Equilibrium Analysis of Carbon Emission Caps in Regional Electricity Markets

Verena Višković

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Department of Statistical Science
University College London

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I, Verena Višković, confirm that the work presented in this thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the work.

Abstract

This thesis uses state-of-the-art equilibrium models to analyse the impact of cap-and-trade (C&T) systems on regional electricity markets, which span areas subject to disparate carbon-reduction policies, e.g., only one area of the market is covered by a C&T. Such markets are vulnerable to carbon leakage, i.e., emission increase in the uncapped subregion as a result of imposing a C&T in the regulated subregion. Specifically, the focus is on the South-East Europe Regional Electricity Market (SEE-REM) for which an *ex ante* analysis of potential leakage into the non-EU ETS part is carried out considering the interaction of (i) an emission cap and hydropower availability and (ii) an emission cap and market power. In a perfectly competitive setting, a mixed-complementarity problem calibrated to SEE-REM is implemented for various C&T emission caps in order to estimate the extent of carbon leakage. The impact of market power is next incorporated using a bi-level model that is reformulated as a mathematical program with equilibrium constraints and implemented as a mixed-integer quadratic problem for SEE-REM in order to investigate how a dominant firm's incentives to manipulate both electricity and carbon prices affect carbon leakage. Furthermore, in a theoretical framework, a bi-level model is developed where at the upper level, the policymaker determines an optimal emission cap over a subregion of an electricity market interconnected to the uncapped subregion. The purpose of this model is to establish the basis for a second-best anti-leakage measure.

Impact Statement

The findings in this thesis contribute to the academic literature and possible future directions of public policy. In the context of academia, this thesis contributes to the literature on carbon leakage estimation and mitigation in several ways. First, carbon leakage resulting from incomplete environmental regulation due to the EU ETS in a regional electricity market in South-East Europe is estimated via an *ex ante* analysis using a calibrated equilibrium model in a perfectly competitive market setting considering different hydropower availability scenarios. Second, the magnitude of carbon leakage in the South-East Europe is also quantified under the assumption of imperfect competition in either the electricity market only or both the electricity and emission-permit markets. Finally, the theoretical model developed studies the leakage-mitigation potential of various anti-leakage policies.

In the context of public policy, the presented findings could help shape future policy directions for the Energy Community. The Energy Community (Community) is an international organisation that gathers EU and non-EU countries in South-East Europe with the aim of integrating the non-EU participants into the internal EU energy market. The non-EU countries have to adapt their national legislation related to energy in order to enable cross-border trade with the EU but are not required to participate in the EU ETS. Thus, their emissions remain uncapped with the possibility of increasing as terms of trade with EU countries deploying costlier technologies subject to the EU ETS are improved. The analysis in this thesis explicates the potential consequence of enhanced trade between capped and uncapped countries in South-East Europe and might shape future steps taken by the Community. One important direction suggested by these findings is the need for an emission cap in the non-EU countries in the Community. This would prevent potentially delaying the achievement of EU emission-reduction targets, mitigate the environmental impact of increased generation in the non-EU as non-EU firms export more to the EU, and protect non-EU consumers from potential electricity price increases while being exposed to higher damage from emissions. The implementation could occur through the creation of a one-way link between the EU ETS and non-EU countries in the Community whereby non-EU countries could use permits issued under the EU ETS for compliance with domestic emission-reduction targets. The revenues collected from sales of permits in the Community could be invested in cleaner technologies in non-EU countries.

The findings in this thesis were disseminated through a scientific publication in *Energy Economics* and participation in academic conferences and seminars. Specifically, the findings in Chapter 2 were presented at the INFORMS Annual Meeting in Philadelphia (U.S.) in 2015, the International Association for Energy Economics conference in Bergen (Norway) in 2016, and seminars at HEC Montréal and UCL. Findings in Chapter 3 were presented at the INFORMS Annual Meeting in Nashville (U.S.) in 2016 and the Enerday conference in Dresden (Germany) in 2018. Finally, findings in Chapter 4 were presented at the student conference of the Centre for Doctoral Training in Financial Computing & Analytics in 2017 and the INFORMS Annual Meeting in Houston (U.S.) in 2017.

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I thank my parents, Klaudija and Alfredo, for supporting me throughout my education, and for their love and support always. Also, I thank my entire family for their affection and presence in my upbringing. I am particularly grateful to Robson for always being there.

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Contents

List of Acronyms

AC	Alternating current
C&T	Cap-and-trade
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCGT	Combined-cycle gas turbine
CCS	Carbon capture and storage
CO_2	Carbon dioxide
DC	Direct current
EC	European Commission
EIA	Energy Information Administration
EIM	Energy Imbalance Market
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	Emission trading system
EU	European Union
FYRM	Former Yugoslav Republic of Macedonia
GDP	Gross domestic product
GHG	Greenhouse gas
GO	Grid owner
GR	Greece
HV	High-voltage
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IPEX	Italian Power Exchange
ISO	Independent system operator

IT	Italy
KKT	Karush–Kuhn–Tucker
MCD	Marginal cost of damage
MCP	Mixed complementarity problem
MIQP	Mixed-integer quadratic programming problem
MPEC	Mathematical program with equilibrium constraints
NAP	National allocation plan
NO_x	Nitrogen oxides
NTC	Net transfer capacities
OECD	Organisation for Economic Co-operation and Development
OPcOP	Optimisation problem constrained by other optimisation problems
PJM	Pennsylvania–New Jersey-Maryland
QP	Quadratic program
RGGI	Regional Greenhouse Gas Initiative
RL	Relative leakage
RO	Romania
RPS	Renewable portfolio standard
RR	Reduction reversal
SEE-REM	South–East Europe Regional Electricity Market
SI	Slovenia
UNFCCC	United Nations Framework Convention for Climate Change
WECC	Western Electricity Coordinating Council

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Chapter 1

Introduction

Life without electricity in residential, commercial, and industrial sectors could not be imagined nowadays. Other than being essential for human life as we know it, electricity distinguishes itself from other commodities by several essential features. First, the lack of large-scale storage necessitates real-time supply-demand balance. Second, transmission of electricity is over grids where the path taken is determined by physical (Kirchhoff's) laws rather than direct control in a transmission network. The transmission grid is a highly complex system that requires constant control to balance generation and consumption instantaneously due to lack of storage. Because of these peculiarities, the supply of electricity was for a long time considered to be a public service in many countries justifying state intervention for the purpose of guaranteeing the quality of service at reasonable prices (Gómez-Expósito et al., 2008).

Industrial application of electricity was rendered possible in the second half of the 19th century and was initially, due to lack of transmission facilities, organised locally in some areas where it served to provide lighting. This gave origin to several private and public systems, which subsequently evolved into vertically integrated utilities providing generation, transmission, distribution, and retailing of electricity. With the evolution of transmission facilities, local systems interconnected and grew into national systems. The large vertically integrated utilities were the prevailing paradigm of electricity-industry organisation in many countries until the late 20th century when various aspects of this organisation started to be challenged. This paved the way towards deregulation of the electricity industry through separation of competitive and monopolistic activities (Figure 1.1), i.e., while transmission and distribution are still viewed as natural monopolies subject to state regulation, generation and retailing can be organised through markets.

The movement to deregulate network utilities, e.g., rail and telecommunica-

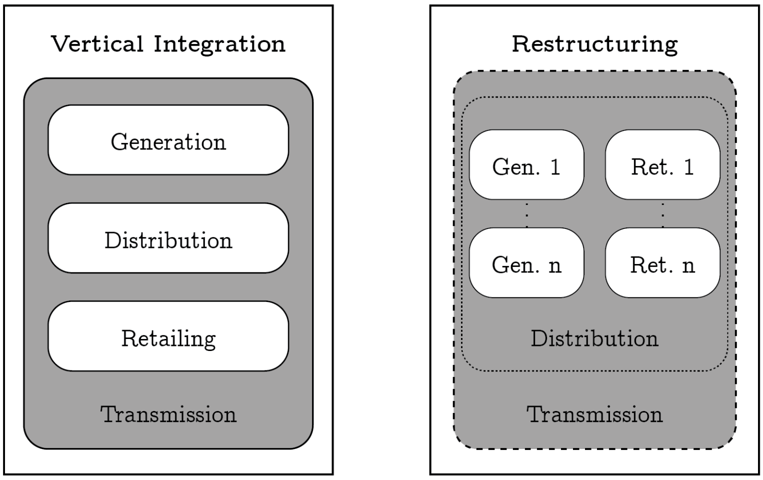


Figure 1.1: Unbundling of vertically integrated utilities

tion, that started in the U.S. in 1970s eventually caught up with the electricity industry (Newbery, 2000). The first jurisdiction to reform its electricity industry was Chile in 1982 followed by more thorough restructuring in England and Wales (1990) and Argentina and Norway (1991) (Gómez-Expósito et al., 2008). Since then, most countries around the world have followed suit by introducing some level of competition in their electricity industry (IEA, 2016). Deregulation was motivated by the appearance of new technologies, e.g., combined-cycle gas turbine (CCGT), requirement for lower electricity prices, faster response to technological changes, which could not have been sustained by a state as the owner and manager of the utilities in the old paradigm, and development in information technology, which enabled the exchange of information necessary for the decentralised management of competitive electricity markets (Rothwell and Gómez, 2003). While deregulation in some industries such as telecommunication and transportation resulted in considerable decrease in operating cost and consumer gain from lower product prices as well as introduction of new products and services, deregulation of the electricity industry was not deemed as impressive and has failed to achieve substantial consumer savings (Hyman, 2010). In addition, one of the frequently discussed features of deregulated electricity industry is market power, i.e., the ability of a firm or group of firms to raise prices above competitive levels, to which the electricity industry is particularly susceptible due to inelastic demand and lack of storage facilities. Despite mixed experiences about deregulation, it seems to persist in the electricity industry as a way forward where we learn from past events.

Historically, electricity consumption has been used as an indicator of countries' industrial standard (Gómez-Expósito et al., 2008) since it closely followed the growth of gross domestic product (GDP). This relationship seems to have changed in recent years in developed member countries of the Organisation for Economic Co-operation and Development (OECD) as their economies are leaning more towards services and less energy-intensive technologies are used in their manufacturing (EIA, 2017). The shift towards less energy-intensive technologies is of utmost importance since electricity production has a substantial environmental impact and, together with heat production, is responsible for 25% of global greenhouse gas (GHG) emissions (IPCC, 2014). In fact, energy efficiency and decarbonisation of the electricity industry are at the centre of climate policy of many countries, e.g., the European Union (EU) 2030 targets (i) at least 40% cut in GHG emissions from 1990 levels, (ii) at least 27% share for renewable energy, and (iii) at least 27% improvement in energy efficiency (EC, 2018d).

Concerns related to the impact of GHGs in the atmosphere started to be more widely acknowledged and discussed in 1980s (Freestone and Streck, 2009) following the discovery of the ozone-depleted region over Antarctica (Stolarski, 1988). By 1992, the UN General Assembly had declared climate change a "common concern of mankind" (UNGA, 1988), and the Intergovernmental Panel on Climate Change (IPCC) and the United Nations Framework Convention for Climate Change (UNFCC) had been established (IPCC, 2013; UNFCCC, 2017). Since 1994, parties of the UNFCCC have convened every year in meetings known as the Conference of Parties (COP). The Kyoto Protocol, resulting from COP3 in 1994, strengthens the commitments of industrialised countries to reduce GHGs emissions and introduces market mechanisms to help parties reach their emission-reduction goals (UNFCCC, 2017). One of the mechanisms sets the foundation for emission trading systems (ETS) (UNFCCC, 2017). Also known as cap-and-trade (C&T), this mechanism caps the total quantity of CO_2 emissions in a region. The shadow price on the resulting binding constraint is subsequently paid by polluting producers as a cost of compliance with the C&T.

Carbon can be explicitly priced through either carbon tax or a C&T. Since CO_2 emissions are damaging globally independently of their origin, economically, the first-best outcome for emission reduction is a single global carbon market where all participants face the same carbon price. However, on the basis of common but differentiated responsibilities, under the Kyoto Protocol in 1997, not all countries had to set binding emission-reduction targets. This resulted in unilateral actions by the countries around the world. In fact, explicit carbon pricing covers 20%-25% of global emissions (World Bank, 2017), part of which are covered by twenty regional, national, or sub-national C&T systems currently operating (World Bank, 2017) with the largest being the EU ETS (EC, 2018a).

Globally, more comprehensive efforts were achieved in 2015 during COP21 in Paris, where the main outcome was to pursue efforts to limit average temperature rise in this century to 1.5°C above pre-industrial levels (UNFCCC, 2015). This outcome is part of the Paris Agreement, which is considered to be a historic milestone to which all nations are expected to contribute. However, the Paris Agreement represents a process that helps parties to reach their CO_2 emission-reduction targets rather than itself setting targets. Targets are set at national levels[1] and, if parties decide, may be legally binding at the national level, but they are not binding under the agreement itself (UNFCCC, 2017). This means that unilateral CO_2 emission-reduction policies could persist for the foreseeable future.

The fragmented nature of existing climate policies around the world could render the achievement of climate objectives under international agreements, such as the Paris Agreement, more difficult. In addition, the fragmentation could lead to emission leakage, which is defined as the displacement of emissions from a region subject to a tighter regulation to regions with less regulation, as well as the leakage of the economic activity. Leakage of emissions and economic activity could delay the achievement of environmental objectives and harm the competitiveness of regions with unilateral policies. The electricity industry is particularly vulnerable to such an outcome due to the misalignment of the territory of a regional power market and the regulatory jurisdiction of environmental agencies. In the U.S., such examples include California and the Pennsylvania-New Jersey-Maryland (PJM) Interconnection. PJM spans thirteen states and the District of Columbia (PJM, 2018), yet only two of these states, i.e., Maryland and Delaware, are covered by the emission cap set by the Regional Greenhouse Gas Initiative (RGGI) (C2ES, 2018). The carbon-leakage situation in California could also be further exacerbated by the introduction of the real-time Energy Imbalance Market (EIM) as it allows out-of-state imports from uncapped regions to serve demand in the California Independent System Operator (CAISO) territory (CARB, 2017). Furthermore, South-East Europe is potentially at risk of being exposed to carbon leakage as a region with some countries subject to the EU ETS and others exempt from it.

Despite considerable efforts to tackle climate change, CO_2 emissions from human activity reached record levels in 2016 (WMO, 2017). This indicates that there is need for careful examination of the policies in place, quantification of emission

[1] Targets can also be set jointly by a group of parties.

leakage, and mitigation of emission leakage via anti-leakage measures. This thesis uses equilibrium models to analyse the impact of emission trading on regional electricity markets, which comprise areas subject to disparate emission-reduction policies, e.g., one area is capped by a C&T and one is exempt from it. Specifically, the focus is on the South-East Europe Regional Electricity Market (SEE-REM) for which a theoretical *ex ante* analysis of potential leakage into the uncapped part is investigated considering the interaction of (i) a CO_2 emission cap and hydropower availability and (ii) a CO_2 emission cap and exercise of market power. Furthermore, using a bi-level model, a comparison of leakage mitigation potential of different anti-leakage policies is carried out. At the upper level of the bi-level model, a policymaker determines an optimal emission cap over a capped subregion of an electricity market interconnected to an uncapped subregion by varying emissions considered damaging for its constituents.

1.1 Implications of the EU Emissions Trading System for the South-East Europe Regional Electricity Market

Part of the contents in this Section are published in Višković et al. (2017).

Convincing evidence provided by a recent IPCC report suggests that human activity is causing climate change (Stocker et al., 2013). Regardless of whether the power sector is vertically integrated or deregulated, policymakers have implemented several measures to facilitate the reduction of GHG emissions using both market-based mechanisms, e.g., taxes, subsidies, and emissions trading, and other policy instruments, e.g., voluntary agreements and regulatory protocols.[2] An example of legally binding GHG emissions controls is the 20-20-20 targets[3] set by the EU. One of the EU 20-20-20 targets is the reduction in GHG emissions by 20% by the year

[2]Whether deregulation of the power sector makes it easier for the government to reduce GHG emissions remains debatable. On the one hand, the lock-in of sunk capital by incumbents under the regulated paradigm has been viewed as a barrier to environmental policies so that deregulation is typically associated with the adoption of new technology. For example, an empirical study by Hyman (2010) suggests that a significant investment in gas-fired facilities in the U.K. was undertaken after restructuring. Indeed, recent expansion of distributed energy resources seemingly suggests that deregulation is more likely to lead to emissions reduction when mandated by the government via market-based instruments (von Hirschhausen, 2014). On the other hand, Wilson (2002) argues that the traditional vertically integrated paradigm is more likely to enforce policy due to its tighter regulation and a more involved role for the state.

[3]EU 20-20-20 refers to the EU's three climate targets to be reached by 2020. First, 20% reduction in GHGs compared to 1990 levels. Second, 20% improvement in energy efficiency relative to 1990 levels. Third, 20% of EU energy to be produced from renewables.

2020 compared to those in 1990 (EC, 2007). In order to facilitate this transition, the EU launched its ETS as a market-based mechanism in 2005. The ETS sets a cap on aggregated emissions, and companies receive or buy tradeable emissions allowances within the cap. The cap is reduced over time in order to curb emissions. Today, it is the most extensive international C&T system covering 11,000 power stations, industrial plants, and airlines in 31 countries (EC, 2018a).

The trading of CO_2 allowances represents an increased cost for both electricity producers and energy-intensive industries. If either such industries were to move their production to countries with less-strict climate policies (EC, 2009; Chen, 2009) or the countries in the regulated area were to increase their imports from non-regulated areas (Chen, 2009), then so-called "carbon leakage" would result. Thus, perversely, a C&T system could lead to an increase in CO_2 emissions in the non-regulated areas (Chen, 2009). Electricity generation in the EU ETS is for the most part covered without the possibility of leakage with the exception of some borders with non-regulated areas like in South-East Europe. In particular, SEE-REM comprises countries that are part of the EU and may partly offset the emission reduction from domestic production with imports from non-regulated neighbouring countries. The potential for such carbon leakage to occur as a consequence of the EU ETS in the context of SEE-REM has received little attention in the literature.

Carbon leakage might delay the achievement of environmental objectives such as EU 20-20-20 by reducing allowance prices so that producers have less incentive to switch to less-polluting sources of power generation or to implement carbon-reduction technologies in conventional sources (Višković et al., 2014) than they would otherwise. While reducing domestic emissions, the EU ETS does not account for increased emissions in the non-regulated area that result from increased exports from the non-ETS to the ETS area in order to meet the ETS electricity demand.

We use a stylised 22-node network to model the electricity sector and associated emissions of SEE-REM (Figure 1.3) comprising neighbouring countries with inconsistent CO_2 emission-reduction regulation (i.e., only some countries are covered by the EU ETS). We employ an equilibrium model where firms and the grid owner (GO) are maximising their profits subject to the market-clearing condition (Figure 1.2). Furthermore, flows on transmission lines follow Kirchhoff's current law, i.e., the sum of power injections into a node must equal zero, and voltage law, i.e., total change in voltage around the loop must sum to zero. For example, in a three-node network, injections at two nodes will determine the withdrawal at the third node. In order to quantify how an injection or withdrawal of power at a certain node will distribute across the network, we employ a DC load-flow model

(Schweppe et al., 1988). A calculation for a simple three-node network is demonstrated in Appendix D.

The equilibrium model estimates the magnitude of leakage (in percentage terms) relative to the emissions from the ETS[4] part of SEE-REM in the short term before any adjustment in capacity can occur with consideration of the impacts of hydropower availability on market outcomes. Under this framework, we treat both availability of hydropower and allowance prices exogenously, thereby not allowing for 1) possible impact of hydro availability on the allowance price or 2) changing dispatch of hydropower in response to the allowance price. Parametric treatment of allowance prices is equivalent to treating the allowance price as a carbon tax, determined by the larger ETS area where the allowances are initially allocated through auction. Given that we have a fixed cap under the C&T, our assumption implies that the increase in SEE-REM emissions covered by ETS would be offset elsewhere in the wider ETS not covered in our model.

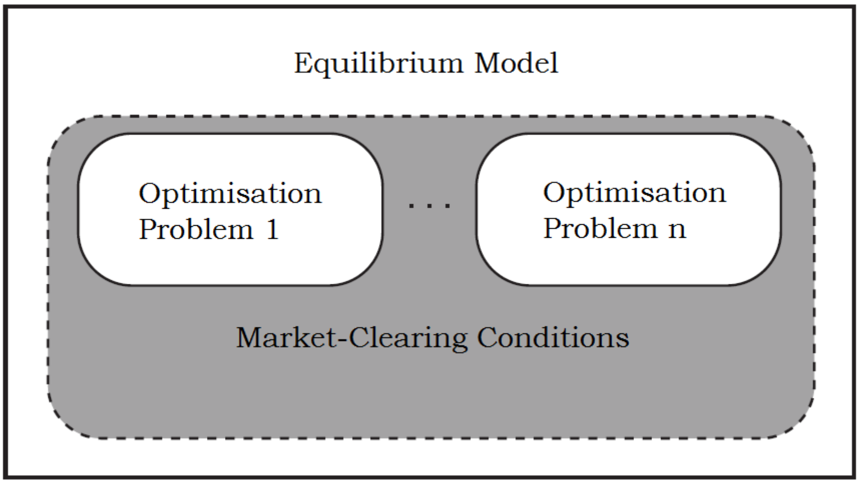


Figure 1.2: Equilibrium model

There are three central findings resulting from our study: (i) emissions leaked into the non-ETS area could amount to 6.3% to 40.5% of the emissions reduction in the SEE-REM ETS area;[5] (ii) higher electricity prices in some non-ETS countries

[4]The International Energy Agency (IEA) publishes one figure for both electricity and heat sectors. Thus, it is not straightforward to obtain an estimate of electricity sector emissions only for the entire EU ETS. However, according to the IEA, the emissions from electricity and heat generation of the countries modelled in SEE-REM were approximately 23% of the electricity and heat generation emissions of the whole EU ETS in 2013 (IEA, 2015).

[5]The level of leakage to the non-ETS part of SEE-REM is equivalent to approximately 0.5% of electricity and heating emissions of the entire EU ETS. We obtain this figure by dividing our average estimated increase in CO_2 emissions in the non-ETS part of SEE-REM (6.5 Mt) as a result of a positive CO_2 price by the total EU ETS electricity and heating emissions (1256.2 Mt).

could mitigate leakage due to non-ETS demand response that lowers consumption; and (iii) higher CO_2 emissions could occur in the ETS area of SEE-REM as a result of demand response to lower electricity prices from greater availability of cheap hydropower throughout the entire SEE-REM. Moreover, the results observed under (i) and (ii) suggest a need for a more careful assessment of what to consider as CO_2 emissions within the ETS, i.e., the regulator should also take into account the imports into the ETS area as part of the CO_2 emissions produced by the EU and decide whether imports should be subject to the C&T regime. However, our findings highlight the benefit of expanding the EU ETS to neighbouring countries within a regional electricity market in order to maximise the effectiveness of the program. We believe that the EU ETS paves a promising pathway to enhancing the coverage of the program.

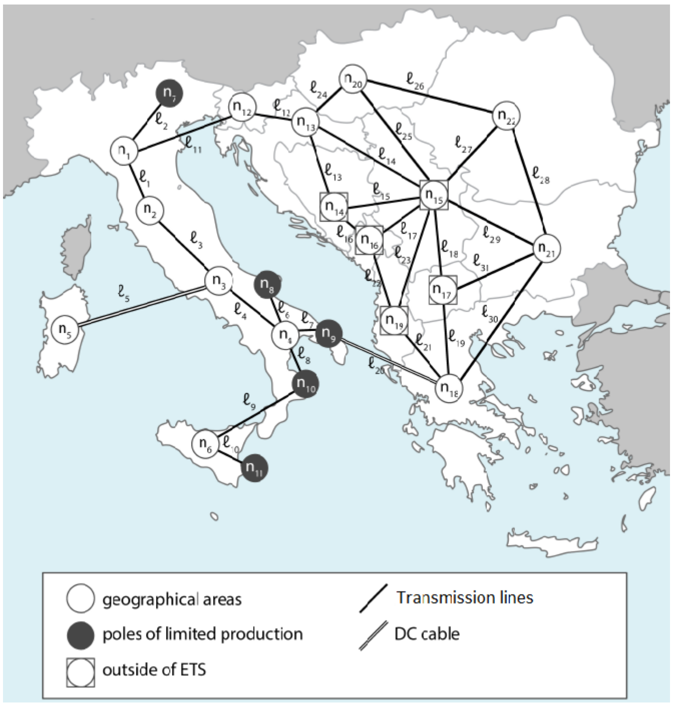


Figure 1.3: SEE-REM nodal representation

1.2 Economic and Environmental Consequences of Market Power in the South-East Europe Regional Electricity Market

Two major historic processes of the last four decades have shaped current electricity markets worldwide. First, the deregulation of the electricity industry, which in some cases resulted in electricity markets characterised by oligopolistic ownership structures (Wilson, 2002) potentially subject to the exercise of market power, i.e., the ability to manipulate prices above competitive levels (Mas-Colell et al., 1995). Electricity markets are particularly vulnerable to the exercise of market power due to relatively inelastic short-term demand and lack of storage (Borenstein, 2000). Furthermore, market separation due to network congestion can play an important role in the extent to which market power can be exercised (Neuhoff et al., 2005). Empirical evidence suggests that strategic behaviour is a common occurrence in electricity markets. For example, although in both PJM and California the market was found to be mostly competitive, in PJM, behaviour of some agents was deemed consistent with economic withholding (Monitoring Analytics, 2018), whereas in California, demand and supply conditions developed during 2017 enhance potential for exercise of market power beyond 2017 (CAISO, 2017). Moreover, Just and Weber (2015) find that the the participants in the German balancing mechanism behave as expected under strategic behaviour. Similarly, in periods of network congestion, market participants in some zones of Nord Pool adopt behaviour that resembles the exercise of market power (Tangerås and Mauritzen, 2018). The exercise of market power can result in production inefficiencies, price distortions, and redistribution of income among market participants.

Second, concerns about the effects of GHGs on climate change led to carbon pricing through transferable property rights, e.g., allowances or permits. Emission permits are commonly traded under C&T systems, which can also be subject to market power. For example, Hahn (1984) shows that any initial allocation of permits to a participant with market power that deviates from the quantity of permits consumed in equilibrium results in market inefficiencies, i.e., a participant with market power will either raise the permit price above or push it below the perfectly competitive level.

The exercise of market power in a single market has attracted attention in the literature; however, the interaction of a product and permit market both subject to market power has been less investigated. Kolstad and Wolak (2003) examine the circumstances in the California electricity market in 2000 and 2001 where part of the market (Los Angeles area) was subject to the NO_x C&T. They find evidence that prospects of exercising market power in the electricity market might have been enhanced via the C&T. Specifically, firms that owned plants both in the area subject to the C&T and outside of it might have intentionally paid higher permit prices. Due to the higher permit price, they were able to justify higher offers into the electricity market despite not using the more-polluting plants in a way consistent with the higher marginal cost of production given by the higher permit price. In this manner, they could have earned higher profits on less-polluting plants and/or uncapped plants.

A binding cap in the regulated area results in a positive permit price, which translates into higher electricity prices in the capped subregion. Higher electricity prices entice the uncapped subregion's production leading to an increase in emissions in the uncapped region. Since exercise of market power results in prices above perfectly competitive levels, the question is whether the exercise of market power by a firm located in the capped subregion of a regional market can exacerbate carbon leakage.

For the purpose of answering this question, we study the SEE-REM market (Figure 1.3) that spans EU and non-EU countries in which EU members are covered by the EU ETS and non-EU countries are exempt from it. We choose a single firm with capacity in the ETS part of the market as the dominant firm. In order to investigate the impact of market power in both electricity and permit markets, we analyse three market settings. First, we have a perfect competition setting where all firms are price takers in both electricity and permit markets. Second, a leader-follower setting provides the leader with market power in the electricity market only, whereas all other firms are price takers, and the C&T is modelled through an exogenous permit price, which can be considered as a carbon tax. Finally, a leader-follower setting provides the leader with market power in both electricity and permit markets, whereas all other firms are price takers, and the C&T is modelled through an ETS emission constraint. The two leader-follower settings are represented by a bi-level model whereby at the upper level, the leader decides its output anticipating the reaction of the follower firms and the independent system operator (ISO) at the lower level (Figure 1.4). Via this framework, we analyse the impact of market power on prices, firm outputs, consumption, flows, emissions, and social welfare.

We find that under perfect competition, a binding cap on ETS emissions curbs ETS production. As the cap tightens, the price differential between ETS and non-ETS areas of the market increases, thereby enticing non-ETS production and leading to higher non-ETS emissions. Consequently, there is carbon leakage between 39%-11% for caps of 10%-40% reduction, respectively, compared to the baseline (Vištović et al., 2017).

The leader's strategy for exercising market power depends on the marginal technology (Figure 1.5), which changes with the stringency of the environmental regulation. When natural gas is the marginal technology, which occurs at lower carbon tax levels, the leader's strategy is to withhold production from its dominant

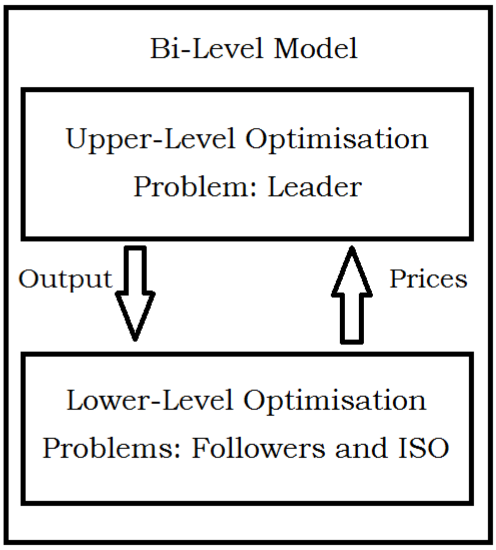


Figure 1.4: Leader-follower bi-level model

technology (coal) in order to raise electricity prices and reap higher profits on its operating power plants. Higher electricity prices entice ETS natural gas (including the leader's) and non-ETS production, which partly replace the share vacated by the leader's coal plants. As a result, ETS (non-ETS) emissions fall below (rise above) the perfectly competitive levels. Since the reduction in ETS emissions offsets the increase in non-ETS emissions, carbon leakage is lower compared to the perfectly competitive setting. For a carbon tax such that coal reaches cost parity with natural gas, the leader adopts an opposite strategy coal-wise. In particular, it expands coal production in order to set equilibrium prices. Higher electricity prices entice ETS coal and non-ETS production resulting in ETS and non-ETS emissions as well as carbon leakage above the perfectly competitive level.

In an attempt to reduce the permit price when natural gas is the marginal technology, the leader holds back more coal and expands more gas production compared to the carbon-tax setting. A lower abatement cost results in higher ETS natural gas production and ETS emissions compared to carbon-tax setting leading to higher carbon leakage. When coal reaches parity with natural gas in terms of marginal cost, the leader expands coal to a lesser extent compared to the carbon-tax setting as it does not want to increase the permit price. Contrary to the carbon-tax setting, since the fringe firms in the ETS cannot increase coal production because of the cap, they increase natural gas production. This leads to lower ETS emissions and carbon leakage compared to the carbon-tax setting. Generally, the leader is able to reap higher profits when it has the ability to manipulate both markets, except in the

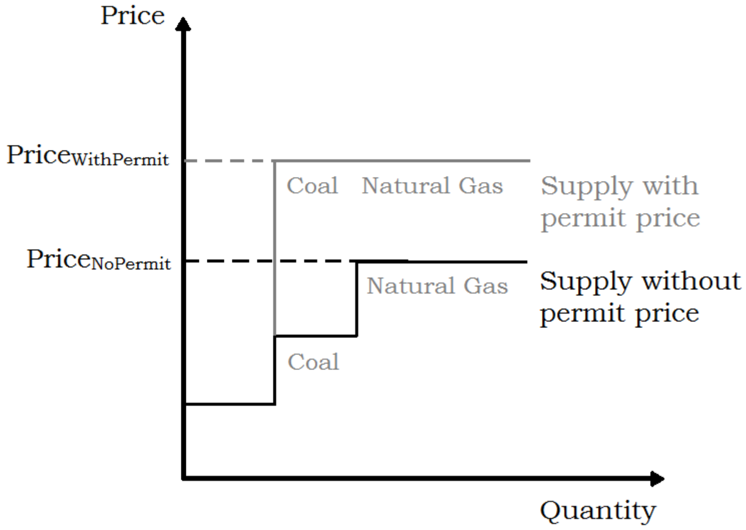


Figure 1.5: Representative supply stack function

case of a tighter cap when its expansion of coal production is limited by the effect it might have on the permit price.

In the framework of our analysis, the exercise of market power is generally advantageous for the environment in the short term as it reduces ETS emissions compared to perfect competition (Fowlie, 2009); however, this could have undesirable consequences in the long term. ETS emission reduction happens at the cost of lower consumer surplus and C&T permit revenues due to the lower permit price and/or lower demand for permits. Thus, other than lower consumer surplus, less revenues are collected from the permit sales, which could be invested in new technologies or regions with a weak climate policy in place, e.g., via the Green Climate Fund (GCF, 2018). In addition, a lower permit price could offer a weaker incentive for investment into renewables and carbon capture and storage (CCS) (World Bank, 2016), which are important for the decarbonisation of the electricity industry. A future with insufficient decarbonisation in the electricity markets subject to market power could lead to outcomes described under cost parity between coal and natural gas, i.e., outcomes unfavourable not only for consumers but also the environment.

Market power exercised in an ETS country generally results in lower carbon leakage; however, this is because the ETS emission reduction offsets the non-ETS emission increase. Therefore, as non-ETS firms export more to the ETS area under imperfectly competitive settings, non-ETS consumers face higher electricity prices and higher emissions. This is particularly concerning as the examined non-ETS countries plan to enlarge their lignite fleet over the next years (CEE Bankwatch, 2017), which would provide more availability for exports of dirty electricity into the environmentally concerned ETS countries and could further increase non-ETS emissions. While non-ETS countries are in the process of joining the EU and will, as part of their membership, have to participate in the EU ETS, the earliest accession is foreseen for 2025 (EC, 2018c), thereby leaving several years where carbon leakage could delay environmental goals set by the EU and harm non-ETS consumers. One way to mitigate this effect is to use the Energy Community[6] to establish a one-way link[7] between the EU ETS and non-ETS countries whereby the the non-ETS countries could set environmental targets and recognise EU ETS permits for compliance with these targets. This could level the playing field between EU and non-EU firms in SEE-REM, reduce emission leakage, and, even though non-ETS consumers would face higher electricity prices, these would reflect the internalised cost of emission damage. Moreover, it could also help to attract capital from environmentally concerned foreign investors.

1.3 Regional Carbon Policies in an Interconnected Power System: How Expanded Coverage Could Exacerbate Emissions Leakage

Carbon leakage resulting from unilateral policies has been widely discussed in the literature as it can undermine emission-reduction objectives, and since CO_2 emissions are damaging globally independently of their origin, it is necessary to complement unilateral policies with measures for carbon-leakage mitigation. On a global level, several studies estimate the magnitude of leakage that could occur as a result of such unilateral policies (Paltsev, 2001) and how leakage could further be exacerbated as a result of free trade (Kuik and Gerlagh, 2003). Especially at risk are carbon-intensive sectors subject to international trade, e.g., manufacture of chemical products, manufacture of iron and steel, and mining and extraction of fossil fuels (EC, 2014b).

We explore a second-best solution in which a cap is optimally determined by a regulator with consideration of minimising emission damage caused by leakage.

[6]The Energy Community is an international organisation for energy policy that was established by nine countries ("contracting parties") from the South-East European and Black Sea regions with the objective of integrating the contracting parties into the EU internal energy market. The Energy Community was established in 2005 by signing the "Treaty Establishing Energy Community" (Energy Community, 2005) when none of the contracting parties was part of the EU.

[7]A similar link was initially established between the EU and Norway prior to developing into a bi-lateral link (World Bank, 2016).

Specifically, we focus on a regional electricity market represented by two nodes connected by a congested line. The policymaker may implement a C&T that has jurisdiction over only one of the nodes. The node[8] under the policymaker's jurisdiction is a net importer of power from the unregulated node, which has cheaper but dirtier generation. In addition, due to the fact that CO_2 is a global pollutant, its resulting damage is not limited to the node where the emission occurs. The question that arises from this context is: *Which emissions should be considered damaging for the node under the policymaker's jurisdiction when setting the socially optimal cap for the C&T?*

To answer this question, we develop three different coverage policies under which the policymaker can choose to take account of damage from emissions from (i) the regulated node only (known as *partial* coverage), (ii) both nodes (*modified* coverage), and (iii) the regulated node plus imports from the unregulated node (*import* coverage). The analysis is based on a bi-level model (Figure 1.6) in which at the upper level, the policymaker determines the socially optimal cap for the node participating in the C&T; at the lower level, two producers (one at each node) compete to sell their output while an ISO manages the grid in a socially optimal way. The lower level includes a market-clearing condition for the C&T. Under each coverage policy, we identify the optimal emission cap, production quantities, the carbon permit price, and the marginal value of transmission capacity. The marginal value of transmission capacity (the dual variable of the transmission constraint) is used as a proxy to measure the potential for carbon leakage under each coverage. We prove analytically that the partial-coverage policy increases total regional emissions and is also subject to a higher risk of carbon leakage vis-à-vis full coverage. In mitigating total emissions, the modified-coverage policy sets a tighter emission cap at the regulated node, which actually increases the potential for leakage relative to the partial-coverage policy. Finally, by targeting only those emissions imported from the unregulated node, the import-coverage policy reduces leakage vis-à-vis modified coverage at the expense of a higher level of total regional emissions.

1.4 Structure of the Thesis

The rest of this thesis is organised into four chapters. Chapter 2 develops the stylised model for SEE-REM and quantifies the magnitude of carbon leakage into the non-ETS part of SEE-REM considering the interaction of permit price and hydropower availability under perfect competition. In Chapter 3, carbon leakage in SEE-REM

[8] The setting resembles the situation faced by California, see Section 4.3.1.

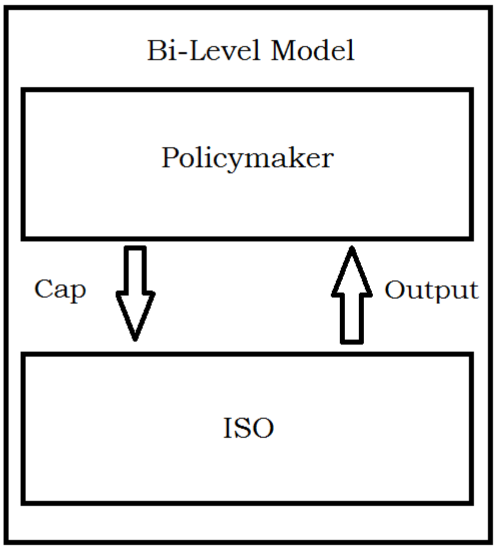


Figure 1.6: Policymaker and ISO bi-level model

is investigated under imperfect competition in either the electricity market only or both electricity and permit markets via a bi-level model. In a theoretical framework, Chapter 4 develops a bi-level model for the purpose of establishing the basis for a second-based anti-leakage measure. Finally, Chapter 5 concludes this thesis by summarising the results, outlining the limitations, and providing grounds for future research. Part of the contents in Sections 1.1, 2.1, 2.2, 2.3, 2.4, 5.1, and Appendix A are published in Višković et al. (2017) - DOI: 10.1016/j.eneco.2017.04.033.

Chapter 2

Implications of the EU Emissions Trading System for the South-East Europe Regional Electricity Market

Part of the contents in Sections 2.1, 2.2, 2.3, and 2.4 are published in Višković et al. (2017).

2.1 Introduction

The EU ETS was designed with the purpose of helping EU countries achieve their carbon-reduction objectives set under the Kyoto Protocol. It was established in 2005, and, since then, it has evolved over three phases, viz., trial phase (2005-2007), second phase (2008-2012), and third phase (2013-2020). Since its beginning, the EU ETS has been the largest carbon market and has contributed to the knowledge of emission trading with several important lessons. First, because the end of the trial phase saw a considerable drop in permit price due to, among others, unavailability of emission data and no possibility of banking[9] permits, banking has been allowed in subsequent phases (Newell et al., 2013). Second, caps set at national levels determined by national allocation plans (NAPs) were replaced by an EU-wide cap in phase three for the purpose of achieving emission targets in a more cost-effective way. Third, the struggle with excess allowances since 2009 caused prevalently by the financial crisis and use of international credits (EC, 2018f), which drove down the allowance price, was tackled with short- and long-term mechanisms. The short-term mechanism entails holding back allowances in the middle of phase three and auctioning them later on in the same phase, whereas the long-term mechanism,

[9]Option that enables entities covered by a C&T to hold permits for future compliance periods (World Bank, 2016).

due to launch in 2019, involves adjusting demand and supply via a market stability reserve in order to absorb major shocks to the system. Fourth, free allocation of allowances for sectors deemed at risk of carbon leakage in order to mitigate emission leakage and safeguard the competitiveness of firms operating under the EU ETS.

Despite the anti-leakage remedy in place, emission leakage in the EU ETS has been increasingly investigated. This is not surprising as free allocation might not deliver leakage mitigation if firms receiving permits for free collect revenues by selling permits and decrease their output (Carbon Trust, 2010). However, carbon leakage estimates in the literature vary depending on the method used, e.g., empirical studies fail to find substantial leakage, whereas *ex ante* studies indicate that there might be considerable leakage in some sectors (Vivid Economics and Ecofys, 2014). While the difference between the two methodologies might be attributed to factors such as model assumptions used in *ex ante* models and the length of time over which carbon leakage may occur, there is a need for quantifying carbon leakage and developing more efficient anti-leakage methods as carbon leakage might result in several undesirable consequences. Examples include undermining carbon-reduction objectives, adversely affecting the competitiveness of firms in the EU ETS, harming consumers in the non-regulated area, and generating windfall profits for non-regulated firms.

We contribute to the *ex ante* carbon-leakage literature by studying the interaction between permit price and hydropower availability in SEE-REM via a bottom-up partial-equilibrium framework, thereby estimating the magnitude of carbon leakage. We find that 6.3% to 40.5% of the emission reduction achieved in the ETS part of SEE-REM could be leaked to the non-ETS part depending on the allowance price. Somewhat surprisingly, greater hydropower availability may increase emissions in the ETS part of SEE-REM. However, carbon leakage might be limited by demand response to higher electricity prices in the non-ETS area of SEE-REM. Such carbon leakage can affect both the competitiveness of producers in ETS member countries on the periphery of the ETS and the achievement of EU targets for CO_2 emission reduction. Meanwhile, higher non-ETS electricity prices imply that the current policy can have undesirable outcomes for consumers in non-ETS countries, while non-ETS producers would experience an increase in their profits due to higher power prices as well as exports. The presence of carbon leakage in SEE-REM suggests that current EU policy might become more effective when it is expanded to cover more countries in the future.

2.2 Literature Review

Up until the 1970s, least-cost methods were adequate for supporting decisions in the electric power system due to tight regulation of the electricity industry. Hobbs (1995) points out that with deregulation and unbundling, there is a need for optimisation models that account better for endogenous price formation and strategic interactions in electricity markets. Starting from Hobbs (2001), complementarity models have evolved to analyse deregulated electricity industries (Gabriel et al., 2012).

Concerns about environmental issues in the past decade have increased the need for policy-enabling models. Such models have illustrated that mechanisms such as C&T and renewable portfolio standards (RPS) do not always work as intended (Tanaka and Chen, 2013). For instance, Limpaitoon et al. (2011) study the impact of the C&T mechanism on electricity markets in the presence of transmission congestion and strategic behaviour. They find the possibility of less-polluting firms' exercise of market power in electricity markets by withholding supply or over-consuming permits, leading to higher electricity and permit prices. Inflated permit prices translate into a higher abatement cost for more-polluting firms. Those relatively dirty firms then decrease their generation and surrender their market share to "cleaner" firms, which results in "cleaner" firms' earning higher profits (Chen and Hobbs, 2005; Limpaitoon et al., 2014). The deployment of such strategies is supported by empirical evidence (Kolstad and Wolak, 2003).

An emission tax could also interact with power transmission in a surprising way. For instance, Downward (2010) reports that a carbon tax could cause changes in the merit order and reverse flow direction that could result in higher emissions in the regulated area. An increase in emissions in the regulated area is possible under a carbon tax in very specific circumstances because, unlike a C&T, a carbon tax does not impose a cap on emissions; rather it aims to reduce emissions only through increasing abatement cost. Thus, unlike a carbon tax, the cap in a C&T system should guarantee that an increase in domestic emissions does not happen. However, in the presence of a C&T, increased emissions could occur outside of the regulated area, thereby causing emission leakage.[10]

Carbon leakage also occurs in other C&T programs. In the context of RGGI,

[10]The EU adopts a narrower definition in which carbon leakage refers only to an increase in non-regulated area emissions resulting from relocation of industry to the non-regulated area (EC, 2009). We adopt the broader definition used by (Chen, 2009) in our analysis: carbon leakage is defined as a displacement of CO_2 emissions from a regulated to a non-regulated area as a consequence of imposing a carbon-reduction policy in the regulated area.

Burtraw et al. (2006) find that carbon leakage could lead to an increase in profits earned by generating facilities located outside of the regulated region. A large part of these higher profits is due to the increased electricity prices paid by consumers outside of the regulated area, suggesting that the incurred emission cost is more than offset by increased profits earned from the non-regulated region. Further considering RGGI, Palmer et al. (2006) find that although individually some firms could lose value, the electricity sector in the North-East U.S., on aggregate, could gain value because the change in revenues through a higher power price is greater than the change in emission costs. A large portion of the aggregate gain in value results from assets located outside of the regulated area, suggesting incidence of the C&T policy on consumers outside of the C&T region. In addition, Chen (2009) quantifies the magnitude of carbon leakage in the short term under RGGI. The paper finds that emissions in the non-regulated area might increase with a higher allowance price; however, for the same allowance prices, relative leakage might decrease.

In the context of the California C&T, as one of the possible solutions for mitigating leakage, the California Air Resource Board (CARB) introduced the obligation to report emissions associated with imports into California, the so-called "first deliverer" policy.[11] Bushnell et al. (2014) find that even with a default emission rate for imported emissions, the "first deliverer" policy could still lead to emission leakage in the Western Electricity Coordinating Council (WECC) context through contract reshuffling.

While the relevant authorities in the U.S. are trying to tackle the problem of carbon leakage by proposing solutions such as the "first deliverer" policy, to the best of our knowledge, the possibility of carbon leakage in SEE-REM in relation to the EU ETS has not yet been carefully examined. Although there are numerous studies examining the EU ETS, such as its impact on electricity prices and emissions (Chen et al., 2008) and the interaction between the deployment of renewable energy and the CO_2 price (Weigt et al., 2013; Van den Bergh et al., 2013), our contribution is to examine the extent of carbon leakage in electricity markets under the EU ETS when considering the effect of hydropower availability.

[11] The "first deliverer" policy requires importers of electricity into California to report and pay for the associated emissions. These emissions can be based either on actual plant-specific emissions or on a default emissions factor established by the CARB.

2.3 Mathematical Formulation

2.3.1 Assumptions

We model the electricity industry via a bottom-up partial equilibrium approach in which three players are considered: producers, consumers, and a GO. Such a model can be implemented computationally both as a single optimisation problem and as a mixed complementarity problem (MCP) in which each entity's optimisation is addressed separately. In this study, we choose the latter approach based on Hobbs (2001).

Producers are modelled as being price takers. Each producer owns a number of generating units located at different nodes, which are characterised by their marginal costs of production, $C_{i,n}$, and a CO_2 emission rate based on different technologies,[12] $E_{i,n}$. Moreover, each producer's objective is to maximise its profit subject to constraints related to maximum generation capacity, energy balance, and non-negative quantities. Finally, each producer takes capacity, $X_{i,n}^{MAX}$, as fixed and decides how to operate generating units that it owns during each time block.

Consumers are represented by the inverse-demand function at each node, $D_{t,m}^{int} - D_{t,m}^{slp} \sum_j s_{t,j,m}$, which could be viewed as the result of solving their utility-maximisation problems. $D_{t,m}^{int}$ and $D_{t,m}^{slp}$ are the inverse demand intercept and slope, respectively, and $\sum_j s_{t,j,m}$ is the electricity sold by all firms at each node in each time period, which is equivalent to the demanded quantity at each node in each time period. The GO's profit is given by charging a wheeling fee for power transmitted through the grid. In a sense, it optimally allocates scarce transmission resources while being constrained by the maximum transmission capacity on the lines and Kirchhoff's laws. As is common in power system economics, flows on the lines are modelled using the DC load-flow model. We have one market-clearing condition for the electricity market, which equates the difference between sales and generation with net imports at each node. Finally, the MCP is given by the set of equations representing producers' and the GO's Karush-Kuhn-Tucker (KKT) conditions and the market-clearing condition (Gabriel et al., 2012). The solution to this MCP exists, is unique, and represents the Nash equilibrium (Hobbs, 2001). The rest of this section is dedicated to a detailed description of each player's optimisation problem. Appendix A.1 provides the associated nomenclature.

[12] Note that we separate ownership based on technology, e.g., all lignite-fired units will be owned by the same firm. Therefore, we use the same index i to distinguish between firms and technologies.

2.3.2 Producer i's Optimisation Problem and KKT conditions

Producer i's optimisation problem is given by (2.1)-(2.4). Specifically, producer i maximises its annual profit in (2.1) subject to maximum capacity (2.2), energy-balance (2.3), and sales and generation non-negativity (2.4) constraints. Profit is given by the difference between revenue from sales and generation cost. Revenue in every time block t derives from quantities sold at each node, $s_{t,i,n}$, multiplied by the electricity price at node n, $\left(D^{int}_{t,n} - D^{slp}_{t,n}\sum_j s_{t,j,n}\right)$. The generation cost in every time block t is given by quantities produced, $x_{t,i,n}$, multiplied by the marginal cost of generation, $C_{i,n}$, and wheeling fee, $\tau_{t,n}$. The wheeling fee is a transmission–based fee that is the shadow price of the market-clearing condition (2.18), and is calculated on the basis of transmitting power from node n to node m through an arbitrary node that acts like a hub. Specifically, the GO pays the wheeling fee, $\tau_{t,n}$, to the producer to transmit power from node n to the hub and charges the producer the wheeling fee, $\tau_{t,m}$, to transmit power from the hub to node m (Hobbs, 2001). Thus, the actual cost of transmission for the producer for transmitting of power from node n to node m is given by $\tau_{t,m}s_{t,i,m} - \tau_{t,n}x_{t,i,n}$. Producers in the ETS area have an additional cost due to emissions and are distinguished by the binary parameter, T_n. The emissions cost is given by the quantities produced multiplied by emissions intensity rate, $E_{i,n}$, and the cost of CO_2 emissions, R. In order to calculate the annual profit, we multiply profit in every time block with the number of hours, N_t, that belong to that time block and sum over all t. Shadow prices $\lambda_{t,i,n}$ and $\theta_{t,i}$ are given in parenthesis for (2.2) and (2.3), respectively.

$$\max_{s_{t,i,m},x_{t,i,n}} \sum_t N_t \Bigg(\sum_m \left[\left(D^{int}_{t,m} - D^{slp}_{t,m} \sum_j s_{t,j,m} \right) - \tau_{t,m} \right] s_{t,i,m} - \sum_n \left(C_{i,n} - \tau_{t,n} \right) x_{t,i,n} - \sum_n T_n x_{t,i,n} E_{i,n} R \Bigg) \quad (2.1)$$

$$\text{s.t. } x_{t,i,n} - X^{MAX}_{i,n} \leq 0 \quad (\lambda_{t,i,n}) \quad \forall t,n \quad (2.2)$$

$$\sum_n s_{t,i,n} - \sum_n x_{t,i,n} = 0 \quad (\theta_{t,i}) \quad \forall t \quad (2.3)$$

$$s_{t,i,n} \geq 0,\ x_{t,i,n} \geq 0 \quad \forall t,n \quad (2.4)$$

Each producer i solves its optimisation problem by taking the decisions of all other producers j and the wheeling fee, $\tau_{t,n}$, as given. The KKT conditions for producer i's optimisation problem are given in Equations (2.5)-(2.8), of which (2.5)-(2.7) are complementary slackness conditions. In particular, (2.5) states that if sales are positive, then the revenue from sales is equal to the rent on generation. Equation

(2.6) states that if generation is positive, then the rent on generation is equal to the cost of generation and the shadow price of generation capacity. Finally, in (2.7), if the shadow price on maximum generation capacity is positive, then the maximum generation capacity constraint is binding.

$$0 \leq s_{t,i,m} \perp N_t \left(D^{int}_{t,m} - D^{slp}_{t,m} \sum_j s_{t,j,m} - \tau_{t,m} \right) - \theta_{t,i} \leq 0 \quad \forall t,i,m \tag{2.5}$$

$$0 \leq x_{t,i,n} \perp N_t \left(-C_{i,n} - T_n E_{i,n} R + \tau_{t,n} \right) - \lambda_{t,i,n} + \theta_{t,i} \leq 0 \quad \forall t,i,n \tag{2.6}$$

$$0 \leq \lambda_{t,i,n} \perp x_{t,i,n} - X^{MAX}_{i,n} \leq 0 \quad \forall t,i,n \tag{2.7}$$

$$\sum_m s_{t,i,m} - \sum_n x_{t,i,n} = 0 \quad (\theta_{t,i}\ free)\ \forall t,i \tag{2.8}$$

2.3.3 The Grid Owner's Optimisation Problem and KKT conditions

The GO maximises its annual profit (2.9) subject to constraints given by the physical laws that apply to power flows (2.10)-(2.12) while taking the wheeling fee, $\tau_{t,n}$, and the producers' decisions as given. The GO's profit in every time block t is the product of the wheeling fee, exogenous to the GO, and the net import at each node. The net import at every node is the difference between power flowing to and from that node, and this difference is obtained from the product of the power flows on the lines connected to that node and the incidence matrix, $A_{\ell,n}$. In order to obtain the annual profit, we multiply the profit from every time block t by N_t and sum over all t. According to the DC load-flow approximation, flows on alternating current (AC) lines, $f_{t,\ell^{AC}}$, $\ell^{AC} \in \mathscr{L}^{AC}$, are defined in (2.10) and are given by the product of the network transfer matrix, $H_{\ell^{AC},n^{AC}}$, and voltage angles, $d_{t,n^{AC}}$ (Gabriel and Leuthold, 2010; Bjørndal et al., 2013). Flows on all lines are subject to lower and upper thermal limits, K_ℓ, given in (2.11) and (2.12), respectively.

$$\max_{d_{t,n}, f_{t,\ell}} \quad \textstyle\sum_t N_t \left(\sum_n \tau_{t,n} \left(-\sum_{\ell \in \mathscr{L}} A_{\ell,n} f_{t,\ell} \right) \right) \tag{2.9}$$

$$\text{s.t.} \quad f_{t,\ell^{AC}} = \textstyle\sum_{n^{AC} \in \mathscr{N}^{AC}} H_{\ell^{AC},n^{AC}} d_{t,n^{AC}} \quad (\gamma_{t,\ell^{AC}}), \quad \forall t, \ell^{AC} \in \mathscr{L}^{AC} \tag{2.10}$$

$$-f_{t,\ell} - K_\ell \leq 0 \quad (\mu^-_{t,\ell} \geq 0), \quad \forall t,\ell \tag{2.11}$$

$$f_{t,\ell} - K_\ell \leq 0 \quad (\mu^+_{t,\ell} \geq 0), \quad \forall t,\ell \tag{2.12}$$

The KKT conditions of the GO's optimisation problem are given in (2.13a)-(2.17). Equations (2.13a)–(2.13b) state that the revenue of the GO on line ℓ is equal to the shadow prices on the transmission capacity of that line. Shadow prices on transmission capacity, based on the direction of the flow, are dual variables of (2.16) and (2.17) where the constraint is not binding if the dual is zero.

$$-N_t\left(\sum_n \tau_{t,n}A_{\ell^{AC},n}\right)-\gamma_{t,\ell^{AC}}+\mu^-_{t,\ell^{AC}}-\mu^+_{t,\ell^{AC}}=0 \quad (f_{t,\ell^{AC}}\ free) \quad \forall t,\ell^{AC}\in\mathscr{L}^{AC} \tag{2.13a}$$

$$-N_t\left(\sum_n \tau_{t,n}A_{\ell,n}\right)+\mu^-_{t,\ell}-\mu^+_{t,\ell}=0 \quad (f_{t,\ell}\ free) \quad \forall t,\ell\in\mathscr{L}\setminus\mathscr{L}^{AC} \tag{2.13b}$$

$$\sum_{\ell^{AC}\in\mathscr{L}^{AC}} H_{\ell^{AC},n^{AC}}\gamma_{t,\ell^{AC}}=0 \quad (d_{t,n^{AC}}\ free) \quad \forall t,n^{AC}\in\mathscr{N}^{AC} \tag{2.14}$$

$$f_{t,\ell^{AC}}-\sum_{n^{AC}\in\mathscr{N}^{AC}} H_{\ell^{AC},n^{AC}}d_{t,n^{AC}}=0 \quad \left(\gamma_{t,\ell^{AC}}\ free\right) \quad \forall t,\ell^{AC}\in\mathscr{L}^{AC} \tag{2.15}$$

$$0\leq\mu^-_{t,\ell}\perp -f_{t,\ell}-K_\ell\leq 0 \quad \forall t,\ell \tag{2.16}$$

$$0\leq\mu^+_{t,\ell}\perp f_{t,\ell}-K_\ell\leq 0 \quad \forall t,\ell \tag{2.17}$$

2.3.4 Market-Clearing Conditions

We impose a mass-balance condition in the electricity market by equating the difference between sales and production with net imports at each node, where import is given by the product of the network incidence matrix and power flows, $-\sum_\ell A_{\ell,n}f_{t,\ell}$ as in Equation (2.18). The difference between shadow prices, $\tau_{t,n}$, is precisely the wheeling fee earned by the GO in (2.9) and paid by producers in (2.1).

$$N_t\Big(\sum_i s_{t,i,n}-\sum_i x_{t,i,n}\Big)=N_t\Big(-\sum_\ell A_{\ell,n}f_{t,\ell}\Big) \quad (\tau_{t,n}\ free) \quad \forall t,n \tag{2.18}$$

2.3.5 MCP

The MCP is given by (2.5)-(2.8), (2.13a)-(2.17), and (2.18). It is a square system of ten blocks of equations and ten blocks of variables $\{\gamma_{t,\ell}$, $\theta_{t,i}$, $\tau_{t,n}$, $d_{t,n}$, $f_{t,\ell}$, $\lambda_{t,i,n}$, $\mu^-_{t,\ell}$, $\mu^+_{t,\ell}$, $s_{t,i,n}$, and $x_{t,i,n}\}$. The "squareness" of the problem is necessary for finding a solution computationally by using MCP solvers (Hobbs, 2001). The solution is a set of prices, quantities, flows, and consumption resulting from satisfying each agent's KKT conditions for profit maximisation while clearing the electricity market. This solution represents the Nash equilibrium where none of the players has the incentive to change its decisions unilaterally (Hobbs, 2001).

2.4 Data Implementation, Calibration, and Results

2.4.1 Data and Assumptions

We assess the extent of carbon leakage in the thirteen SEE-REM countries by using a 22-node network with a high-voltage (HV) grid. We model only thermal and nuclear power units that are described by their marginal costs of production and CO_2 emission intensities. Our analysis focuses on one year with four representative time blocks per month. Next, we describe the SEE-REM and provide a detailed description of how we obtained and implemented data for our numerical example of SEE-REM.

2.4.1.1 South-East Europe Regional Electricity Market

Countries in SEE-REM are chosen based on their association with the Energy Community and are: Albania (n_{19}), Bosnia and Herzegovina (n_{14}), Bulgaria (n_{21}), Croatia (n_{13}), Former Yugoslav Republic of Macedonia (n_{17}), Greece (n_{18}), Hungary (n_{20}), Italy (($n_1 - n_{11}$)), United Nations Interim Administration Mission in Kosovo (n_{15}), Montenegro (n_{16}), Republic of Serbia (n_{15}), Romania (n_{22}), and Slovenia (n_{12}). As of 2013, seven of these countries are EU members and are, thus, subject to the EU ETS, viz., Bulgaria, Croatia, Greece, Hungary, Italy, Romania, and Slovenia.

In our numerical example, we apply a similar approach used in Green (2007) to simplify nodal representation of SEE-REM based on a 22-node network. Each country is modelled by only one node with the exception of Serbia, Kosovo, and Italy. Serbia and Kosovo are jointly modelled as one node only because of lack of data in relation to the transmission capacities with Kosovo. Italy is modelled by 11 nodes representing existing 11 pricing zones.[13] Therefore, for the purpose of using the DC load flow to model flows, we calculate the nodal network transfer matrix based on Schweppe et al. (1988).

2.4.1.2 Line-Specific Data

In relation to the network, we have one line between every pair of nodes. Limits of power flows on lines are given by the Net Transfer Capacities (NTCs), which are divided between winter values and summer values and are published by the European Network of Transmission System Operators for Electricity (ENTSO-E) in ENTSO-E (2011) and ENTSO-E (2012), respectively. The limits of power flows on the lines within Italy are obtained from the Italian TSO, Terna (Terna, 2013b). Note that NTCs are limits on commercial flows rather than actual thermal limits of

[13] Other countries use either uniform or tariff pricing (EBRD, 2010).

the lines; however, we use NTCs as an approximation due to lack of actual data. Moreover, we distinguish between AC and DC lines and use the DC load-flow approximation to model the flows. Further discussion on both NTCs and DC load flow can be found in Appendix A.3.1.

2.4.1.3 Node-Specific Capacities

Thermal units are divided into six different technologies based on type of fuel and/or type of turbine, viz., coal, lignite, natural gas-steam turbine, CCGT, fuel oil, and mixed fuels. With the exception of distinguishing between types of units fired by natural gas, ENTSO-E uses the same categories and publishes generation capacities per category per country on a yearly basis (ENTSO-E, 2013). In order to understand better the mixed fuels category, we use more detailed production data (Appendix A.3.2.)

The differences between technologies are reflected in their marginal costs of production and CO_2 emission intensities (Table A.3-6), which are calculated from emission factors (EU, 2012). We assume that mixed fuels are steam-turbine units that can be fired by both natural gas and fuel oil, and, thus, their emissions are given by the combination of emissions of natural gas and fuel oil. By contrast, for CCGT emissions, we assume that these are 20% lower than natural gas-steam turbine emissions because of the increased efficiency of power production of the CCGT (52%-60%) compared to the natural gas-steam turbine (35%-42%) (IEA, 2010).

2.4.1.4 Nodal Demand

In order to represent the linear inverse-demand function for each node, we estimate the coefficients of the function from reference demand, reference price, load curve, and reference elasticity as described in Appendix A.2. Because we are modelling only nuclear and thermal power units, to estimate reference demand, we start from consumption net of import/export, renewables, and hydropower units' production (Bushnell and Chen, 2012), which leaves us with residual consumption. The load curve serves the purpose of adding some variation to the average hourly demand. The process of obtaining residual demand from residual consumption and calculating the load curve is explained in detail in Appendix A.3.3.

Reference prices are obtained by running a cost-minimisation linear program with fixed demand where nodal electricity prices are given by dual variables on energy mass-balance constraints. These prices are then fed into the MCP with the price-responsive inverse-demand function. The elasticity is assumed to be -0.25 for the whole system, which is consistent with that used in the literature (Egerer et al., 2014; Dietrich et al., 2005; Weigt, 2006).

2.4.2 Scenario Description

For the purpose of analysing carbon leakage and market outcomes in SEE–REM under the CO_2 reduction targets (e.g., EU 20-20-20) and different levels of hydropower production, we propose three sets of scenarios where each set has a baseline scenario. The three baseline scenarios are defined by the level of hydropower production as listed in Table 2.1. In addition, we vary the price of CO_2 allowances (0, 10, 20, 30, 40, 50 in €/t, where "t" is an abbreviation for metric tons) for each level of hydropower production. We have 18 scenarios in total, of which three are baseline scenarios with CO_2 prices of zero, and 15 scenarios with prices of CO_2 allowances from €10/MWh-€50/MWh.

Scenario	Description
Baseline	Used for calibration based on data from 2013
Base-dry	Base year for hydropower production based on 2011 data
Base-wet	Base year for hydropower production based on 2010 data

Table 2.1: Scenario and description

2.4.3 Calibration

We analyse the calibration of our baseline scenario considering three market outcomes: generation per fuel type, emissions, and electricity prices. Generally, production per fuel type is overestimated for cheaper fuels and underestimated for more expensive fuels; however, total production in SEE-REM is overestimated by 9.55%. As a consequence of overestimation of production, emissions in SEE-REM are also overestimated by 4.99%. Price patterns across nodes are well captured; however, prices in the model are lower at nodes that in reality have higher production from expensive fuels.

Generation Fuel Mix We divide the analysis of production by type of fuel into ETS and non-ETS areas (Figures 2.1 and 2.2, respectively). In the ETS area, production from cheaper sources such as coal, natural gas, nuclear, and lignite is overestimated by 22.10%, 12.46%, 11.02%, and 14.56%, respectively. Production in the non-ETS area is mostly given by lignite-fired power plants, and it is overestimated by 32.07%. Production from relatively more expensive fuels like mixed fuels and fuel oil in both ETS and non-ETS is underestimated. Because of this, the overall production in the ETS area is overestimated by 6.91% and in the non-ETS area by 29.66%. Finally, the overall production in the SEE–REM area is overestimated by 9.55%, which is of less concern for our study because we aim to capture the price variation among the nodes.

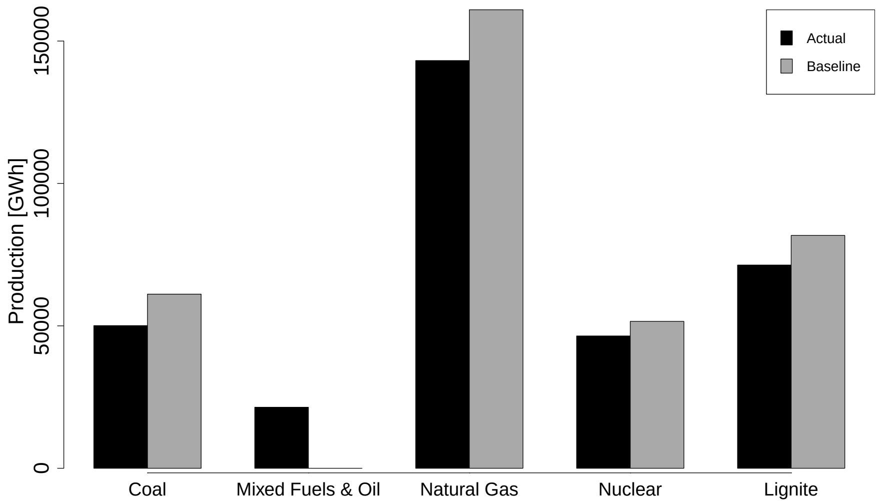


Figure 2.1: Generation per type of fuel in the ETS area

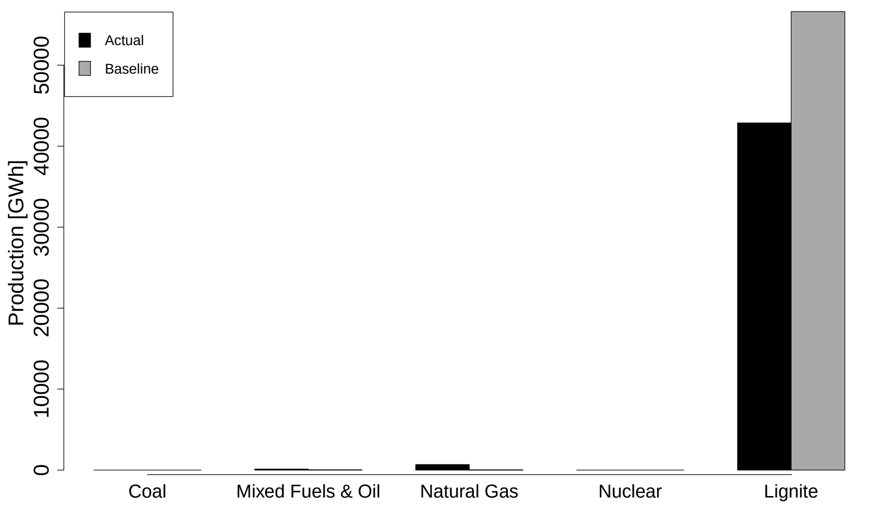


Figure 2.2: Generation per type of fuel in the non-ETS area

We believe that there are two explanations for the discrepancies found in generation from more expensive fuels. First, the model chooses the optimal solution for generating from each fuel based on given constraints; however, in reality, the choice of operating generating units might not always be efficient (e.g., less-efficient units based on fuel oil, for example, might be required to deal with short-term situations, like ensuring network security). Second, the model does not include any dynamic power plant constraints (e.g., ramp-up constraints), the absence of which might mean larger cost differences between generating technologies in the model than in reality for certain time periods (e.g., ramping hours). Consequently, technologies using more expensive fuels might not become viable options. Although estimation of production per fuel type varies based on fuel type, overall SEE-REM production is overestimated by 9.55%, which, considering that we do not take into account ramping constraints, we believe to be a reasonable calibration.

Emissions Emissions in the ETS and non-ETS areas (Figure 2.3) are underestimated by 0.24% and overestimated by 29.95%, respectively, with the total SEE-REM emissions being overestimated by 4.99%. The overestimation of emissions is related to the overestimation of production. Although it is expected that emissions are overestimated given that generation is overestimated, the emissions are calibrated more closely than generation. The reason for this discrepancy is related to the fact that the actual generation mix contains more polluting fuels (such as fuel oil) than the modelled one.

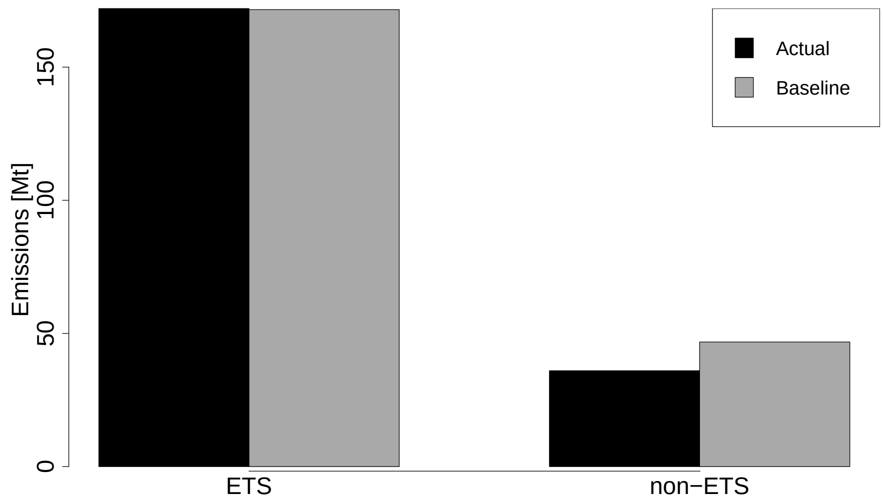


Figure 2.3: Emissions in the ETS and non-ETS areas

Electricity Prices We compare average annual wholesale electricity prices for six pricing zones in Italy (IT), Slovenia (SI), Greece (GR), Hungary (HU), and Romania (RO). Actual and modelled prices are shown in Figure 2.4. Because we are modelling residual demand, the actual prices need to be adjusted for the purpose of comparison such that point elasticity is preserved. A detailed explanation for obtaining adjusted prices is provided in Appendix A.3.4. The model seems to capture well the differences in prices between the nodes as the pattern is reproduced quite closely. There are a few exceptions, viz., IT6 and GR, where more expensive fuels, including oil and mixed fuels, are used more frequently in reality. Because our model does not capture the generation from these expensive fuels, it does not fully capture electricity prices at these nodes either.

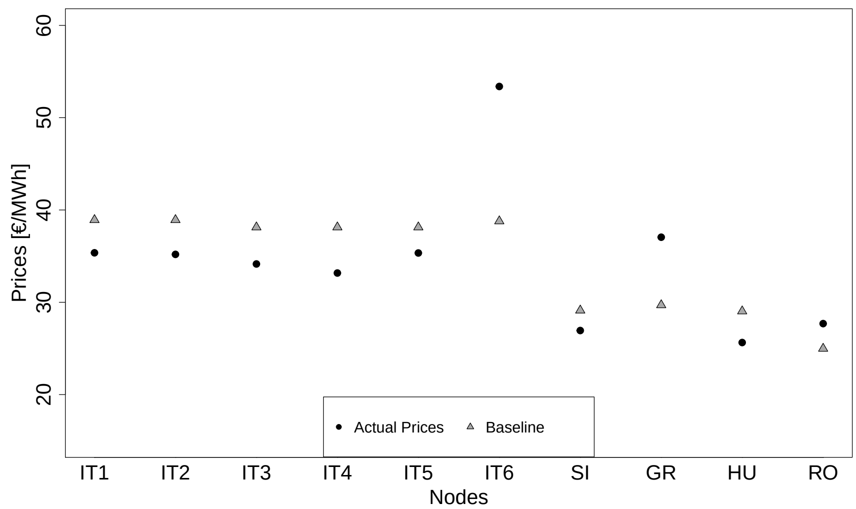


Figure 2.4: Electricity prices in Italy, Slovenia, Greece, Hungary, and Romania in 2013

2.4.4 Carbon Leakage Measures

In this study, we define carbon leakage as the increase in emissions in the non-regulated area as a result of imposing the cap on emissions in the regulated area. This definition is consistent with that in Chen (2009). In order to measure carbon leakage, Chen (2009) considers two metrics, leakage and relative leakage (RL). The author defines leakage as the change in emissions in the non-regulated area before and after the introduction of the cap, and this is given by $\Delta CO_2^N = Z_A^N - Z_B^N$, where Z are the emissions with the subscript B (A) indicating the state before (after) the cap and superscript N (ETS) indicates the non-ETS (ETS) area of the regional market. Furthermore, the author defines RL as the percentage of leakage in terms of the emission reduction in the regulated area. Relative leakage is given in Equation (2.19).

$$RL = \left| \frac{\Delta CO_2^N}{\Delta CO_2^{ETS}} \right| \times 100\% \tag{2.19}$$

RL measures the impact of carbon leakage relative to the reduction in the regulated area. For example, if RL is equal to 50%, then it means that the emissions in the non-regulated area increase by 50% of the reduction achieved in the regulated area. Because ΔCO_2^{ETS} (ΔCO_2^N) is the product of the $\Delta output^{ETS}$ ($\Delta output^N$) and the emission rate, a one unit increase in output with non-zero emission rate in the non-regulated area means that RL will be greater than zero. If $\Delta CO_2^N > \Delta CO_2^{ETS}$, then RL will be greater than 100%. However, as Chen (2009) points out, whether

$\Delta CO_2^N > \Delta CO_2^{ETS}$ depends on the circumstances, e.g., the generation mix for a certain load level, of the particular market under consideration.

Although RL is an intuitive measure of carbon leakage, it is sensitive to emission reduction in the regulated area. In the specific case of SEE-REM, this indicates a steady decrease in relative leakage with a higher allowance price because the generating capacity in the non-ETS area is relatively small compared to the whole SEE-REM generating capacity and demand. This means that carbon leakage in SEE-REM is limited by the installed generating capacity in the non-ETS area. However, this also suggests that the RL measure will not be able to detect more subtle effects, such as demand response in the non-ETS area, that might occur and are not related to reduction of emissions in the ETS area. For this purpose, we introduce a more robust measure for carbon leakage called reduction reversal (RR).

RR measures the difference between total emissions after the cap and total emissions expected to be achieved under the no-leakage assumption relative to the total emissions before the cap. Under the assumption of "no leakage," we expect the emissions of N to remain the same while at the same time we expect a reduction in the ETS; therefore, the total expected emissions are given by $\left(Z_A^{ETS} + Z_B^N\right)$. The RR is given in Equation (2.20), and it can trivially be reduced to Equation (2.21). As such, RR measures the reversal of emission reduction achieved in the ETS area under the cap.

$$RR = \left(\frac{\left(Z_A^{ETS} + Z_A^N\right) - \left(Z_A^{ETS} + Z_B^N\right)}{Z_B^{TOT}} \right) \times 100\% \tag{2.20}$$

$$RR = \left(\frac{\Delta CO_2^N}{Z_B^{TOT}} \right) \times 100\% \tag{2.21}$$

A drawback of RR lies in the total expected emissions assumption because the emission reduction that has been achieved in the ETS area under the cap is partly a result of the ability to import from the non-ETS area. This means that the reduction of emissions in the ETS examined in isolation of the non-ETS might not be achieved, *ceteris paribus*. As such, RR is not as useful as RL for quantifying carbon leakage. However, because RR is not sensitive to ETS reduction of emissions, it has the ability to pick up subtler effects, such as the reduction of leakage due to demand response in the non-ETS area that might influence carbon leakage. For the sake of completeness of examination of carbon leakage, we report and comment on both RR and RL.

2.4.5 Results Analysis and Discussion

In this section, we analyse the results and divide our analysis of CO_2 reduction into demand response, fuel switching, and carbon leakage. Our analysis is divided as such because we are focusing on the short-term impact of C&T, i.e., before any adjustments to capacity and retrofitting can be made. Specifically, in our model, we assume that renewables are generating at their maximum feasible levels for the considered period of time. However, in the longer term, CO_2 emissions can also be reduced through new renewable generation. Nevertheless, the effect of increases in renewables on the magnitude of emission leakage is ambiguous,[14] but this is beyond the scope of our study. We have three central findings:

- Carbon leakage may be limited by demand response to higher electricity prices in non-ETS countries.
- Greater hydropower availability may result in higher ETS emissions compared to the baseline.
- Depending on the allowance price, 6.3% to 40.5% of the emission reduction achieved in the ETS part of SEE-REM could be displaced to the non-ETS part.

In Table 2.3, we present main results related to emission and carbon leakage in different scenarios. We have three types of water years, viz., wet, dry, and normal, with six levels of CO_2 allowance prices (€0/t-€50/t). Each type of water year has a base scenario where the price of allowances is equal to €0/t against which we compare emissions reduction/increase and carbon leakage.

2.4.5.1 Demand Response

Introduction of allowance prices translates into a higher cost of production for the producers in the ETS area, thereby leading to higher electricity prices. Higher electricity prices in the ETS area suppress power quantity demanded and induce increased imports from the non-ETS area. The latter is due to the fact that higher ETS-region electricity prices offer economic incentives for non-ETS producers to increase their exports while, at the same time, driving up non-ETS prices. The increase in domestic prices in the non-ETS area driven by higher allowance prices

[14]On the one hand, if the cost of newly introduced renewables is lower than those units that ramp up their outputs in non-ETS countries due to emissions trading, then leakage should be mitigated. On the other hand, even if this is the case, then other ramping units might be needed due to intermittence of renewables (Rintamäki et al., 2016), and, consequently, the impact of renewables on emissions leakage might be limited.

might eventually curb non-ETS consumption (particularly evident in the wet-year scenarios), which then offsets the emissions caused by higher exports from the non-ETS area, thereby resulting in a decrease in leakage as measured by RR. In summary, the decrease in carbon leakage is given by non-ETS consumers' response to higher electricity prices due to the price-responsive demand assumption. In fact, the decrease in carbon leakage does not occur in the case of fixed demand (Table 2.4). With fixed demand, the only recourse to a higher CO_2 price is fuel switching. Consequently, although modelled emissions are higher in Table 2.4 compared to those in Table 2.3, carbon leakage as measured by RR monotonically increases with the CO_2 price.

2.4.5.2 Fuel Switching

As for the decomposition of CO_2 reduction, the inclusion of allowance prices changes the merit order of supply, thereby leading to fuel switching. In Table 2.2, we examine the three most frequently used technologies and how their costs vary and compare with price of allowances. Figure 2.5 indicates that the biggest incremental drops in emissions occur at €10/t and €40/t. The former is expected because of the introduction of the allowance price, and the latter occurs when the price of natural gas becomes the cheapest among the three examined fuels. Although coal becomes cheaper than lignite at €20/t, the cost difference is not sufficiently high to cause a major decrease in emissions.

Price of ETS allowances [€/t]					
0	10	20	30	40	50
Lignite	Lignite	Coal	Coal	Nat. gas	Nat. gas
Coal	Coal	Lignite	Lignite	Coal	Coal
Nat. gas	Nat. gas	Nat. gas	Nat. gas	Lignite	Lignite

Table 2.2: Relation of fuel costs with the cheapest fuel at the top and the most expensive one at the bottom

	CO_2 Price	€0/t		€10/t		€20/t		€30/t		€40/t		€50/t	
	Scenario	ETS	N	ETS	N	ETS	N	ETS	N	ETS	N	ETS	N
Emissions [Mt CO_2]	Actual 2013	172	35										
	Base dry	194	48.9	177	54.9	163	55.0	152	54.9	107	55.4	100	55.3
	Baseline	172	46.8	154	52.2	141	52.3	131	52.2	89	52.4	83	52.4
	Base wet	184	43.6	164	51.7	151	51.9	140	51.9	100	51.9	94	51.8
Change to baseline [%]	Base dry	0	0	-9	12	-16	12	-22	12	-45	13	-48	13
	Baseline	0	0	-10	12	-18	12	-24	12	-48	12	-52	12
	Base wet	0	0	-11	19	-18	19	-24	19	-46	19	-49	19
RR [%]	Base dry	0.00		2.47		2.51		2.47		2.68		2.63	
	Baseline	0.00		2.47		2.51		2.47		2.56		2.56	
	Base wet	0.00		3.56		3.65		3.65		3.65		3.60	
RL [%]	Base dry	0.00		35.29		19.68		14.29		7.47		6.81	
	Baseline	0.00		30.00		17.74		13.17		6.75		6.29	
	Base wet	0.00		40.50		25.15		18.86		9.88		9.11	

Table 2.3: Main results related to emissions and carbon leakage

	CO_2 Price	€0/t		€10/t		€20/t		€30/t		€40/t		€50/t	
	Scenario	ETS	N	ETS	N	ETS	N	ETS	N	ETS	N	ETS	N
Emissions [Mt CO_2]	Actual 2013	172	35										
	Base dry	194	48.9	187	54.8	185	55.2	185	55.2	143	56.7	143	56.7
	Baseline	174	43.9	166	51.9	163	52.6	163	52.7	120	53.9	120	54.0
	Base wet	185	42.6	176	51.3	172	52.4	172	52.5	132	53.1	132	53.2
Change to baseline [%]	Base dry	0	0	-4	12	-5	13	-5	13	-26	16	-26	16
	Baseline	0	0	-5	18	-6	20	-6	20	-31	23	-31	23
	Base wet	0	0	-5	20	-7	23	-7	23	-29	25	-29	25
RR [%]	Base dry	0.00		2.43		2.59		2.59		3.21		3.21	
	Baseline	0.00		3.67		3.99		4.04		4.59		4.64	
	Base wet	0.00		3.82		4.31		4.35		4.61		4.66	
RL [%]	Base dry	0.00		84.29		70.00		70.00		15.29		15.29	
	Baseline	0.00		100.00		79.09		80.00		18.52		18.70	
	Base wet	0.00		96.67		75.38		76.15		19.81		20.0	

Table 2.4: Main results related to emissions and carbon leakage in the fixed-demand case

2.4.5.3 Emissions, Carbon Leakage, and Demand Response

In relation to the interaction between CO_2 allowances prices and levels of hydropower production, three observations are worth noting. First, ETS and non-ETS emissions are higher in the dry year compared to the baseline. Higher emissions in the dry year are expected because a larger proportion of demand is covered by conventional thermal generation due to unavailability of hydropower capacity.

Second, emissions in the SEE-REM ETS area are higher in wet-year scenarios. This is in contrast to our initial belief that high availability of non-polluting hydropower would lead to lower emissions under wet-year scenarios compared to the baseline. This is mainly because higher availability of cheap non-polluting hydropower lowers electricity prices, thereby inflating consumption and emissions. Although the rebound effect is mostly defined in the context of energy efficiency (Gillingham et al., 2016), the increase in electricity consumption and emissions in the ETS area in the case of higher hydropower availability can be viewed similarly.

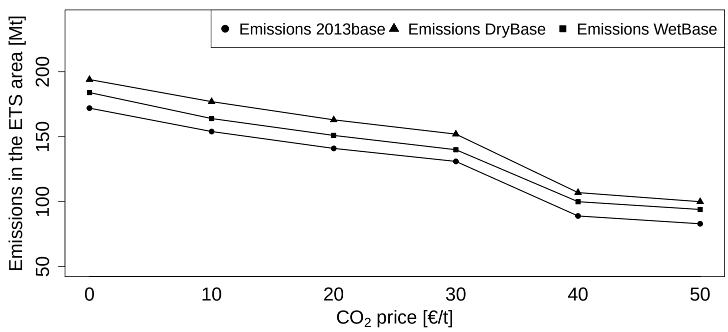


Figure 2.5: CO_2 emissions in the ETS area

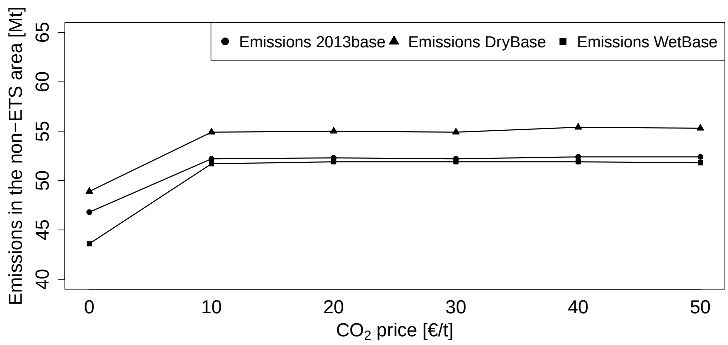


Figure 2.6: CO_2 emissions in the non-ETS area

Third, higher CO_2 allowance prices lead to consistently less leakage according to RL (Figure 2.7), which is not the case if we look at the RR measure where leakage varies depending on the price of allowances (Figure 2.8). According to RL,

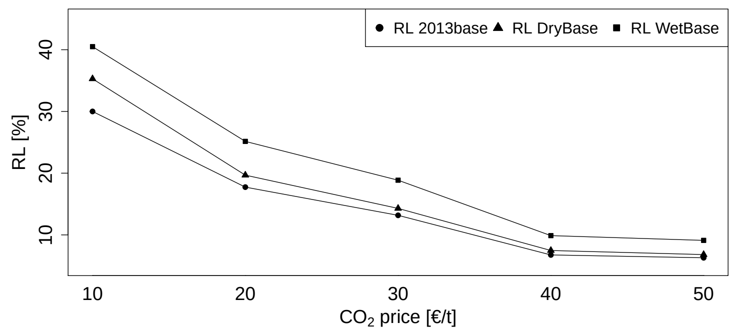


Figure 2.7: Relative carbon leakage

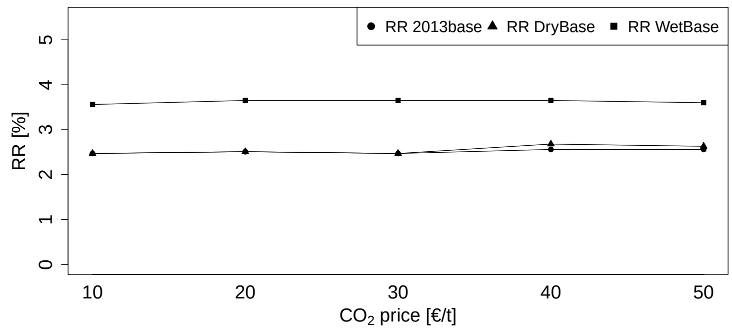


Figure 2.8: Reduction reversal

for an allowance price of €10/t, approximately 40.5% of the reduction achieved under the ETS is displaced to the non-ETS area. This decreases as allowance prices increase, reaching approximately 6.3% at a price of €50/t. Indeed, by examining the non-ETS emissions across different allowance prices, we notice that the decline in leakage according to RL is given almost only by the increase in reduction in the ETS area. Although RL provides a useful way of quantifying leakage, its sensitivity to the reduction in the ETS area (along with relatively low installed capacity in the non-ETS area) renders it difficult to discern effects on leakage other than the reduction in the ETS area. In fact, if we examine the RR measure, which is not sensitive to the reduction in the ETS area, then we can see that there might be other effects causing the decrease in leakage such as the demand response in the non-ETS area (explained in detail in Section 2.4.5.1).

2.5 Conclusions

The EU has been one of the leaders in the action against climate change among industrialised countries with the EU ETS covering 75% of international carbon trading. Since its establishment, the EU ETS has developed and improved in several aspects of market design, and it has contributed to the understanding of C&T systems.

However, as with other unilateral climate policies, the EU ETS might be subject to carbon leakage. Although carbon leakage is well defined in theory, in practice, it is difficult to quantify. In fact, even after thirteen years of the existence of the EU ETS and with several studies carried out, conclusions about carbon leakage have remained ambiguous as estimates vary across different studies. Yet, *ex ante* analysis of carbon leakage has shown that considerable leakage can occur in some sectors. Allevi et al. (2017), as one example, find that emission leakage in the Italian and European cement industry can be substantial and cannot be entirely mitigated by using neither the free-allowance allocation nor border carbon adjustments.

Since carbon leakage might be considerable at a sectoral level and the EU does not deem power generation at risk of carbon leakage as relocation in the power industry is not very common, we contribute to the literature by quantifying carbon leakage in the EU where EU-member states are neighbouring with countries not subject to the EU ETS. In particular, we investigate the possibility of emission leakage in South-East Europe where the EU aims to integrate non-EU countries participating in the Energy Community into the EU's internal energy market. These countries are incorporating the EU's legislation related to the energy industry into their national legislations in order to enable cross-border trade and integration (Energy Community, 2018); however, they are not subject to the emission cap.

Although countries in the Energy Community are prospective EU members, the EU suggests that first accessions are several years away (EC, 2018c). Therefore, without a binding environmental regulation in place, enhanced trade via the Energy Community might exacerbate carbon leakage. In fact, we find that between 6.3% and 40.5% of the emission reductions achieved in the South-East European electricity market under the EU ETS could be leaked into the examined non-EU countries. Due to the high dependency on hydropower production in the non-EU countries, it is not surprising that lower availability of hydropower leads to higher leakage. On the other hand, somewhat intriguingly, greater availability of hydropower exacerbates leakage as consumers react to lower electricity prices. Finally, leakage could be bounded by the demand response to higher electricity prices in the non-EU countries.

This study examines a perfectly competitive electricity market. However, despite facilitating entrance of new firms into the market via deregulation, today's electricity industries are often characterised by high market concentration. Thus, a model with an imperfectly competitive market structure might better reflect the reality of electricity markets. For this purpose, in the following chapter, we investigate the potential for carbon leakage in SEE-REM considering imperfect competition.

Chapter 3

Economic and Environmental Consequences of Market Power in the South-East Europe Regional Electricity Market

3.1 Introduction

One of the main aims of the liberalisation of the electricity industry in the EU was to introduce competition in the supply side by removing barriers that were precluding new producers from importing or producing their own electricity (EC, 2018e). However, liberalised electricity markets across Europe remain subject to high market concentration with a few firms holding large shares of the market. For example, in France, Estonia, and Croatia, the market share of the largest firm is above 80%, whereas in all other EU countries, except for Poland, the cumulative market share of firms producing more than 5% of electricity ranges from just under 40% in Italy to more than 90% in Slovenia (Eurostat, 2018b). High market concentration could result in imperfectly competitive markets at risk of market power especially during periods of peak demand with low elasticity (Borenstein et al., 1999). In addition, such imperfectly competitive market structures could also be reflected in emission-permit markets raising concern about the effectiveness of emission trading and the strength of the permit price.

Conventional electricity producers are facing a squeeze on their profit margins as subsidised renewable energy sources drive down wholesale electricity prices (Ecofys, 2016), and alarming consequences of climate change are pressing policy-makers to put a price tag on emissions. Although the long-term objective is to decarbonise the electricity industry, in the short term, market concentration in electricity and permit markets might hamper environmental targets if the polluting firms manipulate the permit price to their advantage. As we show, the fragmentation of climate policy that leads to an uneven playing field for firms operating in countries with disparate emission-reduction targets could incentivise firms subject to a C&T to lower permit prices. This could worsen the environmental situation in the countries with laxer regulation and lead to detrimental environmental consequences by diminishing incentive for investment in clean technologies.

Market power in electricity and emission-permit markets in SEE-REM, which comprises both EU members subject to the EU ETS and non-EU members exempt from it, could affect carbon leakage. We formulate three market settings: perfect competition and two leader-follower versions in which a leader can exercise market power in either the electricity market or both the electricity and permit markets. Under perfect competition, carbon leakage is equal to 11%-39% of ETS emission reduction depending on the cap stringency. Generally, in the leader-follower setting where the leader can exert power in the electricity market only, the leader's withholding results in ETS emissions below and non-ETS emissions above perfectly competitive levels. However, carbon leakage is lower vis-à-vis PC as the ETS emission reduction offsets the non-ETS emission increase. Finally, in the leader-follower setting where the leader can exert market power in both electricity and permit markets, ETS emissions rise due to a lower permit price, which exacerbates carbon leakage compared to one where leader manipulates the electricity market only. This result is reversed when the leader's prevailing technology becomes the marginal one.

3.2 Literature Review

The impact of market power in electricity markets is commonly examined through market settings such as Cournot oligopoly, dominant firm-competitive fringe, and multiple dominant firms with a competitive fringe. For example, Gabriel and Leuthold (2010) use a bi-level model to study the impact of market power by a single dominant firm in an electricity market. They find that the dominant producer is able to raise electricity prices above perfectly competitive levels by holding back capacity. However, the withholding is bounded by the cheapest plant of the follower firm, and the level of withholding increases with the marginal cost of the cheapest unit of the fringe until the leader has reached its maximum profit (Gabriel and Leuthold, 2010). In addition, their analysis shows that the leader can reap higher profits if it is the sole firm at a certain node, whereas this potential is lower when the leader and the fringe both own capacity at the same node.

Growing concerns over climate change and an increasing implementation of carbon-reduction policies emphasise the relevance of the interaction of imperfectly competitive electricity markets with permit markets. The exercise of market power in an electricity market can indirectly affect a perfectly competitive permit market. Limpaitoon et al. (2011) develop an equilibrium model of an oligopolistic electricity market in conjunction with a C&T where firms are price takers to study the impact of market structure on market outcomes. Although it is generally expected that more competitive markets have higher permit prices, Limpaitoon et al. (2011) find that this might not be the case when the ownership of relatively cleaner power plants is concentrated among fewer firms. In particular, if cleaner firms withhold generation in order to raise electricity prices, then dirtier firms increase production to compensate partly for the share vacated by the cleaner ones. This leads to more consumption of permits, thereby driving up the permit price.

Firms with market power in the product market could also have market power in the permit market and, thus, directly manipulate the permit price in their favour. Sartzetakis (1997) models a product market as a Cournot duopoly where one of the firms is a Stackelberg leader in the permit market. He concludes that a leader can intentionally raise the permit price as part of its strategy to raise competitors' costs (Salop and Scheffman, 1983) and that its ability to do so depends on its pre-regulation market share, regulation stringency, and the competitiveness of the product market. In the context of electricity markets with a secondary C&T, i.e., where firms trade permits among themselves, Chen and Hobbs (2005) find that the permit price is a function of both the share of a firm's capacity in the electricity market and the direction and magnitude of its net position in a C&T. More specifically, if a leader is a net seller in the permit market, then holding back permits is profitable as it results in a higher permit price, which means that the leader can reap higher profits from the sale of permits (Chen et al., 2006). However, this strategy may not be profitable when a leader is a net buyer of permits, in which case it could be profitable for the leader to resort to a monopsonistic strategy and try to lower the permit price.

Carbon pricing through market-based mechanisms is one of the cornerstones of climate policy; however, when implemented unilaterally, one of its main caveats is emission leakage, which has been widely discussed in the literature. Emission leakage can occur through imports increase from and production re-location to regions without environmental regulation as well as via international fossil-fuel markets. Furthermore, the magnitude of leakage depends on several factors, e.g., initial permit allocation, international fossil fuel prices, hydropower availability, and market power. Output-based allocation seems to be more efficient at mitigating leakage compared to other forms of allocation such as grandfathering or auction (Jensen and Rasmussen, 2000; Bushnell and Chen, 2012). Emission leakage through imports and re-location can be considerable depending on the sector and can further increase if the decline in fossil-fuels price resulting from lower demand from the regulated regions entices non-regulated regions' demand, thereby increasing the emission intensity of the non-regulated regions' production (Fischer and Fox, 2012). Low availability of hydropower can push up electricity prices in the region with a unilateral C&T, which could offer higher incentives for firms in the uncapped region to export, thereby increasing leakage (Višković et al., 2017).

Interaction between market power and carbon leakage in the short term has been examined by Fowlie (2009) in the context of the California spot and forward electricity markets. Imperfectly competitive market conditions are reflected by firms that are asymmetric Cournot oligopolists. Firms are price takers in the permit market facing a permit price of \$25/t, which reflects their inability to manipulate the permit price as the permit price is determined by a much larger C&T. Fowlie (2009) shows that not only strategic behaviour in an electricity market subject to unilateral carbon-reduction policy reduces emission leakage compared to perfect competition but also the less competitive the product markets, the lower the leakage.

In the same spirit as Fowlie (2009), we examine the interaction of market power and leakage in the short run. Unlike the Cournot model in Fowlie (2009), we assume that the leader anticipates its competitors' reactions to its decisions as a Stackelberg leader. In addition, we allow for market power in the permit market. In fact, our model of the coupled electricity and permit markets is similar to Chen et al. (2006); however, different from them, we model the first-stage C&T, i.e., initial allocation of permits rather than the secondary C&T market where market participants can sell or buy permits from each other.

To complement the preceding literature, we analyse the impact of market power exercised by a single dominant firm located in the regulated subregion of a regional market on carbon leakage under varying environmental regulation stringency. Market power can be exerted in the electricity market only or both in the electricity and permit markets. The former can help explain the incentives that strategic behaviour in a regulated subregion of an electricity market provides to unregulated firms, whereas the latter isolates the incentives resulting from a change in the permit price. Our aim is to answer the following research questions:

1. *What is the impact of the stringency of the environmental regulation under perfect competition?*

2. *What is the incremental impact of market power in electricity markets only?*

3. *What is the incremental impact of market power in both electricity and permit markets?*

We find that under perfect competition the cap initially curbs natural gas production before inducing fuel switching at higher levels as the cap tightens. The tightening of the cap leads to lower emission leakage as the emission reduction in the ETS area of SEE-REM dominates the emission increase in non-ETS area. The incremental impact of market power in the electricity market only initially leads to withholding of the leader's dominant technology, coal, before leading to its expansion under a more stringent cap. Natural gas production is generally expanded by the leader as the leader's natural gas plants can earn higher profits due to higher electricity prices resulting from either withholding or expanding of coal production. The fuel switching induced by the leader's manipulation under looser caps results in carbon leakage below perfectly competitive levels due to greater emission reduction in the ETS area. The additional ability to manipulate the C&T market offers the leader the incentive to withhold more coal initially in a bid to lower the permit price and to expand coal by a lesser extent under a more stringent cap in a bid not to increase the permit price. The lower degree of fuel switching resulting from the manipulation of the C&T market under looser caps leads to an increase in ETS emissions and carbon leakage, whereas lesser coal expansion under a tighter cap leads to lower ETS emissions and carbon leakage.

3.3 Mathematical Formulation

3.3.1 Model Structural Assumptions

We formulate three market settings, viz., perfect competition in both electricity and permit markets, leader-follower where the leader has market power in the electricity market only, and leader-follower where the leader has market power in both electricity and permit markets.

We consider a multi-period auction-based electricity market with one strategic firm and an ISO whose problem embeds follower firms. Firms are denoted by i, which is partitioned into s and j, referring to the leader and the follower firms, respectively. Firms own generating units, u, at different nodes, n. At each time period, t, firms are dispatched by the ISO with the objective of maximising total net surplus in the market, thereby, in the presence of transmission-constrained networks, determining locational marginal prices (LMPs), $\lambda_{t,n}$ (Hogan, 1992; Schweppe et al., 1988). Firms sell power at the nodes where they own capacity, and the ISO transports power from firms to consumers, i.e., purchasing power at nodes with excess supply and selling it to nodes with excess demand. Therefore, the ISO is both an auctioneer and an arbitrageur. The arbitrage is necessary to eliminate any non-cost price differences that might occur in the system (Hobbs, 2001). The transmission network is divided into AC and DC parts. We assume that in the AC network, power flows according to Kirchhoff's voltage and current laws, where these flows are approximated using the DC load-flow model (Schweppe et al., 1988). Since flows on DC lines are treated as controllable, we do not subject them to Kirchhoff's circuit law (Bjørndal et al., 2014).

3.3.2 Lower-Level Problem with Welfare-Maximising ISO

At the lower level, we have the ISO, whose problem is given by Equations (3.1)-(3.9). The ISO's objective (3.1) is to maximise social welfare by deciding quantities demanded by consumers, $d_{t,n}$, quantities generated by follower firms, $x_{t,n,j,u}$, flows, $f_{t,\ell}$, and voltage angles, $v_{t,n}$, while taking $x_{t,n,s,u}$ as given. The objective function is constrained by firms' generation capacities, $X_{n,j,u}$, (3.2), and transmission capacities, $K_{t,\ell}$, in positive and negative directions (Equations (3.3) and (3.4), respectively). Furthermore, flows on AC lines, $f_{t,\ell^{AC}} \in \mathscr{L}^{AC}$, are defined in Equation (3.5). Equation (3.6) represents the swing bus, where at an arbitrarily chosen node, the voltage angle is set to zero through the binary parameter, $S_{n^{AC}}$. Equations (3.7)-(3.9) are market-clearing conditions. Equation (3.7) imposes the condition of zero net imports, $-\sum_n \sum_\ell A_{\ell,n} f_{t,\ell}$, across all nodes, which derives from arbitrage and ensures equilibrium. Equation (3.8) guarantees that the difference between quantities demanded and produced at each node equals net imports at that node, i.e., the mass-balance equation that clears the electricity market. Finally, Equation (3.9) is the ETS market-clearing constraint and states that emissions produced by generating units located at nodes within the ETS (given by the product of generated quantities, $x_{t,n,i,u}$, and emission intensities of the respective units, $E_{n,i,u}$) must be less or equal to the emission cap, Z, exogenous to the ISO's problem. Variables in brackets on the right are the dual variables of the problem, which represent shadow prices of the associated constraints. Moreover, if the dual variable of a constraint given by an inequality is strictly positive, then the associated constraint is binding. For example, if the constraint on total emissions in the ETS is binding, then its shadow price, ρ, is the permit price.

The model at the lower level is a quadratic program (QP) that results from optimisation problems of the individual agents in the market and the equilibrium conditions that interrelate these optimisation problems. The model is similar to the POOLCO models in Hobbs (2001) and Metzler et al. (2003) with the exception that arbitrage is exogenous to the producers' problem. It is possible to represent this set of interrelated problems as a QP if the inverse-demand and supply functions are linear (Hashimoto, 1985). The solution to this problem is a Nash-Cournot equilibrium.

$$\max_{d_{t,n}\geq 0, x_{t,n,j,u}\geq 0, f_{t,\ell}, v_{t,n}} \sum_t N_t \Big[\sum_n \Big(D^{int}_{t,n} d_{t,n} - \frac{1}{2} D^{slp}_{t,n} d^2_{t,n} - \sum_j \sum_{u\in\mathscr{U}_{n,j}} C_{n,j,u} x_{t,n,j,u}\Big)\Big] \tag{3.1}$$

s.t.

$$N_t(x_{t,n,j,u} - X_{n,j,u}) \leq 0 \ (\beta_{t,n,j,u}) \ \forall t,n,j,u\in\mathscr{U}_{n,j} \tag{3.2}$$

$$N_t(-f_{t,\ell} - K_{t,\ell}) \leq 0 \ (\mu^-_{t,\ell}) \ \forall t,\ell, \tag{3.3}$$

$$N_t(f_{t,\ell} - K_{t,\ell}) \leq 0 \ (\mu^+_{t,\ell}) \ \forall t,\ell \tag{3.4}$$

$$N_t(f_{t,\ell^{AC}} - \sum_{n^{AC}\in\mathscr{N}^{AC}} H_{\ell^{AC},n^{AC}} v_{t,n^{AC}}) = 0 \ (\gamma_{t,\ell^{AC}}) \ \forall t,\ell^{AC}\in\mathscr{L}^{AC} \tag{3.5}$$

$$N_t(S_{n^{AC}} v_{t,n^{AC}}) = 0 \ (\eta_{t,n^{AC}}) \ \forall t,n^{AC}\in\mathscr{N}^{AC} \tag{3.6}$$

$$-N_t \sum_n \sum_\ell A_{\ell,n} f_{t,\ell} = 0 \ (\delta_t) \ \forall t \tag{3.7}$$

$$N_t\Big(d_{t,n} - \sum_i \sum_{u\in\mathscr{U}_{n,i}} x_{t,n,i,u} + \sum_\ell A_{\ell,n} f_{t,\ell}\Big) = 0 \ (\lambda_{t,n}) \ \forall t,n \tag{3.8}$$

$$-Z + \sum_t \sum_{n\in\mathscr{N}^{ETS}} \sum_i \sum_{u\in\mathscr{U}_{n,i}} N_t E_{n,i,u} x_{t,n,i,u} \leq 0 \ (\rho) \tag{3.9}$$

3.3.3 Optimisation Problem Constrained by an Optimisation Problem (OPcOP)

At the upper level, we have one strategic firm who acts as a Stackelberg leader (Gabriel and Leuthold, 2010) anticipating the market's reaction to its produced quantities, $x_{t,n,s,u}$. The strategic firm is distinguished by the index s, and its objective is to maximise its profit, which is the difference between the revenues collected from the sale of electricity, $\lambda_{t,n} x_{t,n,s,u}$, and the costs of generation and emissions, $C_{n,s,u} x_{t,n,s,u}$, and $\rho E_{n,s,u} x_{t,n,s,u}$, respectively. The strategic firm's objective function is subject to its generation capacities, $X_{n,s,u}$, (3.11), and the ISO's optimisation problem given in Equations (3.1)-(3.9).

$$\max_{x_{t,n,s,u}\geq 0} \sum_t N_t \left(\sum_n \sum_{u\in\mathscr{U}_{n,s}} \Big(\lambda_{t,n} - (C_{n,s,u} + \rho E_{n,s,u})\Big) x_{t,n,s,u} \right) \tag{3.10}$$

s.t.

$$N_t(x_{t,n,s,u} - X_{n,s,u}) \leq 0 \ (\beta_{t,n,s,u}) \ \forall t,n,u \in \mathscr{U}_{n,s} \tag{3.11}$$

(3.1)-(3.9)

3.3.4 Mathematical Program with Equilibrium Constraints (MPEC)

The OPcOP in Section 3.3.3 can be expressed as an MPEC, where the lower level is written in terms of its KKT conditions given in Equations (B.3-1a)-(B.3-12) in Section B.3.2 in Appendix B. The strategic firm at the upper level first decides its quantities, which are then perceived as exogenous by the ISO at the lower level. Note that the primal and dual variables of the lower level become decision variables of the upper level.

$$\max_{\Gamma\cup\Xi\cup\Psi} \sum_t N_t \left(\sum_n \sum_{u\in\mathscr{U}_{n,s}} \Big(\lambda_{t,n} - (C_{n,s,u} + \rho E_{n,s,u})\Big) x_{t,n,s,u} \right) \tag{3.12}$$

s.t.

(3.11), (B.3-1a)-(B.3-12)

where Γ is the set of upper-level decision variables, Ξ is the set of lower-level primal variables, and Ψ is the set of lower-level dual variables, i.e., $\Gamma = \{x_{t,n,s,u} \geq 0\}$, $\Xi = \{x_{t,n,j,u} \geq 0, d_{t,n} \geq 0, v_{t,n^{AC}}, f_{t,\ell}\}$, and $\Psi = \{\beta_{t,n,j,u} \geq 0, \gamma_{t,\ell^{AC}}, \delta_t, \eta_{t,n^{AC}}, \lambda_{t,n}, \mu^-_{t,\ell} \geq 0, \mu^+_{t,\ell} \geq 0, \rho \geq 0\}$.

For larger problem instances, it is not always possible to implement an MPEC directly. However, an MPEC can be transformed into a mixed-integer quadratic programming (MIQP) problem (Gabriel and Leuthold, 2010) through the replacement of complementarity constraints with disjunctive constraints (Fortuny-Amat and McCarl, 1981) and reformulation of the bilinear terms in the leader's objective function with the aid of strong duality from the lower level (Dorn, 1960; Huppmann and Egerer, 2015). The transformation of the MPEC into an MIQP (Equations (B.3-13) - (B.3-25)) is described in Section B.3.3.

3.3.5 Leader-Follower with Carbon Tax

The leader-follower market setting with a carbon tax studies the case of market power in electricity markets only and differs from the leader-follower setting with an ETS constraint in two ways. First, in the leader's objective function given in Equation (3.12), the permit price, ρ, is replaced with an exogenous carbon tax, R. Second, in the lower-level problem, we no longer have the ETS constraint given by Equation (3.9), but we subtract the term $\sum_t N_t \left(\sum_{n \in \mathcal{N}^{ETS}} \sum_j \sum_u RE_{n,j,u} x_{t,n,j,u} \right)$ from the ISO's objective function given in Equation (3.1). The model is then transformed into an MIQP using strong duality from the lower-level problem.

3.4 Data Implementation

In this section, we describe the data implementation of our numerical example, whereas the calibration to actual data is shown in Appendix B.1. We model the full year via 48 time blocks, i.e., four per month, weighted as explained in Section A.3.3. The numerical example for SEE-REM is the same as in Chapter 2 with three exceptions. First, we take into account the ownership of power plants, and, in addition to installed capacity per node aggregated by type of technology, we explicitly model the Italian firm, Enel, which is the leader in our model. Second, we model hydropower production. Third, we use availability factors to account for plant outages and revisions. Nodal representation of SEE-REM together with transmission line data (transmission capacity,[15] resistance, and reactance), technology characteristics (marginal cost of generation and emission rates), calculation of residual demand, and adjusted actual electricity prices remain the same as in Chapter 2.

We explicitly model Enel through its installed capacities (estimates of installed capacities for 2013 collected from firm's website). The remaining installed capacities are assigned to 21 other actual firms[16] and one fringe such that the aggregate installed capacities per country match those from ENTSO-E (2013). When a power plant is owned by two or more firms, its capacity is split between firms proportionally to the ownership. We classify firms' installed capacities into 7 technologies, viz., coal, lignite, natural gas-simple cycle, CCGT, fuel oil, and mixed fuels.

Hydropower production is modelled using hydropower availabilities rather than installed capacities of hydropower plants. In this way, any constraints related

[15]For simplicity, we consider only summer values.

[16]A2A, Axpo Energia Spa, EDF Edison, ENI, EPH, GDF Suez, Iren Energia, Sorgenia, Elektroprivreda Bosne i Hercegovine (EPBIH), BEH, CEZ Electro Bulgaria (CEZ), Hrvatksa Elektroprivreda (HEP), Holding Slovenske Elektrarne (HSE), GEN Energija, Elektroprivreda Srbije (EPS), Electrica, Elektroprivreda Makedonije (ELEM), Elektroprivreda Crne Gore (EPCG), PPC, Protergia, MVM.

to water flows or reservoir values are already taken into account. Hydropower availabilities per firm are obtained[17] by dividing annual hydropower production by the number of hours in a year and using modelled firms' share of hydropower production. This way of modelling hydropower production means that hydropower production matches actual annual hydropower production exactly from ENTSO-E (2013) under perfect competition (Figures B.1-1a and B.1-1b). Hydropower is included in the model at a marginal cost of €0/MWh. Non-hydro renewable production is netted out from the demand.

We use availability factors to account for plant outages. We multiply the net installed capacity by availability factors in order to obtain the available (also called derated (Bushnell et al., 2008)) capacity. We use different availability factors per technology reported in Table 3.1. Since the unavailability of power plants can vary throughout the year depending on various conditions (ENTSO-E, 2013), the values that we use represent average availability throughout the year.

Technology	Natural Gas	Coal	Oil	Nuclear	Lignite
Availability factor [%]	75	84	86	90	85

Table 3.1: Availability factors per technology (Schröder et al., 2013)

Under perfect competition and leader-follower settings with market power in both markets, the ETS constraint is imposed only on the SEE-REM EU ETS participants in the electricity sector, whereas the actual EU ETS spans more countries and sectors (EC, 2018a). This modelling assumption means that what the leader manipulates is the notional SEE-REM-only ETS price. This simplification is suitable for the scope of our work where we aim to assess the impact of strategic behaviour *ceteris paribus* instead of replicating what is happening in SEE-REM. On the other hand, in the leader-follower setting with market power only in the electricity market, the permit price is treated exogenously, thereby effectively acting as a carbon tax. The exogenous permit price assumption represents the upper limit that a permit price can have on the activity in the SEE-REM part of ETS as it means that any changes in the SEE-REM ETS emissions would be offset elsewhere in the ETS.

[17] Because Italy is modelled by 11 nodes, we approximate hydropower availabilities per node considering firms' hydropower fleet locations and regional hydropower production data from Terna (2013a).

3.5 Economic Analysis of the Results

3.5.1 Scenario Description

For the purpose of examining the effect of market power in both electricity and permit markets, we have three market settings:

- Perfect competition in both electricity and permit markets (PC).
- Stackelberg leader-follower setting (S-T) in which Enel is the leader with market power in the electricity market only, whereas the permit price is an exogenous carbon tax corresponding to the permit price from the respective PC scenario.
- Stackelberg leader-follower setting (S) in which Enel has market power in both electricity and permit markets, whereas all other firms are price takers in both markets.

We examine the impact of the stringency of regulation in PC and S by considering four cases with a binding emission cap corresponding to an ETS part of SEE-REM emission reduction of 10%-40% compared to the baseline scenario. The baseline scenario is established by running PC and S without an emission cap and is labelled "PC-B0" and "S-B0," respectively. The scenarios with binding caps are labelled "B10"-"B40," which corresponds to the percentage ETS emission reduction. Finally, since each S-T scenario has a carbon tax equal to the permit price from the respective PC scenario, its label corresponds to the PC scenario from which the permit price is taken. We have a total of fourteen scenarios, which are summarised in Table 3.2.

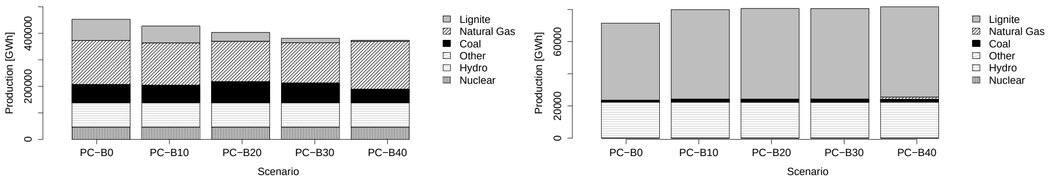
Scenario	Description
PC-B0 to PC-B40	Perfect competition with ETS cap equal to 0%-40% reduction in emissions.
S-B0 to S-B40	Stackelberg leader-follower with ETS cap equal to 0%-40% reduction in emissions.
S-T-B10 to S-T-B40	Stackelberg leader-follower with carbon tax equal to the respective PC scenario permit price.

Table 3.2: Scenario description

3.5.2 Perfect Competition Analysis

Given the scope of our analysis, we divide the analysis between ETS and non-ETS areas of SEE-REM. In this section, we analyse the perfect competition market setting, i.e., scenarios PC-B0 to PC-B40, by first focusing on the most important impacts of the binding cap and then elaborating on the findings in more detail.

The ETS part of SEE-REM is where consumption and production are concentrated (Tables B.2-10 and B.2-16) and is also a net importer of dirty electricity from the non-ETS part importing 2%-7% of its total consumption in PC-B0 to PC-40, respectively. A binding emission cap curbs ETS production (Figure 3.1a). The stringency of the cap has contrasting effects on different technologies, i.e., looser caps affect more expensive and cleaner technologies and vice versa. In fact, in scenarios PC-B10 to PC-B30, natural gas is the most affected as it is the highest-cost fuel. However, by tightening the cap, we observe the effect of fuel switching through which cheaper and dirtier technologies in the generation mix are replaced by cleaner and more expensive ones. For example, in PC-B20 and PC-B30, coal production expands to replace declining lignite production. Similarly, in PC-B40, natural gas production rebounds above the PC-B0 level as it replaces declining coal and lignite production. Despite the fuel switching, the deficit between ETS production and consumption widens with a tighter cap leading to higher imports from the non-ETS area (Figure 3.2). Consequently, non-ETS production generally grows (Figure 3.1b) with the exception of PC-B30 where the effect of demand response in the non-ETS area offsets higher exports to the ETS area. Higher non-ETS production leads to non-ETS emissions increase between 17% and 20% in PC-B10 to PC-B40 compared to PC-B0. This results in carbon leakage of 38.59% to 11.10% in PC-B10 to PC-B40, respectively (Table 3.9).



(a) Production in the ETS area

(b) Production in the non-ETS area

Figure 3.1: Annual production in the ETS and non-ETS part of SEE-REM in PC scenarios

In PC-B0, total production in SEE-REM is equal to 524,387 GWh (Table B.2-10), of which 86% is produced in the ETS area and 14% in the non-ETS area. Without the binding emission cap, the merit order of the most represented fossil fuels is given by lignite, coal, and natural gas from cheapest to most expensive, respectively, with proportions in the ETS generation mix of 18%, 15%, and 36%, respectively. By contrast, the non-ETS area heavily relies on lignite production accounting for ca.

67% of their total production. ETS consumption exceeds ETS production by 7,269 GWh (Table B.2-16), which is equal to the imports from the non-ETS area. This is not surprising given the abundance of resources in the non-ETS countries compared to the relatively small population. However, it is somewhat concerning as non-ETS countries have a higher emission intensity emitting on average 0.57 t/MWh compared to an average of 0.39 t/MWh emitted by the ETS countries. In fact, non-ETS (ETS) emissions account for 19% (81%) of total SEE-REM emissions.

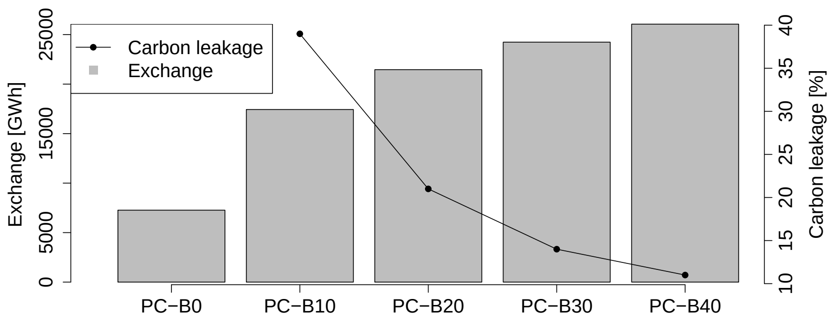


Figure 3.2: Annual exchange between ETS and non-ETS areas and carbon leakage in PC scenarios

In PC-B10, the permit price equals €8.64/t, which leaves the merit order unchanged, but it translates into higher electricity prices in the ETS area, thus, curbing ETS production by 5.61% compared to PC-B0 (Table B.2-11). Specifically, natural gas, coal, and lignite production reduces by 3.85%, 3.28%, and 20.33%, respectively. Coal and lignite reduction is observed at nodes where producers own little or no natural gas capacity, e.g., Greece and Bulgaria. Higher electricity prices contract ETS consumption by 15,250 GWh, which leads to a deficit of 10,167 GWh larger than PC-B0 and net imports into the ETS area of 17,436 GWh (Table B.2-16). As this is met by increased non-ETS production, non-ETS emissions grow by 16%. Therefore, as a consequence of imposing a binding cap on ETS emissions, 38.6% of the emission reduction achieved in the ETS area is leaked into the non-ETS part of SEE-REM.

In PC-B20, the cap of 142,255 kt results in a permit price of €20.02/t, which changes the merit order between coal and lignite, i.e., coal's marginal cost of production is now lower than lignite's. Due to a tighter cap, ETS production drops by 5.69% compared to PC-B10 (Table B.2-12). In particular, natural gas and lignite production decreases by 4.59% and 47.78%, respectively. By contrast, production from coal increases by 20.54% as it partly replaces the share vacated by ETS-based lignite plants, which is a result of fuel switching. However, the deficit between production and consumption in the ETS area widens further compared to PC-B10 reaching 21,458 GWh. This increases non-ETS exports and emissions by 14,189 GWh and 7,467 kt, respectively, compared to PC-B0 leading to a carbon leakage of 20.99%.

In PC-B30, the binding cap sets the permit price to €31.75/t and makes lignite as expensive as natural gas. Despite sharing same position in the merit order, due to its higher carbon content compared to natural gas, lignite production falls drastically (50.30%) compared to PC-B20 (Table B.2-13). Moreover, although coal production decreases by 6.52% compared to PC-B20, it is 12.67% above PC-B10. This together with a small increase of 0.02% in natural gas production compared to PC-B20 is the effect of fuel switching as lignite production is now replaced by coal and natural gas. Imports from the non-ETS area climb 16,967 GWh above the PC-B0 level resulting in non-ETS emissions increase of 18%. Interestingly, the non-ETS emission increase in PC-B30 is lower than in PC-B20 despite greater non-ETS exports. This could be due to the contraction in non-ETS demand as non-ETS consumers respond to higher non-ETS electricity prices caused by increased exports to the more expensive ETS area. Nevertheless, carbon leakage is equal to 13.81%.

In PC-B40, the permit price is equal to €35.77/t, which alters the merit order such that lignite is the most expensive followed by coal and natural gas at parity. Consequently, overall ETS production drops by 17.5% compared to PC-B0 (Table B.2-14). In particular, coal production drops by 25.81% and 31.92% compared to PC-B0 and PC-B30, respectively. Lignite production decreases to approximately 5% of the PC-B0 level. By contrast, natural gas production increases by 19.33% and 9.48% compared to the PC-B30 and PC-B0 scenarios, respectively, as it replaces coal and lignite. However, the ETS exports increase and exceed the PC-B0 level by 18,785 GWh leading to more pressure on non-ETS firms to export. As non-ETS production expands by 10,186 GWh compared to PC-B0 carbon leakage is equal to 11.10%.

As electricity prices incrementally increase and SEE-REM electricity consumption falls from 524,386 GWh in PC-B0 to 455,313 GWh in PC-B40, consumer surplus decreases by 21.24% in PC-B40 compared to PC-B0 (Table B.2-18). In addition, due to decreasing electricity consumption, the GO's revenue decreases by 20.85% in PC-B30 compared to PC-B0. However, in PC-B40, the GO's total revenues are above the PC-B20 level due to higher revenues associated with imports to expensive ETS nodes. Despite the incrementally higher abatement cost, producer surplus is incrementally increasing from PC-B0 to PC-B40 due to windfall profits of relatively cleaner and non-ETS firms. In fact, compared to PC-B0, in PC-B40, producer surplus increases by 34.45%. In PC-B10 to PC-B40, social welfare includes revenues from emission permit sales, which increase incrementally from €1 billion in PC-B10 to almost three times more in PC-B30. Compared to PC-B30, revenues from emission permits in PC-B40 fall by €135 million as the decrease in ETS production offsets a modest increase of €4.02/t in permit price. However, the prevalent effect on social welfare is the declining consumer surplus dominating any increase in producer surplus and emission permit revenues. Consequently, total social welfare falls by 3.43% in PC-B40 compared to PC-B0.

3.5.3 Perfect Competition versus Stackelberg: PC-B0 and S-B0

In this section, we examine the impact of market power in SEE-REM in the absence of an ETS emission cap, i.e., scenarios PC-B0 and S-B0. For the purpose of analysing the impact of the dominant producer (Enel), we conduct the analysis in two stages. First, we analyse the situation in Italy under PC-B0 because Italy is the only country within SEE-REM where Enel owns capacity and, thus, has the greatest impact. Second, we analyse the change in market outcomes resulting from the exercise of market power in Italy and the rest of SEE-REM by grouping the Italian nodes into four regions, viz., North (n_1, n_2, and n_7), South (n_3, n_4, n_8, n_9, and n_{10}), Sardinia (n_5), and Sicily (n_6 and n_{11}).

3.5.3.1 Perfect Competition (PC-B0)

In PC-B0, total electricity production in Italy amounts to approximately 60% of the total ETS production (Table 3.3), the bulk of which is located in the North (61%), followed by the South (31%), and the islands (jointly 8%). The generation mix is given by natural gas (57%), coal (23%), and hydro (20%). In the North, the majority of the production comes from natural gas (65%) followed by coal (23%), whereas in the South, coal is the most represented fossil fuel (47%), albeit with a small advantage over natural gas (45%). In Sardinia (Sicily), coal (natural gas) is the prevailing fuel with the share of 73% (93%). In PC-B0, emissions in Italy are approximately 57% of SEE-REM ETS emissions (Table 3.4). Total electricity consumption in Italy is 274,171 GWh, of which North accounts for 67%, the South for 24%, and the islands jointly for 9%. The North accounts for the majority of production, consumption, and imports, importing a net of 20,576 GWh, of which 81% from the South and 19% from Slovenia. By contrast, the South is the major net exporter, sending 16,614 GWh to the North and 4,550 GWh to Sardinia.

In PC-B0, Enel produces 83,085 GWh of electricity, which accounts for ap-

Table 3.3: Production per fuel type [GWh] in Italy in PC-B0

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	12,215	106,324	204	44,793	163,536
of which Enel	*6,144*	*17,872*	*62*	*13,225*	*37,303*
of which fringe firms	*6,071*	*88,452*	*142*	*31,568*	*126,232*
South	39,014	37,170	-	6,913	83,097
of which Enel	*34,305*	-	-	*3,213*	*37,518*
of which fringe firms	*4,709*	*37,170*	-	*3,700*	*45,579*
Sardinia	8,830	2,701	45	486	12,062
of which Enel	*4,415*	-	-	*486*	*4,901*
of which fringe firms	*4,415*	*2,701*	*45*	-	*7,161*
Sicily	-	7,473	-	584	8,057
of which Enel	-	*2,778*	-	*584*	*3,362*
of which fringe firms	-	*4,695*	-	-	*4,695*
Total	60,059	153,668	249	52,776	266,752
of which Enel	*44,864*	*20,650*	*62*	*17,509*	*83,085*
of which fringe firms	*15,195*	*133,018*	*187*	*35,268*	*183,667*

proximately 30% of the total production in Italy. Enel predominantly generates from coal (54%) followed by natural gas (25%). The majority of Enel's production is located in the North and the South (45% in each region). The remaining 10% is split between the islands. In the North, most of Enel's generation is from natural gas-fired plants (48%) followed by coal-fired plants (16%). In the South and Sardinia, Enel predominantly generates from coal (approximately 90% in each region), whereas in Sicily, it predominantly generates from natural gas (83%). Enel's coal production is of particular importance as it accounts for approximately 75% of total coal production in Italy. The largest part of Enel's coal production is located in the South, where it accounts for 88% of South's coal production, whereas in the North and Sardinia it accounts for approximately 50%.

3.5.3.2 Impact of Strategic Behaviour (S-B0)

The leader manipulates the electricity market by adjusting its production quantities and anticipating the reaction of the fringe firms and the ISO at the lower level. Overall in Italy, Enel holds back a total of 5,146 GWh of production, of which 4,164 GWh is from natural gas and 919 GWh from coal (Table B.2-1). By withholding, Enel raises electricity prices in Italy such that consumption drops by 1,557 GWh compared to PC-B0 (Table B.2-15). The fringe firms in Italy react to higher electricity prices and replace 75% of the production withheld by Enel by expanding their production by 3,853 GWh, most of which comes from natural gas (3,603 GWh). On a regional level, Enel withholds coal production (855 GWh) in the South

Table 3.4: Consumption [GWh], net imports/exports [GWh], and emissions [kt] in Italy in perfect competition

Region \ Scenario	PC-B0	PC-B10	PC-B20	PC-B30	PC-B40
Consumption					
North	184,112	180,201	175,360	170,453	168,668
South	65,422	63,986	62,092	60,1412	59,473
Sardinia	16,612	16,245	15,799	15,350	15,196
Sicily	8,025	7,849	7,616	7,377	7,295
Total	274,171	268,281	260,868	253,322	250,631
Imports/Exports					
North	20,576	20,858	20,891	20,197	15,552
South	-17,675	- 17,490	- 17,029	- 18,789	- 19,573
Sardinia	4,550	4,272	3,940	3,517	4,966
Sicily	-32	- 32	- 18	- 117	- 255
Total	7,419	7,607	7,784	4,809	690
Emissions					
North	47,894	46,285	44,498	42,963	42,655
South	42,597	42,009	41,154	41,085	36,807
Sardinia	7,610	7,557	7,510	7,500	6,231
Sicily	2,713	2,649	2,559	2,508	2,529
Total	100,814	98,500	95,722	94,057	88,223

and natural gas production (4,784 GWh) in the North. As consumption in the South and the North declines, follower firms in the South reduce their production substantially (7,434 GWh). The fringe firms' reaction in the South results in a decrease in exports to the North by 8,795 GWh. By contrast, in the North, higher electricity prices entice the fringe firms' natural gas production, which increases by 12,209 GWh. The contrasting effect on fringe firms' natural gas production in the South and in the North can be explained by Enel's strategy to choke off fringe firms' production in the South in order to raise further electricity prices in the North allowing it to earn higher profits locally. Furthermore, in Sicily, Enel drives down follower firms' natural gas production by 1,161 GWh and expands its own production from natural gas by 557 GWh in order to profit locally. This leads to a change in Sicily's position from a net exporter to a net importer, which adds burden to the producers in the South that now export 529 GWh to Sicily. The least manipulation occurs in Sardinia, which leaves its exchange with the rest of the system almost unchanged compared to PC-B0.

Enel's strategic behaviour affects other ETS countries' prices through imports but not directly via capacity withholding. In particular, consumption in the ETS (excluding Italy) drops by 186 GWh (Table B.2-17) curbing the fringe firms' production by 546 GWh, which leads to an increase in ETS (excluding Italy) imports of 360 GWh. This change in imports reverses the position of ETS (excluding Italy) countries from net exporters to net importers. On the other hand, producers located in the non-ETS countries receive a signal from higher ETS electricity prices and, therefore, increase their production by 96 GWh, thus, covering the net increase in total ETS (including Italy) imports. The actions of the dominant producer in S-B0 result in electricity market inefficiencies as Enel promotes less cost-effective, albeit cleaner, production, which leads to an ETS emission reduction of 989 kt, i.e., a decrease of 0.56% compared to PC-B0. Yet, the change in import/export patterns in the entire ETS area increases net ETS imports from the non-ETS area by 96 GWh leading to 86 kt higher non-ETS emissions compared to PC-B0. In other words, 8.7% of the emission reduction achieved in the ETS area is relocated into the non-ETS area as a consequence of Enel's strategic behaviour.

As displayed in Table 3.5, through the manipulation of electricity prices, Enel increases its profits by €13 million, 1.05% above PC-B0. As other producers in the market also benefit from higher electricity prices, producer surplus rises to €216 million (3.57%) above PC-B0. Conversely, lower ETS consumption and higher electricity prices decrease consumer surplus by €248 million (0.73%) compared to PC-B0 (Table B.2-18). The GO's revenue is higher in S-B0 compared to PC-B0 despite lower total production in S-B0 due to higher exports from the cheap non-ETS producers to a more expensive ETS area. Finally, as a result of strategic behaviour, overall social welfare decreases by €24 million (0.06%) compared to PC-B0.

Table 3.5: Strategic producer's profit [k€]

Setting \ Scenario	B0	B10	B20	B30	B40
PC	1,285,520.55	1,191,826.37	1,056,901.47	915,116.14	869,808.46
S-T *(change from PC)*	13,491.77	15,408.45	15,192.45	30,679.90	45,623.22
% change	*1.05%*	*1.29%*	*1.44%*	*3.35%*	*5.25%*
S *(change from PC)*	13,491.77	25,579.51	35,451.86	32,101.86	38,087.96
% change	*1.05%*	*2.15%*	*3.35%*	*3.51%*	*4.38%*

3.5.4 Perfect Competition versus Stackelberg - Carbon Tax and Binding ETS constraint (10% to 30% Reduction)

3.5.4.1 Perfect Competition (PC-B10 to PC-B30)

As a result of a binding ETS constraint, production in Italy (Tables 3.6-3.8) is curbed by 6,078 GWh, 13,667 GWh, and 18,239 GWh in PC-B10, PC-B20, and PC-B30, respectively, compared to PC-B0. For permit prices between €8.64/t-€31.75/t in the three scenarios, since natural gas remains the most expensive technology in Italy, the proportion of natural gas in the generation mix decreases leaving a larger share to coal. Consumption drops by 5,890 GWh, 13,302 GWh, and 20,849 GWh in PC-B10, PC-B20, and PC-B30, respectively, compared to PC-B0. The reduction in consumption is less than that in production in PC-B10 and PC-B20 as Italy increases imports from cheaper nodes, i.e., Slovenia and Greece. On the contrary, in PC-B30, as lignite reaches cost parity with natural gas, imports from Greece are curbed, thus resulting in a larger decrease in consumption than in production. Emissions in Italy decrease by 2,314 kt, 5,092 kt, and 6,757 kt in PC-B10, PC-B20, and PC-B30, respectively, compared to PC-B0. As the largest concentration of natural gas production within Italy is in the North, the North is the most affected region by the production reduction. Enel shrinks its natural gas production by 4,411 GWh, 5,279 GWh, and 5,724 GWh in PC-B10, PC-B20, and PC-B30, respectively, compared to PC-B0.

Table 3.6: Production per fuel type [GWh] in Italy in PC-B10

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	12,215	102,304	31	44,793	159,343
of which Enel	*6,144*	*11,141*	*19*	*13,225*	*30,530*
of which fringe firms	*6,071*	*91,163*	*12*	*31,568*	*128,814*
South	39,014	35,549	-	6,913	81,476
of which Enel	*34,305*	-	-	*3,213*	*37,518*
of which fringe firms	*4,709*	*35,549*	-	*3,700*	*43,958*
Sardinia	8,830	2,648	10	486	11,974
of which Enel	*4,415*	-	-	*486*	*4,901*
of which fringe firms	*4,415*	*2,648*	*10*	-	*7,073*
Sicily	-	7,297	-	584	7,881
of which Enel	-	*5,141*	-	*584*	*5,725*
of which fringe firms	-	*2,156*	-	-	*2,156*
Total	60,059	147,798	41	52,776	260,674
of which Enel	*44,864*	*16,282*	*19*	*17,509*	*78,673*
of which fringe firms	*15,195*	*131,516*	*22*	*35,268*	*182,001*

Table 3.7: Production per fuel type [GWh] in Italy in PC-B20

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	12,215	97,462	-	44,793	154,469
of which Enel	*6,144*	*10,477*	-	*13,225*	*29,847*
of which fringe firms	*6,071*	*86,984*	-	*31,568*	*124,623*
South	39,014	33,194	-	6,913	79,122
of which Enel	*34,305*	-	-	*3,213*	*37,518*
of which fringe firms	*4,709*	*33,194*	-	*3,700*	*41,604*
Sardinia	8,830	2,543	-	486	11,859
of which Enel	*4,415*	-	-	*486*	*4,901*
of which fringe firms	*4,415*	*2,543*	-	-	*6,958*
Sicily	-	7,051	-	584	7,635
of which Enel	-	*4,956*	-	*584*	*5,540*
of which fringe firms	-	*2,095*	-	-	*2,095*
Total	60,059	140,249	-	52,776	253,085
of which Enel	*44,864*	*15,433*	-	*17,509*	*77,806*
of which fringe firms	*15,195*	*124,816*	-	*35,268*	*175,279*

Table 3.8: Production per fuel type [GWh] in Italy in PC-B30

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	12,215	93,248	-	44,793	150,256
of which Enel	*6,144*	*10,178*	-	*13,225*	*29,547*
of which fringe firms	*6,071*	*83,071*	-	*31,568*	*120,709*
South	39,014	33,004	-	6,913	78,931
of which Enel	*34,305*	-	-	*3,213*	*37,518*
of which fringe firms	*4,709*	*33,004*	-	*3,700*	*41,413*
Sardinia	8,830	2,516	-	486	11,832
of which Enel	*4,415*	-	-	*486*	*4,901*
of which fringe firms	*4,415*	*2,516*	-	-	*6,931*
Sicily	-	6,910	-	584	7,494
of which Enel	-	*4,810*	-	*584*	*5,394*
of which fringe firms	-	*2,100*	-	-	*2,100*
Total	60,059	135,678	-	52,776	248,513
of which Enel	*44,864*	*14,988*	-	*17,509*	*77,360*
of which fringe firms	*15,195*	*120,690*	-	*35,268*	*171,152*

3.5.4.2 Impact of Market Power in the Electricity Market (S-T-B10 to S-T-B30)

In S-T-B10 and S-T-B20 (Tables B.2-2 and B.2-4), Enel adopts the same strategy as in S-B0 coal-wise and manipulates the electricity market through the most important exchange link, i.e., between the North and the South, by withholding capacity in the regions where it has the largest share, viz., the South and the islands. Enel holds back production from the South and the islands to choke off fringe firms' production in the South and Sardinia. In Sicily, fringe firms react by increasing production, but this only partly replaces Enel's withholding resulting in higher imports. As the islands import more from the South and the South's production decreases, exports to the North are reduced, thus, driving up electricity prices. Contrary to S-B0, Enel uses this outcome to expand its natural gas production in the North, thereby profiting locally. A possible explanation for this change in strategy is the increased availability of unused natural gas plants compared to S-B0 due to the introduction of environmental regulation, which curbs primarily natural gas production. If the leader adopted the withholding strategy in the North, given the greater availability of fringe firms' natural gas plants, the fringe firm would have incentive to produce thereby lowering leader's profits.

In S-T-B30, Enel's withholding follows the same pattern as in S-T-B10 and S-T-B20 (Table B.2-6); however, as lignite reaches cost parity with natural gas, fringe firms in the South sell electricity to consumers located in Greece. The expansion of production in the South boosts exports to the North. Since Enel can no longer profit locally alongside fringe firms in the North, it chokes off their production by replacing it with its own.

Higher electricity prices curb consumption in Italy by 1,308 GWh, 1,185 GWh, and 2,129 GWh, in S-T-B10, S-T-B20, and S-T-B30, respectively, compared to the respective PC scenarios. Production, however, shrinks to a lesser extent, decreasing by 708 GWh and 865 GWh, in S-T-B10 and S-T-B20, respectively, compared to PC-B10 and PC-B20, whereas in S-T-B30, it increases by 2,429 GWh due to increased exports to Greece. Enel's strategic behaviour reduces the deficit between production and consumption in Italy, thus, lowering imports. In addition, since Enel's strategy results in the replacement of coal production with natural gas, emissions in Italy decrease by 590 kt, 772 kt, and 447 kt in S-T-B10, S-T-B20, and S-T-B30, respectively, compared to PC-B10, PC-B20, and PC-B30.

The effect of higher electricity prices nominally carries over to other ETS countries. In fact, consumption in other ETS countries falls by 63 GWh, 157 GWh, and 156 GWh in S-T-B10, S-T-B20, and S-T-B30, respectively, compared to PC-B10, PC-B20, and PC-B30. On the other hand, production in the other ETS countries is more affected, decreasing by 1,175 GWh, 509 GWh, and 4,876 GWh in S-T-B10, S-T-B20, and S-T-B30, respectively, compared to PC-B10, PC-B20, and PC-B30. Therefore, the deficit in the ETS area (excluding Italy) widens compared to the PC scenarios. This is covered by the non-ETS producers partly by re-directing imports not required by Italy, partly by increasing their production, and partly by selling electricity not consumed in the domestic market due to higher electricity prices. In this way, emissions in the ETS area (including Italy) drop by 1,404 kt, 231 kt, and 6,670 kt in S-T-B10, S-T-B20, and S-T-B30, respectively, below PC-B10, PC-B20, and PC-B30 levels (Tables B.2-11, B.2-12, and B.2-13). By contrast, non-ETS emissions increase by 428 kt, 19 kt, and 96 kt in S-T-B10, S-T-B20, and S-T-B30, respectively, above PC-B10, PC-B20, and PC-B30 levels. However, since the reduction in ETS emissions compared to PC-B0 is the dominant effect offsetting the non-ETS emissions increase, carbon leakage is below the respective perfectly competitive scenarios (Table 3.9).

By manipulating the electricity market in Italy, Enel earns profits €15.4 million (1.29%), €15 million (1.44%), and €30.6 million (3.35%), in S-T-B10, S-T-B20, and S-T-B30, respectively, above PC-B10, PC-B20, and PC-B30 levels. Due to higher electricity prices and lower consumption, consumer surplus decreases €201 million, €224 million, and €372 million below the respective perfectly competitive levels. Higher electricity prices benefit the producers resulting in an increase of aggregate profits €175 million, €188 million, and €332 million in excess of the respective perfectly competitive levels. The GO's revenues increase €8 million, €18 million, and €16 million compared to the respective perfectly competitive scenarios since there is more exchange between ETS and non-ETS at a higher price differential. Due to lower ETS production, C&T permit revenues decline €12 million, €21 million, and €226 million compared to the respective perfectly competitive scenarios, with the biggest decrease resulting from S-T-B30 when natural gas replaces lignite in the ETS excluding Italy. Strategic behaviour has a welfare-decreasing effect whereby social welfare declines by €30 million, €39 million, and €250 million compared to the respective perfectly competitive scenarios.

Table 3.9: Carbon leakage [%] and permit price [€/t]

Setting \ Scenario	B10	B20	B30	B40
PC	38.59	20.99	13.81	11.10
S-T	38.00	20.47	12.34	11.72
S	40.62	20.95	13.84	11.04

Setting \ Scenario	B10	B20	B30	B40
PC	8.64	20.02	31.75	35.77
S	6.55	17.81	31.75	35.77

3.5.4.3 Impact of Market Power in Both the Electricity and Permit Markets (S-B10 to S-B30)

In S-B10 to S-B30, the dominant producer can manipulate an additional variable vis-à-vis the carbon-tax scenarios, i.e., the endogenously determined C&T permit price. Since the leader is a buyer of permits, it engages in a monopsonistic strategy, thereby trying to push the permit price down. For this purpose, the leader withholds more coal compared to S-T-B10 to S-T-B30 as, due to its higher pollution content, coal has more impact on the permit price. Natural gas-wise, the leader's strategy depends on the availability of fringe firms' natural gas production. In S-B10, the leader adopts the same strategy as in S-B0, but withholds considerably less as there is a cap in place and, thus, more fringe firms' production availability. On the other hand, in S-B20 and S-B30, its strategy is similar to S-T-B10 to S-T-B30, i.e., the leader expands natural gas production. In S-B20, the leader expands natural gas production more than in S-T-B20 as in S-B20, it holds back more coal. On the contrary, in S-B30, in an attempt to lower the permit price, the leader expands its natural gas production less than in S-T-B30.

In an attempt to lower the C&T permit price, Enel withholds coal production by 3,558 GWh, 3,934 GWh, and 3,124 GWh in S-B10, S-B20, and S-B30, respectively, compared to PC-B10, PC-B20, and PC-B30 (Tables B.2-3, B.2-5, and B.2-7). Due to a higher impact of coal on emissions and, thus, the permit price, it is not surprising that Enel is withholding more coal compared to the respective carbon tax scenarios. As a result, in S-B10 and S-B20, Enel brings the C&T permit price below PC-B10 and PC-B20 levels resulting in savings of approximately €2/t. By contrast, in S-B30, Enel is not able to affect the C&T permit price. One possible explanation is that in order to do so, Enel would have to withhold even more coal production resulting in higher electricity prices, but since the availability of fringe firms' natural gas production is high, if Enel holds back too much, then its production might simply be replaced by the fringe firms'. Therefore, Enel's strategy would end up not being profitable. In a way, Enel has to balance between the effect of raising electricity prices and lowering the permit price.

In S-B10, S-B20, and S-B30, by withholding more coal production in the South, Enel raises average electricity prices in the South compared to S-T-B10, S-T-B20, and S-T-B30, respectively. Higher electricity prices in the South at a lower or equal cost of abatement compared to S-T-B10, S-T-B20, and S-T-B30 entice fringe firms' natural gas production in the South, thus increasing the flow on the line between the South and the North. Consequently, average electricity prices in the North are below S-T-B10, S-T-B20, and S-T-B30 levels, thereby curbing fringe firms' natural gas production in the North. As Enel's withholding has a higher impact on electricity prices in the South in S-B10 compared to S-B20 and S-B30, in S-B10, Enel also curbs its natural gas production in the North, whereas in S-B20 and S-B30, it chokes off fringe firms' production and partly replaces it with its own.

In contrast to Italy, in S-B10 and S-B20, the dominant effect on other ETS countries is the lower permit price, which entices production from coal and natural gas (Tables B.2-11 and B.2-12) and brings electricity prices below the respective perfectly competitive levels. As a result, ETS electricity consumption grows by 2,185 GWh and 1,835 GWh in S-B10 and S-B20 above the PC-B10 and PC-B20, respectively. Since emissions from producers located in the ETS cannot exceed the emissions set by the cap, in order to offset higher emissions from coal and natural gas, follower firms reduce lignite production. Essentially, firms in the ETS (excluding Italy) resort to fuel switching in order to meet part of the ETS excess electricity consumption over the PC-B10 and PC-B20 levels. The remainder of the excess ETS consumption is met by non-ETS firms that increase their exports into the ETS area (excluding Italy). In S-B10, since the effect of lower electricity prices carries over to some of the non-ETS area, non-ETS consumption increases by 173 GWh. In order to meet higher domestic consumption and net exports of 353 GWh to the ETS area (including Italy), non-ETS producers increase their production by 526 GWh. Hence, non-ETS emissions grow by 406 kt (0.86%) and the leakage increases by 2.02 percentage points compared to PC-B10. Given the relatively low capacity of the non-ETS producers, in S-B20, as they choose to sell more electricity in the ETS area, non-ETS prices increase. Consumers in the non-ETS respond by decreasing their consumption by 72 GWh, leaving an extra 114 GWh of unregulated electricity available for export to the ETS. Since Italy reduces its imports by 139 GWh, non-ETS firms can export 253 GWh more to the rest of the ETS. ETS emissions fall by 791 kt, which, as a result of limited fuel switching, is 99 kt less than in S-B10. On the other hand, due to lower available capacity, non-ETS emissions increase only by 30 kt, 376 kt less compared to the S-B10, thus, maintaining similar levels as PC-B20.

In S-B30, emissions within the binding cap shift from Italy to the rest of the ETS as ETS (excluding Italy) production climbs above the PC-B30 level by 2,202 GWh. Since natural gas reaches cost parity with lignite, lignite production increases by 2,845 GWh, driving out 779 GWh of natural gas production. Contrary to S-B10 and S-B20, in S-B30, as the permit price remains as in PC-B30, ETS electricity prices increase compared to PC-B30, thereby driving down ETS consumption by

145 GWh. ETS (excluding Italy) imports decrease by 2,347 GWh allowing non-ETS producers to re-direct exports towards Italy. Similar to S-B20, as non-ETS firms sell more electricity in the ETS area, non-ETS production expands and consumption shrinks, enabling 155 GWh more electricity for export to the ETS area compared to PC-B30. The effect on non-ETS emissions is modest resulting in carbon leakage similar to that in PC-B30.

An additional variable available for manipulation provides Enel with an extra opportunity to increase its profits. In fact, Enel raises its profits in S-B10, S-B20, and S-B30 to €26 million, €35 million, and €32 million over its profits under PC-B10, PC-B20, and PC-B30, respectively. The increase is higher compared to the respective carbon tax scenarios. Since ETS producers benefit from a lower abatement cost in S-B10 and S-B20 and, in Italy, higher electricity prices, producer surplus increases by €222 million and €300 million compared to PC-B10 and PC-B20, respectively. The increase in producer surplus is well above the increase in S-T-B10 and S-T-B20. In S-B30, the increase compared to PC-B30 is much closer to the increase observed in S-T-B30 as Enel is no longer able to influence the permit price. In relation to consumer surplus, in S-B10 and S-B20, we have two competing effects, i.e., the increase in electricity prices in Italy and the decrease in electricity prices in the rest of ETS and some non-ETS countries. The latter is prevalent in S-B10, leading to consumer surplus above PC-B10, whereas the opposite is true for S-B20. However, in both cases, consumer surplus is well above the respective carbon tax levels. As with producer surplus, in S-B30, the effect of strategic behaviour on consumer surplus is similar to S-T-B30. The GO's revenue decreases in S-B10 and S-B20 compared to PC-B10 and PC-B20, respectively, as the price differential between the ETS and non-ETS areas decreases. On the other hand, in S-B30, the effect on the GO's revenue is similar to S-T-B30. C&T permit revenue is lower in S-B10 and S-B20 compared to PC-B10 and PC-B20, and S-T-B10 and S-T-B20, respectively, due to lower C&T permit prices. On the contrary, in S-B30, C&T permit revenue is higher than S-T-B30 due to higher ETS emissions at the same permit price. Overall, Enel's strategic behaviour has a welfare-decreasing effect lowering social welfare by €70 million, €62 million, and €45 million compared to the respective perfect competition scenarios.

3.5.5 Perfect Competition versus Stackelberg - Carbon Tax and ETS Binding Constraint (40% Reduction)

3.5.5.1 Perfect Competition (PC-40)

At an allowance price of €35.77/t, natural gas reaches parity with coal. This change in the merit order shifts production within the ETS towards natural gas-rich firms located in Italy, thereby increasing the proportion of Italian production in the ETS to 67%. Due to higher electricity prices, consumption falls to 250,631 GWh, a decrease of 8.6% compared to PC-B0. A considerable drop in emissions occurs because of the switch to natural gas with emissions equal to 88,223 kt, i.e., a decrease of 12.5% compared to PC-B0. Another consequence of the increased production from natural gas is the import/export pattern. First, imports from Slovenia decline to 1,918 GWh and are the lowest among PC scenarios. Second, the flow on the line between Italy and Greece is reversed whereby Italy now exports 1,228 GWh of electricity to Greece. In the specific case of Enel (Table 3.10), since its production is mostly generated from coal, the cut in coal production offsets the increase in natural gas production resulting in a total production cut of 21,785 GWh compared to PC-B0.

3.5.5.2 Impact of Market Power in the Electricity Market (S-T-B40)

As Italy gains a larger share of total ETS production due to the cost parity between coal and natural gas, Enel enjoys more leverage for manipulating the market. Enel uses this partly to reinstate coal production, which comprises most of its production. In contrast to the other S-T scenarios (Table B.2-8), Enel expands its coal production in the South and in the North in order to set equilibrium prices. While the fringe firms' reaction is similar to S-T-B20 natural gas-wise resulting in production reduction of 15,052 GWh compared to PC-B40, higher equilibrium prices entice fringe firms' coal production. Enel's strategy in the South and the islands affects the flows in Italy in a similar way to S-T-B20, thus allowing Enel to profit locally in the North by partly replacing fringe firms' natural gas production.

Table 3.10: Production per fuel type (GWh) in Italy in PC-B40

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	8,703	99,619	-	44,793	153,116
of which Enel	*5,289*	*10,865*	-	*13,225*	*29,380*
of which fringe firms	*3,414*	*88,754*	-	*31,568*	*123,736*
South	27,737	44,396	-	6,913	79,046
of which Enel	*23,379*	-	-	*3,213*	*26,592*
of which fringe firms	*4,358*	*44,396*	-	*3,700*	*52,453*
Sardinia	7,034	2,710	-	486	10,230
of which Enel	*4,415*	-	-	*486*	*4,901*
of which fringe firms	*2,619*	*2,710*	-	-	*5,329*
Sicily	-	6,966	-	584	7,550
of which Enel	-	*4,842*	-	*584*	*5,426*
of which fringe firms	-	*2,124*	-	-	*2,124*
Total	43,474	153,691	-	52,776	249,942
of which Enel	*33,084*	*15,708*	-	*17,509*	*66,300*
of which fringe firms	*10,391*	*137,984*	-	*35,268*	*183,642*

Average electricity prices climb above PC-B40 levels in most countries across the SEE-REM such that electricity consumption in ETS falls by 2,843 GWh and non-ETS by 38 GWh. Higher electricity prices provide an opportunity for ETS (excluding Italy) lignite and coal plants to reinstate their production partly, which increases by 276 GWh and 2,611 GWh, respectively, cutting out natural gas production by 2,720 GWh compared to PC-B40 (Table B.2-14). Consequently, the rest of ETS net imports decline by 353 GWh and emissions increase by 1,188 kt compared to PC-B40. Since non-ETS firms react to higher prices in the ETS area, non-ETS production increases by 14 GWh, exports by 52 GWh, and emissions by 6 kt. Leakage to the non-ETS part of SEE-REM is equal to 11.72%, 0.62 percentage points above the PC-B40 level due to a smaller reduction in ETS emissions in S-T-B40. In conclusion, a carbon tax equal to €35.77/t has detrimental consequences on SEE-REM emissions in the presence of market power resulting in total SEE-REM emissions 3,706 kt above the perfectly competitive level.

In S-T-B40, Enel boosts its profits by €45.6 million or 5.25% more than in PC-B40. The increase in electricity prices is damaging for the consumers whose surplus decreases by €440 million compared to PC-B40. On the other hand, producer surplus climbs €415 million above competitive levels. The GO earns higher revenues due to the higher price differential between ETS and non-ETS countries, and the C&T permit revenues grow due to higher emissions in the ETS. The latter has the crucial impact on social welfare pushing it up by €113 million.

3.5.5.3 Impact of Market Power in Both Electricity and Permit Markets (S-B40)

In S-B40, Enel's strategy for raising electricity prices is similar to that in S-T-B40 (Table B.2-9). However, since Enel does not want to push the permit price above the PC-B40 level, it expands coal production to a lesser extent than in S-T-B40. In contrast to S-T-B40, fringe firms' coal production decreases as in S-B40 there is a cap on ETS emissions. However, similar to S-B20, fringe firms' natural gas production in the South increases, thereby sending more electricity to the North. In the North, Enel chokes off fringe firms' natural gas production and partly replaces it with its own in order to profit locally.

As shown in Table B.2-14, due to a considerable decrease in Italy's emissions, production shifts towards the rest of ETS and increases by 1,397 GWh compared to PC-B40. Most of the production is generated from natural gas as the cap on emissions forces cleaner production in comparison to S-T-B40. In fact, total ETS emissions are 593 kt lower than in PC-B40 and 4,293 kt lower than in S-T-B40. In addition, given such a substantial increase in ETS (excluding Italy) production, non-ETS production remains unvaried. However, non-ETS firms decide to sell a larger part of their production to the ETS, but this derives from a decrease in non-ETS consumption. Therefore, non-ETS emissions remain unvaried despite the increase in exports to the ETS of 56 GWh. Finally, considering this together with a decline in ETS emissions, it is not surprising that carbon leakage (11.04%) is somewhat lower than in PC-B40.

Enel's ability to manipulate the market is also echoed in its profits whereby these increase by €38 million compared to PC-B40, i.e., the largest increment in both amount and percentage terms in Enel's profits is associated with the tightest cap. Nevertheless, the increment is smaller compared to S-T-B40. One possible explanation is that the unwillingness to drive up the permit price and the limit on emissions given by the cap in S-B40 bind Enel's ability to substitute coal for natural gas compared to S-T-B40. In relation to social welfare, the effect on the specific components is similar to S-T-B40 with the exception of the C&T permit revenues. Particularly, consumer surplus is the most negatively affected portion of welfare falling €375 million below PC-B40. Producers benefit from higher electricity prices with their aggregate profits climbing €343 million above PC-B40. The GO earns €13 million higher revenues as a result of moving more electricity towards expensive nodes in Italy in comparison with S-T-B40. In contrast to S-T-B40, C&T permit revenues fall due to lower ETS production and result in an amount €21 million below the PC-B40 level. The overall effect on social welfare is negative, i.e., a €39 million reduction compared to PC-B40.

3.6 Conclusions

Several years after the deregulation of the electricity industry, European markets are not only subject to high degree of market concentration, which facilitates exercise of market power, but also face other challenges on their path to a low-carbon economy. For example, even though C&T systems are one of the preferred policies for carbon pricing, they could be subject to abuse of market power if the oligopolistic market structure of electricity markets is echoed in the permit markets. Moreover, exercise of market power in regional electricity markets is particularly relevant in the post-Paris Agreement world as the picture of environmental policies around the globe remains fragmented. This means that, in regional electricity markets, large producers, which could exercise market power, are competing against firms with potentially substantially lower costs of production as uncapped firms do not face abatement costs. If firms exposed to such competition could manipulate the permit price, then they could withhold production in order to push down the permit price, thereby lowering their abatement cost. Under-consuming permits over time could result in surplus permits that could weaken the permit price in the long run, which is an undesirable consequence already experienced in the EU ETS due to a decrease in production following a financial crisis and over-use of international credits (EC, 2018f). Going forward, a strong permit price sends the correct signal for investment in low-carbon technologies and safeguards the effectiveness of a C&T system. Therefore, quantifying the effects of interaction between electricity and permit markets subject to market power is of policy relevance.

In order to contribute to the understanding of imperfectly competitive regional electricity markets in conjunction with a C&T system subject to market power, we develop a stylised model of SEE-REM consisting of a subregion capped by the EU ETS and an uncapped subregion. For the purpose of understanding the impact of market power in the electricity market only and both electricity and permit markets, we have three market settings, viz., perfect competition in both markets, leader-follower model where a leader can manipulate the electricity market only, and leader-follower where a leader can manipulate both the electricity and permit markets. From this study, it follows that between 11% and 39% of the emission reduction achieved in the ETS area of SEE-REM can be leaked to the non-ETS area under the perfectly competitive setting. The strategy of the leader in imperfectly competitive settings depends on the merit order. Specifically, if the leader can manipulate only the electricity market and its main technology is cheaper than the marginal technology, then ETS emissions and carbon leakage are below perfectly competitive levels. On the other hand, if leader's main technology is the marginal technology, then these results are overturned. The manipulation of the permit market in addition to the electricity market leads to higher ETS emissions and carbon leakage when considering the merit order in which the leader's dominant technology is cheaper than the marginal one. The contrary is true when the leader's main technology becomes the marginal one.

Considering the damaging effects of carbon leakage found in this study and bearing in mind that CO_2 emissions are damaging everywhere independently of where these originated, in the following chapter, we develop a leakage-mitigation measure to complement a unilateral climate policy. In particular, we use a bi-level model, and, at the upper level, take the perspective of a policymaker that sets an optimal emission cap over the regulated part of a regional market under its jurisdiction while anticipating the reaction of the entire regional electricity market at the lower level.

Chapter 4

Regional Carbon Policies in an Interconnected Power System: How Expanded Coverage Could Exacerbate Emission Leakage

4.1 Introduction

The first-best economic outcome, i.e., a global uniform carbon price, envisaged at the time of origin of the Kyoto Protocol is hard to achieve even after more than twenty years as countries continue to reduce emissions at their own pace. The Paris Agreement has made some steps in that direction such as combining elements of the bottom-up, e.g., emission-target setting, and top-down approaches, e.g., monitoring and reporting procedures, achieving a commitment to carbon-reduction targets from the vast majority of countries, and facilitating linking of climate policies. However, due to self-pacing related to the emission-reduction targets as well as the individual choice of strategy, the challenge of fragmented climate policies remains the reality and so does the risk of carbon leakage. Furthermore, linking climate policies could adversely affect carbon leakage. In the context of electricity markets, Burtraw et al. (2013) show that even though the linkage of C&T systems should reduce leakage between systems in the link as carbon prices even out, it could exacerbate carbon leakage to uncapped regions of the electricity market. Specifically, as the permit price of the cheaper pre-linkage system increases, it provides more incentive for firms in the uncapped area to sell electricity to the linked systems. Therefore, the pursuit of a second-best economic outcome, i.e., unilateral climate policy implemented alongside an anti-leakage measure, persists. This is particularly important for electricity markets due to not only the misalignment of the wholesale market and jurisdiction of the environmental regulators but also the fact that they are potentially suitable linking partners.[18]

In order to explore a second-best anti-leakage measure, we take a bi-level modelling approach by considering the impact of an emission cap that limits the cost of damage associated with emissions from a subregion of a regional power market. In particular, a welfare-maximising policymaker sets the cap by internalising the damage costs of emissions when facing profit-maximising producers in two nodes connected by a congested transmission line. We show analytically that a partial-coverage policy could degrade the maximised social welfare and increase the total regional CO_2 emissions with the potential for further carbon leakage due to a higher nodal price difference. A modified carbon policy that takes CO_2 emissions from both nodes into account results in a tighter cap, which increases maximised social welfare and decreases total CO_2 emissions vis-à-vis the partial-coverage policy. Yet, this modified policy enhances the scope for carbon leakage as it leads to a greater difference in equilibrium nodal prices. As a compromise, we find that an import-coverage policy, similar to the one implemented by the California government, that counts only domestic and imported CO_2 emissions could effectively alleviate the potential for carbon leakage at the cost of lower maximised social welfare with higher total emissions than those under the modified-coverage policy that includes total CO_2 emissions.

4.2 Literature Review

To safeguard the environmental effectiveness of unilateral policies, a variety of corrective measures has been proposed, including border carbon adjustment that contains a carbon tariff on emissions from production of goods imported from an unregulated region and/or a production rebate for emissions from production of goods exported to unregulated regions, e.g., Markusen (1975) and Hoel (1996). Furthermore, Copeland (1996) finds that if a carbon tariff is more finely targeted to the pollution content of the imported product, then it could incentivise more intensive emitters to improve their production processes. Although carbon tariffs have not been implemented yet, studies using computable general equilibrium models of global trade suggest that these have potential for reducing carbon leakage. For instance, Böhringer et al. (2012) apply a carbon tariff based on average emissions of the unregulated region and find that carbon leakage could be further reduced if

[18] Linking could be smoother if systems have previously engaged on other issues and are familiar and connected through other regulatory and/or political systems (Ranson and Stavins, 2016).

the tariffs are specially tailored to firms' emissions (Böhringer et al., 2017). Despite proving effective in numerical studies, tariffs could be legally and politically challenging to implement as their introduction could lead to retaliation from countries affected by carbon tariffs, which could result in trade wars (Böhringer et al., 2017).

The allowance allocation in a C&T plays an important role in carbon-leakage mitigation. Output-based updating has been prominently discussed in the literature due to its leakage mitigation potential compared to other forms of allocation, e.g., auctions (Fischer and Fox, 2007). In the context of the California electricity market C&T, Bushnell and Chen (2012) compare output-based updating allocation with an alternative approach based on auctions. The study finds that if the updating is based on an average industry emission rate, then the output-based allocation reduces leakage in comparison to the auction. By contrast, a more finely targeted updating based on fuel types could lead to a similar magnitude of leakage with permit prices above the auction level. Another example of disparate regulation stringency that could result in carbon leakage arises in the context of plant vintage differentiation in states with a C&T under the U.S. Clean Power Plan. In particular, Palmer et al. (2017) find that allocating allowances solely to natural gas producers is the most effective way of reducing leakage, albeit closely followed by allocating allowances to both natural gas and coal producers. In practice, the EU uses auctioning as a form of allowance allocation but allocates some allowances free of charge to sectors (other than power generation) exposed to the risk of carbon leakage (EC, 2018b). The free allowance allocation is benchmarked on the most efficient installation in each sector (EC, 2018b).

The mandatory purchase of allowances for emissions associated with electricity imported from an unregulated region has been implemented in California (Title 17, California Code of Regulations, sections 95801-96022). However, studies have shown that even with this approach, the problem of carbon leakage might persist due to contract shuffling. For instance, Chen et al. (2011) examine all-inclusive coverage plans encompassing emissions from production in the regulated area and from imports into the regulated area. These are compared to more conventional source-based (covering emissions only from production in the regulated area) and load-based (covering emissions only from total consumption in the regulated area) plans. The authors find that all-inclusive plans result in more regulated emission reduction compared to the conventional alternatives; however, these do not prove to be very effective at reducing carbon leakage, as the emissions for the entire region remain unchanged.

4.3 Analytical Model

4.3.1 Assumptions

We assume a regional electricity market with two nodes, $j = E, W$. Each node j has its own inverse-demand function, $A_j - B_j x_j$, where $A_j > 0$ (in \$/MW) is the vertical intercept, $B_j > 0$ (in \$/MW^2) is the slope parameter, and x_j (in MW) is the total energy consumption. The inverse-demand function represents the maximum willingness to pay to consume x_j MW of power at node j. The power sector at node j is perfectly competitive and produces power at total cost $C_j y_j$, where $C_j > 0$ (in \$/MW) is the levelised cost of generation and y_j (in MW) is node j's production. A single transmission line of capacity $K > 0$ (in MW) connects the two nodes, and an ISO controls the net power flow to node E on the transmission line, f (in MW), in order to maximise social welfare. Each node's power sector has a CO_2 emission rate, $R_j \geq 0$ (in t/MW, where "t" is the International System of Units abbreviation for "metric ton"), and the cost of damage from emissions is quadratic in the total system emissions, $\frac{1}{2}D\left(\sum_j R_j y_j\right)^2$, where $D \geq 0$ (in \$/t^2) reflects the cost of the externality (Requate, 2006). Given an emission cap of $z \geq 0$ (in t), this power sector determines the profit-maximising production level at each node along with the optimal net flow to node E. The emission cap is set by a welfare-maximising policymaker at the upper level who anticipates the industry equilibrium at the lower level. Since the policymaker is unable to intervene directly in the sector's operations at the lower level, i.e., it has no control over y_j or f, it can only indirectly align the private incentives of industry with social ones by selecting z. The consequence of the emission cap is that producers must pay a rate of ρ (in \$/t) to cover their emissions, where ρ is the shadow price on the C&T constraint.

We model a single representative time period without uncertainty in either demand or production. In order to ensure interior solutions with a congested transmission line and to analyse an economically non-trivial situation in which the high-consumption node E has relatively expensive but less-polluting generation (and *vice versa* for node W), we assume $A_E > A_W > C_E > C_W > 0$, $R_W > R_E$, and $\frac{A_E}{B_E} > \frac{A_W}{B_W}$. We ensure that node W is not "too" expensive, i.e., cost of production at node W inclusive of the marginal cost of damage from emissions does not exceed that at node E: $0 \leq D < \check{D} \equiv \frac{(C_E - C_W)B_E B_W}{(R_W - R_E)[B_E R_W(A_W + B_W K) + B_W R_E(A_E - B_E K)] + (R_E C_W - R_W C_E)(R_E B_W + R_W B_E)}$.[19] Likewise, we rule out a transmission line that is "too" big, i.e., it is smaller than the op-

[19] This comes from requiring the marginal cost of generation at node W, $C_W + DR_W(R_E y_E + R_W y_W)$, to be less than that at node E, $C_E + DR_E(R_E y_E + R_W y_W)$.

timal import at node E if all production occurred at node W: $0 \leq K < \check{K} \equiv \frac{B_W(A_E - C_W) + DR_W^2(A_E - A_W)}{B_E B_W + DR_W^2(B_E + B_W)}$.

The assumptions related to a capped region with a relatively less-polluting generation mix interconnected and dependent on imports from an uncapped region with relatively more-polluting generation mix resemble some real electricity markets. One important example is the California electricity market. In 2015, CO_2 emissions from the electricity sector (in-state generation and imports) accounted for 19% of total emissions in California (CARB, 2017). Of this, approximately 40% was due to imported electricity (CARB, 2017) despite the fact that imported electricity deriving from polluting sources covered not more than 24% of California's electricity consumption[20] (California Energy Commission, 2018). Relatively high-polluting imported electricity compared to the electricity generated in California is due to the fact that a substantial part of imported electricity derives from coal-fired power plants, whereas California's production from thermal sources predominantly derives from natural gas.

In order to investigate the consequences of partial coverage, we will formulate the following three coverage policies in addition to the one with full coverage (FC):

Partial Coverage (PC) The policymaker has jurisdiction over only node E and sets its emission cap taking into account only consumer surplus, producer surplus, merchandising surplus from grid operations, and the cost of damage from emissions at node E.

Modified Coverage (MC) This is the same as PC except that the policymaker incorporates the cost of damage from emissions from node-W production into its objective function.

Import Coverage (IC) This is the same as PC except that the policymaker incorporates the cost of damage from emissions from net imports from node W into its objective function.

4.3.2 Problem Formulation and Analytical Solutions

4.3.2.1 Full Coverage

This is a bi-level problem in which the lower level consists of industry equilibrium in the presence of a C&T constraint. The upper level is the welfare-maximisation

[20] The reason why we say "not more than 24%" is because, according to California Energy Commission (2018), a large part of imported electricity derives from so-called "Unspecified Sources," which could be natural gas, coal, and/or hydropower.

problem of the policymaker in which the decision is to select the optimal emission cap. Starting at the lower level, the industry's problems are as follows:

$$\max_{y_E \geq 0} \quad p_E y_E - (C_E + \rho R_E)\, y_E \tag{4.1}$$

$$\max_{y_W \geq 0} \quad p_W y_W - (C_W + \rho R_W)\, y_W \tag{4.2}$$

$$\max_f \quad [A_E - B_E y_E]\, f - [A_W - B_W y_W]\, f - \frac{1}{2}(B_E + B_W)\, f^2 \tag{4.3}$$

$$\text{s.t.} \quad -K \leq f \leq K : \mu^-, \mu^+ \tag{4.4}$$

$$y_E + f \geq 0 : \beta_E \tag{4.5}$$

$$y_W - f \geq 0 : \beta_W \tag{4.6}$$

$$0 \leq \rho \perp \quad z - (R_E y_E + R_W y_W) \geq 0 \tag{4.7}$$

The producers' optimisation problems are (4.1) and (4.2), which involve selecting y_j to maximise profit while taking f, p_j, and ρ as given. Note that p_j will equal $A_j - B_j x_j$, but each producer is unable to withhold output in order manipulate the price due to the assumption of perfect competition. Meanwhile, the ISO takes y_j as given (Sauma and Oren, 2006) and selects transmission flow, f, in order to maximise the change in social welfare (4.3) subject to constraints on transmission capacity and non-negativity of consumption (4.4)-(4.6). Given the emission cap, z, set by the policymaker at the upper level, industry must ensure that emissions from regional production comply with this limit. The shadow price, ρ, on (4.7) serves as an effective tax on both producers. Since each of the three problems is convex, it may be replaced by its KKT conditions for optimality:

$$0 \leq y_E \perp -[A_E - B_E (y_E + f)] + C_E + \rho R_E \geq 0 \tag{4.8}$$

$$0 \leq y_W \perp -[A_W - B_W (y_W - f)] + C_W + \rho R_W \geq 0 \tag{4.9}$$

$$\begin{aligned} &-[A_E - B_E (y_E + f)] + [A_W - B_W (y_W - f)] \\ &\quad +\mu^+ - \mu^- - \beta_E + \beta_W = 0 \text{ with } f \text{ free} \end{aligned} \tag{4.10}$$

$$0 \leq \mu^- \perp f + K \geq 0 \tag{4.11}$$

$$0 \leq \mu^+ \perp K - f \geq 0 \tag{4.12}$$

$$0 \leq \beta_E \perp y_E + f \geq 0 \tag{4.13}$$

$$0 \leq \beta_W \perp y_W - f \geq 0 \tag{4.14}$$

We assume that (4.5)–(4.6) are met with strict inequalities, which means that $\beta_j^*(z) = 0$ via (4.13)–(4.14). Searching for interior solutions parameterised on z, i.e., $y_E^*(z) > 0$ and $y_W^*(z) > 0$, with $f^*(z) = K$, from (4.11) and (4.12), we obtain $\mu^{*,-}(z) = 0$ and $\mu^{*,+}(z) \geq 0$. Next, solving (4.8) and (4.9) togther with (4.7) yields:

$$\rho^*(z) = \frac{R_E B_W (A_E - C_E - B_E K) + R_W B_E (A_W - C_W + B_W K) - B_E B_W z}{B_W R_E^2 + B_E R_W^2} \tag{4.15}$$

$$y_E^*(z) = \frac{R_W^2 (A_E - C_E - B_E K) - R_E R_W (A_W - C_W + B_W K) + B_W R_E z}{B_W R_E^2 + B_E R_W^2} \tag{4.16}$$

$$y_W^*(z) = \frac{R_E^2 (A_W - C_W + B_W K) - R_E R_W (A_E - C_E - B_E K) + B_E R_W z}{B_W R_E^2 + B_E R_W^2} \tag{4.17}$$

Finally, from (4.10), we obtain:

$$\mu^{*,+}(z) = C_E - C_W + \frac{(R_W - R_E)\left[B_E B_W z - B_E R_W (A_W - C_W + B_W K)\right]}{B_W R_E^2 + B_E R_W^2} - \frac{(R_W - R_E) B_W R_E (A_E - C_E - B_E K)}{B_W R_E^2 + B_E R_W^2} \tag{4.18}$$

Moving to the upper level, the policymaker's problem is to set $z \geq 0$ in order to maximise (4.19) subject to the lower-level problems as follows:

$$\begin{aligned} \max_{z \geq 0} \quad & A_E (y_E + f) - \frac{1}{2} B_E (y_E + f)^2 \\ & + A_W (y_W - f) - \frac{1}{2} B_W (y_W - f)^2 \\ & - C_E y_E - C_W y_W - \frac{1}{2} D (R_E y_E + R_W y_W)^2 \qquad (4.19) \\ \text{s.t.} \quad & (4.1) - (4.7) \end{aligned}$$

The terms in (4.19) comprise social welfare and consist of, in turn, gross consumer surplus at node E, gross consumer surplus at node W, cost of generation at node E, cost of generation at node W, and the total cost of damage from emissions.[21] Note that the upper-level decision variable, z, does not explicitly appear in the upper-level objective function (4.19). However, it is implicitly represented through the dependence of the lower-level decision variables on z. Specifically, the policymaker's bi-level problem may be converted to an MPEC as the lower-level problems may be

[21] A complete breakdown of the social welfare involves the *gross consumer surplus* at each node, $A_E (y_E + f) - \frac{1}{2} B_E (y_E + f)^2$ and $A_W (y_W - f) - \frac{1}{2} B_W (y_W - f)^2$, the *gross producer surplus* at each node, $p_E y_E$ and $p_W y_W$, *government revenue* collected from sales of C&T permits, $\rho R_E y_E$ and $\rho R_W y_W$, and *net merchandising surplus* for the ISO, $(p_E - p_W) f$. On the other side of the ledger, we have the *consumers' cost of purchasing power* at each node, $p_E (y_E + f)$ and $p_W (y_W - f)$, *generation cost* at each node, $C_E y_E$ and $C_W y_W$, the *generators' cost of C&T permit purchases*, $\rho R_E y_E$ and $\rho R_W y_W$, and the *cost of damage from emissions*, $\frac{1}{2} D (R_E y_E + R_W y_W)^2$.

replaced by their KKT conditions. Since we search for interior solutions, the lower-level solutions parameterised on z, (4.15)–(4.18), may be subsequently inserted into the upper-level objective function, thereby yielding the following QP problem as all of the lower-level solutions are linear in z:

$$\begin{aligned}\max_{z\geq 0} \quad & A_E\left(y_E^*(z)+f^*(z)\right)-\frac{1}{2}B_E\left(y_E^*(z)+f^*(z)\right)^2\\ & +A_W\left(y_W^*(z)-f^*(z)\right)-\frac{1}{2}B_W\left(y_W^*(z)-f^*(z)\right)^2\\ & -C_E y_E^*(z)-C_W y_W^*(z)-\frac{1}{2}D\left(R_E y_E^*(z)+R_W y_W^*(z)\right)^2 \qquad (4.20)\end{aligned}$$

Since (4.20) is a convex QP, the following first-order necessary condition for it is also sufficient:

$$\begin{aligned}& A_E y_E^{*\prime}(z)-B_E\left(y_E^*(z)+K\right)y_E^{*\prime}(z)+A_W y_W^{*\prime}(z)\\ & -B_W\left(y_W^*(z)-K\right)y_W^{*\prime}(z)-C_E y_E^{*\prime}(z)-C_W y_W^{*\prime}(z)\\ & -D\left(R_E y_E^*(z)+R_W y_W^*(z)\right)\left(R_E y_E^{*\prime}(z)+R_W y_W^{*\prime}(z)\right)=0 \qquad (4.21)\end{aligned}$$

Solving, we obtain:

$$z^*=\frac{\left[B_E R_W\left(A_W-C_W+B_W K\right)+B_W R_E\left(A_E-C_E-B_E K\right)\right]}{B_E B_W+D\left(R_W^2 B_E+R_E^2 B_W\right)} \qquad (4.22)$$

Inserting z^* into the lower-level parameterised solutions (4.15)–(4.18), we obtain the following solutions for $\rho^*(z^*)$, $y_E^*(z^*)$, $y_W^*(z^*)$, and $\mu^{*,+}(z^*)$:

$$\begin{aligned}\rho^*(z^*) &= \frac{D\left[R_E B_W\left(A_E-C_E-B_E K\right)+R_W B_E\left(A_W-C_W+B_W K\right)\right]}{B_E B_W+D\left(R_W^2 B_E+R_E^2 B_W\right)} \qquad (4.23)\\ y_E^*(z^*) &= \frac{\left(DR_W^2+B_W\right)\left(A_E-C_E-B_E K\right)-DR_E R_W\left(A_W-C_W+B_W K\right)}{B_E B_W+D\left(R_W^2 B_E+R_E^2 B_W\right)} \qquad (4.24)\\ y_W^*(z^*) &= \frac{\left(DR_E^2+B_E\right)\left(A_W-C_W+B_W K\right)-DR_E R_W\left(A_E-C_E-B_E K\right)}{B_E B_W+D\left(R_W^2 B_E+R_E^2 B_W\right)} \qquad (4.25)\\ \mu^{*,+}(z^*) &= C_E-C_W\\ & -\frac{D\left(R_W-R_E\right)\left[B_E R_W\left(A_W-C_W+B_W K\right)\right]}{B_E B_W+D\left(R_W^2 B_E+R_E^2 B_W\right)}\\ & +\frac{D\left(R_W-R_E\right)\left[B_W R_E\left(A_E-C_E-B_E K\right)\right]}{B_E B_W+D\left(R_W^2 B_E+R_E^2 B_W\right)} \qquad (4.26)\end{aligned}$$

It may be verified that the FC solutions are identical to those that would result from central planning, e.g., $\rho^*(z^*)$ would be the same as the implied Pigouvian tax, Dz^*.

4.3.2.2 Partial Coverage

Under PC, the policymaker also solves a bi-level problem, but the C&T constraint applies only to node-E production. Thus, at the upper level, the policymaker selects the optimal emission cap considering only node-E consumer surplus, producer surplus, and cost of damage from emissions. Starting again from the lower level, we have the following formulations:

$$
\begin{array}{rll}
 & (4.1) & \\
\max_{y_W \geq 0} & p_W y_W - C_W y_W & (4.27) \\
 & (4.3) \text{ s.t. } (4.4) - (4.6) & \\
0 \leq \rho \perp & z - R_E y_E \geq 0 & (4.28)
\end{array}
$$

Here, the producer at node W (4.27) is not subject to the emission cap (4.28), whereas the problems of the node-E producer and the ISO are unchanged. The new KKT conditions for optimality are:

$$
\begin{array}{c}
(4.8) \\
0 \leq y_W \perp -[A_W - B_W (y_W - f)] + C_W \geq 0 \qquad (4.29) \\
(4.10) - (4.14)
\end{array}
$$

In order to obtain an equilibrium, we again assume that (4.5)–(4.6) are met with strict inequalities, which means that $\hat{\beta}_j(z) = 0$ via (4.13)–(4.14). Searching for interior solutions parameterised on z, i.e., $\hat{y}_E(z) > 0$ and $\hat{y}_W(z) > 0$, with $\hat{f}(z) = K$, from (4.11) and (4.12), we obtain $\hat{\mu}^-(z) = 0$ and $\hat{\mu}^+(z) \geq 0$. Next, solving (4.8) and (4.29) together with (4.28) yields:

$$
\hat{\rho}(z) = \frac{R_E (A_E - C_E - B_E K) - B_E z}{R_E^2} \qquad (4.30)
$$

$$
\hat{y}_E(z) = \frac{z}{R_E} \qquad (4.31)
$$

$$
\hat{y}_W(z) = \frac{[A_W - C_W + B_W K]}{B_W} \qquad (4.32)
$$

Finally, from (4.10), we obtain:

$$
\hat{\mu}^+(z) = \frac{[R_E (A_E - C_W - B_E K) - B_E z]}{R_E} \qquad (4.33)
$$

Moving to the upper level, the policymaker sets $z \geq 0$ in order to maximise only the node-E components of (4.19) subject to the PC lower-level problems, which is then converted to an MPEC as the lower-level problems may be replaced by their KKT conditions. Since we search for interior solutions, the lower-level solutions parameterised on z may be inserted into the upper-level objective function, thereby yielding the following QP:

$$\begin{aligned}\max_{z\geq 0} \quad & A_E\left(\hat{y}_E(z)+\hat{f}(z)\right)-\frac{1}{2}B_E\left(\hat{y}_E(z)+\hat{f}(z)\right)^2 \\ & -C_E\hat{y}_E(z)-\hat{P}_E(z)\hat{f}(z)+(\hat{P}_E(z)-\hat{P}_W(z))\hat{f}(z) \\ & -\frac{1}{2}D\left(R_E\hat{y}_E(z)\right)^2 \end{aligned} \tag{4.34}$$

where $\hat{P}_E(z)=A_E-B_E(\hat{y}_E(z)+\hat{f}(z))$ and $\hat{P}_W(z)=A_W-B_W(\hat{y}_W(z)-\hat{f}(z))$. Note that (4.34) differs from (4.20) not only by the missing node-W terms but also due to the presence of the $-\hat{P}_E(z)\hat{f}(z)+(\hat{P}_E(z)-\hat{P}_W(z))\hat{f}(z)$ term, which captures the cost to consumers at node E of importing $\hat{f}(z)$ and the ISO's merchandising surplus.[22]

Next, differentiating (4.34) with respect to z, we obtain the following first-order necessary condition:

$$A_E\hat{y}_E'(z)-B_E\left(\hat{y}_E(z)+K\right)\hat{y}_E'(z)-C_E\hat{y}_E'(z)-DR_E^2\hat{y}_E(z)\hat{y}_E'(z)=0 \tag{4.35}$$

Solving, we obtain:

$$\hat{z}=\frac{R_E\left(A_E-C_E-B_EK\right)}{B_E+DR_E^2} \tag{4.36}$$

Inserting $\hat{z}$ into the lower-level parameterised solutions (4.30)–(4.33), we obtain:

$$\hat{\rho}(\hat{z}) \quad = \quad \frac{DR_E\left(A_E-C_E-B_EK\right)}{B_E+DR_E^2} \tag{4.37}$$

$$\hat{y}_E(\hat{z}) \quad = \quad \frac{A_E-C_E-B_EK}{B_E+DR_E^2} \tag{4.38}$$

[22]The complete breakdown of the social welfare here involves the *gross consumer surplus* at node E, $A_E\left(y_E+f\right)-\frac{1}{2}B_E\left(y_E+f\right)^2$, the *gross producer surplus* at node E, p_Ey_E, *government revenue* collected from sales of C&T permits, ρR_Ey_E, and *net merchandising surplus* for the ISO, $(p_E-p_W)f$. We assume that node E is large enough that the ISO's revenues are fully attributed to its welfare. If the two nodes were more equal in terms of their consumption, then a more equitable split of the merchandising surplus could be accommodated (Huppmann and Egerer, 2015). On the other side of the ledger, we have the *consumers' cost of purchasing power* at node E, $p_E(y_E+f)$, *generation cost* at node E, C_Ey_E, the *generator's cost of C&T permit purchases* at node E, ρR_Ey_E, and the *cost of damage from emissions* at node E, $\frac{1}{2}D\left(R_Ey_E\right)^2$.

$$\hat{y}_W(\hat{z}) = \frac{A_W - C_W + B_W K}{B_W} \tag{4.39}$$

$$\hat{\mu}^+(\hat{z}) = C_E - C_W + \frac{DR_E^2\left(A_E - C_E - B_E K\right)}{B_E + DR_E^2} \tag{4.40}$$

The total emissions (including those at node W) under PC are:

$$R_E\hat{y}_E(\hat{z}) + R_W\hat{y}_W(\hat{z}) = \frac{R_E B_W (A_E - C_E - B_E K)}{B_W\left(B_E + DR_E^2\right)} + \frac{+R_W\left(B_E + DR_E^2\right)(A_W - C_W + B_W K)}{B_W\left(B_E + DR_E^2\right)} \tag{4.41}$$

4.3.2.3 Modified Coverage

Under MC, the C&T constraint is again applicable only to node-E production. However, at the upper level, the policymaker selects the optimal emission cap considering only node-E consumer surplus and producer surplus as well as the cost of damage from emissions from both nodes. Thus, it attempts to internalise the cost of damage from total emissions at node W. In terms of the lower-level formulation and equilibrium conditions, they are unchanged from those under PC, i.e., the solution is still (4.30)–(4.33). This is because industry at the lower level obtains a solution parameterised on z and still faces a partial C&T constraint.

At the upper level, the policymaker's objective function is similar to that under PC (4.42) with an adjustment to the cost of damage from emissions to reflect that in (4.20). As in the PC case, we assume that the merchandising surplus accrues fully to an ISO based at node E:

$$\begin{aligned} \max_{z \geq 0} \quad & A_E\left(\hat{y}_E(z) + \hat{f}(z)\right) - \frac{1}{2}B_E\left(\hat{y}_E(z) + \hat{f}(z)\right)^2 - C_E\hat{y}_E(z) \\ & -\hat{P}_E(z)\hat{f}(z) + (\hat{P}_E(z) - \hat{P}_W(z))\hat{f}(z) \\ & -\frac{1}{2}D\left(R_E\hat{y}_E(z) + R_W\hat{y}_W(z)\right)^2 \end{aligned} \tag{4.42}$$

We obtain the following first-order necessary condition to the QP in (4.42):

$$\begin{aligned} & A_E\hat{y}'_E(z) - B_E\left(\hat{y}_E(z) + K\right)\hat{y}'_E(z) - C_E\hat{y}'_E(z) \\ & -D\left(R_E\hat{y}_E(z) + R_W\hat{y}_W(z)\right)\left(R_E\hat{y}'_E(z) + R_W\hat{y}'_W(z)\right) = 0 \end{aligned} \tag{4.43}$$

Solving, we obtain:

$$\tilde{z} = \frac{\left[R_E B_W\left(A_E - C_E - B_E K\right) - DR_W R_E^2\left(A_W - C_W + B_W K\right)\right]}{B_W\left(B_E + DR_E^2\right)} \tag{4.44}$$

Inserting $\tilde{z}$ into the lower-level parameterised solutions (4.30)–(4.33), we obtain:

$$\hat{\rho}(\tilde{z}) = D\frac{\left[B_W R_E\left(A_E - C_E - B_E K\right) + B_E R_W\left(A_W - C_W + B_W K\right)\right]}{B_W\left(B_E + DR_E^2\right)} \tag{4.45}$$

$$\hat{y}_E(\tilde{z}) = \frac{\left[B_W\left(A_E - C_E - B_E K\right) - DR_W R_E\left(A_W - C_W + B_W K\right)\right]}{B_W\left(B_E + DR_E^2\right)} \tag{4.46}$$

$$\hat{y}_W(\tilde{z}) = \frac{A_W - C_W + B_W K}{B_W} \tag{4.47}$$

$$\hat{\mu}^+(\tilde{z}) = C_E - C_W + DR_E\frac{\left[B_W R_E\left(A_E - C_E - B_E K\right) + B_E R_W\left(A_W - C_W + B_W K\right)\right]}{B_W\left(B_E + DR_E^2\right)} \tag{4.48}$$

The total emissions (including those at node W) under MC are:

$$R_E\hat{y}_E(\tilde{z}) + R_W\hat{y}_W(\tilde{z}) = \frac{R_E B_W\left(A_E - C_E - B_E K\right)}{B_W\left(B_E + DR_E^2\right)} + \frac{R_W B_E\left(A_W - C_W + B_W K\right)}{B_W\left(B_E + DR_E^2\right)} \tag{4.49}$$

4.3.2.4 Import Coverage

In contrast to the MC model in Section 4.3.2.3, the policymaker at the upper level under IC selects the optimal emission cap considering node-E consumer surplus and producer surplus along with the cost of damage from emissions associated with the total quantity demanded at node E, i.e., emissions from domestic production and imports from node W. As under MC, the lower-level formulation and equilibrium are unchanged from Section 4.3.2.2, thereby resulting in the same lower-level solutions (4.30)–(4.33).

At the upper level, the objective function is slightly changed from that in (4.42) to replace total emissions at node W, $R_W y_W$, by imported emissions from node W, $R_W f$, in the final term:[23]

$$\begin{aligned}\max_{z\geq 0} \quad & A_E\left(\hat{y}_E(z) + \hat{f}(z)\right) - \frac{1}{2}B_E\left(\hat{y}_E(z) + \hat{f}(z)\right)^2 - C_E\hat{y}_E(z) \\ & -\hat{P}_E(z)\hat{f}(z) + (\hat{P}_E(z) - \hat{P}_W(z))\hat{f}(z) \\ & -\frac{1}{2}D\left(R_E\hat{y}_E(z) + R_W\hat{f}(z)\right)^2\end{aligned} \tag{4.50}$$

As under MC, we obtain the following first-order necessary condition to the

[23]The term $R_W\hat{f}(z)$ in (4.50) derives from the expression $max\{0, R_W\hat{f}(z)\}$; however, since we are interested only in interior solutions, we assume that $max\{0, R_W\hat{f}(z)\} = R_W\hat{f}(z)$.

QP in (4.50):

$$\begin{aligned} A_E \hat{y}'_E(z) - B_E\left(\hat{y}_E(z)+K\right)\hat{y}'_E(z) - C_E\hat{y}'_E(z) \\ -D\left(R_E\hat{y}_E(z)+R_W K\right)R_E\hat{y}'_E(z) = 0 \end{aligned} \tag{4.51}$$

Solving, we obtain:

$$\underline{z} = \frac{R_E(A_E - B_E K - C_E - D R_E R_W K)}{B_E + D R_E^2} \tag{4.52}$$

Inserting $\underline{z}$ into the lower-level parameterised solutions (4.30)–(4.33), we obtain:

$$\hat{\rho}(\underline{z}) = \frac{D\left[R_E\left(A_E - C_E\right) + (R_W - R_E)B_E K\right]}{B_E + D R_E^2} \tag{4.53}$$

$$\hat{y}_E(\underline{z}) = \frac{A_E - B_E K - C_E - D R_E R_W K}{B_E + D R_E^2} \tag{4.54}$$

$$\hat{y}_W(\underline{z}) = \frac{A_W - C_W + B_W K}{B_W} \tag{4.55}$$

$$\hat{\mu}^+(\underline{z}) = -C_W + \frac{D R_E\left[R_E(A_E - B_E K) + R_W B_E K\right] + B_E C_E}{B_E + D R_E^2} \tag{4.56}$$

The total emissions (including those at node W) under IC are:

$$\begin{aligned} R_E\hat{y}_E(\underline{z}) + R_W\hat{y}_W(\underline{z}) = {} & \frac{R_E B_W(A_E - C_E - B_E K) + R_W B_E(A_W - C_W + B_W K)}{B_W\left(B_E + D R_E^2\right)} \\ & + \frac{D R_E^2 R_W(A_W - C_W)}{B_W\left(B_E + D R_E^2\right)} \end{aligned} \tag{4.57}$$

4.3.3 Lower-Level Equilibrium Characterisation

In order to characterise equilibria and the basis for the interior solutions to the problems in Sections 4.3.2.1–4.3.2.4, we focus on the lower-level solutions to the full- and partial-coverage cases, (4.15)–(4.18) and (4.30)–(4.33), respectively, while holding z and K constant.[24] The corresponding linear relationship between z and K for each equation in each case is plotted in Figure 4.1 along with a label on the appropriate side of each line to ensure an interior solution. For each case, an interior solution is assured if all four lower-level variables are strictly positive, i.e., $\Omega^{FC} = \{\rho^*(z) > 0, y^*_E(z) > 0, y^*_W(z) > 0, \mu^{*,+}(z) > 0\}$ and $\Omega^{PC} = \{\hat{\rho}(z) > 0, \hat{y}_E(z) > 0, \hat{y}_W(z) > 0, \hat{\mu}^+(z) > 0\}$. Equivalently, z and K must be in the ranges

[24] Actually, the lower-level equilibria in the remaining cases are identical to those under PC, which is why we forego their characterisation.

sketched out by the corresponding lines for each case in order for each interior solution set to be non-empty. Moreover, the intersection between the two sets, $\Omega = \Omega^{FC} \cap \Omega^{PC}$, will be non-empty only if z and K are restricted as indicated by the shaded region in Figure 4.1.

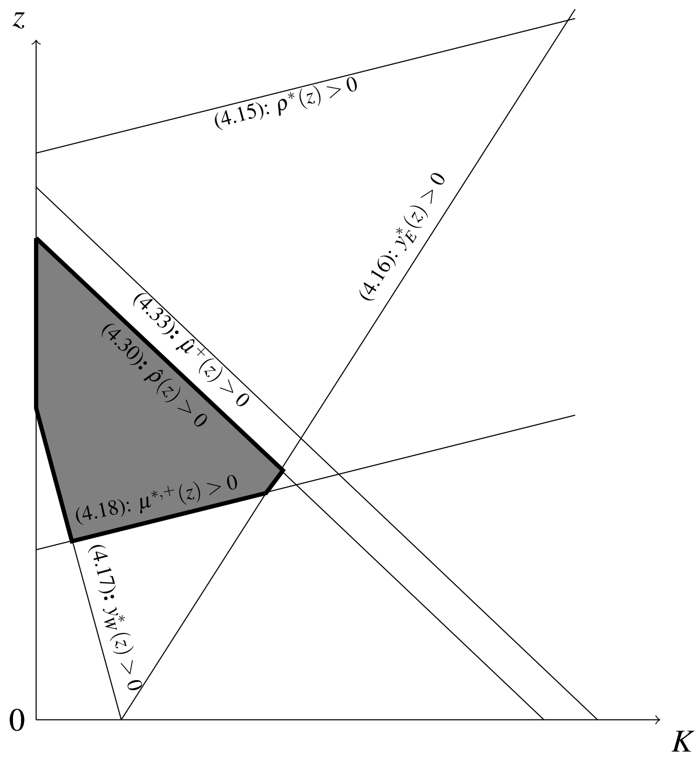


Figure 4.1: Characterisation of lower-level equilibria with respect to K and z

Intuitively, the FC interior solution set first establishes an upper bound on the emission limit, z, such that the C&T permit price is strictly positive (4.15). Indeed, if the emission limit is too lax, then it will be relatively easy to comply with, thereby causing the C&T permit price to crash to zero. Analogously, (4.15) establishes a lower limit on the size of the transmission line, K, below which relatively dirty production at node W will be minimal and obviate the need for a carbon policy. Next, (4.16) establishes an upper limit on K above which node-E generation will be zero as production from node W will satisfy all regional consumption. By the same token, (4.16) puts a floor on the emission limit as any tighter carbon policy will curb node-E production. Likewise, (4.17) puts a floor on the emission limit to ensure that node-W production is viable along with a minimum size for the transmission line. Finally, (4.18) puts a lower bound (an upper bound) on the emission limit (line capacity) below (above) which transmission capacity will not have marginal value.

The PC interior solution set can be characterised similarly: (4.30) and (4.33) establish upper bounds on z and K. However, the latter restriction is binding as long as the former one is, which means that (4.33) can be effectively disregarded. Likewise, (4.31) and (4.32) can be shown to be positive for any positive values of z and K. Focusing on (4.30), therefore, we note that while it is similar to the corresponding FC restriction in terms of establishing an upper limit on z, it actually requires an upper limit on K rather than a lower limit as under FC. The reason for this contrasting requirement has to do with the fact that the carbon policy applies only to node E under PC. Hence, if the transmission line is relatively large, then emissions will be under the limit z, thereby rendering a zero C&T permit price as node-E consumption will be heavily dependent on relatively dirty generation from node W that is exempt from the C&T permit price.

4.3.4 Comparative Statics

We analyse the impact of *ceteris paribus* changes in transmission capacity,[25] K, and the cost of damage from emissions, D, on the emission cap, the C&T permit price, and the marginal value of transmission capacity. In particular, the latter serves as a proxy for potential carbon leakage under PC, MC, and IC as it reflects the propensity for expanding transmission capacity, which will attract more node-W imports to node E. Indeed, it represents the nodal price difference with a congested transmission line (or, equivalently, the marginal value of an infinitesimal increase in transmission capacity), and its realised value reflects the incentive of the transmission owner to expand capacity. Thus, through the following comparative statics, we formalise how alternative emission-coverage policies perform with respect to total emissions and the threat of carbon leakage. Following the exposition in Section 4.3.3, we assume that parameters are varied in a way to yield interior solutions, i.e., Ω is non-empty.

We explore how emission cap, permit price, and marginal value of transmission capacity are affected by the transmission capacity and the damage cost parameter. The variation of the emission cap, permit price, and marginal value of transmission capacity with parameters K and D is summarised in Table 4.1 where "+" ("-") means that the variable increases (decreases) with the parameter. All proofs of the following propositions are in Appendix C.

The impact of D on the emission cap, z, is intuitive as a policymaker would tighten the cap, z, in face of a larger D in the attempt to equalise the marginal damage with the permit price, ρ, thereby raising the permit price. The impact of D on

[25] Since we conduct a *ceteris paribus* analysis with respect to transmission capacity, we do not consider the capital costs of expanding the transmission line in the social welfare calculation.

Table 4.1: Emission cap, permit price, and marginal value of transmissions capacity change with K and D

Variable	Parameter K	D
z^*	+	-
$\hat{z}$	-	-
$\tilde{z}$	-	-
$\underline{z}$	-	-
$\rho^{+,*}(z^*)$	+	+
$\hat{\rho}(\hat{z})$	-	+
$\hat{\rho}(\tilde{z})$	+	+
$\hat{\rho}(\underline{z})$	+	+
$\mu^{*,+}(z^*)$	-	-
$\hat{\mu}^+(\hat{z})$	-	+
$\hat{\mu}^+(\tilde{z})$	+	+
$\hat{\mu}^+(\underline{z})$	+	+

the marginal value of transmission capacity, μ^+, a proxy for the leakage potential, is aligned with the impact on the permit price, ρ, except for the FC policy. Under PC, MC, and IC, a change in ρ will impact only the power price at node E, whereas the power price at node W will be equal to C_W since node W is not under the C&T. In turn, this will be reflected in the power price differential, μ^+. Under FC, when emissions from both nodes E and W are covered by the cap, the power price at node W will increase by more than that at node E due to node W's higher emission rate. Thus, the price differential between the two nodes will shrink leading to a reduction in the marginal value of transmission capacity.

The impact of transmission capacity, K, on the emission cap, z, depends on the emissions considered damaging by the policymaker at the upper level. Under all policies, an increase in K causes clean production at node E to be replaced by dirty production at node W. Under FC, since node-W emissions are covered by the cap, raising the emission cap, z, is necessary to equate the marginal damage cost of emissions with the permit price. The contrary is true for PC, MC, and IC where only emissions from node E are covered by the cap. Consequently, an increase in K lowers "local" emissions. If emissions from node W are included in the policymaker's problem either directly (FC) or indirectly (MC and IC), then the policymaker adjusts the cap so that it raises the permit price in the attempt to equalise the marginal damage of increased dirtier production. On the other hand, when node-W emissions are not included in the policymaker's problem (PC), the increase in imports from node W suppresses the demand for the permits due to lower emissions at node E, which leads to a drop in the permit price.

Proposition 1. *Impact of D and K on z.*

(i) Under FC, total emissions, z^*, increase (decrease) due to a ceteris paribus *increase in the transmission capacity, K (in the damage cost parameter, D).*

(ii) Under PC, MC, and IC, the node-E emission cap, $\hat{z}$, $\tilde{z}$, and $\underline{z}$, respectively, decreases due to a ceteris paribus *increase in either the transmission capacity, K, or the damage parameter, D.*

Both findings under Proposition 1(i) are generally intuitive: a larger transmission line increases total emissions because more node-W generation is able to meet node-E consumption. Conversely, a higher cost of damage parameter stifles consumption, thereby reducing generation in proportion to its emission rate and subsequently reducing overall emissions. The impact of the damage cost parameter on the emission cap in Proposition 1(ii) is similar to that under FC. Unlike the FC result, the policymaker under PC, MC, and IC actually tightens the emission cap, which applies only to node-E generation, if the transmission capacity increases. Concerned mainly about node-E welfare and emissions, the policymaker is unable to trade off the system-wide benefits and costs of the larger transmission line. Thus, it attempts to curtail relatively clean generation at node E via a more stringent emission cap, which may exacerbate not only total emissions but also carbon leakage. This latter aspect can be formalised via the following result where we investigate how the marginal value of transmission capacity is affected by the transmission capacity and the damage cost parameter:

Proposition 2. *Impact of D and K on μ^+.*

(i) Under FC, the marginal value of transmission capacity, $\mu^{*,+}$, decreases due to a ceteris paribus *increase in either the transmission capacity, K, or the damage cost parameter, D.*

(ii) Under PC, the marginal value of transmission capacity, $\hat{\mu}^+(\hat{z})$, decreases (increases) due to a ceteris paribus *increase in the transmission capacity, K (in the damage cost parameter, D).*

(iii) Under MC and IC, the marginal value of transmission capacity, $\hat{\mu}^+(\tilde{z})$ and $\hat{\mu}^+(\underline{z})$, increases due to a ceteris paribus *increase in either the transmission capacity, K, or the damage cost parameter, D.*

Proposition 2(i)'s findings are generally intuitive: the transmission line has a lower marginal value the larger its capacity becomes, while a higher damage cost, D, will curb node-W production, resulting in less exports to node E. These comparative statics may also be visualised in Figures 4.2 and 4.3 as a high K (low z or high D) will decrease $\mu^{*,+}$. In relation to Proposition 3(i), since node W is not impacted by carbon policy, its equilibrium power price under PC will be lower than that under FC. Moreover, the equilibrium power price at node E will tend to be higher under PC as it bears the brunt of a tighter emission cap. Consequently, the higher nodal price difference leads to a higher marginal value of transmission capacity and potential for carbon leakage. Also in contrast to the FC result, the marginal value of transmission capacity under PC actually increases with the damage cost parameter D (Proposition 2(ii)). Specifically, by setting an emission cap only for node E, the policymaker enlarges the nodal price difference when facing an increased damage cost D by reducing its optimal emission cap, $\hat{z}$, thereby worsening emission leakage.

Proposition 3. *Comparison of μ^+ across policies.*

(i) Under PC, the marginal value of transmission capacity, $\hat{\mu}(\hat{z}^+)$, is higher than that under FC, $\mu^{*,+}(z^*)$.

(ii) Under MC, the marginal value of transmission capacity, $\hat{\mu}^+(\tilde{z})$, is higher than that under both FC, $\mu^{*,+}(z^*)$, and PC, $\hat{\mu}^+(\hat{z})$.

(iii) Under IC, the marginal value of transmission capacity, $\hat{\mu}^+(\underline{z})$, is lower than that under MC, $\hat{\mu}^+(\tilde{z})$, and greater than that under PC, $\hat{\mu}^+(\hat{z})$.

According to Proposition 3(ii), due to a tighter node-E cap under MC (see Proposition 4(i)), the marginal value of transmission capacity under MC is greater than that under FC and PC. Moreover, as shown in Proposition 2(iii), although the marginal value of transmission capacity under MC increases with the damage cost parameter as under PC (but in contrast to FC), it actually increases with the transmission capacity (in contrast to both FC and PC). The explanation for the increase in $\hat{\mu}^+(\tilde{z})$ with respect to D is similar to that under PC, i.e., a tighter node-E cap only exacerbates the nodal price difference and enhances the prospect of carbon leakage. This attribute is especially striking when considering the positive impact of K on $\hat{\mu}^+(\tilde{z})$. Indeed, unlike the conventional behaviour of shadow prices that decrease with capacity, here, the attempt by the policymaker at node E to internalise the cost of damage from emissions at node E via a tighter emission cap more than offsets the (direct) effect of a higher capacity on the shadow price of transmission. Hence, although total regional emissions are lower under MC relative to PC, the potential for carbon leakage is increased.

As shown in Proposition 3(iii), since the node-E emission cap is looser (tighter) under IC compared to MC (PC) according to Proposition 4(ii), the marginal value of transmission capacity under IC is lower (greater) than that under MC (PC). Thus, IC alleviates the potential for carbon leakage, albeit at the cost of higher total regional emissions relative to MC. Furthermore, although the marginal value of transmission capacity still increases with respect to the transmission capacity and the damage cost parameter (as under MC) (see Proposition 2(iii)), its rate of increase with respect to D is lower than under MC.

Proposition 4. *Comparison of z across policies.*

(i) Under MC, both the node-E emission cap, $\tilde{z}$, and the total system emissions are lower than those under PC.

(ii) Under IC, both the node-E emission cap, $\underline{z}$, and the total system emissions are higher (lower) than those under MC (PC).

As shown in Proposition 4(i), accounting for node-W emissions leads the policymaker to set a tighter cap in MC than in PC, and thus, obtain lower total emissions with the former. In comparing IC with PC and MC, we find that including only the imported node-W emissions on top of the node-E emissions leads the policymaker to set a looser cap and to obtain higher total emissions in comparison to MC but still lower than those under PC (see Proposition 4(ii)).

Proposition 5. *Impact of D and K on ρ.*

(i) Under FC, MC, and IC, the C&T permit price, $\rho^*(z^*)$, $\hat{\rho}(\tilde{z})$, and $\hat{\rho}(\underline{z})$, respectively, increases due to a ceteris paribus *increase in either the transmission capacity, K, or the damage cost parameter, D.*

(ii) Under PC, the C&T permit price, $\hat{\rho}(\hat{z})$, decreases (increases) due to a ceteris paribus *increase in the transmission capacity, K (in the damage cost parameter, D).*

Following a similar logic as in the case of marginal value of transmission, the C&T permit price under FC can be shown to be increasing with both the transmission capacity and the damage cost parameter (see Proposition 5(i)). First, a larger transmission capacity enables more node-W production to meet consumption at node E, thereby giving the price signal for consumption to be curbed. Second, a higher damage cost parameter tightens the emission cap, which makes C&T permits more scarce. Although the C&T permit price under PC still increases due to a higher damage cost as under FC, the finding with respect to the transmission capacity is reversed as shown in Proposition 5(ii). Intuitively, a larger line displaces node-E production with node-W production, which is exempt from the emission cap. Thus, even though the node-E emission cap tightens as the transmission capacity increases, which should increase the C&T permit price, it is more than offset by the in influx of additional node-W imports. Hence, node E has lower local emissions, thereby causing the C&T permit price to crash.

4.4 Numerical Examples

Numerical examples are presented in this section using data in Table 4.2 in order to illustrate our findings in Section 4.3. Except for allowing D and K to change within the interior solution set, Ω, as sketched in Figure 4.1, data in Table 4.2 are fixed in our analyses. More specifically, we vary parameters D and K within respective intervals of $[0, 0.26]$ and $[1, 110]$ in order to examine how the marginal value of transmission capacity, μ^+, the price of C&T permits, ρ, the cap on emissions, z, total emissions in the system, and social welfare as defined in (4.19) vary in response to D and K.

Table 4.2: Data for numerical examples

Parameter	Value
A_E	200
A_W	150
B_E	1
B_W	1
C_E	80
C_W	20
R_E	1
R_W	1.8

According to Proposition 2, as the emission cap internalises the increasing damage from emissions, D, the incentive to increase the capacity of the line decreases in the case of FC and increases in all other coverage policies (Figure 4.2). Moreover, as indicated in Proposition 3(i), the incentive under PC is higher than that under FC due to the fact that production at node W is not directly curbed by the carbon policy. Under PC, the incentive to expand the line increases due to the tightening cap that induces a higher price at node E that, in turn, entices node-W

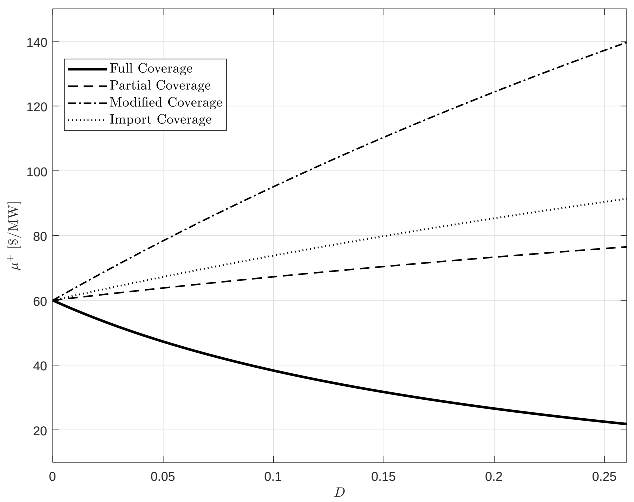


Figure 4.2: Impact of the damage cost parameter on the marginal value of transmission capacity

production. This incentive grows further under MC (see Proposition 3(ii)) as the cap is tightened by including damage from emissions from node W, thus, setting the cap by considering damage from both nodes while imposing the policy only over node E. This effect is alleviated under IC when we internalise only the damage from emissions associated with imports from node W (see Proposition 3(iii)) rather than all the emissions from node W.

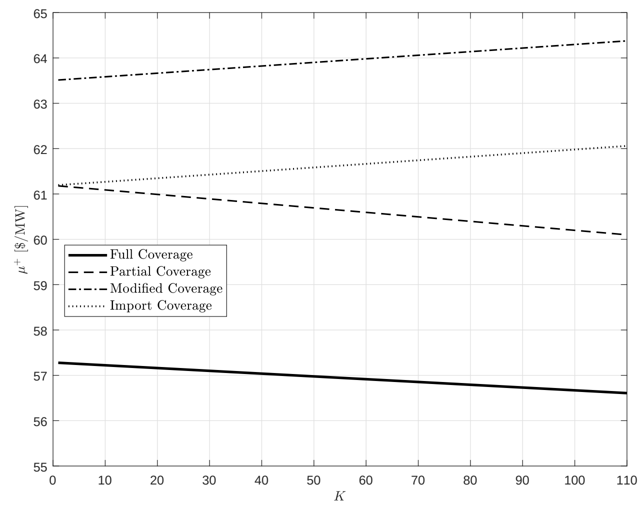


Figure 4.3: Impact of the transmission capacity on the marginal value of transmission capacity

In agreement with Proposition 2, the incentive to expand the line decreases with larger line capacity under FC and PC (Figure 4.3). Furthermore, as identified in Proposition 3(i), the incentive is higher under PC due to the exemption of node-W producers from the C&T. The incentive grows even further as a tighter cap is imposed on node E under MC. As shown in Proposition 2(iii), under MC and IC, a larger line actually increases the incentive to increase the line capacity further due to the higher nodal price difference.

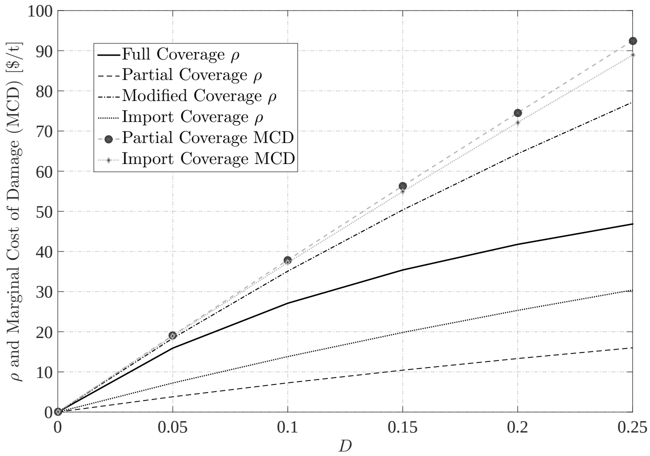


Figure 4.4: Impact of the damage cost parameter on the C&T price

As the damage cost parameter increases, so does the C&T price in the policy-maker's attempt of equalising it with the marginal cost of damage and in order to curb production while keeping in mind the indirect effect of doing so, i.e., higher electricity prices that could induce an increase in production (Figure 4.4). This effect occurs under all policies as indicated in Proposition 5; however, only under FC and MC is the policymaker able to equalise the permit price with the marginal cost of damage as these are the only two policies where total emissions in the system are taken into account by the policymaker. The C&T price is lower under PC compared to the one under FC due to the smaller size of the C&T. Under MC, however, due to a more stringent cap over the same market size (see Proposition 4(i)), the C&T price is higher than under PC and FC. The C&T price under IC drops to levels closer to the price under PC because of the less stringent cap compared to the one under MC (see Proposition 4(ii)).

According to Proposition 5(i), as the line increases, a higher C&T price is required to deter more-polluting imports from node W under FC (Figure 4.5). Not only is the C&T price lower under PC due to the smaller size of the C&T, but also the C&T price decreases with a larger line as more production is displaced from node E to node W (see Proposition 5(ii)). In fact, PC is the only policy in which the

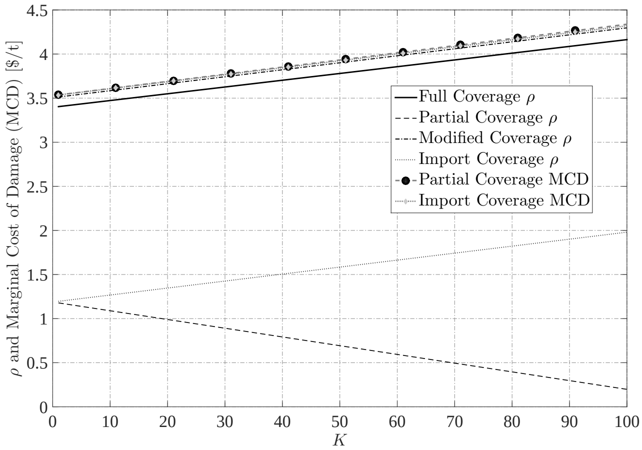


Figure 4.5: Impact of the transmission capacity on the C&T price

price of permits actually diverges from the marginal cost of damage as K increases. The C&T price is higher under MC compared to the one under FC as it imposes a tighter cap on a smaller size of C&T. In line with Proposition 5(i), the C&T price is increasing with a larger line as it tries to compensate for increased emissions at node W. IC presents a compromise between MC and PC as the C&T price is lower than under MC, but, in contrast with PC (see Proposition 5(i)), the C&T price is increasing with a larger line, thus, trying to curb emissions in the system.

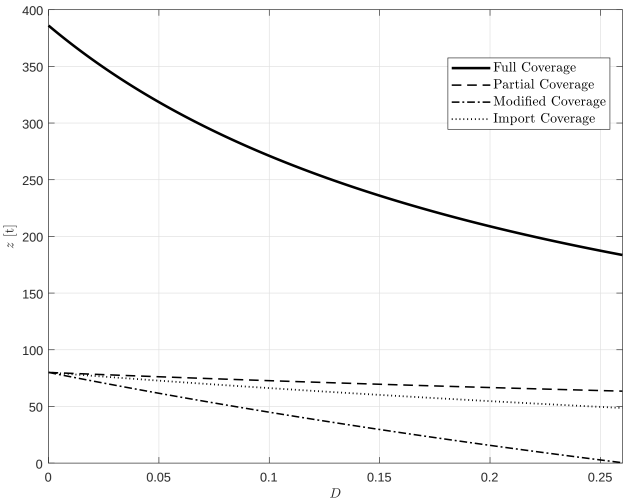


Figure 4.6: Impact of the damage cost parameter on the node-E cap (cap for both nodes under FC)

Figures 4.6 and 4.7 indicate the impact of the damage cost parameter and the transmission capacity on the optimal carbon policy, respectively. As seen in Propo-

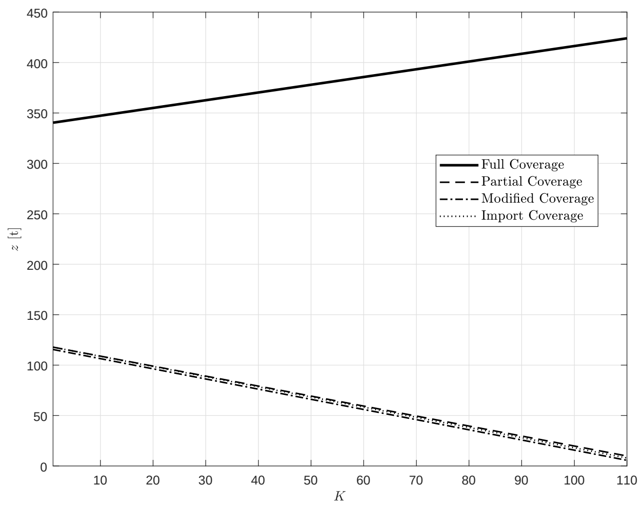


Figure 4.7: Impact of the transmission capacity on the node-E cap (cap for both nodes under FC)

sition 1, while the cap becomes tighter under all policies as the former increases, and only under FC does the cap loosen as the transmission capacity increases. Figures 4.8 and 4.9 illustrate the intuitive findings that total emissions decrease (increase) with the damage cost parameter (transmission capacity). As noted with reference to carbon leakage, IC is a compromise between PC and MC also in terms of total emissions. Likewise, Figures 4.10 and Table 4.3 present similar findings and insights with respect to the total social welfare in the region.

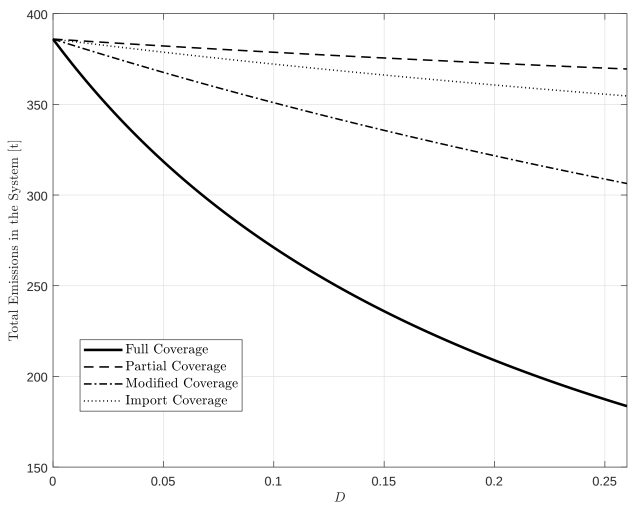


Figure 4.8: Impact of the damage cost parameter on total emissions

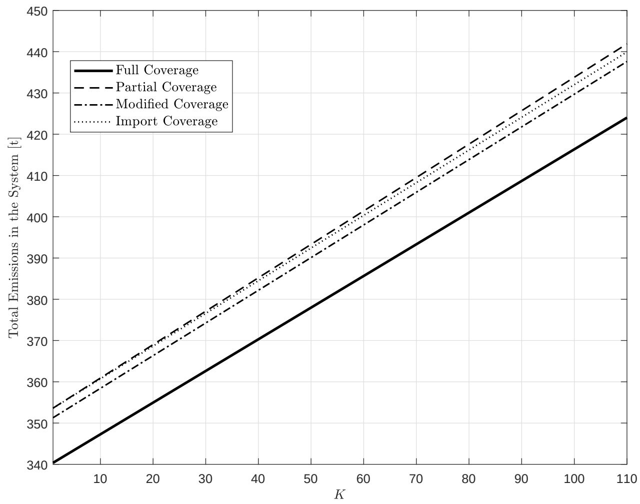


Figure 4.9: Impact of the transmission capacity on total emissions

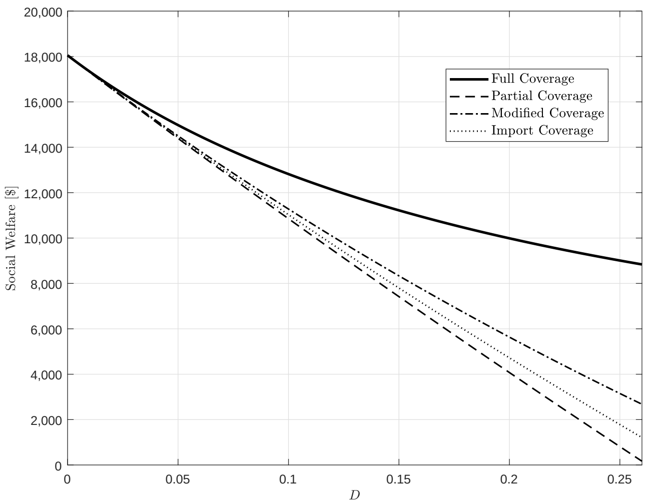


Figure 4.10: Impact of the damage cost parameter on social welfare

Table 4.3: Impact of transmission capacity K on social welfare [$] across policies

	K [MW]			
Policy	25	50	75	100
Full Coverage	16,479	17,905	19,327	20,746
Partial Coverage	16,453	17,876	19,294	20,709
Modified Coverage	16,457	17,881	19,301	20,717
Import Coverage	16,454	17,878	19,298	20,714

4.5 Conclusions

Awareness of potential carbon leakage has existed since the formation of unilateral carbon-reduction policies. The risk of carbon leakage will continue to exist until there is a uniform global carbon market. Several anti-leakage remedies have been proposed including free allocation of allowances for industries deemed at risk of carbon leakage, mandatory purchase of permits for emissions from imports from regions with less strict regulation, and border-carbon adjustments. Free allocation has been the EU's choice for leakage mitigation (EC, 2018b), although some *ex ante* studies have shown that it does not completely eliminate emission leakage (Allevi et al., 2017). Mandatory allowance purchase has been implemented in California, but studies have shown that the leakage mitigation could be overturned by contract shuffling in the uncapped region (Chen et al., 2011). Finally, despite proving effective at reducing emission leakage, border-carbon adjustments are legally and politically challenging to implement (Böhringer et al., 2017).

To contribute to the literature, we analyse the impact of several anti-leakage policies on carbon leakage via a bi-level model of a regional electricity market where a capped and an uncapped subregion are interconnected via a congested line. At the upper level, we have a policymaker setting an optimal cap over a subregion under its jurisdiction, whereas at the lower level, we have firms dispatched by an ISO competing in a perfectly competitive electricity market. The policymaker considers various anti-leakage policies differentiated by the emissions that the policymaker deems damaging for its constituents. The partial-coverage policy includes emissions from the capped subregion only, whereas modified coverage includes emissions from both the capped and uncapped regions. A middle ground is the import-coverage policy, which includes emissions from the capped region and emissions associated with the imports into the capped region. Partial coverage leads to the highest (lowest) total emissions (permit price) and results in the lowest social welfare. Modified coverage reverses these results leading to the most desirable environmental outcome; however, it exacerbates the potential for carbon leakage as the higher permit price in the regulated subregion poses a higher incentive for unregulated firms to export more to the regulated subregion. Hence, import coverage is a compromise between the partial- and modified-coverage policies as it lowers the potential for carbon leakage compared to modified coverage while keeping the total emissions (permit price) below (above) partial coverage.

Chapter 5

Conclusions

Global energy demand is projected to increase by 30% by 2040 relative to 2017 levels with electricity playing an important role as it gains a larger share in heating and transportation (IEA, 2017). Thus, monitoring, controlling, and reducing the environmental impact of electricity generation is increasingly important in order to ensure achievement of carbon-reduction targets. In fact, the electricity industry is subject to several policies aimed at carbon-emission reduction, e.g., minimum share of renewables in the final consumption/production, improvement of energy efficiency, and carbon pricing. While renewable investment is projected to surge as the capital costs of renewables and storage decrease (IRENA, 2017), a first-best economic solution for carbon pricing remains a challenge.

The Paris Agreement resulting from COP21 has been declared one of the biggest diplomatic successes bringing the vast majority of countries together against climate change. However, Cramton et al. (2017) argue that on top of common objectives, parties should engage in common action, a non-trivial task due to sometimes conflicting interests of the parties involved in international negotiations. While the provisions of the Paris Agreement facilitate linking climate policies of different jurisdictions, such coordination is complex and not immediate. Thus, carbon pricing remains regional with prices varying considerably between different regions (OECD, 2016). The fragmentation of carbon markets and disparity of carbon prices can lead to emission leakage, which could decrease the effectiveness of carbon-reduction targets.

Despite efforts to tackle climate change, alarming consequences indicate that more immediate action needs to be taken than can be achieved via international agreements. Therefore, understanding the environmental impact of electricity generation and preventing carbon leakage in the short term is of significant value. For this purpose, we provide an *ex ante* analysis of carbon leakage in South-East Europe spanning countries subject to the EU ETS and uncapped non-EU countries. Due to the importance of hydropower in South-East Europe and the presence of oligopolistic market structures of recently liberalised electricity markets, we estimate the magnitude of carbon leakage under different hydropower availability scenarios and examine the impact of market power only in the electricity and in both electricity and permit markets. Finally, we develop an analytical model in order to investigate a second-best anti-leakage measure in a regional electricity market where subregions with disparate climate policies are connected by a congested line.

5.1 Implications of the EU Emissions Trading System for the South-East Europe Regional Electricity Market

The contents of this Sections are published in Višković et al. (2017).

In the fight against climate change, a variety of policy instruments has been developed with the aim of reducing the GHG emissions. One of the most utilised instruments is the C&T scheme, e.g., EU ETS. In a C&T scheme, a cap on emissions in a certain area is imposed through the allocation of emission allowances to producers who can then trade these allowances among themselves. Achieving objectives under such schemes might be delayed due to their jurisdictional coverage. Specifically, a high price for emission allowances implies a high marginal abatement cost and a high power price when firms internalise emission cost even if the allowances are grandfathered. The higher power prices in the regulated region provide economic incentives for producers located in the neighbouring non-regulated areas to export to the regulated area, thereby causing carbon leakage. Carbon leakage has previously been examined in the context of the U.S. and New Zealand markets; however, to the best of our knowledge, a study of carbon leakage in the context of the SEE-REM has not been carried out yet.

We use SEE-REM, a simplified 22-node stylised network system, to study a hydro-abundant regional power market with inconsistent CO_2 policies. Our focus is on short-term estimates of carbon leakage, i.e., not considering the possibility of changes in capacity. Due to the fact that SEE-REM is relatively small compared to the entire EU ETS, the allowance prices, in addition to amount of hydropower, are treated exogenously to the model, thereby ignoring the interactions between hydropower availability and the allowance price. With those assumptions, we implicitly assume that any increase in emissions in the ETS part of SEE-REM will be offset elsewhere in the remaining EU ETS. Finally, we make an implicit assumption that the allowances are allocated through auction with prices equal to the permit prices obtained by the models,[26] as it is the case in the EU ETS, and that the price of allowances is equal to the assumed carbon price in our scenarios.

Through the examination of the EU ETS in SEE-REM taking into account different allowance prices and hydropower availability scenarios, we have three main findings. First, from reduction reversal we find that carbon leakage may be limited by demand response in the non-ETS area as a result of higher domestic electricity prices. Second, ETS emissions may be higher in the wet year than in the baseline year due to demand response in the ETS area as a result of lower electricity prices. Third, according to relative leakage, between 6.3% to 40.5% of the reduction achieved in the SEE-REM ETS area could be leaked to the SEE-REM non-ETS area. These findings indicate the possibility of undesirable outcomes resulting from the EU ETS on the periphery of the EU, i.e., emissions leaked into the non-ETS part of SEE-REM, which lead to higher electricity prices in that part. However, similar to the U.S. Clean Air Act IV SO_2 trading program, the initial design of the program partly reflects the intention of the government to ensure "buy-in" of the energy sector. Incomplete coverage of the EU ETS, while worrisome to economists, does pave a pathway that allows for a gradual expansion of the ETS in the future to enhance its efficacy.

The findings in this study are limited by the assumptions related to the considered model and data implementation. First, we model only residual demand and make an assumption that the producers are perfectly competitive, and, thus, we do not take into account the ownership structure. This means that any market power that producers might have is not reflected in the model. Second, we make an assumption that the consumers are represented by price-responsive demand with elasticity of -0.25 and face nodal prices, which, in some cases, leads to a decrease in carbon leakage. This means that when receiving a price signal at the relevant node, consumers will respond. In reality, electricity prices in Europe are frequently given by zonal, uniform, or tariff prices and are often fixed for a period of time, which means that consumers would not be able to react so quickly to the change in nodal prices. In addition, short-run demand might be more inelastic in reality, which means that demand response to higher electricity prices might be lower in reality. Thus, the decrease in leakage according to reduction reversal that occurs as a result of demand response in the model might be overestimated. On the other hand,

[26] Alternative allocation mechanisms impact carbon leakage differently. It has often been observed that, e.g., output-based allocation could effectively lower the marginal cost of production, thereby mitigating leakage (Bushnell and Chen, 2012; Burtraw et al., 2006).

since the decrease in leakage according to relative leakage depends mostly on the reduction in the ETS area, relative leakage is more robust *vis-à-vis* the elasticity assumption. Finally, the model does not include any dynamic power plant constraints, which might affect the resulting generation mix.

For future work, it would be interesting to examine carbon leakage in an imperfect competition setting. This could be carried out by including hydro and renewable power producers in the model in order to account for all market participants who might have market power. In order to account for hydro and renewable electricity generation, the model would have to include hydro scheduling (Bushnell, 2003) and stochastic scenarios for wind production (Maurovich-Horvat et al., 2015). Furthermore, we could include an additional constraint for zonal pricing and consider different values for elasticity. Finally, a capacity-investment model would be needed to provide insights about the long-term effects of a C&T policy on carbon leakage.

5.2 Economic and Environmental Consequences of Market Power in the South-East Europe Regional Electricity Market

The consequences of market power in electricity markets are well known and documented in the literature. However, electricity market outcomes can also be affected by market power exercised in C&T systems. Since there is an increasing number of regional C&T systems appearing as part of the global action against climate change, there is a growing need for understanding how electricity and C&T permit markets can interact when subject to market power in terms of consequences for carbon emissions and leakage.

For this purpose, we develop a bi-level model of SEE-REM as a regional electricity market comprising EU member states subject to the EU ETS and non-EU countries exempt from it. In order to examine the effects of market power in electricity and permit markets on market outcomes, we specify three market settings, viz., perfectly competitive electricity and C&T permit markets, imperfectly competitive electricity market where firms are price takers in the C&T permit market, and imperfectly competitive electricity and C&T permit markets. We find that under perfect competition, between 11%-39% of ETS emissions reduction can be leaked into the non-ETS part of SEE-REM. Despite higher non-ETS production and emissions enticed by higher electricity prices resulting from the exercise of market power in the electricity market, carbon leakage is lower as ETS emissions are curbed due to strategic withholding. The contrary is true when the leader's dominant technology becomes the marginal technology, which results in the expansion of its dirty production and worsens the environmental situation compared to perfect competition. The exercise of market power in both markets generally results in higher ETS emissions and carbon leakage compared to the case with market power only in the electricity market as it entices more fringe firms' production due to a lower abatement cost. However, when the leader's dominant technology becomes the marginal technology, the expansion of dirty production is limited by the effect that it might have on the C&T permit price, thus improving environmental outcomes at a cost of lower profits.

The findings in this study are subject to some overarching limitations. First, we conduct a short-term analysis without the possibility of investment or retrofitting. Second, we assume that renewable generation is operating at its maximum availability, whereas the quantity of renewables available could play an important role on the dispatch of some fossil-fuel-based technologies. Finally, the value chosen for point elasticity could either over- or under-estimate the leader's ability to exercise market power.

Going forward, since the leader affects outcomes in Italy where it owns capacity more than other ETS countries and, thus, indirectly non-ETS countries, it would be relevant to investigate how the effects of market power could spill over to the non-ETS directly through the Italy-Montenegro link currently under construction (ENTSO-E, 2016). In addition, our analysis shows that the leader has the incentive to lower the C&T permit price in order to decrease its marginal cost, whereas a higher C&T permit price offers more incentives for non-ETS firms to export to the ETS. These incentives would be in conflict if a leader owned capacity on both sides of the ETS border. Therefore, understanding the interaction of these conflicting incentives is pertinent to our analysis. Finally, in the spirit of Spiridonova (2016), it would be relevant to consider more firms with market power, which would constitute an equilibrium problem with equilibrium constraints.

5.3 Regional Carbon Policies in an Interconnected Power System: How Expanded Coverage Could Exacerbate Emission Leakage

Given the stipulations of the Paris Agreement, a variety of carbon policies implemented around the world will likely remain in effect in the foreseeable future. One concern is that polices with different stringencies might result in so-called carbon leakage, where pollution from emissions in a region with less stringent policy might increase in response to a more stringent policy implemented by the neighbouring region. Regional electricity markets are particularly susceptible to carbon leakage due to the dependency of regions with capped emissions on imports from uncapped regions, e.g., California EIM and PJM. Since carbon leakage can have a detrimental effect on emission-reduction targets, this calls for implementation of corrective measures for carbon leakage mitigation. Several measures such as carbon tariffs, free allowance allocation, and mandatory purchase of permits for emissions from goods imported from an unregulated area have been proposed, but each of these faces some limitations.

We develop an analytical bi-level model in which we use a C&T cap in a regional electricity market as a remedy for carbon leakage. Specifically, we consider a policymaker whose goal is to set an optimal emission cap for the node in its jurisdiction, which depends on imports from an unregulated node. Despite the limited reach of its jurisdiction, the policymaker is aware that damage from CO_2 emissions, regardless of its origin, affects regional welfare. This leads to the question: which emissions should the policymaker consider damaging when setting the cap, keeping in mind that it cannot force producers at the unregulated node to comply with the C&T?

For the purpose of answering this question, we propose three coverage policies, viz., partial-, modified-, and import-coverage, and compare these to the full-coverage policy representing the first-best solution. We find that the partial coverage, which is comparable to the conventional source-based regulation, leads to a shadow price on transmission capacity higher than full coverage due to the price differential driven by the price of permits at the regulated node. Consequently, unregulated producers are perversely incentivised to export to the regulated area, thereby resulting in a greater potential for carbon leakage. Somewhat surprisingly, the potential for carbon leakage is further exacerbated as the price differential widens when the cap is set considering damage from total emissions in the system as per modified coverage. A middle ground for mitigating carbon leakage is the import coverage; however, this welfare-decreasing policy leads to higher total CO_2 emissions compared to modified coverage. This is mainly because the policymaker implements a looser cap under import coverage compared to that under modified coverage as only emissions from imports to the regulated node are considered to be damaging. In conclusion, we find that the import-coverage policy, broadly consistent with the one used in California, is a potential way forward due to its lower potential for carbon leakage compared to the modified-coverage policy and broader scope compared to the partial-coverage policy.

Implementation of partial-, modified-, or import-coverage policies could be subject to critiques applied to carbon tariffs as they might be politically or legally challenging to implement. For example, the industry at the regulated node under the modified-coverage policy could be opposed to paying for the cost of emissions generated elsewhere. In addition, the policies analysed might face similar difficulties as the one implemented in California, viz., obtaining the emission rate of the unregulated region. For example, the EU estimates the carbon footprint of goods imported into the EU based on emission intensities of the EU's domestic production processes (Eurostat, 2018a).

In this study, carbon leakage is limited by the maximum capacity of the transmission line connecting the regulated and non-regulated subregions of the regional power market. However, carbon leakage can also be limited by the installed capacity in the non-regulated subregion. This aspect is beyond the scope of our analysis, but it would be relevant to include it in future research in order to understand the interaction between the transmission line and the non-regulated subregion generation capacity. Furthermore, since the analysis in this study suggests that carbon leakage could be exacerbated by a larger transmission line capacity under some policies, it would be pertinent to introduce multiple operational periods and uncertainty that would allow for a long-term analysis involving capacity investment in both generation and transmission (Conejo et al., 2016; Strand et al., 2014).

Appendix A

Appendix Chapter 2

The contents of this Appendix are published in Višković et al. (2017).

A.1 Nomenclature

Indices and Sets

$i, j \in \mathscr{I}$	Producers
$\ell \in \mathscr{L}$	Lines
$\ell^{AC} \in \mathscr{L}^{AC}$	AC lines, $\mathscr{L}^{AC} \subseteq \mathscr{L}$
$n, m \in \mathscr{N}$	Nodes
$n^{AC} \in \mathscr{N}^{AC}$	Nodes part of the AC network, $\mathscr{N}^{AC} \subseteq \mathscr{N}$
$n^{DC} \in \mathscr{N}^{DC}$	Nodes part of the DC network, $\mathscr{N}^{DC} \subseteq \mathscr{N}$, $\mathscr{N}^{AC} \cup \mathscr{N}^{DC} = \mathscr{N}$
$t \in \mathscr{T}$	Time blocks

Parameters

$A_{\ell,n}$	Network incidence matrix, 1 indicates a node where the line starts and -1 a node where the line finishes [–]
$C_{i,n}$	Marginal cost of production for producer i at node n [€/MWh]
$D^{int}_{t,n}$	Inverse demand intercept at node n for time block t [€/MWh]
$D^{slp}_{t,n}$	Inverse demand slope at node n for time block t [€/MW^{2}h]
$E_{i,n}$	Carbon intensity of production for producer i at node n [t/MWh]
$H_{\ell^{AC},n^{AC}}$	Element of the network transfer admittance matrix for the line $\ell^{AC} \in \mathscr{L}^{AC}$ that connects nodes $n^{AC} \in \mathscr{N}^{AC}$ [S]
K_ℓ	Capacity of line ℓ [MW]
N_t	Size of each time block [h]
R	Price of emissions allowances [€/t]
T_n	Binary parameter equals 1 if node n is in the ETS and 0 otherwise
$X^{MAX}_{i,n}$	Maximum production capacity for producer i at node n [MW]

Z	Carbon cap [t]

Dual Variables

$\gamma_{t,\ell^{AC}}$	Dual variable for flow constraint on line $\ell^{AC} \in \mathscr{L}^{AC}$ for time block t [€/MW]
$\theta_{t,i}$	Dual variable for energy–balance constraint for producer i for time block t [€/MW]
$\lambda_{t,i,n}$	Dual variable for generation capacity constraint for producer i at node n for time block t [€/MW]
$\mu^{-}_{t,\ell}$	Dual variable for line capacity constraint, lower bound on line ℓ for time block t [€/MW]
$\mu^{+}_{t,\ell}$	Dual variable for line capacity constraint, upper bound on line ℓ for time block t [€/MW]
$\tau_{t,n}$	Dual variable on electricity market–clearing conditions (wheeling fee) at node n for time block t [€/MWh]

Primal Variables

$d_{t,n^{AC}}$	Voltage angle at node $n^{AC} \in \mathscr{N}^{AC}$ for time block t [rad]
$f_{t,\ell}$	Flow on line ℓ for time block t [MW]
$s_{t,i,n}$	Power sold by producer i at node n for time block t [MW]
$x_{t,i,n}$	Power generated by producer i at node n for time block t [MW]

A.2 Demand Coefficients Calculation

If the inverse-demand function in its general form is given by (A.2-1), where $p(q)$ is the price in function of the quantity sold and q is the quantity, then a and b are the intercept and the slope of the inverse-demand function, respectively.

$$p(q) = a + bq \tag{A.2-1}$$

The intercept and the slope of the inverse-demand function can be calculated using reference price p^{ref}, reference quantity q^{ref}, and elasticity ε (Dietrich et al., 2005), as shown in (A.2-2) and (A.2-3), respectively. Considering the granularity of our data, i.e., monthly, if we use (A.2-2) and (A.2-3), then we would obtain only one representative hour per month that is based on the monthly average. However, because we want to distinguish between peak and off-peak hours, we use hourly load profile data to calculate the load curve (see Section 2.4.1.4) and then obtain the intercept and slope based on (A.2-4) and (A.2-5), respectively.

$$a = p^{ref} - bq^{ref} \tag{A.2-2}$$

$$b = \frac{p^{ref}}{q^{ref}} \frac{1}{\varepsilon} \tag{A.2-3}$$

$$a = p^{ref} - bq^{ref} loadcurve \tag{A.2-4}$$

$$b = \frac{p^{ref}}{q^{ref} loadcurve} \frac{1}{\varepsilon} \tag{A.2-5}$$

A.3 Data for SEE-REM

A.3.1 Line-Specific Data in Detail

Although NTCs are limits on commercial flows between two connecting areas rather than actual thermal limits of the lines, the calculation of the former is based on the latter (ENTSO, 2001). Thus, we use NTCs as an approximation due to the lack of data on actual thermal capacity limits. We distinguish between AC and DC lines, and because power flows on AC lines are subject to both Kirchhoff's laws, we model these flows using DC load-flow approximation. The DC load-flow approximation is obtained from network transfer and susceptance matrices (Schweppe et al., 1988), for which we require line reactance and resistance values (Glover et al., 1987) that depend on the physical characteristics of AC lines (Terna, 2011). Resistance and reactance values are displayed in Table A.3-1. In addition, we divide the nodes in the network into the ones connected by the AC and DC lines. DC lines do not follow the loop-flow law, and are, thus, not subject to Equation (2.10). This means that the model does not give solutions for voltage angles at nodes connected by a DC line. Consequently, flows on lines connecting a node in the DC part of the network and a node in the AC part of the network cannot be subject to Equation (2.10) either. Therefore, flows on these lines are treated like commercial flows. A similar approach was used by Bjørndal et al. (2014) to model a market consisting of nodal and zonal pricing areas.

Number of conductors	Voltage [kV]	Resistance [Ω/km]	Reactance [Ω/km]
1	< 380	0.059	0.236
3	≥ 380	0.019	0.078

Table A.3-1: Line resistance and reactance values (Glover et al. (1987) and own calculation)

A.3.2 Node-Specific Capacities in Detail

Since ENTSO-E does not define well the category "mixed fuels," which typically refers to units that can be fired by more than one type of fuel, we adjust the generating capacities in the ENTSO-E's mixed fuel category by using more detailed generation data (Eurostat, 2014) and utility companies' published information about generation capacities. In addition, because we model Italy by eleven nodes, we distribute capacities obtained from ENTSO-E (2013) across nodes based on information about capacities by regions (Terna, 2013a), which we then aggregate into zones as defined by the Italian Power Exchange (IPEX) (GME, 2015). The capacities that we obtain are in Table A.3-2.

Node	Gas	Coal	Oil	CCGT	Nuclear	Lignite	Mixed
n_1	1.55	1.27	1.98	16.89	0	0	3.51
n_2	0.57	0.11	1.12	1.48	0	0	0.39
n_3	1.14	1.49	2.75	2.93	0	0	0.15
n_4	0.61	0.03	0.15	5.28	0	0	1.14
n_5	0.13	0.89	0.55	0.43	0	0	0.09
n_6	0.83	0	1.24	1.41	0	0	0.23
n_7	0	0.12	0.61	0	0	0	0
n_8	0.01	0	0	0.30	0	0	0
n_9	0	2.64	0	0.99	0	0	0
n_{10}	0.65	0	0.65	0	0	0	0
n_{11}	0	0	0	0.36	0	0	0
n_{12}	0.08	0.22	0.15	0	0.69	0.58	0.36
n_{13}	0.42	0.32	0.49	0.19	0	0	0.37
n_{14}	0	0	0	0	0	1.57	0
n_{15}	0.31	0	0	0	0	5.28	0
n_{16}	0	0	0	0	0	0.22	0
n_{17}	0.03	0	0.19	0	0	0.72	0
n_{18}	2.72	0	0.70	2.19	0	4.46	0
n_{19}	0	0	0	0	0	0	0
n_{20}	2.99	0.28	0.41	1.72	1.89	0.75	0
n_{21}	0.80	1.71	0	0	2.00	4.20	0
n_{22}	2.38	1.18	0	0.86	1.30	5.12	0

Table A.3-2: Installed generation capacity mix per node [GW]

A.3.3 Nodal Demand in Detail

In order to obtain residual demand, we divide the residual monthly consumption by the number of hours in that month in order to obtain residual hourly demand. From this, we have one hour representing the average hourly residual demand per month. Because the standard frequency of reporting consumption data is monthly, we can only represent each month by the average hourly demand in that month by using consumption data. In order to distinguish between peak and off-peak hours, we use load profiles for which we can obtain hourly data. With the help of load profile data, we obtain the load curve for four blocks per month. We aggregate load data so that we obtain hourly load for the whole SEE–REM. Subsequently, we divide every month into four blocks corresponding to base, shoulder, peak, and super–peak loads (Paul et al., 2009) as defined in Table A.3-3.

Block	Interval
Base load	min {load} - 70^{th} percentile {load}
Shoulder load	70^{th} percentile {load} - 95^{th} percentile {load}
Peak load	95^{th} percentile {load} - 99^{th} percentile {load}
Super-peak load	99^{th} percentile {load} - max{load}

Table A.3-3: Intervals corresponding to four blocks

The load curve is given by the ratio of the block average load (over the number of hours in that block) and the monthly average load (over the number of hours in that month). Four load curves for each month are listed in Table A.3-4. Essentially, the load curve is a multiplier for the reference demand that adds variation to the average demand through inverse-demand function coefficients, $D^{int}_{t,n}$ and $D^{slp}_{t,n}$, (see Equations (A.2-4) and (A.2-5) in Appendix A.2). Since the number of hours in each block, N_t, varies based on the number of days in a month, in Table A.3-5, we show the number of hours in each of the blocks of 28-day, 30-day, and 31-day months. Demand across Italy is distributed using regional consumption data (Terna, 2013a).

Block	Base load	Shoulder load	Peak load	Super-peak load
Jan	0.9	1.2	1.24	1.27
Feb	0.92	1.17	1.21	1.23
Jun	0.91	1.17	1.31	1.35
Dec	0.90	1.21	1.30	1.34

Table A.3-4: Load curve for block per month

A.3.4 Electricity Prices

The data for Italy, Slovenia, and Greece are available from IPEX's Website where Slovenia and Greece are virtual zones. Data for Hungary are available from the Hungarian Power Exchange (HUPX), and data for Romania are on the Romanian electricity and gas market operator's (OPCOM) Website. Although there are some other countries in SEE-REM that have day-ahead markets, since these markets did

	Number of days in month		
Blocks	31	28	30
Base load	520	470	504
Shoulder load	186	168	180
Peak load	30	27	28
Super-peak load	8	7	8

Table A.3-5: Number of hours per block

Fuel	Cost [€/MWh]	Emission Intensity [t/MWh]
Lignite	21.0	0.826
Coal	22.0	0.746
Nuclear	10.0	0.000
Oil	50.0	0.930
Natural Gas - steam turbine	47.3	0.435
CCGT	35.7	0.363
Mixed fuels	48.0	0.800

Table A.3-6: Marginal cost of production per fuel and emission intensity

not exist in 2013, e.g., Bulgaria launched its Independent Energy Exchange only in 2015 (Reuters, 2015), we exclude them from our analysis.

Electricity prices derived from the inverse-demand function (in the baseline scenario) correspond to generation quantities associated with residual demand. Therefore, these prices are not directly comparable to actual market electricity prices that correspond to total demand under the assumed value of elasticity. Thus, for the purpose of more direct comparison, we adjust the actual prices by rearranging Equation (A.3-1) in order to preserve the assumed elasticity. Here, ε stands for elasticity, p for price of electricity, and q for generated quantity. Furthermore, δq represents the difference between the total and residual quantity, and δp is the difference between prices corresponding to those two quantities.

$$\varepsilon = \frac{\delta q}{\delta p}\frac{p}{q} \tag{A.3-1}$$

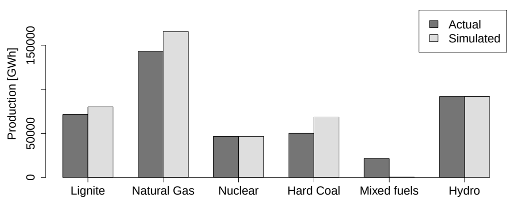
Appendix B

Appendix Chapter 3

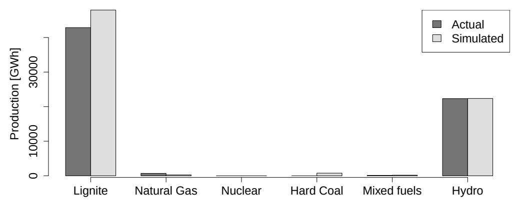
B.1 Calibration

For the purpose of calibration, we compare the simulated results under perfect competition at a permit price of €0/t with actual quantities from 2013. Generally, we are able to capture the main characteristics of the modelled system in terms of generation mix and emissions for ETS and non-ETS areas as well as electricity prices. In relation to the annual production in ETS (Figure B.1-1a), production from some fuel sources is overestimated (lignite, natural gas, and hard coal by 12.25%, 15.67%, and 37.05%, respectively), whereas there is hardly any production from mixed fuels and fuel oil (mixed fuels and fuel oil rarely seem to be viable options in our modelling framework). Overall production in ETS is overestimated by 6.76%. In the non-ETS area (Figure B.1-1b), we have an overproduction from lignite of 11.84% and overall overproduction of 8.33% compared to actual quantities. Consequently, production in the entire SEE-REM is overestimated by 6.98%. This overproduction could be explained by limitations of our model concerning technical constraints such as ramping, start-up costs, etc.

We calibrate average annual prices using the assumption of perfect competition



(a) Production in the ETS area



(b) Production in the non-ETS area

Figure B.1-1: Annual production per technology in the ETS and non-ETS area of SEE-REM Sources: Eurostat (2014) and ENTSO-E (2013) and Cournot oligopoly (CO) where all actual firms considered in Section 3.4 are Cournot oligopolists (Figure B.1-2). As expected, the actual prices are bounded by the perfect competition setting and Cournot oligopoly setting apart from the price at node IT6. A possible explanation for this is a relatively large installed capacity of mixed fuels and fuel oil at node IT6 that could determine the actual price at that node; however, because our model almost never generates power from these sources, simulated prices remain relatively low.

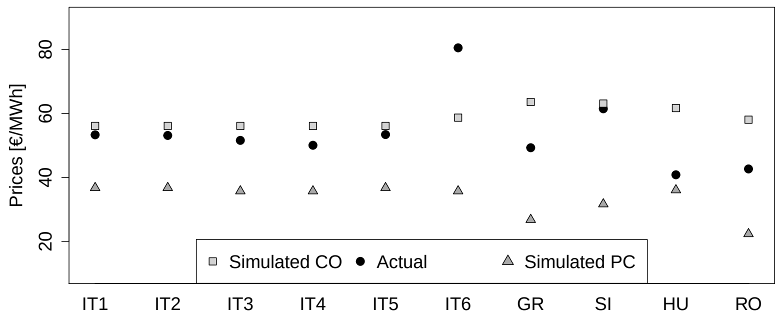


Figure B.1-2: Average annual prices Sources: Countries' power exchanges

Under perfect competition, annual emissions for 2013 (Figure B.1-3) are overestimated in both ETS and non-ETS areas by 3.49% and 14.29%, respectively. Because the non-ETS area of SEE-REM is relatively small, overall SEE-REM emissions are overestimated by 5.31%, which we deem to be reasonable for the purpose of our analysis.

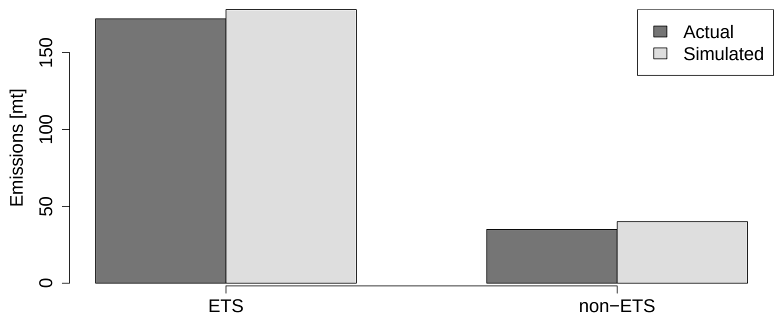


Figure B.1-3: Annual emissions in SEE-REM Source: Own calculation based on Eurostat (2014) and EU (2012)

B.2 Additional Results

Table B.2-1: Change in production [GWh] from PC-B0 in Italy in S-B0

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	-	7,486	181	-	7,667
of which Enel	*-*	*- 4,722*	*- 62*	*-*	*- 4,784*
of which fringe firms	*-*	*12,209*	*243*	*-*	*12,452*
South	- 855	- 7,434	-	-	- 8,290
of which Enel	*- 855*	*-*	*-*	*-*	*- 855*
of which fringe firms	*-*	*- 7,434*	*-*	*-*	*- 7,434*
Sardinia	- 64	- 11	7	-	- 68
of which Enel	*- 64*	*-*	*-*	*-*	*- 64*
of which fringe firms	*-*	*- 11*	*7*	*-*	*- 4*
Sicily	-	- 602	-	- 1	- 603
of which Enel	*-*	*558*	*-*	*- 1*	*557*
of which fringe firms	*-*	*- 1,161*	*-*	*-*	*- 1,161*
Total	- 919	- 561	188	- 1	- 1,293
of which Enel	*- 919*	*- 4,164*	*- 62*	*- 1*	*- 5,146*
of which fringe firms	*-*	*3,603*	*250*	*-*	*3,853*

Table B.2-2: Change in production [GWh] from PC-B10 in Italy in S-T-B10

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	-	4,855	41	-	4,896
of which Enel	*-*	*2,334*	*- 19*	*-*	*2,315*
of which fringe firms	*-*	*2,521*	*60*	*-*	*2,581*
South	- 764	- 4,244	-	-	- 5,009
of which Enel	*- 764*	*-*	*-*	*-*	*- 764*
of which fringe firms	*-*	*- 4,244*	*-*	*-*	*- 4,244*
Sardinia	- 158	- 179	-	-	- 337
of which Enel	*- 158*	*-*	*-*	*-*	*- 158*
of which fringe firms	*0*	*- 179*	*-*	*-*	*- 179*
Sicily	-	- 258	-	-	- 258
of which Enel	*-*	*- 1,443*	*-*	*-*	*- 1,443*
of which fringe firms	*-*	*1,185*	*-*	*-*	*1,185*
Total	- 923	174	41	-	- 708
of which Enel	*- 923*	*891*	*- 19*	*-*	*- 51*
of which fringe firms	*-*	*- 717*	*60*	*-*	*- 657*

Table B.2-3: Change in production [GWh] from PC-B10 in Italy in S-B10

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	-1	-4,565	228	-	-4,338
of which Enel	*- 1*	*- 1,558*	*57*	-	*- 1,502*
of which fringe firms	-	*- 3,008*	*171*	-	*- 2,837*
South	-3,334	9,494	-	-	6,160
of which Enel	*- 3,334*	-	-	-	*- 3,334*
of which fringe firms	-	*9,494*	-	-	*9,494*
Sardinia	-223	-1,134	4	-	-1,353
of which Enel	*- 223*	-	-	-	*- 223*
of which fringe firms	-	*- 1,134*	*4*	-	*- 1,130*
Sicily	-	-1,034	-	-	-1,034
of which Enel	-	*- 751*	-	-	*- 751*
of which fringe firms	-	*- 284*	-	-	*- 284*
Total	-3,558	2,760	232	-	-566
of which Enel	*- 3,558*	*- 2,308*	*57*	-	*- 5,809*
of which fringe firms	-	*5,068*	*175*	-	*5,243*

Table B.2-4: Change in production [GWh] from PC-B20 in Italy in S-T-B20

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	-	9,505	-	-	9,505
of which Enel	-	*4,437*	-	-	*4,437*
of which fringe firms	-	*5,068*	-	-	*5,068*
South	-898	-7,233	-	-	-8,131
of which Enel	*- 898*	-	-	-	*- 898*
of which fringe firms	-	*- 7,233*	-	-	*- 7,233*
Sardinia	-302	-1,488	-	-	-1,790
of which Enel	*- 302*	-	-	-	*- 302*
of which fringe firms	-	*- 1,488*	-	-	*- 1,488*
Sicily	-	-448	-	-1	-450
of which Enel	-	*- 787*	-	*- 1*	*- 788*
of which fringe firms	-	*339*	-	-	*339*
Total	-1,200	336	-	-1	-865
of which Enel	*- 1,200*	*3,650*	-	*- 1*	*2,449*
of which fringe firms	-	*- 3,314*	-	-	*- 3,314*

Table B.2-5: Change in production [GWh] from PC-B20 in Italy in S-B20

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	-223	-491	27	-	-687
of which Enel	*- 223*	*5,007*	*14*	-	*4,798*
of which fringe firms	-	*- 5,498*	*13*	-	*- 5,485*
South	-3,206	5,427	-	-	2,222
of which Enel	*- 3,206*	-	-	-	*- 3,206*
of which fringe firms	-	*5,427*	-	-	*5,427*
Sardinia	-505	-1,271	-	-	-1,776
of which Enel	*- 505*	-	-	-	*- 505*
of which fringe firms	-	*- 1,271*	-	-	*- 1,271*
Sicily	-	-483	-	-	-483
of which Enel	-	*- 1,884*	-	-	*- 1,884*
of which fringe firms	-	*1,401*	-	-	*1,401*
Total	-3,934	3,182	27	-	-724
of which Enel	*- 3,934*	*3,123*	*14*	-	*- 797*
of which fringe firms	-	*59*	*13*	-	*73*

Table B.2-6: Change in production [GWh] from PC-B30 in Italy in S-T-B30

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	- 139	- 3,798	-	- 4	- 3,940
of which Enel	*- 139*	*6,799*	-	*- 4*	*6,656*
of which fringe firms	-	*- 10,597*	-	-	*- 10,597*
South	- 2,825	11,102	-	- 3	8,275
of which Enel	*- 2,825*	-	-	*- 3*	*- 2,827*
of which fringe firms	-	*11,102*	-	-	*11,102*
Sardinia	- 524	294	-	-	- 230
of which Enel	*- 524*	-	-	-	*- 524*
of which fringe firms	-	*294*	-	-	*294*
Sicily	-	- 1,675	-	- 1	- 1,676
of which Enel	-	*- 611*	-	*- 1*	*- 612*
of which fringe firms	-	*- 1,064*	-	-	*- 1,064*
Total	- 3,487	5,924	-	- 8	2,429
of which Enel	*- 3,487*	*6,188*	-	*- 8*	*2,693*
of which fringe firms	-	*- 264*	-	-	*- 264*

Table B.2-7: Change in production [GWh] from PC-B30 in Italy in S-B30

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	-97	-3,913	-	-	-4,009
of which Enel	*- 97*	*4,222*	-	-	*4,125*
of which fringe firms	-	*- 8,134*	-	-	*- 8,134*
South	-2,559	3,981	-	-	1,422
of which Enel	*- 2,559*	-	-	-	*- 2,559*
of which fringe firms	-	*3,981*	-	-	*3,981*
Sardinia	-468	-568	-	-1	-1,037
of which Enel	*- 468*	-	-	*- 1*	*- 470*
of which fringe firms	-	*- 568*	-	-	*- 568*
Sicily	-	-964	-	-	-964
of which Enel	-	*- 1,524*	-	-	*- 1,524*
of which fringe firms	-	*560*	-	-	*560*
Total	-3,124	-1,464	-	-1	-4,589
of which Enel	*- 3,124*	*2,698*	-	*- 1*	*- 427*
of which fringe firms	-	*- 4,162*	-	-	*- 4,162*

Table B.2-8: Change in production [GWh] from PC-B40 in Italy in S-T-B40

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	2,917	335	-	-	3,252
of which Enel	*261*	*3,213*	-	-	*3,473*
of which fringe firms	*2,656*	*- 2,878*	-	-	*- 221*
South	5,549	- 11,029	-	-	- 5,480
of which Enel	*5,197*	-	-	-	*5,197*
of which fringe firms	*352*	*- 11,029*	-	-	*- 10,677*
Sardinia	992	- 776	-	-	216
of which Enel	*- 804*	-	-	-	*- 804*
of which fringe firms	*1,796*	*- 776*	-	-	*1,020*
Sicily	-	- 1,048	-	-	- 1,048
of which Enel	-	*- 678*	-	-	*- 678*
of which fringe firms	-	*- 370*	-	-	*- 370*
Total	9,459	- 12,518	-	-	- 3,060
of which Enel	*4,654*	*2,534*	-	-	*7,189*
of which fringe firms	*4,804*	*- 15,053*	-	-	*- 10,249*

Table B.2-9: Change in production [GWh] from PC-B40 in Italy in S-B40

	Coal	Natural Gas	Other Fossil Fuels	Hydro	Total
North	-1,009	-7,958	-	-	-8,967
of which Enel	*- 660*	*5,559*	-	-	*4,900*
of which fringe firms	*- 349*	*- 13,517*	-	-	*- 13,866*
South	2,696	3,874	-	-	6,569
of which Enel	*4,920*	-	-	-	*4,920*
of which fringe firms	*- 2,224*	*3,874*	-	-	*1,650*
Sardinia	-1,473	-623	-5	-5	-2,106
of which Enel	*- 1,395*	-	*- 5*	*- 5*	*- 1,406*
of which fringe firms	*- 77*	*- 623*	-	-	*- 700*
Sicily	-	732	-	-	732
of which Enel	-	*- 98*	-	-	*- 98*
of which fringe firms	-	*829*	-	-	*829*
Total	214	-3,975	-5	-5	-3,772
of which Enel	*2,865*	*5,462*	*- 5*	*- 5*	*8,316*
of which fringe firms	*- 2,651*	*- 9,437*	-	-	*- 12,087*

Table B.2-10: Production per fuel type [GWh] in SEE-REM in B0

	Coal	Natural Gas	Lignite	Other Fossil Fuels	Nuclear	Hydro	Total
PC-B0							
ETS excl. Italy	*8,560*	*11,909*	*80,108*	*146*	*46,421*	*38,991*	*186,136*
ETS	68,619	165,577	80,108	395	46,421	91,768	452,888
Non-ETS	759	251	47,947	173	-	22,369	71,499
Total	69,378	165,828	128,056	568	46,421	114,136	524,387
S-B0 (change from PC-B0)							
ETS excl. Italy	*- 110*	*- 395*	*- 28*	*- 12*	-	-	*- 546*
ETS	- 1,029	- 957	- 28	176	-	- 1	- 1,839
Non-ETS	- 1	- 15	116	- 2	-	-	98
Total	- 1,031	- 972	88	174	-	- 1	- 1,741

Table B.2-11: Production per fuel type [GWh] in SEE-REM in B10

	Coal	Natural Gas	Lignite	Other Fossil Fuels	Nuclear	Hydro	Total
PC-B10							
ETS excl. Italy	*6,307*	*11,201*	*63,826*	*50*	*46,421*	*38,991*	*166,796*
ETS	66,366	158,999	63,826	91	46,421	91,768	427,470
Non-ETS	1,604	237	55,552	126	-	22,369	79,888
Total	67,970	159,236	119,378	218	46,421	114,136	507,358
S-T-B10 (change from PC-B10)							
ETS excl. Italy	*- 109*	*- 322*	*- 734*	*- 10*	-	-	*- 1,175*
ETS	- 1,032	- 148	- 734	30	-	-	- 1,883
Non-ETS	- 45	- 7	540	19	-	-	508
Total	- 1,077	- 154	- 194	49	-	-	- 1,376
S-B10 (change from PC-B10)							
ETS excl. Italy	*4,050*	*619*	*- 3,262*	*- 1*	-	-	*1,405*
ETS	492	3,379	- 3,262	231	-	-	839
Non-ETS	0	60	512	- 45	-	-	526
Total	492	3,439	- 2,751	185	-	-	1,365

Table B.2-12: Production per fuel type [GWh] in SEE-REM in B20

	Coal	Natural Gas	Lignite	Other Fossil Fuels	Nuclear	Hydro	Total
PC-B20							
ETS excl. Italy	*19,938*	*11,369*	*33,324*	*3*	*46,421*	*38,991*	*150,048*
ETS	79,998	151,618	33,324	3	46,421	91,768	403,132
Non-ETS	1,604	229	56,371	53	-	22,369	80,625
Total	81,602	151,847	89,695	56	46,421	114,136	483,757
S-T-B20 (change from PC-B20)							
ETS excl. Italy	*84*	*- 423*	*- 169*	*- 1*	-	-	*- 509*
ETS	- 1,116	- 87	- 169	- 1	-	- 1	- 1,374
Non-ETS	-	- 2	-	21	-	-	20
Total	- 1,116	- 89	- 169	20	-	- 1	- 1,355
S-B20 (change from PC-B20)							
ETS excl. Italy	*1,396*	*509*	*- 323*	-	-	-	*1,582*
ETS	- 2,538	3,691	- 323	27	-	-	857
Non-ETS	-	18	3	22	-	-	42
Total	- 2,538	3,709	- 320	48	-	-	900

Table B.2-13: Production per fuel type [GWh] in SEE-REM in B30

	Coal	Natural Gas	Lignite	Other Fossil Fuels	Nuclear	Hydro	Total
PC-B30							
ETS excl. Italy	*14,716*	*15,861*	*16,561*	-	*46,421*	*38,991*	*132,550*
ETS	74,775	151,539	16,561	-	46,421	91,768	381,063
Non-ETS	1,604	346	56,211	31	-	22,369	80,561
Total	76,379	151,885	72,772	31	46,421	114,136	461,624
S-T-B30 (change from PC-B30)							
ETS excl. Italy	*- 171*	*5,737*	*- 10,442*	-	-	-	*- 4,876*
ETS	- 3,658	11,661	- 10,442	-	-	- 8	- 2,448
Non-ETS	-	64	4	69	-	-	137
Total	- 3,658	11,725	- 10,438	69	-	- 8	- 2,310
S-B30 (change from PC-B30)							
ETS excl. Italy	*121*	*- 765*	*2,845*	-	-	-	*2,202*
ETS	- 3,002	- 2,228	2,845	-	-	- 1	- 2,387
Non-ETS	-	49	4	41	-	-	95
Total	- 3,002	- 2,179	2,850	41	-	- 1	- 2,291

Table B.2-14: Production per fuel type [GWh] in SEE-REM in B40

	Coal	Natural Gas	Lignite	Other Fossil Fuels	Nuclear	Hydro	Total
PC-B40							
ETS excl. Italy	*7,432*	*27,111*	*3,732*	-	*46,421*	*38,991*	*123,687*
ETS	50,906	180,802	3,732	-	46,421	91,768	373,629
Non-ETS	1,604	1,399	56,176	137	-	22,369	81,685
Total	52,510	182,201	59,908	137	46,421	114,136	455,313
S-T-B40 (change from PC-B40)							
ETS excl. Italy	*2,611*	*- 2,721*	*276*	-	-	-	*165*
ETS	12,069	- 15,239	276	-	-	-	- 2,895
Non-ETS	-	14	0	-	-	-	14
Total	12,069	- 15,225	276	-	-	-	- 2,880
S-B40 (change from PC-B40)							
ETS excl. Italy	*185*	*974*	*239*	-	-	-	*1,397*
ETS	399	- 3,001	239	-	-	- 5	- 2,369
Non-ETS	-	-	-	-	-	-	-
Total	399	- 3,001	239	-	-	- 5	- 2,369

Table B.2-15: Consumption [GWh], net imports/exports [GWh], and emissions [kt] change from the respective PC scenario in Italy in perfect competition

Region \ Scenario	S-B0	S-T-B10	S-T-B20	S-T-B30	S-T-B40	S-B10	S-B20	S-B30	S-B40
Consumption									
North	- 1,128	- 911	- 803	- 1,244	- 1,517	- 377	- 312	- 1,231	- 1,294
South	- 284	- 251	- 195	- 550	- 743	- 518	- 336	- 577	- 521
Sardinia	- 71	- 96	- 149	- 268	- 305	- 32	- 173	- 208	- 268
Sicily	- 75	- 49	- 38	- 68	- 91	- 66	- 44	- 71	- 64
Total	- 1,557	- 1,308	- 1,185	- 2,129	- 2,655	- 993	- 864	- 2,087	- 2,147
Imports/Exports									
North	- 8,795	- 5,807	- 10,308	2,697	- 4,770	3,961	376	2,778	7,672
South	8,006	4,757	7,936	- 8,825	4,737	- 6,678	- 2,557	- 1,999	- 7,091
Sardinia	- 3	241	1,640	- 38	-521	1,321	1,603	830	1,833
Sicily	529	209	412	1,608	958	968	439	893	- 796
Total	- 264	- 600	- 319	- 4,558	405	- 427	- 139	2,502	1,619
Emissions									
North	2,875	1,797	3,451	- 1,478	2,298	- 1,450	- 318	- 1,489	- 3,640
South	- 3,335	- 2,110	- 3,295	1,923	136	959	- 419	- 462	3,417
Sardinia	- 45	- 183	- 765	- 284	459	- 574	- 838	- 555	- 1,325
Sicily	- 219	- 93	- 163	- 608	- 381	- 375	- 175	- 350	266
Total	- 724	- 590	- 772	- 447	2,512	- 1,440	- 1,750	- 2,856	- 1,282

Table B.2-16: Consumption [GWh], net imports/exports [GWh], and emissions [kt] in SEE-REM in perfect competition

Area \ Scenario	PC-B0	PC-B10	PC-B20	PC-B30	PC-B40
Consumption					
Italy	274,171	268,281	260,868	253,322	250,631
ETS excl. Italy	185,986	176,626	163,722	151,977	149,051
ETS	460,157	444,906	424,590	405,299	399,682
Non-ETS	64,230	62,452	59,167	56,325	55,631
Total	524,387	507,358	483,757	461,624	455,313
Import/Export					
Italy	7,419	7,607	7,783.56	4,808.85	690
ETS excl. Italy	-150	9,829	13,674	19,427	25,364
ETS	7,269	17,436	21,458	24,236	26,054
Non-ETS	-7,269	- 17,436	- 21,458	- 24,236	- 26,054
Emissions					
Italy	100,814	98,500	95,722	94,057	88,223
ETS excl. Italy	77,005	61,537	46,533	30,416	18,469
ETS	177,819	160,037	142,255	124,473	106,692
Non-ETS	40,441	47,303	47,907	47,806	48,334
Total	218,260	207,340	190,163	172,280	155,026

Table B.2-17: SEE-REM consumption [GWh], net imports/exports [GWh], and emissions [kt] change in Stackelberg scenarios from the respective perfect competition scenarios

Area \ Scenario	S-B0	S-T-B10	S-T-B20	S-T-B30	S-T-B40	S-B10	S-B20	S-B30	S-B40
Consumption									
Italy	- 1,557	- 1,308	- 1,185	- 2,129	- 2,655	- 993	- 864	- 2,087	- 2,147
ETS excl. Italy	- 186	- 63	- 157	- 156	- 187	2,185	1,835	- 145	- 165
ETS	- 1,743	- 1,370	- 1,341	- 2,286	- 2,843	1,192	971	- 2,232	- 2,313
Non-ETS	1	- 6	- 13	- 25	- 38	173	- 72	- 59	- 56
Total	- 1,741	- 1,376	- 1,355	- 2,310	- 2,880	1,365	899	- 2,291	- 2,369
Import/Export									
Italy	- 264	- 600	- 319	- 4,558	405	- 427	- 139	2,502	1,619
ETS excl. Italy	360	1,113	352	4,720	- 353	780	253	- 2,347	- 1,563
ETS	96	513	33	162	52	353	114	155	56
Non-ETS	- 96	- 513	- 33	- 162	- 52	- 353	- 114	- 155	- 56
Emissions									
Italy	- 724	- 590	- 772	- 447	2,512	- 1,440	- 1,750	- 2,856	- 1,282
ETS excl. Italy	- 265	- 814	- 231	- 6,670	1,188	550	959	2,164	689
ETS	- 989	- 1,404	- 1,003	- 7,117	3,700	- 890	- 791	- 692	- 593
Non-ETS	86	428	19	96	6	406	30	64	0
Total	-902	-976	-984	-7,021	3,706	-484	-761	-628	0

Table B.2-18: Social welfare decomposition [k€]

	PC-B0	PC-B10	PB-B20	PC-B30	PC-B40
Consumer Surplus	34,060,674.71	32,162,419.90	29,740,503.33	27,513,602.39	26,827,551.91
Producer Surplus	6,057,451.93	6,531,211.25	7,291,906.66	7,942,116.07	8,143,983.74
Grid Owner's Revenue	337,281.15	320,509.63	273,508.40	266,945.76	281,362.59
C&T Permit Revenue		1,382,226.23	2,848,368.29	3,951,966.29	3,816,382.50
Social Welfare	40,455,407.79	40,396,367.01	40,154,286.68	39,674,630.51	39,069,280.74
Change from PC	-	S-T-B10	S-T-B20	S-T-B30	S-T-B40
Consumer Surplus	-	- 201,450.25	- 224,431.43	- 371,669.51	- 440,007.55
Producer Surplus	-	174,878.54	188,044.29	331,664.23	414,761.45
Grid Owner's Revenue	-	8,226.29	17,667.18	16,179.93	6,891.34
C&T Permit Revenue	-	- 11,630.40	- 20,502.78	- 225,893.08	132,319.18
Social Welfare	-	- 29,975.82	- 39,222.74	- 249,718.43	113,964.42
Change from PC	S-B0	S-B10	S-B20	S-B30	S-B40
Consumer Surplus	- 248,029.42	73,012.37	- 23,632.63	- 367,983.29	- 374,590.70
Producer Surplus	216,198.99	221,847.30	300,403.90	336,639.89	343,381.27
Grid Owner's Revenue	8,058.52	- 24,285.63	- 9,648.18	8,547.39	13,459.91
C&T Permit Revenue	-	- 340,487.94	- 328,634.78	- 21,967.33	- 21,219.23
Social Welfare	- 23,771.91	- 69,913.90	- 61,511.69	- 44,763.34	- 38,968.75

B.3 Nomenclature and Mathematical Formulation

B.3.1 Nomenclature

Indices and Sets:

Γ:	Upper-level decision variables
Ξ:	Lower-level primal decision variables
Ψ:	Lower-level dual variables
$i \in \mathscr{I}$	Firms
$j \in \mathscr{I}^F$	Follower firms price-takers $\mathscr{I}^{\mathscr{F}} \subseteq \mathscr{I}$
$s \in \mathscr{I}^S$	Strategic producer index, $\mathscr{I}^{\mathscr{S}} \cap \mathscr{I}^{\mathscr{F}} = \emptyset$, $\mathscr{I}^{\mathscr{S}} \cup \mathscr{I}^{\mathscr{F}} = \mathscr{I}$
$u \in \mathscr{U}_{n,i}$	Generating units of firm i located at node n
$\ell \in \mathscr{L}$	Lines
$\ell^{AC} \in \mathscr{L}^{\mathscr{AC}}$	AC lines, $\mathscr{L}^{\mathscr{AC}} \subseteq \mathscr{L}$
$n \in \mathscr{N}$	Nodes
$n^{AC} \in \mathscr{N}^{AC}$	Nodes part of the AC network, $\mathscr{N}^{AC} \subseteq \mathscr{N}$
$n^{DC} \in \mathscr{N}^{DC}$	Nodes part of the DC network, $\mathscr{N}^{DC} \cup \mathscr{N}^{AC} = \mathscr{N}$
$n \in \mathscr{N}^{ETS}$	Nodes in the ETS area, $\mathscr{N}^{ETS} \in \mathscr{N}$
$t \in \mathscr{T}$	Time blocks

Parameters:

$A_{\ell,n}$	Network incidence matrix, 1 indicates a node where the line starts and -1 a node where the line finishes [-]
$C_{n,i,u}$	Marginal cost of production of generation unit u owned by firm i at node n [€/MWh]
$D^{int}_{t,n}$	Inverse demand intercept at node n in time block t [€/MWh]
$D^{slp}_{t,n}$	Inverse demand slope at node n in time block t [€/MW^{2}h]
$E_{n,i,u}$	Carbon intensity of production of generating unit u owned by firm i at node n [t/MWh]
$H_{\ell^{AC},n^{AC}}$	Network transfer admittance matrix for nodes $n^{AC} \in \mathscr{N}^{AC}$ and lines $\ell^{AC} \in \mathscr{L}^{AC}$ [S]
$K_{t,\ell}$	Capacity of line ℓ in time block t [MW]
N_t	Number of hours in time block t [h]
R	Carbon tax [€/t]
$S_{n^{AC}}$	Indicates the swing bus, 1 if swing, 0 otherwise at node $n^{AC} \in \mathscr{N}^{AC}$ [-]
$X_{n,i,u}$	Maximum production capacity of generation unit u owned by firm i at node n [MW]

Z Carbon cap [t]

$M, \overline{M}, \widetilde{M}, \hat{M}, \check{M}, \underline{M}$ Large constants used in disjunctive constraints

Primal Variables:

$d_{t,n}$ Demand at node n in time block t [MW]

$f_{t,\ell}$ Flow on line ℓ in time block t [MW]

$v_{t,n^{AC}}$ Voltage angle at node $n^{AC} \in \mathscr{N}^{AC}$ in time block t [rad]

$x_{t,n,i,u}$ Quantity produced by generating unit u owned by firm i at node n in time block t [MW]

Dual Variables:

$\beta_{t,n,i,u}$ Maximum generation capacity constraint of generating unit u owned by firm i at node n in time block t [€/MW]

$\gamma_{t,\ell^{AC}}$ Definition of AC flow on line $\ell^{AC} \in \mathscr{L}^{AC}$ in time block t [€/MW]

δ_t Hub price in time block t [€/MWh]

$\eta_{t,n^{AC}}$ Swing bus constraint at node $n^{AC} \in \mathscr{N}^{AC}$ in time block t [-]

$\lambda_{t,n}$ Energy mass-balance constraint at node n in time block t [€/MWh]

$\mu^-_{t,\ell}$ Maximum capacity constraint in negative direction on line ℓ in time block t [€/MW]

$\mu^+_{t,\ell}$ Maximum capacity constraint in positive direction on line ℓ in time block t [€/MW]

ρ Price of CO_2 allowances [€/t]

Binary Variables:

$r_{t,n}$ Auxiliary variable used to handle the KKT condition with respect to demand at node n in time period t and $d_{t,n}$

$\overline{r}_{t,n,j,u}$ Auxiliary variable used to handle the KKT condition with respect to non-strategic producer j's generation from unit u located at node n in time period t and $x_{t,n,j,u}$

$\tilde{r}_{t,n,j,u}$ Auxiliary variable used to handle complementarity condition between generation constraint of non-strategic producer j's unit u located at node n in time period t and the shadow price of generation capacity $\beta_{t,n,j,u}$

$\hat{r}_{t,\ell}$ Auxiliary variable used to handle complementarity condition between transmission line ℓ's capacity constraint in time period t and shadow price in positive direction $\mu^+_{t,\ell}$

$\check{r}_{t,\ell}$ Auxiliary variable used to handle complementarity condition between

	transmission line ℓ's capacity constraint in time period t and the shadow price in negative direction $\mu_{t,\ell}^{-}$
$\underline{r}$	Auxiliary variable used to handle complementarity condition between the emissions constraint and price of CO_2 allowances ρ

B.3.2 KKT Conditions of the Lower-Level Problem

$$0 \le x_{t,n,j,u} \perp N_t\Big(-\lambda_{t,n} + C_{n,j,u} + \rho E_{n,j,u} + \beta_{t,n,j,u}\Big) \ge 0 \;\forall t, j, u \in \mathscr{U}_{n,j}, n \in \mathscr{N}^{ETS} \tag{B.3-1a}$$

$$0 \le x_{t,n,j,u} \perp N_t\Big(-\lambda_{t,n} + C_{n,j,u} + \beta_{t,n,j,u}\Big) \ge 0 \;\forall t, j, u \in \mathscr{U}_{n,j}, n \in \mathscr{N} \setminus \mathscr{N}^{ETS} \tag{B.3-1b}$$

$$0 \le d_{t,n} \perp N_t\Big(-D^{int}_{t,n} + D^{slp}_{t,n} d_{t,n} + \lambda_{t,n}\Big) \ge 0 \;\forall t, n \tag{B.3-2}$$

$$N_t\Big(\sum_{n^{AC}\in\mathscr{N}^{AC}} (\delta_t - \lambda_{t,n^{AC}}) A_{\ell^{AC},n^{AC}} - \gamma_{t,\ell^{AC}} + \mu^-_{t,\ell^{AC}} - \mu^+_{t,\ell^{AC}}\Big) = 0 \;(f_{t,\ell^{AC}}\, free) \quad \forall t, \ell^{AC} \in \mathscr{L}^{AC} \tag{B.3-3a}$$

$$N_t\Big(\sum_n (\delta_t - \lambda_{t,n}) A_{\ell,n} + \mu^-_{t,\ell} - \mu^+_{t,\ell}\Big) = 0 \;(f_{t,\ell}\, free) \quad \forall t, \ell \in \mathscr{L} \setminus \mathscr{L}^{AC} \tag{B.3-3b}$$

$$N_t\Big(\sum_{\ell^{AC}\in\mathscr{L}^{AC}} H_{\ell^{AC},n^{AC}} \gamma_{t,\ell^{AC}} - S_{n^{AC}} \eta_{t,n^{AC}}\Big) = 0 \;(v_{t,n^{AC}}\, free) \;\forall t, n^{AC} \in \mathscr{N}^{AC} \tag{B.3-4}$$

$$0 \le \beta_{t,n,j,u} \perp N_t(X_{n,j,u} - x_{t,n,j,u}) \ge 0 \;\forall t, n, j, u \tag{B.3-5}$$

$$N_t\Big(f_{t,\ell^{AC}} - \sum_{n^{AC}\in\mathscr{N}^{AC}} H_{\ell^{AC},n^{AC}} v_{t,n^{AC}}\Big) = 0 \;(\gamma_{t,\ell^{AC}}\, free) \;\forall t, \ell^{AC} \in \mathscr{L}^{AC} \tag{B.3-6}$$

$$0 \le \mu^-_{t,\ell} \perp N_t(f_{t,\ell} + K_{t,\ell}) \ge 0 \;\forall t, \ell \tag{B.3-7}$$

$$0 \le \mu^+_{t,\ell} \perp N_t(-f_{t,\ell} + K_{t,\ell}) \ge 0 \;\forall t, \ell \tag{B.3-8}$$

$$N_t\Big(S_{n^{AC}} v_{t,n^{AC}}\Big) = 0 \;(\eta_{t,n^{AC}}\, free) \;\forall t, n^{AC} \in \mathscr{N}^{AC} \tag{B.3-9}$$

$$-N_t \sum_n \sum_\ell A_{\ell,n} f_{t,\ell} = 0 \;(\delta_t\, free) \;\forall t \tag{B.3-10}$$

$$N_t\Big(d_{t,n} - \sum_i \sum_u x_{t,n,i,u} + \sum_\ell A_{\ell,n} f_{t,\ell}\Big) = 0 \;(\lambda_{t,n}\, free) \;\forall t, n \tag{B.3-11}$$

$$0 \le \rho \perp Z - \sum_t \sum_{n\in\mathscr{N}^{ETS}} \sum_i \sum_u N_t E_{n,i,u} x_{t,n,i,u} \ge 0 \tag{B.3-12}$$

B.3.3 MIQP Reformulation

The MPEC in Section 3.3.4 has two types of non-convexities. First, the complementarity conditions arising from the constraints can be circumvented by disjunctive constraints (B.3-14) - (B.3-25) (Fortuny-Amat and McCarl, 1981). Second, the bilinear terms in the leader's objective function can be removed by using strong duality from the lower level. In particular, we find the dual problem of the lower level (Dorn, 1960) and verify that strong duality holds (Huppmann and Egerer, 2015). We then use strong duality to express the bilinear terms in the leader's objective function in terms of lower-level primal and dual variables in (B.3-13), thereby rendering the objective function quadratic.

$$\max_{\Phi} \sum_t N_t \Big(\sum_n D^{int}_{t,n} d_{t,n} - \sum_n D^{slp}_{t,n} d^2_{t,n} - \sum_{\ell} (\mu^-_{t,\ell} + \mu^+_{t,\ell}) K_{t,\ell} - \sum_n \sum_i \sum_u C_{n,i,u} x_{t,n,i,u} - \sum_n \sum_j \sum_u \beta_{t,n,j,u} X_{n,j,u} \Big) - \rho Z \tag{B.3-13}$$

s.t. (B.3-3a), (B.3-3b), (B.3-4), (B.3-6), (B.3-9), (B.3-10), (B.3-11)

$$0 \le N_t(-D^{int}_{t,n} + D^{slp}_{t,n} d_{t,n} + \lambda_{t,n}) \le M r_{t,n} \ \forall t,n \tag{B.3-14}$$

$$0 \le d_{t,n} \le M(1 - r_{t,n}) \ \forall t,n \tag{B.3-15}$$

$$0 \le N_t \Big(-\lambda_{t,n} + C_{n,j,u} + \rho E_{n,j,u} + \beta_{t,n,j,u} \Big) \le \overline{M} \overline{r}_{t,n,j,u} \quad \forall t,j,u \in \mathscr{U}_{n,j}, n \in \mathscr{N}^{ETS} \tag{B.3-16a}$$

$$0 \le N_t \Big(-\lambda_{t,n} + C_{n,j,u} + \beta_{t,n,j,u} \Big) \le \overline{M} \overline{r}_{t,n,j,u} \quad \forall t,j,u \in \mathscr{U}_{n,j}, n \in \mathscr{N} \setminus \mathscr{N}^{ETS} \tag{B.3-16b}$$

$$0 \le x_{t,n,j,u} \le \overline{M}(1 - \overline{r}_{t,n,j,u}) \forall t,n,j,u \in \mathscr{U}_{n,j} \tag{B.3-17}$$

$$0 \le N_t(-f_{t,\ell} + K_{t,\ell}) \le \hat{M} \hat{r}_{t,\ell} \tag{B.3-18}$$

$$0 \le \mu^+_{t,\ell} \le \hat{M}(1 - \hat{r}_{t,\ell}) \tag{B.3-19}$$

$$0 \le N_t(f_{t,\ell} + K_{t,\ell}) \le \check{M} \check{r}_{t,\ell} \tag{B.3-20}$$

$$0 \le \mu^-_{t,\ell} \le \check{M}(1-\check{r}_{t,\ell}) \tag{B.3-21}$$

$$0 \le N_t(X_{n,j,u} - x_{t,n,j,u}) \le \widetilde{M}\tilde{r}_{t,n,j,u} \forall t,n,j,u \in \mathscr{U}_{n,j} \tag{B.3-22}$$

$$0 \le \beta_{t,n,j,u} \le \widetilde{M}(1-\tilde{r}_{t,n,j,u}) \forall t,n,j,u \in \mathscr{U}_{n,j} \tag{B.3-23}$$

$$0 \le Z - \sum_t \sum_{n \in \mathscr{N}^{ETS}} \sum_i \sum_u N_t E_{n,i,u} x_{t,n,i,u} \le \underline{Mr} \tag{B.3-24}$$

$$0 \le \rho \le \underline{M}(1-\underline{r}) \tag{B.3-25}$$

$\underline{r} \in \{0,1\}$; $r_{t,n} \in \{0,1\}$, $\forall t,n$; $\tilde{r}_{t,n,j,u}, \overline{r}_{t,n,j,u} \in \{0,1\}$, $\forall t,n,j,u \in \mathscr{U}_{n,j}$; $\hat{r}_{t,\ell}, \check{r}_{t,\ell} \in \{0,1\}$, $\forall t,\ell$

Where we define:

$\Phi = \{d_{t,n}, x_{t,n,i,u}, f_{t,\ell}, v_{t,n^{AC}}, \lambda_{t,n}, \delta_t, \mu^+_{t,\ell}, \mu^-_{t,\ell}, \beta_{t,n,j,u}, \gamma_{t,\ell^{AC}}, \eta_{t,n^{AC}}, \rho, \underline{r}, r_{t,n}, \overline{r}_{t,n,j,u}, \hat{r}_{t,\ell}, \check{r}_{t,\ell}, \tilde{r}_{t,n,j,u}\}$.

Appendix C

Proofs of Propositions for Chapter 4

Proof of Proposition 1(i)

The result follows from partial differentiation of (4.22) with respect to either K or D:

$$\frac{\partial z^*}{\partial K} = \frac{(R_W - R_E) B_E B_W}{B_E B_W + D\left(R_W^2 B_E + R_E^2 B_W\right)} > 0$$

$$\frac{\partial z^*}{\partial D} = -\frac{\left(R_W^2 B_E + R_E^2 B_W\right)\left[B_E R_W \left(A_W - C_W + B_W K\right) + B_W R_E \left(A_E - C_E - B_E K\right)\right]}{\left[B_E B_W + D\left(R_W^2 B_E + R_E^2 B_W\right)\right]^2} < 0$$

$\square$

Proofs of Proposition 1(ii)

The result follows from partial differentiation of (4.36) with respect to either K or D:

$$\frac{\partial \hat{z}}{\partial K} = -\frac{B_E R_E}{B_E + D R_E^2} < 0$$

$$\frac{\partial \hat{z}}{\partial D} = -R_E^2 \frac{R_E \left(A_E - C_E - B_E K\right)}{\left(B_E + D R_E^2\right)^2} < 0$$

$\square$

The result follows from partial differentiation of (4.44) with respect to either K or D:

$$\frac{\partial \tilde{z}}{\partial K} = -\frac{R_E \left(B_E + D R_W R_E\right)}{B_E + D R_E^2} < 0$$

$$\frac{\partial \tilde{z}}{\partial D} = -R_E^2 \frac{\left[B_W R_E \left(A_E - C_E - B_E K\right) + B_E R_W \left(A_W - C_W + B_W K\right)\right]}{B_W \left(B_E + D R_E^2\right)^2} < 0$$

$\square$

The result follows from partial differentiation of (4.52) with respect to either

K or D:

$$\frac{\partial \underline{z}}{\partial K} = -\frac{R_E(B_E + DR_E R_W)}{B_E + DR_E^2} < 0$$
$$\frac{\partial \underline{z}}{\partial D} = -R_E^2 \frac{R_E\left(A_E - C_E - B_E K\right) + B_E R_W K}{\left(B_E + DR_E^2\right)^2} < 0$$

$\square$

Proof of Proposition 2(i)

The result follows from partial differentiation of (4.26) with respect to either K or D evaluated at z^*:

$$\frac{\partial \mu^{*,+}(z^*)}{\partial K} = -\frac{D\left(R_W - R_E\right)^2 B_E B_W}{B_E B_W + D\left(R_W^2 B_E + R_E^2 B_W\right)} < 0$$
$$\frac{\partial \mu^{*,+}(z^*)}{\partial D} = -\frac{\left(R_W - R_E\right) B_E B_W \left[B_E R_W\left(A_W - C_W + B_W K\right) + B_W R_E\left(A_E - C_E - B_E K\right)\right]}{\left[B_E B_W + D\left(R_W^2 B_E + R_E^2 B_W\right)\right]^2} < 0$$

$\square$

Proof of Proposition 2(ii)

The result follows from partial differentiation of (4.40) with respect to either K or D evaluated at $\hat{z}$:

$$\frac{\partial \hat{\mu}^{+}(\hat{z})}{\partial K} = -\frac{B_E DR_E^2}{B_E + DR_E^2} < 0$$
$$\frac{\partial \hat{\mu}^{+}(\hat{z})}{\partial D} = \frac{B_E R_E^2\left(A_E - C_E - B_E K\right)}{\left(B_E + DR_E^2\right)^2} > 0$$

$\square$

Proofs of Proposition 2(iii)

The result follows from partial differentiation of (4.48) with respect to either K or D evaluated at $\tilde{z}$:

$$\frac{\partial \hat{\mu}^{+}(\tilde{z})}{\partial K} = \frac{B_E DR_E\left(R_W - R_E\right)}{B_E + DR_E^2} > 0$$
$$\frac{\partial \hat{\mu}^{+}(\tilde{z})}{\partial D} = B_E R_E \frac{\left[B_W R_E\left(A_E - C_E - B_E K\right) + B_E R_W\left(A_W - C_W + B_W K\right)\right]}{B_W\left(B_E + DR_E^2\right)^2} > 0$$

$\square$

The result follows from partial differentiation of (4.56) with respect to either

K or D evaluated at $\underline{z}$:

$$\frac{\partial\hat{\mu}^{+}(\underline{z})}{\partial K} = \frac{DR_E B_E\left[R_W - R_E\right]}{B_E + DR_E^2} > 0$$
$$\frac{\partial\hat{\mu}^{+}(\underline{z})}{\partial D} = \frac{R_E B_E\left[R_E(A_E - B_E K - C_E) + B_E R_W K\right]}{\left(B_E + DR_E^2\right)^2} > 0$$

□

Proof of Proposition 3(i)

We compare (4.40) with (4.26):

$$\begin{aligned}
&\hat{\mu}^{+}(\hat{z}) > \mu^{*,+}(z^{*}) \\
&\quad\Rightarrow \frac{DR_E^2\left(A_E - C_E - B_E K\right)}{B_E + DR_E^2} \\
&\qquad > -\frac{D\left(R_W - R_E\right)\left[B_E R_W\left(A_W - C_W + B_W K\right) + B_W R_E\left(A_E - C_E - B_E K\right)\right]}{B_E B_W + D\left(R_W^2 B_E + R_E^2 B_W\right)}
\end{aligned}$$

Since the left-hand side is always positive and the right-hand side is always negative, the result follows. □

Proof of Proposition 3(ii)

We compare (4.48) with (4.40):

$$\begin{aligned}
&\hat{\mu}^{+}(\tilde{z}) > \hat{\mu}^{+}(\hat{z}) \\
&\quad\Rightarrow \frac{DR_E^2\left(A_E - C_E - B_E K\right)}{B_E + DR_E^2} + \frac{DR_E R_W B_E\left(A_W - C_W + B_W K\right)}{B_W\left(B_E + DR_E^2\right)} \\
&\qquad > \frac{DR_E^2\left(A_E - C_E - B_E K\right)}{B_E + DR_E^2}
\end{aligned}$$

Since the left-hand side is greater than the right-hand side, the result follows. □

Proofs of Proposition 3(iii)

We first compare (4.56) with (4.48):

$$\begin{aligned}
&\hat{\mu}^{+}(\underline{z}) < \hat{\mu}^{+}(\tilde{z}) \\
&\quad\Rightarrow 0 < A_W - C_W
\end{aligned}$$

Since the right-hand side is positive by assumption, the result follows. Next, we compare (4.56) with (4.40):

$$\begin{aligned}\hat{\mu}^{+}(\underline{z}) &> \hat{\mu}^{+}(\hat{z}) \\ &\Rightarrow DR_E R_W B_E K > 0\end{aligned}$$

Again, the result follows because K is assumed to be positive. □

Proof of Proposition 4(i)

The result follows by comparing (4.44) with (4.36) and (4.49) with (4.41), respectively. □

Proof of Proposition 4(ii)

The results follow by comparing either (4.52) with (4.44) and (4.57) with (4.49) or (4.52) with (4.36) and (4.57) with (4.41). □

Proofs of Proposition 5(i)

The result follows from partial differentiation of (4.23) with respect to either K or D evaluated at z^*:

$$\begin{aligned}\frac{\partial \rho^*(z^*)}{\partial K} &= \frac{D(R_W - R_E) B_E B_W}{B_E B_W + D\left(R_W^2 B_E + R_E^2 B_W\right)} > 0 \\ \frac{\partial \rho^*(z^*)}{\partial D} &= \frac{B_E B_W \left[B_E R_W (A_W - C_W + B_W K) + B_W R_E (A_E - C_E - B_E K)\right]}{\left[B_E B_W + D\left(R_W^2 B_E + R_E^2 B_W\right)\right]^2} > 0\end{aligned}$$

□

The result follows from partial differentiation of (4.45) with respect to either K or D evaluated at $\tilde{z}$:

$$\begin{aligned}\frac{\partial \hat{\rho}(\tilde{z})}{\partial K} &= \frac{DB_E (R_W - R_E)}{B_E + DR_E^2} > 0 \\ \frac{\partial \hat{\rho}(\tilde{z})}{\partial D} &= B_E \frac{\left[B_W R_E (A_E - C_E - B_E K) + B_E R_W (A_W - C_W + B_W K)\right]}{B_W \left(B_E + DR_E^2\right)^2} > 0\end{aligned}$$

□

The result follows from partial differentiation of (4.53) with respect to either K or D evaluated at $\underline{z}$:

$$\frac{\partial \hat{\rho}(\underline{z})}{\partial K} = \frac{D(R_W - R_E) B_E}{B_E + DR_E^2} > 0$$

$$\frac{\partial\hat{\rho}(\underline{z})}{\partial D} = \frac{B_E\left[R_E(A_E - C_E) + (R_W - R_E)B_E K\right]}{\left(B_E + DR_E^2\right)^2} > 0$$

□

Proof of Proposition 5(ii)

The result follows from partial differentiation of (4.37) with respect to either K or D evaluated at $\hat{z}$:

$$\frac{\partial\hat{\rho}(\hat{z})}{\partial K} = -\frac{DR_E B_E}{B_E + DR_E^2} < 0$$
$$\frac{\partial\hat{\rho}(\hat{z})}{\partial D} = \frac{B_E R_E\left(A_E - C_E - B_E K\right)}{\left(B_E + DR_E^2\right)^2} > 0$$

□

Appendix D

DC Load-Flow Calculation

In a three-node network, let $\ell = 1,2,3$ indicate the lines and $n = 1,2,3$ the nodes where $L = N = 3$. Then, rc and rs are column vectors of dimension L, whose elements are line reactance and resistance, respectively. A is the incidence matrix with dimensions $(L \times N)$ and its elements indicate the node where the line begins and ends, i.e., 1 is the beginning of the line and -1 is the end.

$$rc = \begin{bmatrix} 1 \\ 1 \\ 1 \end{bmatrix}$$

$$rs = \begin{bmatrix} 0.1 \\ 0.1 \\ 0.1 \end{bmatrix}$$

$$A = \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ 1 & 0 & -1 \end{bmatrix}$$

Let then H be the network transfer matrix with dimensions $(L \times N)$, whose elements are given by

$$H_{\ell,n} = \frac{rc_\ell}{rc_\ell^2 + rs_\ell^2} A_{\ell,n} \tag{D.1-1}$$

The network transfer matrix is then equal to

$$H = \begin{bmatrix} 0.99 & -0.99 & 0 \\ 0 & 0.99 & -0.99 \\ 0.99 & 0 & -0.99 \end{bmatrix}$$

From the network transfer matrix and voltage angles, v_n, we derive the flow on line ℓ, f_ℓ, whereas from the product of f_ℓ and the incidence matrix, we derive the import at node n.

$$f_\ell = \sum_n H_{\ell,n} v_n$$

$$import_n = \sum_\ell A_{\ell,n} f_\ell$$

For example, if

$$v = \begin{bmatrix} 0 \\ -3.030 \\ 3.030 \end{bmatrix}$$

Then,

$$f = \begin{bmatrix} 3 \\ -6 \\ -3 \end{bmatrix}$$

and

$$import = \begin{bmatrix} 0 \\ -9 \\ -9 \end{bmatrix}$$

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