.

EIA (2000). *International Energy Outlook 2000*, EIA – Energy Information Administration, U.S. Department of Energy, Washington.

European Commission (1997). Energy for the future: renewable sources of energy – White Paper for a Community strategy and action plan, COM(97) 0599 final, *Communication from the Commission* .

European Commission (1999*a*). Commission Communication to the Council and the Parliament: Preparing for Implementation of the Kyoto Protocol, COM (1999) 230, *Communication from the Commission* .

European Commission (1999*b*). *European Union Energy Outlook to 2020 – The Shared Analysis Project, Energy in Europe, Special Issue*, Office for official Publications of the European Communities, Luxembourg.

European Commission (2001*a*). Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market, *Official Journal of the European Communities* .

European Commission (2001*b*). *Green Paper – Towards a European Strategy for the security of energy supply*, Office for Official Publications of the European Communities, Luxembourg.

European Commission (2003*a*). Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC, *Official Journal of the European Communities* .

European Commission (2003*b*). *European Energy and Transport Trends to 2030*, Office for official Publications of the European Communities, Luxembourg.

European Commission (2004). Directive 2004/101/EC, amending Directive 2003/83/EC establishing a scheme for greenhouse gas emission allowance trading within the Community, in respect of the Kyoto Protocol's project mechanisms, European Commission, Brussels.

European Commission (2005*a*). Annual Report on the Implementation of the Gas and Electricity Internal Market, COM(2004) 863 final, *Communication from the Commission* .

European Commission (2005*b*). *Gas Prices, Price Systems 2004*, Office for Official Publications of the European Communities, Luxembourg.

European Commission (2005*c*). The market for solid fuels in the Community in 2003 and 2004, SEC(2005) 105, *Commission Staff Working Document* .

European Commission (2005*d*). The support for electricity from renewable energy sources – Impact Assessment, Annex to the Communication from the Commission COM(2005) 627 final, SEC(2005) 1571 final, *Communication from the Commission* .

European Commission (2005*e*). The support of electricity from renewable energy sources, COM(2005) 627 final, *Communication from the Commission* .

European Transmission System Operators – ETSO (2001*a*), 'Definitions of Transfer Capacities in liberalised Electricity Markets, Final Report April 2001'.

European Transmission System Operators – ETSO (2001*b*), 'Procedures for Cross-Border Transmission Capacity Assessments, Oktober 2001'.

Eurostat (2005). *Online Data*. available at: http://epp.eurostat.cec.eu.int/portal/page?_pageid=1996,45323734&_dad=portal&_schema=PORTAL&screen=welcomeref&open=/&product=EU_MAIN_TREE&depth=1.

Eyckmans J, van Regemorter D & van Steenberghe V (2001). Is Kyoto Fatally Flawed? – An Analysis with MacGEM, *Working Paper Series – Faculty of Economics* **No. 2001-18**. Catholic University of Leuven, Leuven.

FEES – Forum für Energiemodelle und Energiewirtschaftliche Systemanalysen in Deutschland , ed. (1999). Physica, Heidelberg.

Ferris M C (1993). The linear complementarity problem, *Bulletin of the American Mathematical Society* **28**, 169–175.

Ferris M C & Kanzow C (2002). Complementarity and related problems: A survey, *in* P M Pardalos & M G C Resende, eds, *Handbook of Applied Optimization*, Oxford University Press, New York, pp. 5124–530.

Ferris M C, Mangasarian O L & Pang J S, eds (2001). *Complementarity: Applications, Algorithms and Extensions*, Vol. 50 of *Applied Optimization*, Kluwer Academic Publishers, Dordrecht.

Ferris M C & Pang J S (1997). Engineering and economic applications of complementarity problems, *SIAM Reviev* **39**, 669–713.

Ferris M C & Sinapiromsaran K (2000). Formulating and solving nonlinear programs as mixed complementarity problems, *in* V H Nguyen, J J Strodiot & P

Tossings, eds, *Optimization*, Springer-Verlag. volume 481 of Lecture Notes in Economics and Mathematical Systems.

Finon D & Menanteau P (2003). The static and dynamic efficiency of instruments of promotion of renewables, *Energy Studies Review* **12(1)**, 53–82.

Franken M (2000). Wenn Atommeiler in die Jahre kommen – Nach zwei Jahrzehnten Laufzeit beginnen die teuren Reparaturen, *Handelsblatt* p. 51.

Gilbert A, Bode J W & Phylipsen D (2004). *Analysis of the National Allocation Plans for the EU Emissions Trading Scheme, Ecofys Interim Report*, Utrecht, The Netherlands.

Goulder L (1995). Environmental Taxation and the Double Dividend: A Reader's Guide, *International Tax and Public Finance* **2**, 157–183.

Gruber E & Jochem E (1995). Analyse von Hemmnissen und Maßnahmen für die Verwirklichung von CO2-Minderungszielen, *in* Enquete Kommission, ed., *Schutz der Erdatmosphäre Bd 3, Energie, Teilband 2*, Bonn.

Harker P T & Pang J S (1990). Finite-dimensional variational inequality and nonlinear complementarity problems: A survey of theory, algorithms and applications, *Mathematical Programming* **48**, 161–220.

Hennicke, P. et al. (2000). *Kernkraftwerksscharfe Analyse im Rahmen des Projekts Bewertung eines Ausstiegs aus der Kernenergie aus klimapolitischer und volkswirtschaftlicher Sicht, Endfassung des überarbeiteten Endberichts zu Teil I des Zusatzauftrages*, Wuppertal, Freiburg, Berlin available at: http://www.wupperinst.org/energie/produkte/pkb4130.html (10.11.2000).

Hoffmann T (2004*a*). Effizienzkosten hybrider CO2-Regulierung in Deutschland: Eine kritische Betrachtung der EU-Emissionshandelsrichtlinie, *Zeitschrift für Energiewirtschaft* **28(4)**, 255–262.

Hoffmann T (2004*b*). Teilbericht: DIOGENES, *in* Forum für Energiemodelle und Energiewirtschaftliche Systemanalysen in Deutschland, ed., *Energiemodelle zum Klimaschutz in liberalisierten Energiemärkten – Die Rolle erneuerbarer Energieträger*, Lit-Verlag, Münster, pp. 340–354.

Hoffmann T, Löschel A & Moslener U (2006). Harmonizing Emission Allocation: What are the Equity Consequences for the Sectors in and outside the EU-Trading Scheme, *in* C DeMiguel, X Labandeira & B Manzano, eds, *Economic Modelling of Energy and Climate Change Policies*, Edward Elgar, Cheltenham. in press.

Horn M & Ziesing H J (1997). Ausstieg aus der Kernenergie: Wirtschaftliche Auswirkungen aus der Sicht eines Energieversorgungsunternehmens, *DIW-Wochenbericht* **3/97**.

IEA/OECD (2002). *Energy Balances of OECD Countries, 2002*, OECD Publications, Paris.

Jensen S G & Skytte K (2002). Interaction between the power and green certificate markets, *Energy Policy* **30**, 425–435.

Johnstone N (2002), 'The Use of Tradable Permits in Combination with Other Environmental Policy Instruments'. Report ENV/EPOC/WPNEP(2002)28/Final, OECD, Paris.

Jorgenson D (1982). Economic and Process Analysis Models for Energy Policy Assessments, *in* R. Amit and M. Avriel, ed., *Perspectives on Resource Policy Modelling: Energy and Materials*, Ballinger Publishing Company, Cambridge, MA, pp. 199–220.

Karush W (1939). *Minima of functions of several variables with inequalities as side constraints*, Master's Thesis, Department of Mathematics, University of Chicago.

KFA – Forschungszentrum Jülich (1994). *IKARUS-Instrumente für Klimagas Reduktionsstrategien, Teilprojekt 4: Umwandlungssektor Strom- und Wärmeerzeugende Anlagen auf fossiler und nuklearer Grundlage. Teil 1 u. 2*, Jülich.

Kühn I (2000). Ist die Quotenregelung mit Zertifikatshandel für Erneuerbare Energien effizient? – Eine Replik, *Zeitschrift für Energiewirtschaft* **24(4)**, 214–216.

Klepper G & Peterson S (2002). On the Robustness of Marginal Abatement Cost Curves: The influence of World Energy Prices, *Kiel Working Paper* **No. 1138**, 201–218. Institute for World Economics, Kiel.

Klepper G & Peterson S (2004). The EU Emissions Trading Scheme: Allowance Prices, Trade Flows, Competitiveness Effects, *European Environment* **14**, 201–218.

Kuhn H W & Tucker A W (1951). Nonlinear programming, *in* J. Neyman, ed., *Proceedings of the second Berkeley Symposium on Mathematical Statistics and Probability*, University of California Press, Berkely and Los Angeles, pp. 481–492.

Lundgren, S. (1985). Model Integration and the Economics of Nuclear Power, *Economic Reserach Institute, Stockholm School of Economics* .

Madlener, R. and Drillisch, J. (2002). Tradable Certificate Schemes for Single Renewable Electricity Techno-logies: The Case of Small-Scale Hydro Power Promotion in Austria, *in Proceedings of the 25th Annual IAEE International Conference "Innovation and Maturity in Energy Markets: Experience and Prospects"*, University of California Press, Aberdeen, Scotland.

Madlener R & Stagl S (2000). Promoting Renewable Electricity Generation through Guaranteed Feed-in Tariffs vs Tradable Certificates: an Ecological Economics Perspective, *in Proceedings of the 3rd Biennial Conference of the European Society for Ecological Economics*.

Maier-Mannhart H (2000). Zynischer Kuhhandel?, *Energiewirtschaftliche Tagesfragen* **Jahrgang 50, Heft 5**, 272.

Majewski O (1999). Es drohen ruppige Zeiten, *Die Zeit* **34**.

Mangasarian O (1969). *Nonlinear Programming*, McGraw-Hill, New York.

Manne, A. (1977). ETA-Macro: A Model of Energy Economy Interactions, *EA-592 Research Report 1014, Electric Power Research Institute* **1014**.

Mathiesen L (1977). Marginal Cost Pricing in Linear Programming: A Case with Constraints on Dual Variables, *The Scandinavian Journal of Economics* **4**, 468–477.

Mathiesen L (1985). Computation of Economic Equilibrium by a Sequence of Linear Complementarity Problems, *in* A Manne, ed., *Economic Equilibrium – Model Formulation and Solution*, Vol. 23 of *Mathematical Programming Study*, pp. 144–162.

Meller E, Milojcic G, Reichel W & Schöning G (2005). *Jahrbuch der europäischen Energie und Rohstoffwirtschaft 2004*, Verlag Glückauf, Essen.

Menanteau P, Finon D & Lamy M L (2003). Prices versus quantities: Environmental policies for promoting the development of renewable energy, *Energy Policy* **31(8)**, 799–812.

Morthorst P E (2000*a*). Scenarios for the use of GHG-reduction instruments – how can policy-instruments as carbon emission trading and tradable green certificates be used simultaneously to reach a common GHG reduction target?, *Energy & Environment* **11(4)**.

Morthorst P E (2000*b*). The development of a green certificate market, *Energy Policy* **28(15)**.

Morthorst P E (2001). Interactions of tradable green certificate market with a tradable permits market, *Energy Policy* **29(5)**.

NORDEL (2005*a*). *Annual Report 2004*, available at: http://www.nordel.org /Content/Default.asp?PageID=127.

NORDEL (2005*b*). *Annual Statistics 2004*, available at: http://www.nordel.org /Content/Default.asp?PageID=157.

Nordhaus W (1997). *The Swedish Nuclear Dilemma: Energy and the Environment*, Resources for the Future, Washington, DC.

Nuclear Energy Agency (1992), ‘ Nuclear Power Economics and Technology: An Overview’.

OECD (2001*a*). *Database on environmentally related taxes in OECD countries. Available at:http://www.oecd.org/env/policies/taxes/index.htm.*

OECD (2001*b*). *Environmentally Related Taxes in OECD Countries – Issues and Strategies*, OECD Publications, Paris.

Pfaffenberger W & Gerdey H J (1998), ‘Zur Bedeutung der Kernenergie für die Volkswirtschaft und die Umwelt. Zur Abschätzung der Kosten des Ausstiegs. Untersuchung im Auftrag der VDEW e.V.’.

Prognos / EWI (1999), ‘Die längerfristige Entwicklung der Energiemärkte im Zeichen von Wettbewerb und Umwelt – Trendskizze’.

Rutherford T F (1992), ‘Sequential joint maximization’. Working Paper 92-8, Department of Economics, University of Colorado, Boulder.

Rutherford T F (1995). Extensions of GAMS for Complementarity Problems Arising in Applied Economics, *Journal of Economic Dynamics and Control* **19**, 1299–1324.

Rutherford, T. F. and Paltsev, S. (2000). GTAP-Energy in GAMS, *University of Colorado, Working Paper* **00-2**.

Schade D & Weimer-Jehle W (1999). *Kernenergieausstieg und Klimaschutz in Baden-Württemberg*, Akademie für Technikfolgenabschätzung in Baden-Württemberg.

Schmitt D (1999). Kosten eines Kernenergieausstieges in Deutschland, *Energiewirtschaftliche Tagesfragen* **Jahrgang 49, Heft 1/2**, 6–10.

Siemens AG (1999), 'Von Siemens gebaute Kernkraftwerke, Internet-Informationen der Siemens AG'. http://www.siemens.de/kwu/d/foa/n/products/kkw/kw.htm.

Sorrel S & Sijm J (2003). Carbon Trading in the Policy Mix, *Oxford Review of Economic Policy* .

Stelzer L (1992). Investitions- und Wirtschaftlichskeitsrechnungen – Anwendungsmöglichkeiten für die Unternehmen der Elektrizitätswirtschaft, *Elektrizitätswirtschaft* **Jahrgang 91, Heft 16**, 1034–1042.

Takayama T & Judge G (1971). *Spatial and Temporal Price and Allocation Models*, North-Holland Publishing, Amsterdam.

UCTE (2005). *Oline data (year 2004)*, Union for the Co-ordination of Transmission of Electricity – available at: http://www.ucte.org /statistics/onlinedata/consumption/edefault.asp.

UNFCCC (1997). *Kyoto Protocol to the United Nations Framework Convention on Climate Change*. FCCC/CP/L.7/Add.1, Kyoto.

Uyterlinde M A, Daniels B W, de Noord M, de Vries H J, de Zoeten-Dartenset C, Skytte K, Meibom P, Lescot D, Hoffmann T, Stronzik M, Gual M, del Rio P & Hernández F (2003), 'Renewable electricity market developments in the European Union; Final Report of the ADMIRE REBUS project'.

VDEW (997). *Investitionsrechnung in der Elektrizitätswirtschaft*, VDEW – Vereinigung Deutscher Elektrizitätswerke, Frankfurt a. M.

Vögele S (2000). *DIOGENES: Ein gesamtwirtschaftliches Modell zur Analyse von Energie- und Umweltpolitiken – Modellstruktur und Anwendung auf die Elektrizitätswirtschaft von Baden-Württemberg*, Springer, Berlin, Heidelberg, New York.

Vögele S, Hoffmann T & Markewitz P (2004), 'Fuel substitution options in the electricity sector: the dependency on capital malleability. Paper presented at the International Conference on Input-Output and General Equilibrium: Data, Modeling, and Policy Analysis, Brussels, September 2-4'.

Voogt M, Boots M G, Schaeffer G J & Martens J W (2001). Renewable electricity in a liberalised market – the concept of green certificates, *Energy & Environment* **11(1)**.

Walras L (1954). *Elements of Pure Economics*, Allen and Unwin, London.

Wardrop J G (1952). Proceeding of the Institute of Civil Engineers, Part II, p. 325-378.

Weber C (2004). Auswirkungen energie- und umweltpolitischer Instrumente bei unterschiedlichen Marktstrukturen – Analyse mit dem spieltheoretischen Modell POM, *in* Forum für Energiemodelle und Energiewirtschaftliche Systemanalysen in Deutschland, ed., *Energiemodelle zum Klimaschutz in liberalisierten Energiemärkten – Die Rolle erneuerbarer Energieträger*, Lit-Verlag, Münster, pp. 323–339.

Welsch H & Ochsen C (2001). Dismantling of Nuclear Power in Germany: Sectoral and Macroeconomic Effects, *Energy Policy* **29/4**, 279–289.

APPENDIX A

Algebraic Formulations of Models 2

A.1. Algebraic Formulation of Model used in Chapter 2

The decision, which non-nuclear technologies will back up nuclear capacity in the base load, is based on a dynamic linear programming model. The model minimizes investment and operation costs of replacement power plants over the model horizon (in our case 2035) subject to technological as well as policy constraints. The objective function is given as:

$$\text{(A.1.1)} \qquad min \left\{ \sum_{t=1}^{T} \sum_{j=1}^{J(t)} CAN_j(t) \cdot (1+i)^{-t} \cdot \sum_{a=1}^{A} \Delta L_j^a(t) \right\}$$

where:

t	:=	running index for periods,
T	:=	number of periods in the model,
j	:=	running index for technology type,
J(t)	:=	number of different types of capacity available in period t,
a	:=	running index for nuclear power plant,
i	:=	interest rate,
A	:=	number of nuclear power plants,
$CAN_j(t)$	:=	annuity of costs for technology j in period t [DM],
$\Delta L_j^a(t)$	:=	capacity of technology j commissioned in period t to back up nuclear power plant a [kW].

The calculation of the annuity is based on dynamic investment analysis (Stelzer, 1992; VDEW, 1993; Betge, 1998). The annuity for technology j is given as:

$$\text{(A.1.2)} \qquad CAN_j(t) = \left\{ \sum_{s=1}^{n_j} E_j(t+s) \cdot (1+i)^{-s} \right\} \cdot ANF$$

where:

n_j	:=	lifetime of capacity of technology j [periods],
$E_j\,(t+s)$	:=	payments in period t+s resulting from technology j commissioned in period t [DM/kW],
ANF	:=	annuity factor with: $ANF = \frac{(1+i)^{n_j} \cdot i}{(1+i)^{n_j} - 1}$

Payments $E_j\,(t+s)$ are defined as:

$$E_j(t+s) = \big(fc_j(t+1) + vc_j(t+s) \cdot \bar{h}_j + sc_j(t+s)\big) \tag{A.1.3}$$

where:

$fc_j(t+1)$	:=	fixed payments in period t+s for technology j commissioned in period t [DM/kW],
$vc_j(t+s)$	:=	variable payments in period t+s associated with capacity utilization of technology j commissioned in period t [DM/kWh],number of nuclear power plants,
$\bar{h}_j$	:=	annuity of costs for technology j in period t [DM],
$sc_j(t+s)$	:=	fixed repayments and interest payments in period t+s for technology j commissioned in period t [DM/kW].

Fixed payments are composed of personnel expenses and other fixed payments (such as insurance or maintenance costs). Variable payments consist of payments for fuels (incl. fuel taxes) and other variable expenses (e.g. factory supplies).[1] Total costs are minimized subject to three sets of constraints:

a) Technological constraints:

$$\sum_{a=1}^{A} \Delta L_j^a\,(t) \leq \bar{L}_j^{tech}(t), \quad j = [1, ..., J(t)],\, t = [1, ..., T] \tag{A.1.4}$$

where:

$\bar{L}_j^{tech}(t)$	:=	maximum capacity for technology j commissioned in period t to back up nuclear power capacity [kW].

[1]Note that repayment and interest payments apply independent of the operation of the existing power plants within the payback-period. For our core simulations we have assumed a payback-period of 20 years (KFA 1994, Hennicke et al. 2000).

b) Policy constraints (nuclear phase-out):

$$L_a(t) \leq \bar{L}_a(t), \quad a = [1, ...A],\, t = [1, ..., T] \tag{A.1.5}$$

where:

$L_a(t)$:= administered upper bound on capacity of nuclear power plant a in period t (depending on the phase-out regulation CAY, FLY or TAY) [kW].

c) Nuclear back-up constraint:

$$\sum_{a=1}^{A} \left(L_a^{Baseline} - L_a(t)\right) \cdot \bar{h}_{Nuclear} = \sum_{j=1}^{J(t)} \sum_{a=1}^{A} \Delta L_j^a(t) \cdot \bar{h}_j, \quad t = [1, ..., T] \tag{A.1.6}$$

where:

$L_a^{Baseline}$:= baseline capacity for nuclear power plant a in period t [kW].

A.2. Algebraic Formulation of Model used in Chapters 3 and 4

This appendix provides an algebraic summary of the equilibrium conditions for a simple partial equilibrium model designed to investigate the economic implications of emission allocation and emissions trading in a multi-sector, multi-region framework.

Emission mitigation options are captured through marginal abatement cost curves that are differentiated by sectors and regions. Cast as a planning problem, the model corresponds to a nonlinear program that seeks a cost-minimizing abatement scheme subject to initial emission allocation and institutional restrictions for emissions trading between sectors and regions. The nonlinear optimization problem can be interpreted as a market equilibrium problem where prices and quantities are defined using duality theory. In this case, a system of (weak) inequalities and complementary slackness conditions replace the minimization operator yielding a non-linear complementarity problem (see e.g., Rutherford 1995). Two classes of conditions characterize the (competitive) equilibrium for the model: zero profit conditions and market clearance conditions. The former class determines activity levels (quantities) and the latter determines prices. The economic equilibrium features complementarity between equilibrium variables and equilibrium conditions: activities will be operated as long as they break even, positive market prices imply market clearance otherwise commodities are in excess supply and the respective prices fall to zero.

In the generic setting laid out below – each model sector faces a specific emissions constraint vis-à-vis the business-as-usual situation. Without institutional restrictions on the scope of where-flexibility, each sector can trade emissions with other domestic sectors (domestic market) or the international market at an exogenous international emissions price. Arbitrage (zero-profit conditions) determines the efficient level of emission abatement and emission imports or exports at the sectoral level. In the simulations of segmented regulation under the EU-ETS, sectors that are not eligible for international emissions trading are excluded from exports and imports to the international market (the respective decision variables are fixed to zero and the associated equilibrium conditions are dropped). This will in general drive apart the marginal abatement costs for sectors outside the EU-ETS and those sectors that can trade internationally.

Numerically, the algebraic MCP formulation of our model is implemented in GAMS (Brooke, Kendrick and Meeraus (1987)) using PATH (Dirkse and Ferris (1995)) as a solver. Below, we present the GAMS code to replicate the results our analysis. The GAMS file and the EXCEL reporting sheet can be downloaded from the web-site (http://brw.zew.de/simac/). In the algebraic exposition of equilibrium conditions, i is used as an index for sectors and r as an index for regions.

TABLE A.2.1. Variables and parameters of model used in chapters 3 and 4

	Variables: Activity levels
D_{ir}	Emission abatement by sector i in region r
MD_{ir}	Imports of emission allowances by sector i in region r from domestic market
XD_{ir}	Exports of emission allowances by sector i in region r to domestic market
M_{ir}	Imports of emission allowances by sector i in region r from international market
X_{ir}	Exports of emission allowances by sector i in region r to international market
$MCDM_{ir}$	Imports of CDM credits by sector i in region r
	Variables: Price levels
P_{ir}	Marginal abatement costs by sector i in region r
PD_r	Price of domestically tradable allowances in region r
PFX	Price of internationally tradable permits
	Parameters
$TARGET_{ir}$	Effective carbon emission reduction requirement for sector i in region r
$a_{1,ir}$,$a_{2,ir}$, $a_{3,ir}$	Coefficients of marginal abatement cost function for sector i in region r
$\bar{P}_{CDM}$	Exogenous world market price for CDM credits

Zero Profit Conditions

1. Abatement by sector i in region r ($\perp D_{ir}$):

$$a_{1,ir} \cdot D_{ir} + a_{2,ir} \cdot D_{ir}^2 + a_{1,ir} \cdot D_{ir}^3 \geq P_{ir}$$

2. Permit imports by sector i in region r from domestic market ($\perp MD_{ir}$):

$$PD_r \geq P_{ir}$$

3. Permit exports by sector i in region r to domestic market ($\perp XD_{ir}$):

$$P_{ir} \geq PD_r$$

4. Permit imports by sector i in region r from international market ($\perp M_{ir}$):

$$PFX \geq P_{ir}$$

5. Permit exports by sector i in region r to international market ($\perp X_{ir}$):

$$P_{ir} \geq PFX$$

6. Imports of CDM credits by sector i in region r ($\perp MCDM_{ir}$):

$$\bar{P}_{CDM} \geq P_{ir}$$

Market Clearance Conditions

7. Market clearance for abatement by sector i in region r ($\perp P_{ir}$):

$$D_{ir} + M_{ir} + MD_{ir} + MCDM_{ir} \geq TARGET_{ir} + X_{ir} + XD_{ir}$$

8. Market clearance for domestically tradable permits ($\perp PD_{ir}$):

$$\sum_i XD_{ir} \geq \sum_i MD_{ir}$$

9. Market clearance for internationally tradable permits ($\perp PD_{ir}$):

$$\sum_i X_{ir} \geq \sum_i M_{ir}$$

A.3. Algebraic Formulation of Model used in Chapter 5

The electric power market can be modeled as an oligopolistic market equilibrium. We use a static multi-regional trade model of an oligopolistic electricity supply industry where a set of strategically acting firms competes for market shares on regional electricity markets. The basic Let R be the set of all regions (with index $r \in R$), F the set of all firms (with index $f \in F$) and I the set of all generation technologies (with index $i \in I$). Let P be the set of all power plants of technology type i in region r controlled by firm r (with index $p \in P$).

Each power plant p has a fixed generation capacity limit of K_p which can be used at production levels $x_{p,l}$ in order to supply electricity to the different demand segments. Accordingly, $s^{Ind}_{f,r,l}$ denotes supply of firm f in load segment l to industrial customers in region r ($s^{Res}_{f,r}$ denotes supply to residential customers respectively). When $p^{Ind}_{r,l}$ and p^{Res}_{r} are the are the prices for electricity on the industrial and residential market with $D^{Ind}_{r,l}(p^{Ind}_{r,l})$ and $D^{Res}_{r}(p^{Res}_{r})$ denoting iso-elastic demand functions for the respective markets each firm f maximizes its profit Π_f:

$$\underset{s^{Ind}_{f,r,l}, s^{Res}_{f,r}}{\text{Maximize}}\ \Pi_f = \sum_r \sum_l \left[p^{Ind}_{r,l}\left(D^{Ind}_{r,l}\right) \cdot s^{Ind}_{f,r,l} + p^{Res}_{r}\left(D^{Res}_{r}\right) \cdot s^{Res}_{f,r} - C_{f,r,l}\left(s^{Ind}_{f,r,l}, s^{Res}_{f,r}\right)\right] \tag{A.3.1}$$

Let $\sigma^{Ind}_{r,l}$and σ^{Res}_{r} denote the price elasticities of the demand segments. Differentiating for $s^{Ind}_{f,r,l}$ and $s^{Res}_{f,r}$ and substituting $\theta^{Ind}_{f,r,l}$ and $\theta^{Res}_{f,r}$ for the market shares in the different demand segments $s^{Ind}_{f,r,l}/D^{Ind}_{r,l}$ respectively $s^{Res}_{f,r}/D^{Res}_{r}$ yields the well known equilibrium conditions for a Cournot oligopoly where marginal values of supply to industrial and residential customers ($w^{Ind}_{f,r,l}$, $w^{Res}_{f,r}$) equal marginal revenues. For the industrial market segments supply is determined by:

$$w^{Ind}_{f,r,l} = p^{Ind}_{r,l} \cdot \left(1 - \frac{\theta^{Ind}_{f,r,l}}{\sigma^{Ind}_{r,l}}\right) \quad \forall f, r, l \tag{A.3.2}$$

With θ^L_l representing the shares of base- and peak-load demand in total electricity demand (with $\theta^L_{base} + \theta^L_{peakl} = 1$), supply to residential consumers is determined by:

$$\sum_l \theta^L_l \cdot w_{f,r,l} = p_r \cdot \left(1 - \frac{\sum_l \theta^L_l \cdot \theta^{Res}_{f,r}}{\sigma^{Res}_{r}}\right) \quad \forall f, r \tag{A.3.3}$$

Electricity production and supply are subject to different technical and political constraints, such as e.g. capacity limits of production facilities and intra-regional electricity trade.

Producers face minimum targets for the deployment of RES-E capacities and respective policies to reach them. Countries can either promote RES-E production by

subsidizing RES-E production on a per-unit basis. The total magnitude of RES-E subsidies is transferred to the customers via a tax on the electricity consumption. This mimics a feed-in tariff system where RES-E producers receive higher premiums for their product and higher costs are passed through to the consumer. Countries may also specify domestic quotas for RES-E production and facilitate trade in TGC's. We therefore introduced a secondary (competitive) market for tradable green certificates. Depending on the costs and potentials of RES-E production in each region a country can either fulfill its target by domestic production of green electricity or the import of green certificates.

Our model is formulated as a mixed complementarity problem (MCP). Two classes of conditions characterize the equilibrium for our model: zero profit conditions and market clearance conditions. The former class determines activity levels (quantities) and the latter determines prices. The economic equilibrium features complementarity between equilibrium variables and equilibrium conditions:[2] activities will be operated as long as they break even, positive market prices imply market clearance otherwise commodities are in excess supply and the respective prices fall to zero.

Table A.3.1 depicts the sets, parameters and variables of the model.

Table A.3.1. Sets, variables and parameters of model used in chapter 5

Sets:	
R	Set of all regions (with index $r \in R$ where $rs \in R$ is an electricity exporting and $rd \in R$ an importing region)
F	Set of all firms (with index $f \in F$)
I	Set of all generation technologies (with index $i \in I$)
$IR(I)$	Subset of all RES-E technologies (with index $i \in IR$)
P	Set of all power plants of technology type i in region r controlled by firm r (with index $p \in P$)
Parameters:	
$p0^{Ind}_{r,l}$	Reference electricity price in region r on the industrial market for electricity demand in load segment l
$p0^{Res}_{r}$	Reference electricity price in region r on the residential market
$D0^{Ind}_{r,l}$	Reference electricity demand of industrial customers in region r and load segment l
$D0^{Res}_{r,l}$	Reference electricity demand of residential customers in region r and load segment l
$\sigma^{Ind}_{r,l}$	Price elasticity of industrial demand in region r and load segment l

[2]In our algebraic exposition, the variable associated with each equilibrium condition is added in brackets and denoted with an orthogonality symbol ($\perp$).

σ_r^{Res}	Price elasticity of residential demand in region r
$c_{i,r,l}$	Variable production costs of plant of technology type i in region r and load area l
K_p	Generation capacity limit of plant p
$\bar{T}_{rs,rd}$	Capacity limit of all inter-regional exchange points between region rs and region rd
$rm_{r,l}$	Regional reserve requirements in region r and load segment l
gc_r	Regional charges for distribution of electricity in region r
$tf_{rs,rd}$	Charges for inter-regional electricity transmission from region rs to region rd
$dl_{rs,rd}$	Fraction of distribution losses of electricity exchange from region rs to region rd
cc_i	Specific carbon coefficient for electricity generation from technology i
$\bar{CL}_r$	Upper bound on carbon emissions in region r
a_i	Adjustment factor for technology-specific feed-in tariff for RES-E technology $i \in IR$
rq_r	Minimum shares of renewable electricity in the total supply to region r
Price variables:	
$p_{r,l}^{Ind}$	Price for electricity in region r on the industrial market in load segment l
p_r^{Res}	Price for electricity on the residential market in load segment l
$w_{f,r,l}$	Marginal value of electricity supply by firm f in region r and load area l
$\zeta_{r,l}$	Shadow value on reserve capacity constraint in region r and load area l
μ_p	Shadow price on capacity constraint of plant p in load area l
γ_r	Shadow value on the emissions constraint in region r
λ_r	Shadow value on the renewables quota in region r
ρ	Price of tradable green certificates
$\tau_{rs,rd,l}$	Shadow price on transmission capacity between adjacent regions rs and rd
ψ_r	Electricity tax in region r
Activity levels:	
$S_{f,r,l}^{Ind}$	Supply of firm f in load segment l to industrial customers in region r
$S_{f,r}^{Res}$	Supply of firm f in load segment l to residential customers in region r
$X_{p,l}$	Electricity production of plant p in load segment l
$Z_{p,l}$	Set-aside capacity provision of plant $p$in load segment l

$E_{f,rs,rd,l}$	Electricity trade by firm f from region rs to region rd
G_r^{EX}	Green certificates exports of region r to the international market
G_r^{IM}	Green certificates imports of region r from the international market

Zero-profit conditions:

Zero-profit condition for industrial supply ($\perp s_{f,r,l}^{Ind}$):

$$w_{f,r,l} + gc_r + rm_{r,l} \cdot \pi_{r,l} \geq p_{r,l}^{Ind} \cdot \left(1 - \frac{\theta_{f,r,l}^{Ind}}{\sigma_{r,l}^{Ind}}\right)$$

Zero-profit condition for residential supply ($\perp s_{f,r}^{Res}$):

$$\sum_l \theta_l^L \cdot (w_{f,r,l} + gc_r + rm_{r,l} \cdot \pi_{r,l}) \geq p_r \cdot \left(1 - \frac{\sum_l \theta_l^L \cdot \theta_{f,r}^{Res}}{\sigma_r^{Res}}\right)$$

Zero-profit condition for reserve capacity provision ($\perp Z_{p,l}$):

$$\mu_p \geq \zeta_{r,l}$$

Zero-profit condition for inter-regional electricity trade ($\perp E_{rs,rd,l}$):

$$w_{f,rs,l} + tf_{rs,rd,l} + \sum_{rs,rd} (\tau_{rs,rd,l} - \tau_{rd,rs,l}) \geq w_{f,rd,l} \, (1 - tl_{r,rr})$$

Zero-profit conditions for electricity production in case of a quota obligation system ($\perp x_{p,l}$):

$$c_{i,r,l} + \mu_{p,l} + cc_i\gamma_r + \lambda_r \cdot rq_r \geq w_{f,r,l} + \lambda_r \quad \forall i \in IR$$

$$c_{i,r,l} + \mu_{p,l} + cc_i\gamma_r + \lambda_r \cdot rq_r \geq w_{f,r,l} \quad \forall i \notin IR$$

Zero-profit conditions for electricity production in case of a feed-in tariff system ($\perp x_{p,l}$):

$$c_{i,r,l} + \mu_{p,l} + cc_i\gamma_r \geq w_{f,r,l} + a_i\lambda_r \quad \forall i \in IR$$

$$c_{i,r,l} + \mu_{p,l} + cc_i\gamma_r \geq w_{f,r,l} \quad \forall i \notin IR$$

Additional zero-profit conditions for international trade in TGCs:

Zero-profit condition for green certificates imports ($\perp G_r^{IM}$):

$$\rho \geq \lambda_r$$

Zero-profit condition for green certificates exports ($\perp G_r^{EX}$):

$$\lambda_r \geq \rho$$

Market-clearance conditions:

Market-clearance condition for industrial supply ($\perp p_{r,l}^{Ind}$):

$$\sum_f s_{f,r,l}^{Ind} = D0_{r,l}^{Ind} \cdot \left(\frac{(1+\psi_r) \cdot p_{r,l}^{Ind}}{p0_{r,l}^{Ind}} \right)^{\sigma_{r,l}^{Ind}}$$

Market-clearance condition for residential supply ($\perp p_r^{Res}$):

$$\sum_f s_{f,r}^{Res} = D0_{r,l}^{Res} \cdot \left(\frac{(1+\psi_r) \cdot p_r^{Res}}{p0_r^{Res}} \right)^{\sigma_r^{Res}}$$

Market-clearance condition for electricity trade ($\tau_{rs,rd,l}$):

$$\bar{T}_{rs,rd} \geq \sum_{f,rs} E_{f,rs,rd,l} - \sum_{f,rd} E_{f,rs,rd,l}$$

Market-clearance condition for reserve capacity ($\perp \zeta_{r,l}$):

$$\sum_{f,i} Z_{f,r,i,l} \geq rm_{r,l} \cdot \sum_f \left(s_{f,r,l}^{Ind} + \theta_l^L \cdot s_{f,r}^{Res} \right)$$

Market-clearance condition for electricity production ($\perp w_{f,r,l}$):

$$\sum_p x_{p,l} + \sum_{rs,rd,i,l} \left[(1 - dl_{rs,r}) \cdot E_{f,rs,r,l} - E_{f,r,rd,l} \right] \geq s_{f,r,l}^{Ind} + \theta_l^L \cdot s_{f,r}^{Res}$$

Market-clearance condition for electricity production capacity ($\perp \mu_p$):

$$K_p \geq \sum_l \left(X_{p,l} + Z_{p,l} \right)$$

Market-clearance condition for emission constraint ($\perp \gamma_r$):

$$\bar{CL}_r \geq \sum_{p,l} cc_i \cdot X_{p,l}$$

Market-clearance condition for renewable quota ($\perp\lambda_r$):

$$\sum_{f,i\in IR,r,l} X_{f,r,i,l} + G_r^{EX} - G_r^{IM} \geq rq_r \cdot \sum_{f,l} \left(s_{f,r,l}^{Ind} + \theta_l^L \cdot s_{f,r}^{Res}\right)$$

Additional market-clearance condition for ad-valorem electricity tax in case of feed-in tariff systems ($\perp\psi_r$):

$$\sum_l \left(p_{r,l}^{Ind} \cdot \psi_r \cdot \sum_f s_{f,r,l}^{Ind}\right) + p_r^{Res} \cdot \psi_r \cdot \sum_f s_{f,r}^{Res} \geq \sum_{f,ir,l} X_{f,r,ir,,l} \cdot \lambda_r$$

Additional market-clearance condition for international trade in TGCs ($\perp\rho$):

$$\sum_r G_r^{EX} \geq \sum_r G_r^{IM}$$

Market shares and load share:

Market shares in industrial markets ($\perp\theta_{f,r,l}^{Ind}$):

$$\theta_{f,r,l}^{Ind} = \frac{s_{f,r,l}^{Ind}}{\sum_f s_{f,r,l}^{Ind}}$$

Market shares in residential markets ($\perp\theta_{f,r}^{Res}$):

$$\theta_{f,r}^{Res} = \frac{s_{f,r}^{Res}}{\sum_f s_{f,r}^{Res}}$$

Load shares in residential demand ($\perp\theta_l^L$):

$$\theta_l^L = \frac{D0_{r,l}^{Res} \cdot \left(\frac{(1+\psi_r)\cdot p_r^{Res}}{p0_r^{Res}}\right)^{\sigma_r^{Res}}}{\sum_l D0_{r,l}^{Res} \cdot \left(\frac{(1+\psi_r)\cdot p_r^{Res}}{p0_r^{Res}}\right)^{\sigma_r^{Res}}}$$

A.4. Algebraic Formulation of Model used in Chapter 6

This section provides an algebraic summary of equilibrium conditions for a static (dynamic-recursive) multi-region trade model designed to investigate the economic implications of a nuclear phase-out on European level. Before presenting the algebraic exposition this section states the main assumptions and introduces the notation.

Nested separable constant elasticity of substitution (CES) functions characterize the use of inputs in production. All production exhibits non-increasing returns to scale. Goods are produced with capital, labor, energy and material (KLEM). A representative agent in each region is endowed with three primary factors: natural resources (used for fossil fuel production), labor and capital. The representative agent maximizes utility from consumption of a CES composite which combines demands for energy and non-energy commodities. Supplies of labor, capital and natural resources are exogenous. Labor and capital are mobile within domestic borders, but cannot move between regions; natural resources are sector specific. All goods are traded internationally and differentiated by region of origin (Armington, 1969). Lump sum transfers of the representative agent finance the exogenous government demands in each region, and the government transfers all revenues from carbon taxes or auctioned carbon permits to the representative agent. Two classes of conditions characterize the competitive equilibrium for this model: zero profit conditions and market clearance conditions. The former class determines activity levels and the latter determines price levels.

In the algebraic exposition, the notation Π_{ir}^{Z} is used to denote the profit function of sector i in region r, where Z is the name assigned to the associated production activity. Differentiating the profit function with respect to input and output prices provides compensated demand and supply coefficients (Shepard's lemma), which subsequently appear in the market clearance conditions. This study uses i (aliased with j) as an index for commodities (sectors), r (aliased with s) as an index for regions and d as an index for the demand category ($d = Y$: intermediate demand, $d = C$: private household demand, $d = G$: government demand, $d = I$: investment demand). The label EG represents the set of energy goods and the label FF denotes the subset of fossil fuels. Table A.4.1 explains the notations for sets, variables and parameters employed within this algebraic exposition.

In the dynamic-recursive model set-up the path for the economy is a set of connected equilibria where the current period's saving augments capital in the next period. Capital stocks are updated as an intermediate calculation between periods. In this framework all equilibrium conditions are strictly inter-period. Hence, time indices are omitted in the algebraic summary.

TABLE A.4.1. Sets, variables and parameters of model used in chapter 6

Denotation	Description	Values
Sets:		
I	Set of all commodities (sectors) (with index $i \in I$ and index $j \in I$)	
R	Set of all regions (with index $r \in R$ and index $s \in R$)	
D	Set of demand categories (with $d = Y$ as intermediate demand; $d = C$ as private houshold demand; $d = G$ as governmental demand and $d = I$as investment demand)	
$EG(I)$	Energy goods except for crude oil: coal, refined oil, gas and electricity	
$FF(I)$	Primary fossil fuels: coal, crude oil and gas	
$EL(I)$	Electricity	
T	Set of all discrete electricity generation technologies/power plants (with $t = HCO$ as hard coal fired plant; $t = SCO$as soft coal fired plant; $t = OEL$ as oil fired plant; $t = NGS$ as gas fired plant; $t = NUC$ as nuclear plant; $t = BIO$ as plant operated with biomass; $t = HYD$ as hydro plant and $t = WND$ as wind power plant)	
Price variables:		
p_{ir}	Output price of good i produced in region r for domestic market	
p^E_{ir}	Price of aggregate energy inputs into sector i in region r	
p^M_{ir}	Import price aggregate for good i imported to region r	
p^A_{dir}	Price of Armington aggregate for good i in demand category d in region r	
p^I_i	Price of investment demand in region r	
p^G_i	Price of government demand in region r	
p^C_r	Price of aggregate houshold demand in region r	
p^E_{Cr}	Price of aggregate energy inputs into houshold consumption of region r	
w_r	Wage rate in region r	
v_r	Rate of return in region r	
$\overline{p}_{iROW}$	Exogenous world market price of good i	

Denotation	Description	Values
Activity variables:		
Y_{ir}	Level of production for sector i in region r	
E_{ir}	Level of production for aggregate energy input in sector i of region r	
M_{ir}	Level of import aggregate production for good i in region r	
A_{dir}	Level of Armington production for good i in demand category d of region r	
I_r	Aggregate investment in region r	
G_r	Aggregate public output in region r	
C_r	Aggregate household consumption in region r	
E_{Cr}	Level of production for aggregate energy input in household consumption of region r	
Cost shares and endowments:		
θ^X_{jr}	Value share of exports in sector j of region r	
θ_{ijr}	Value share of intermediate good $i$demand in sector j of region $r(j \notin FF)$	
θ^{KLE}_{jr}	Value share of KLE aggregate demand in sector j of region r $(j \notin FF)$	
θ^E_{jr}	Value share of aggregate energy demand in the KLE aggregate of sector $j$in region r $(j \in FF)$	
α^T_{jr}	Value share of labor $(T = L)$ or capital $(T = K)$ in value-added demand of sector j in region r $(j \notin FF)$	
θ^Q_{jr}	Value share of fossil fuel resource in sector j of region r $(j \in FF)$	
θ^{FF}_{jr}	Value share of good i $(T = i)$ or labor $(T = L)$ or capital $(T = K)$ in sector j of region r $(j \in FF)$	
θ^{COA}_{jr}	Value share of coal in aggregate energy demand of sector j in region r	
θ^{ELE}_{jr}	Value share of electricity in aggregate non-coal energy demand of sector j in region r	
β_{ijr}	Value of fossil fuel $i \in gas, crude\,oil, refined\,oil$ in aggregate demand for non-coal fossil fuel composite of of sector $j$in region r	
θ^{ELE}_{Ler}	Benchmark technology cost share of labor input in electricity production by technology e in region r	
θ^{ELE}_{Ktr}	Benchmark technology cost share of capital input in electricity production by technology t in region r	

Denotation	Description	Values
θ_{itr}^{ELE}	Benchmark technology cost share of energy ($i \in EG \setminus \{ELE\}$) and material ($i \in I \setminus \{FF \cup EL$) inputs in electricity production by technology t in region r	
θ_{jBr}^{M}	Value share of imports from ROW ($b = ROW$) or region s ($b = s$) in aggregate import demand of $j$in region r	
θ_{djr}^{A}	Value share of domestic variety j in Armington production for demand category d in region r	
θ_{r}^{I}	Value share of Armington demand in investment for region r	
θ_{r}^{G}	Value share of Armington demand in public good production for region r	
θ_{Cr}^{E}	Value share of aggregate energy demand in aggregate consumption of the representative household in region r	
γ_{ir}	Value share of non-energy i in aggregate non-energy consumption demand of the representative household in region r	
θ_{ELECr}^{E}	Value share of electricity demand in aggregate energy demand of the representative household in region r	
θ_{iCr}^{E}	Value share demand for non-electric energy good $i$in the composite non-electric energy demand of the representative agent in region r	
$\overline{L}_r$	Aggregate labor endowment for region r	
$\overline{K}_r$	Aggregate capital endowment for region r	
$\overline{Q}_{jr}$	Endowment with fossil fuel resource j for region r ($j \in FF$)	
$\overline{G}_r$	Exogenously-specified demand for public output, region r	
θ_{ir}^{X}	Endowment with carbon emission rights for region r	

Key Elasticities:

η	Elasticity of transformation between production for the domestic market and production for the export	4
σ_{KLE}	Elasticity of substitution between the energy aggregate and value-added (Cobb-Douglas) in sectoral production of non-fossil goods	0.5
σ_{Q}	Elasticity of substitution between fossil fuel resources and other composite input in sectoral production of fossil fuels	0
σ_{COA}	Elasticity of substitution between coal and the non-coal energy composite in the energy aggregate of sectoral production	0.5
$\sigma_{ELE,j}$	Elasticity of substitution between electricity and the aggregate of non-coal fossil fuel inputs in the energy aggregate of sectoral production	0.3
σ_{M}	Elasticity of substitution between imports from different regions	8

Denotation	Description	Values
σ_A	Armington elasticity of substitution between the import aggregate and the domestic input	4
$\sigma_{ELE,C}$	Elasticity of substitution between electricity and the non-electric energy composite in aggregate energy demand by the representative household	0.3
σ_{NELE}	Elasticity of substitution between different non-electric energy goods in aggregate energy demand by the representative household	0.8

Adopting the above notations the conditions for the single-period equilibrium of the dynamic-recursive model read as follows:

Zero profit conditions:

1a. Production of goods (except fossil fuels and electricity)

$$\begin{aligned}
\Pi^Y_{jr} &= \left(\theta^X_{jr} p^{1-\eta}_{jr} + \left(1-\theta^X_{jr}\right) p^{1-\eta}_{jr}\right)^{\frac{1}{1-\eta}} \\
&\quad - \sum_{i \notin EG} \theta_{ijr} p^A_{Yir} \\
&\quad - \theta^{KLE}_{jr} \left[\theta^E_{jr} p^{E^{1-\sigma_{KLE}}}_{jr} + \left(1-\theta^E_{jr}\right)\left(w_r^{\alpha^L_{jr}} v_r^{\alpha^K_{jr}}\right)^{1-\sigma_{KLE}}\right]^{\frac{1}{1-\sigma_{KLE}}} \\
&= 0 \ \forall j \notin FF
\end{aligned}$$

1b. Production of fossil fuels:

$$\begin{aligned}
\Pi^Y_{jr} &= \left(\theta^X_{jr} p^{1-\eta}_{jr} + \left(1-\theta^X_{jr}\right) p^{1-\eta}_{jr}\right)^{\frac{1}{1-\eta}} \\
&\quad - \left[\theta^Q_{jr} q_{jr}^{1-\sigma_Q} + \left(1-\theta^Q_{jr}\right)\left(\theta^{FF}_{Ljr} w_r + \theta^{FF}_{Kjr} v_r + \sum_i \theta^{FF}_{ijr} p^A_{Yir}\right)^{1-\sigma_Q}\right]^{\frac{1}{1-\sigma_Q}} \\
&= 0 \ \forall j \in FF
\end{aligned}$$

1c. Electricity production:

$$\begin{aligned}
\Pi^{ELE}_{jtr} &= \left(\theta^X_{jr} p^{1-\eta}_{jr} + \left(1-\theta^X_{jr}\right) p^{1-\eta}_{jr}\right)^{\frac{1}{1-\eta}} \\
&\quad - \left(\theta^{ELE}_{Ltr} w_r + \theta^{ELE}_{Ktr} v_r + \sum_{i \notin \{EL \cup FF\}} \theta^{ELE}_{itr} p^A_{Yir}\right) \\
&= 0 \ \forall j \in EL
\end{aligned}$$

2. Sector-specific energy aggregate:

$$\begin{aligned}
\Pi^E_{jr} &= p^E_{jr} - \left\{ \theta^{COA}_{jr} p^{A^{1-\sigma_{COA}}}_{Y_{COAr}} + \left(1-\theta^{COA}_{jr}\right) \left[\theta^{ELE}_{jr} p^{A^{1-\sigma_{ELE}}}_{Y_{ELEr}} + \left(1-\theta^{ELE}_{jr}\right) \right.\right. \\
&\quad \left.\left. \left(\prod_{i\in\{GAS,CRU,OIL\}} p^{A^{\beta_{ijr}}}_{Yir} \right)^{1-\sigma_{ELEj}} \right]^{\frac{1}{1-\sigma_{ELEj}}} \right\}^{\frac{1}{1-\sigma_{COA}}} \\
&= 0
\end{aligned}$$

3. Aggregate import formation:

$$\begin{aligned}
\Pi^M_{jr} &= p^M_{jr} - \left(\theta^M_{jROWr} \overline{p}^{1-\sigma_M}_{jROW} + \sum_s \theta^M_{jsr} p^{1-\sigma_M}_{js} \right)^{\frac{1}{1-\sigma_M}} \\
&= 0
\end{aligned}$$

4. Armington production:

$$\begin{aligned}
\Pi^A_{djr} &= p^A_{djr} - \left[\theta^A_{djr} p^{1-\sigma_A}_{jr} + \left(1-\theta^A_{djr}\right) p^{M^{1-\sigma_A}}_{jr} \right]^{\frac{1}{1-\sigma_A}} \\
&= 0
\end{aligned}$$

5. Investment:

$$\begin{aligned}
\Pi^I_r &= p^I_r - \sum_i \theta^I_{ir} p^A_{Iir} \\
&= 0
\end{aligned}$$

6. Public good production:

$$\begin{aligned}
\Pi^G_r &= p^G_r - \sum_i \theta^G_{ir} p^A_{Gir} \\
&= 0
\end{aligned}$$

7. Houshold consumption demand:

$$\begin{aligned}
\Pi^C_r &= p^C_r - \left[\theta^E_{Cr} p^{E^{1-\sigma_{EC}}}_{Cr} + \left(1-\theta^E_{Cr}\right) \left(\prod_{i\notin EG} p^{A^{\gamma_{ir}}}_{Cir} \right)^{1-\sigma_{EC}} \right]^{\frac{1}{1-\sigma_{EC}}} \\
&= 0
\end{aligned}$$

8. Houshold energy demand:

$$\begin{aligned}
\Pi^E_{Cr} &= p^E_{Cr} - \Bigg\{ \theta^E_{ELECr} p^{E^{1-\sigma_{ELEC}}}_{ELEr} \\
&\quad + \left(1 - \theta^E_{ELECr}\right) \left[\left(\sum_{i \in EG \setminus \{ELE\}} \theta^E_{iCr} p^{A^{1-\sigma_{NELE}}}_{Cir} \right)^{\frac{1}{1-\sigma_{NELE}}} \right]^{1-\sigma_{ELEC}} \Bigg\}^{\frac{1}{1-\sigma_{ELEC}}} \\
&= 0
\end{aligned}$$

Market clearance conditions

9. Labor:

$$\overline{L}_r = \sum_j Y_{jr} \frac{\partial \Pi^Y_{jr}}{\partial w_r}$$

10. Capital:

$$\overline{K}_r = \sum_j Y_{jr} \frac{\partial \Pi^Y_{jr}}{\partial v_r}$$

11. Fossil fuel production resources:

$$\overline{Q}_{jr} = Y_{jr} \frac{\partial \Pi^Y_{jr}}{\partial q_{jr}} \quad \forall j \in FF$$

12. Output:

$$Y_{ir} = \sum_d \sum_j A_{djr} \frac{\partial \Pi^A_{djr}}{\partial p_{ir}} + \sum_s M_{is} \frac{\partial \Pi^M_{is}}{\partial p_{ir}}$$

13. Sector-specific energy aggregate:

$$E_{ir} = Y_{ir} \frac{\partial \Pi^Y_{ir}}{\partial P^E_{jr}}$$

14. Import aggregate:

$$M_{ir} = \sum_d A_{dir} \frac{\partial \Pi^A_{dir}}{\partial p^M_{ir}}$$

15. Armington aggregate:

$$A_{dir} = \sum_j Y_{jr} \frac{\partial \Pi_{jr}^Y}{\partial p_{dir}^A} + C_r \frac{\partial \Pi_r^C}{\partial p_{dir}^A} + I_r \frac{\partial \Pi_{jr}^I}{\partial p_{dir}^A} + G_r \frac{\partial \Pi_r^G}{\partial p_{dir}^A}$$

16. Final demand:

$$C_r = (1 - mps_r) \frac{\left(w_r \overline{L}_r + v_r \overline{K}_r + \sum_{j \in FF} q_{jr} \overline{Q}_{jr} - p_r^G \overline{G}_r - \overline{B}_r\right)}{p_r^C}$$

17. Investment (savings) demand:

$$I_r = mps_r \frac{\left(w_r \overline{L}_r + v_r \overline{K}_r + \sum_{j \in FF} q_{jr} \overline{Q}_{jr} - p_r^G \overline{G}_r - \overline{B}_r\right)}{p_r^I}$$

18. Household aggregate energy demand:

$$E_{Cr} = C_r \frac{\partial \Pi_r^C}{\partial P_{Cr}^E}$$

19. Balance of payments:

$$\sum_{i,r} \overline{p}_i M_{ir} \frac{\partial \Pi_{ir}^M}{\partial \overline{p}_i} = \sum_{i,r} \overline{p}_i Y_{ir} \frac{\partial \Pi_{ir}^Y}{\partial \overline{p}_i} + \sum_r \overline{B}_r$$

APPENDIX B

Additional Parameter Values and Results

B.1. Additional Parameter Values for Analysis in Chapter 5

Table B.1.1. Benchmark electricity demand and reference prices

Country	Electricity demand in 2004 [in GWh]					Electricity prices in 2004 [in €/MWh]		
		Industrial demand		Residential demand		Industrial		Residential
	Total	base-load	peak-load	base-load	peak-load	big	small	
Austria	62,850	16,125	12,770	18.949	15.006	42	96	98
Belgium	88,357	33,189	12,616	30.832	11.720	57	120	114
Czech Republic	61,728	15,856	13,113	17.931	14.829	41	60	68
Denmark	35,502	8,219	4,978	13.891	8.413	36	71	91
Estonia	5,272	1,666	0,512	2.366	0.728	39	53	58
Finland	86,917	38,426	10,778	29.453	8.261	49	66	79
France	477,238	117,928	62,210	194.497	102.602	45	84	91
Germany	552,673	163,129	122,062	152.999	114.483	63	149	128
Greece	51,221	12,018	6,501	21.223	11.480	53	93	62
Hungary	38,221	10,369	4,588	16.127	7.136	55	166	84
Ireland	21,832	5,602	2,531	9.436	4.263	67	131	106
Italy	321,817	111,707	66,943	89.519	53.647	73	116	141
Latvia	4,882	1,396	0,429	2.338	0.719	35	68	58
Lithuania	6,723	2,153	0,663	2.988	0.919	45	70	54
Luxembourg	6,358	2,456	1,888	1.139	0.875	42	147	122
Poland	130,275	45,190	18,834	46.762	19.489	42	81	65
Portugal	47,900	11,222	9,254	15.030	12.395	61	103	128
Slovakia	26,303	9,057	2,817	11.006	3.423	67	93	105
Slovenia	13,328	4,652	2,390	4.153	2.134	45	97	86
Spain	250,437	83,957	40,540	84.931	41.010	49	97	89
Sweden	146,446	44,702	23,222	51.677	26.845	47	72	84
The Netherlands	110,857	27,816	23,603	32.154	27.284	53	106	103
United Kingdom	332,749	85,660	38,699	143.541	64.849	41	80	85

Source: IEA/OECD (2004) and European Commission (2005a) and own calculations

TABLE B.1.2. Electricity generation costs for conventional power generation technologies across regions [in €/MWh]

Region	Load Segment	Fuel Oil	Hard Coal I	Hard coal II (CCGT)	Hydro I	Hydro II (pumped storage)	Natural Gas I (gas turbine)	Natural gas II (CCGT)	Natural gas III (CCGT)	Nuclear Power	Soft coal I	Soft coal II (CCGT)
Austria	base	0.52	0.30	0.22	0.21	1.11	0.56	0.38	0.41	0.14	0.23	0.25
	peak	0.63	1.78	1.29	1.92	1.11	0.69	0.91	1.24	1.05	1.34	1.69
Belgium	base	0.47	0.30	0.22	0.21	1.26	0.50	0.35	0.38	0.14	0.23	0.25
	peak	0.61	1.82	1.33	1.92	1.26	0.63	0.91	1.23	1.06	1.35	1.70
Czech Republic	base	0.44	0.27	0.19	0.21	0.81	0.50	0.32	0.35	0.13	0.22	0.23
	peak	0.54	1.49	1.00	1.92	0.81	0.62	0.74	1.11	0.97	1.23	1.57
Denmark	base	0.51	0.31	0.24	0.21	0.85	0.58	0.38	0.40	0.15	0.23	0.25
	peak	0.62	1.93	1.44	1.92	0.85	0.71	0.97	1.27	1.10	1.39	1.75
Estonia	base	0.27	0.27	0.19	0.21	0.85	0.38	0.21	0.24	0.13	0.22	0.23
	peak	0.40	1.46	0.97	1.92	0.85	0.50	0.63	1.00	0.96	1.22	1.55
Finland	base	0.43	0.29	0.22	0.21	0.99	0.71	0.32	0.35	0.14	0.23	0.25
	peak	0.54	1.76	1.28	1.92	0.99	0.84	0.85	1.18	1.05	1.33	1.68
France	base	0.49	0.29	0.22	0.21	1.02	0.55	0.36	0.39	0.14	0.23	0.24
	peak	0.60	1.74	1.25	1.92	1.02	0.68	0.88	1.21	1.04	1.32	1.67
Germany	base	0.56	0.31	0.23	0.21	1.38	0.52	0.41	0.44	0.15	0.23	0.25
	peak	0.70	1.88	1.39	1.92	1.38	0.66	1.00	1.31	1.08	1.37	1.73
Greece	base	0.44	0.28	0.20	0.21	1.00	0.67	0.32	0.35	0.14	0.22	0.24
	peak	0.55	1.60	1.11	1.92	1.00	0.80	0.79	1.14	1.00	1.27	1.61
Hungary	base	0.47	0.27	0.19	0.21	1.06	0.57	0.33	0.37	0.13	0.22	0.23
	peak	0.60	1.48	0.98	1.92	1.06	0.69	0.77	1.14	0.97	1.23	1.56
Ireland	base	0.44	0.31	0.23	0.21	1.30	0.77	0.33	0.36	0.15	0.23	0.25
	peak	0.56	1.89	1.40	1.92	1.30	0.90	0.91	1.22	1.09	1.38	1.73
Italy	base	0.44	0.30	0.22	0.21	1.24	0.67	0.33	0.36	0.14	0.23	0.25
	peak	0.55	1.78	1.29	1.92	1.24	0.80	0.86	1.19	1.05	1.34	1.69
Latvia	base	0.39	0.27	0.19	0.21	0.80	1.03	0.29	0.32	0.13	0.22	0.23
	peak	0.49	1.46	0.97	1.92	0.80	1.15	0.69	1.07	0.96	1.22	1.55
Lithuania	base	0.40	0.27	0.19	0.21	0.92	0.61	0.29	0.33	0.13	0.22	0.23
	peak	0.50	1.46	0.97	1.92	0.92	0.72	0.70	1.07	0.96	1.22	1.55
Luxembourg	base	0.44	0.30	0.23	0.21	1.12	0.57	0.33	0.36	0.14	0.23	0.25
	peak	0.56	1.87	1.38	1.92	1.12	0.70	0.90	1.22	1.08	1.37	1.72
Poland	base	0.41	0.27	0.19	0.21	0.77	0.56	0.30	0.33	0.13	0.22	0.23

Region	Load Segment	Fuel Oil	Hard Coal I	Hard coal II (CCGT)	Hydro I	Hydro II (pumped storage)	Natural Gas I (gas turbine)	Natural gas II (CCGT)	Natural gas III (CCGT)	Nuclear Power	Soft coal I	Soft coal II (CCGT)
	peak	0.53	1.49	1.00	1.92	0.77	0.68	0.73	1.10	0.97	1.23	1.57
Portugal	base	0.38	0.28	0.20	0.21	1.11	0.72	0.28	0.32	0.14	0.22	0.24
	peak	0.52	1.57	1.08	1.92	1.11	0.84	0.75	1.11	0.99	1.26	1.60
Slovakia	base	0.57	0.27	0.19	0.21	1.12	0.56	0.40	0.44	0.13	0.22	0.23
	peak	0.68	1.46	0.97	1.92	1.12	0.68	0.81	1.18	0.96	1.22	1.55
Slovenia	base	0.42	0.27	0.19	0.21	0.83	0.66	0.30	0.34	0.13	0.22	0.23
	peak	0.54	1.46	0.97	1.92	0.83	0.78	0.73	1.10	0.96	1.22	1.55
Spain	base	0.44	0.28	0.21	0.21	0.94	0.67	0.32	0.36	0.14	0.22	0.24
	peak	0.56	1.63	1.14	1.92	0.94	0.79	0.81	1.16	1.01	1.28	1.62
Sweden	base	0.68	0.30	0.22	0.21	1.00	0.68	0.48	0.51	0.14	0.23	0.25
	peak	0.79	1.78	1.29	1.92	1.00	0.81	1.01	1.34	1.05	1.34	1.69
Netherlands	base	0.41	0.30	0.23	0.21	1.00	0.65	0.31	0.34	0.14	0.23	0.25
	peak	0.52	1.83	1.34	1.92	1.00	0.78	0.86	1.18	1.07	1.35	1.71
United	base	0.43	0.31	0.23	0.21	0.79	0.56	0.33	0.36	0.15	0.23	0.25
Kingdom	peak	0.52	1.89	1.40	1.92	0.79	0.69	0.89	1.20	1.09	1.38	1.73

Source: Own calculations based on KfA (1994)

B.2. Additional Results of Analysis in Chapter 5

Table B.2.1. Technology mix for electricity production under *FEED_D*, *FEED_H*, *QUOTA_R* and *QUOTA_EU*

	Technology	BaU	FEED_D	FEED_H	QUOTA_R	QUOTA_EU
		[in % of total generation]				
EEA	Nuclear	41,37	41,71	41,68	40,75	40,92
	Soft Coal and Lignite	13,90	14,00	14,01	13,56	13,51
	Hard coal	17,60	17,72	17,73	17,17	17,10
	Natural gas	18,75	18,13	18,15	19,49	19,83
	Fuel Oil				0,85	0,49
	Hydro	8,38	8,44	8,44	8,17	8,14
AUT	Soft Coal and Lignite	7,73	8,19	8,39	5,04	3,80
	Hard coal	22,65	17,45	17,30	17,78	17,23
	Natural gas	21,42	18,13	17,79	13,71	11,64
	Fuel Oil	5,63				
	Hydro	35,94	40,26	40,19	45,57	47,84
	Biomass	0,59	3,99	4,35	4,32	5,36
	Wind	3,94	8,64	8,87	10,08	10,51
	Other RES	2,11	3,34	3,12	3,50	3,61
CZE	Nuclear	26,24	25,84	25,76	27,52	27,74
	Soft Coal and Lignite	46,65	46,90	46,96	45,85	45,71
	Hard coal	2,75	2,76	2,77	2,70	2,69
	Natural gas	10,00	10,06	10,07	9,83	9,80
FRA	Hydro	14,36	14,43	14,45	14,11	14,07
	Nuclear	62,23	60,09	61,77	61,95	58,32
	Natural gas	1,10	1,25	1,23	1,14	1,20
	Fuel Oil	20,94	18,82	17,03	18,73	7,00
	Hydro	15,74	17,91	19,78	18,00	29,85
	Wind					3,42
	Solar		0,37			
	Other RES		1,56	0,20	0,18	0,19
GRE	Soft Coal and Lignite	60,70	60,50	60,50	61,15	10,05
	Natural gas	15,47	15,61	15,61	14,89	
	Hydro	23,83	23,89	23,89	23,96	70,13
	Biomass					0,55
	Wind					17,36
	Other RES					1,91

	Technology	BaU	FEED_D	FEED_H	QUOTA_R	QUOTA_EU
		[in % of total generation]				
ITA	Soft Coal and Lignite	1,16	1,22	1,21	1,40	1,29
	Hard coal	61,72	31,85	32,12	26,98	42,96
	Natural gas	36,10	35,62	35,59	35,84	35,70
	Hydro	1,01	8,59	9,17	10,60	9,05
	Biomass		8,52	8,04	9,16	4,74
	Wind		0,52	0,52	0,60	0,55
	Solar		0,23			
	Other RES		13,45	13,34	15,42	5,71
POL	Soft Coal and Lignite	64,78	65,56	66,58	64,89	64,89
	Natural gas	27,48	27,84	28,14	27,39	27,39
	Fuel oil	5,64	4,47	3,11	5,62	5,62
	Hydro	2,11	2,14	2,16	2,10	2,10
Nordic	Nuclear	42,77	39,04	40,55	38,17	32,61
	Hard coal	24,22	16,39	14,81	16,60	10,22
	Natural gas	1,44				
	Hydro	27,31	35,26	34,00	35,01	37,58
	Biomass		0,22			2,23
	Wind		1,88	5,23	4,66	9,55
	Other RES	4,26	7,21	5,41	5,57	7,81
Baltic	Nuclear	27,61	27,61	27,61	27,61	27,61
	Natural gas	32,01	32,01	32,01	32,01	32,01
	Hydro	40,38	40,38	40,38	40,38	40,38
GBR	Nuclear	25,12	26,31	26,55	26,24	26,10
	Hard coal	36,84	30,52	30,34	30,33	28,27
	Natural gas	37,06	33,03	32,97	33,30	31,37
	Hydro	0,22	0,23	0,23	0,23	0,23
	Biomass		2,37	0,44	0,44	2,18
	Wind		2,40	5,07	5,08	6,73
	Other RES	0,76	5,13	4,40	4,39	5,11
DEU	Nuclear	41,11	39,49	40,05	40,13	42,21
	Soft Coal and Lignite	7,34	3,39	4,87	4,78	5,85
	Hard coal	17,52	14,96	14,67	14,74	15,27
	Natural gas	23,40	19,09	17,56	17,48	20,23
	Fuel oil	9,75	10,29	10,09	10,14	10,01
	Hydro	0,59	1,90	4,42	4,36	0,61
	Biomass		5,73	3,83	3,84	1,61
	Wind		1,38	1,35	1,36	1,23
	Solar		0,47			
	Other RES	0,29	3,31	3,15	3,17	2,98

	Technology	BaU	FEED_D	FEED_H	QUOTA_R	QUOTA_EU
		[in % of total generation]				
BLX	Nuclear	26,40	24,33	24,07	24,09	23,61
	Hard coal	37,09	33,91	34,32	34,19	31,58
	Natural gas	35,09	34,39	34,23	34,34	34,39
	Hydro			0,07	0,07	0,23
	Biomass		2,07	1,30	1,30	2,10
	Wind		3,12	4,26	4,25	5,91
	Other RES	1,42	2,19	1,76	1,76	2,18
SPAP	Nuclear	22,34	26,70	26,73	27,26	24,39
	Soft Coal and Lignite	0,23	0,27	0,27	0,28	0,25
	Hard coal	40,67	19,41	19,02	17,70	31,85
	Natural gas	32,26	22,93	23,29	24,07	30,17
	Hydro	3,04	10,09	14,48	14,77	6,58
	Biomass	0,01	9,24	7,83	7,40	1,88
	Wind	0,03	2,99	3,89	3,97	1,52
	Solar		3,87			
	Other RES	1,42	4,49	4,50	4,55	3,37

FIGURE B.2.1. RES-E deployment in scenarios *FEED_D* and *FEED_R*

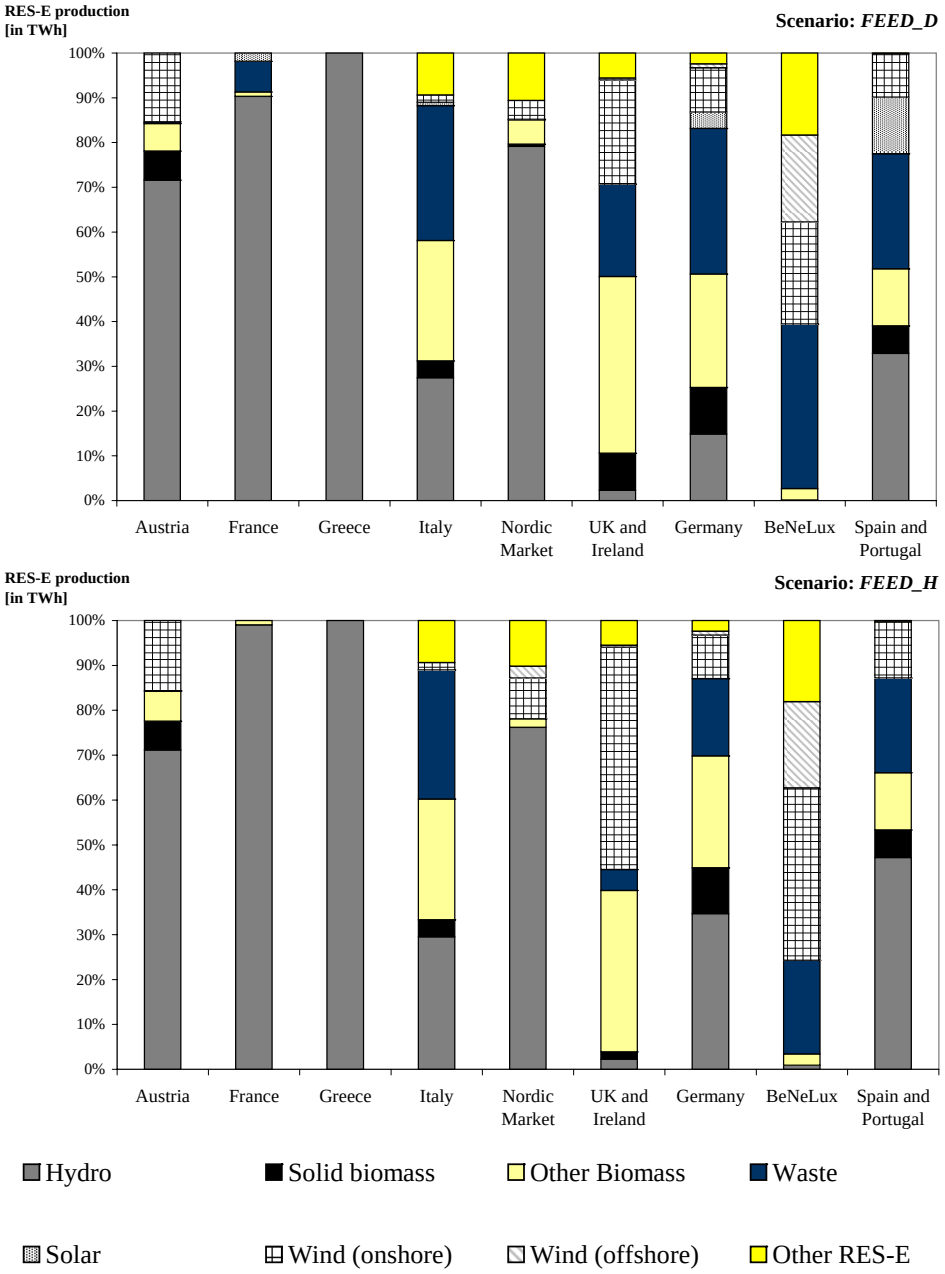
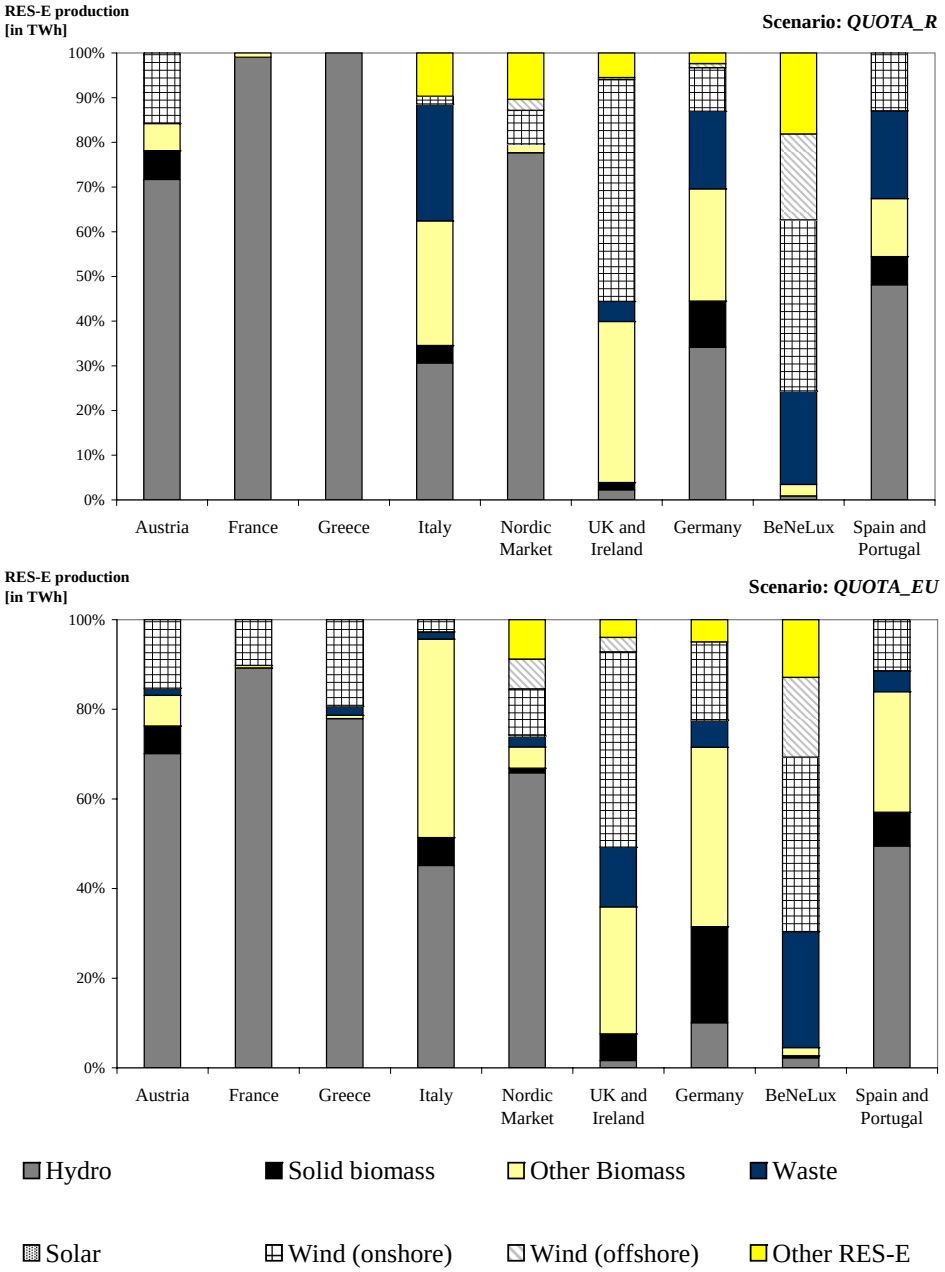


FIGURE B.2.2. RES-E deployment in scenarios *QUOTA_R* and *QUOTA_EU*



B.3. Additional Parameter Values for Analysis in Chapter 6

Table B.3.1. Benchmark technology cost shares for technology t in region r [in percent]

r	t	Coal (θ^{ELE}_{COAtr})	Ref. Oil (θ^{ELE}_{OILtr})	Gas (θ^{ELE}_{GAStr})	M ($\sum_{i \notin \{EL \cup FF\}} \theta^{ELE}_{itr}$)	K (θ^{ELE}_{Ktr})	K (θ^{ELE}_{Ktr})
AUT	HCO	28,46			13,83	10,85	46,85
	SCO	41,79			16,11	4,18	37,92
	OEL		28,50		12,78	2,62	56,10
	NGS			38,51	10,56	2,82	48,11
	BIO				58,40	6,65	34,95
	HYD					10,20	89,80
	WND					20,01	86,26
BEL	HCO	18,68			13,68	11,92	55,72
	SCO	39,55			22,65	6,53	53,32
	OEL		31,99		12,11	2,76	53,15
	NGS			22,91	10,01	2,97	64,12
	NUC				21,17	6,98	71,86
	BIO				57,75	7,31	34,95
	HYD					11,20	88,80
	WND					21,97	85,30
DEU	HCO	49,76			11,52	10,43	28,29
	SCO	42,31			15,79	4,74	37,17
	OEL		29,65		12,50	2,96	54,89
	NGS			37,63	10,33	3,19	48,84
	NUC				14,75	5,06	80,19
	BIO				48,62	6,40	44,98
	HYD					9,81	90,19
	WND					19,24	80,76
DNK	HCO	35,16			17,53	10,35	36,95
	SCO	60,06			14,17	3,51	33,37
	OEL		22,24		13,92	2,72	61,12
	NGS			31,39	11,51	2,93	54,17
	BIO				58,68	6,37	34,95
	HYD					9,77	90,23
	WND					19,17	86,67
ESP	HCO	35,74			14,39	7,01	42,86
	SCO	33,48			18,92	3,05	44,54
	OEL		35,73		11,65	1,48	51,14

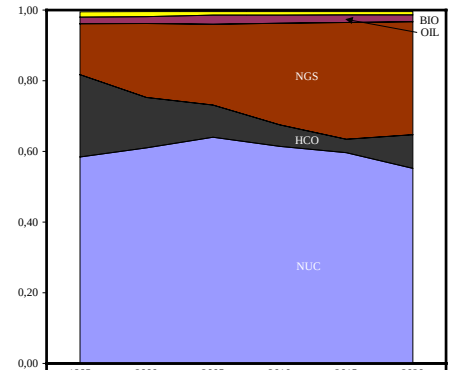
r	t	Coal (θ^{ELE}_{COAtr})	Ref. Oil (θ^{ELE}_{OILtr})	Gas (θ^{ELE}_{GAStr})	M ($\sum_{i \notin \{EL \cup FF\}} \theta^{ELE}_{itr}$)	K (θ^{ELE}_{Ktr})	K (θ^{ELE}_{Ktr})
ESP	NGS			33,54	9,63	1,60	55,24
	NUC				17,68	3,26	79,06
	BIO				60,75	4,30	34,96
	HYD					6,59	93,41
	WND					12,93	89,73
FIN	HCO	31,47			14,09	9,09	45,36
	SCO	44,46			15,57	3,33	36,65
	OEL		38,95		10,98	1,85	48,21
	NGS			27,63	9,08	1,99	61,30
	NUC				14,55	3,55	81,90
	BIO				59,48	5,57	34,95
	HYD					8,54	91,46
	WND					16,76	87,85
FRA	HCO	17,63			13,90	10,36	58,11
	SCO	31,40			19,05	4,70	44,85
	OEL		26,01		13,25	2,58	58,17
	NGS			29,43	10,95	2,78	56,84
	NUC				17,80	5,02	77,18
	BIO				58,70	6,35	34,95
	HYD					9,74	90,26
	WND					19,10	86,71
GBR	HCO	23,71			14,50	6,25	55,54
	SCO	28,76			23,48	3,35	55,27
	OEL		28,37		13,02	1,47	57,14
	NGS			26,48	10,76	1,58	61,18
	NUC				21,94	3,58	74,48
	BIO				61,21	3,83	34,96
	HYD					5,88	94,12
	WND					11,53	90,42
GRC	HCO	32,91			14,80	4,18	48,12
	SCO	45,19			15,90	1,49	37,42
	OEL		30,88		12,65	0,93	55,54
	NGS			29,06	10,46	1,00	59,48
	BIO				62,48	2,56	34,96
	HYD					3,93	96,07
	WND					7,70	92,30

r	t	Coal (θ^{ELE}_{COAtr})	Ref. Oil (θ^{ELE}_{OILtr})	Gas (θ^{ELE}_{GAStr})	M ($\sum_{i \notin \{EL \cup FF\}} \theta^{ELE}_{itr}$)	K (θ^{ELE}_{Ktr})	K (θ^{ELE}_{Ktr})
ITA	HCO	22,07			14,19	8,38	55,36
	SCO	34,28			17,47	3,42	44,84
	OEL		61,16		11,48	2,03	25,33
	NGS			32,32	11,90	2,39	53,38
	BIO				59,91	5,14	34,95
	HYD					7,88	92,12
	WND					15,46	88,49
IRL	HCO	18,99			14,48	6,36	60,17
	SCO	30,20			19,95	2,90	46,96
	OEL		28,00		13,08	1,50	57,42
	NGS			27,01	10,81	1,62	60,57
	BIO				61,15	3,90	34,96
	HYD					5,98	94,02
	WND					11,72	90,32
NLD	HCO	26,25			13,85	10,73	49,17
	SCO	55,32			22,83	5,85	53,74
	OEL		40,31		10,67	2,16	46,86
	NGS			26,53	8,82	2,33	62,32
	NUC				21,33	6,25	72,42
	BIO				58,47	6,58	34,95
	HYD					10,08	89,92
	WND					19,78	86,37
PRT	HCO	33,24			20,50	3,05	43,21
	SCO	49,03			16,57	1,04	39,01
	OEL		23,83		14,00	0,69	61,48
	NGS			50,26	11,57	0,74	51,90
	BIO				63,30	1,73	34,96
	HYD					2,66	97,34
	WND					5,22	94,78
SWE	HCO	18,27			13,85	10,69	57,18
	SCO	32,03			18,83	4,81	44,33
	OEL		21,66		11,32	2,28	64,74
	NGS			46,23	9,36	2,46	41,96
	NUC				17,60	5,14	77,27
	BIO				58,50	6,55	34,95
	HYD					10,05	89,95
	WND					19,71	86,41

B.4. Additional Results of Analysis in Chapter 6

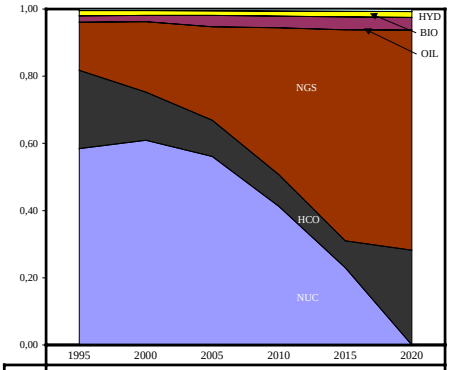
FIGURE B.4.1. Technology mix in electricity production

Belgium
"Business as Usual"



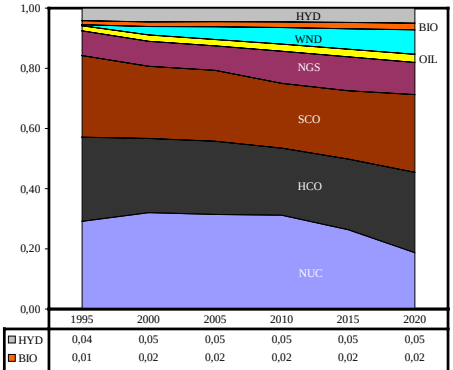
	1995	2000	2005	2010	2015	2020
BIO	0,02	0,01	0,01	0,01	0,01	0,01
OIL	0,02	0,02	0,03	0,02	0,02	0,02
NGS	0,14	0,21	0,23	0,29	0,33	0,32
HCO	0,23	0,14	0,09	0,06	0,04	0,10
NUC	0,58	0,61	0,64	0,61	0,60	0,55

Belgium
"Nuclear Phase-Out"



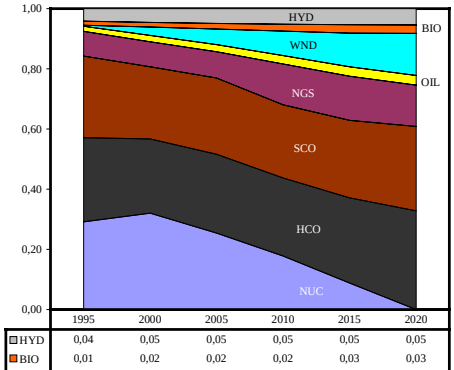
	1995	2000	2005	2010	2015	2020
HYD	0,00	0,00	0,01	0,01	0,01	0,01
BIO	0,02	0,01	0,01	0,01	0,02	0,02
OIL	0,02	0,02	0,03	0,04	0,04	0,04
NGS	0,14	0,21	0,28	0,44	0,63	0,65
HCO	0,23	0,14	0,11	0,09	0,08	0,28
NUC	0,58	0,61	0,56	0,41	0,23	0,00

Germany
"Business as Usual"



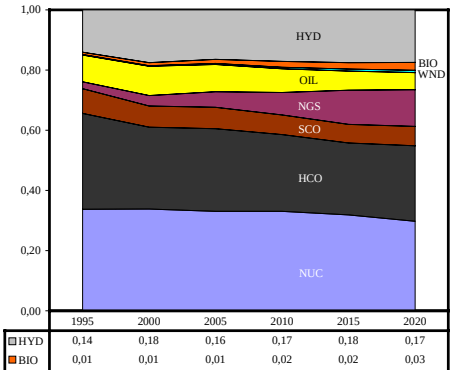
	1995	2000	2005	2010	2015	2020
HYD	0,04	0,05	0,05	0,05	0,05	0,05
BIO	0,01	0,02	0,02	0,02	0,02	0,02
WND	0,00	0,03	0,04	0,06	0,07	0,08
OIL	0,02	0,02	0,02	0,02	0,03	0,03
NGS	0,08	0,08	0,08	0,11	0,11	0,11
SCO	0,27	0,24	0,24	0,22	0,23	0,26
HCO	0,28	0,25	0,24	0,22	0,23	0,27
NUC	0,29	0,32	0,31	0,31	0,26	0,19

Germany
"Nuclear Phase-Out"



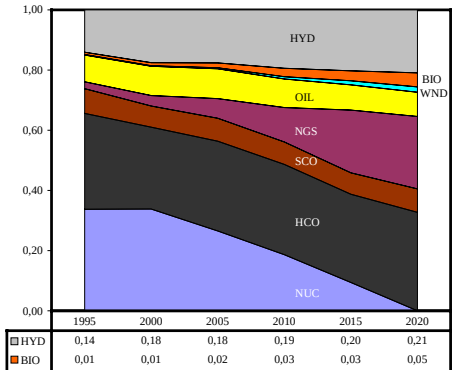
	1995	2000	2005	2010	2015	2020
HYD	0,04	0,05	0,05	0,05	0,05	0,05
BIO	0,01	0,02	0,02	0,02	0,03	0,03
WND	0,00	0,03	0,05	0,08	0,11	0,14
OIL	0,02	0,02	0,02	0,03	0,03	0,03
NGS	0,08	0,08	0,09	0,14	0,15	0,14
SCO	0,27	0,24	0,25	0,24	0,26	0,28
HCO	0,28	0,25	0,26	0,26	0,28	0,33
NUC	0,29	0,32	0,25	0,18	0,09	0,00

Spain
"Business as Usual"



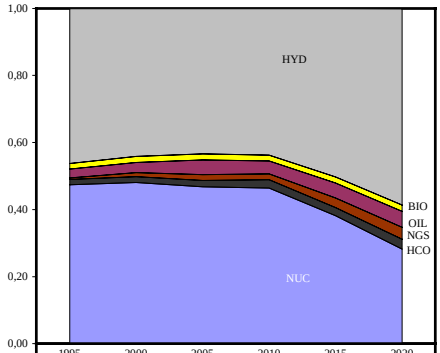
	1995	2000	2005	2010	2015	2020
HYD	0,14	0,18	0,16	0,17	0,18	0,17
BIO	0,01	0,01	0,01	0,02	0,02	0,03
WND	0,00	0,00	0,00	0,00	0,01	0,01
OIL	0,09	0,10	0,09	0,08	0,06	0,06
NGS	0,02	0,03	0,05	0,07	0,11	0,12
SCO	0,08	0,07	0,07	0,07	0,06	0,06
HCO	0,32	0,27	0,28	0,25	0,24	0,25
NUC	0,34	0,34	0,33	0,33	0,32	0,30

Spain
"Nuclear Phase-Out"



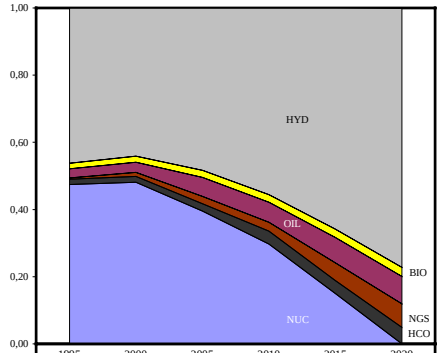
	1995	2000	2005	2010	2015	2020
HYD	0,14	0,18	0,18	0,19	0,20	0,21
BIO	0,01	0,01	0,02	0,03	0,03	0,05
WND	0,00	0,00	0,00	0,01	0,01	0,02
OIL	0,09	0,10	0,10	0,09	0,08	0,08
NGS	0,02	0,03	0,06	0,11	0,21	0,24
SCO	0,08	0,07	0,08	0,07	0,07	0,08
HCO	0,32	0,27	0,30	0,30	0,29	0,33
NUC	0,34	0,34	0,27	0,19	0,09	0,00

Sweden
"Business as Usual"



	1995	2000	2005	2010	2015	2020
HYD	0,46	0,44	0,43	0,44	0,50	0,58
BIO	0,02	0,02	0,02	0,02	0,02	0,02
OIL	0,03	0,03	0,04	0,04	0,04	0,05
NGS	0,00	0,01	0,02	0,02	0,03	0,04
HCO	0,02	0,02	0,02	0,03	0,02	0,03
NUC	0,47	0,48	0,47	0,46	0,38	0,28

Sweden
"Nuclear Phase-Out"



	1995	2000	2005	2010	2015	2020
HYD	0,46	0,44	0,48	0,56	0,66	0,77
BIO	0,02	0,02	0,02	0,02	0,02	0,03
OIL	0,03	0,03	0,06	0,06	0,08	0,08
NGS	0,00	0,01	0,02	0,03	0,05	0,07
HCO	0,02	0,02	0,02	0,04	0,04	0,05
NUC	0,47	0,48	0,40	0,30	0,15	0,00

Lebenslauf

Persönliche Informationen:

Name	**Tim Hoffmann**
Adresse	Kaiserring 22, 68161 Mannheim, Deutschland
Tel./Fax	0621-9508121 / 0621-794223
Email	tim.hoffmann@gmx.de
Geboren am	14.12.1970 in Mannheim
Nationalität	Deutsch

Beruflicher Werdegang:

Jan. 2000 – Jan. 2006	**ZEW – Zentrum für Europäische Wirtschaftsforschung GmbH** Wissenschaftlicher Mitarbeiter im Forschungsbereich Umwelt- und Ressourcenökonomik, Umweltmanagement.
Apr. 1999 – Jun. 1999	**Freiberufliche Tätigkeit für die Stadtwerke Viernheim** Konzeption, Realisation und Auswertung einer Markt- und Kundenzufriedenheitsstudie
Apr. 1998 – Mär. 1999	**ZEW – Zentrum für Europäische Wirtschaftsforschung GmbH** Praktikant, wissenschaftliche Hilfskraft und freie Mitarbeit im Forschungsbereich Umwelt- und Ressourcenökonomik, Umweltmanagement.
Jul. 1990 – Jun. 1991	**Grundwehrdienst im Fernmeldebatallion 970, Mannheim**

Ausbildung:

Sep. 1991 – Dez. 1998	**Studium der Betriebswirtschaftslehre an der Universität Mannheim** Schwerpunkte: Internationales Management, Public & Nonprofit Management, Ökologie und Umweltmanagement Abschluß: Diplom (Note „Gut“)
Aug. 1980 – Mai 1990	**Feudenheim Gymnasium, Mannheim** Abschluß: Abitur (Note „Befriedigend“)

Ehrenwörtliche Erklärung:

Ich erkläre hiermit, dass ich die vorliegende Arbeit ohne unzulässige Hilfe Dritter und ohne Benutzung anderer als der angegebenen Hilfsmittel angefertigt habe. Die aus anderen Quellen direkt oder indirekt übernommenen Daten und Konzepte sind unter Angabe der Quelle gekennzeichnet. Die Arbeit wurde bisher weder im In- noch im Ausland als Dissertation oder Diplom- oder ähnliche Prüfungsarbeit einer anderen Prüfungsbehörde vorgelegt.

Mannheim, 4. März 2006

Tim Hoffmann