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Carbon policies: do they deliver in the long run?

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Abstract

Carbon taxation and emission trading are policy instruments for achieving significant CO_2 emission reduction by inducing a shift in technology and fuel choice. Simulations with a quantitative agent-based model of a competitive electricity generation sector show that under both policies CO_2 emissions increase for 10-15 years due to the long life cycle of power plants. Dramatic reductions materialize after 20-40 years when a tight cap or sufficient tax level is maintained. When taxes are set equivalent to trading prices, taxation induces earlier investment in CO_2 abatement, a better balance between capital and operating costs and lower long-run electricity prices.

1 Introduction

Currently, electric power production is largely based on the combustion of fossil fuels, predominantly coal and natural gas, except in countries with abundant hydropower. This inevitably leads to the emission of CO_2, as carbon capture and storage and renewable energy sources are not feasible or available yet on a large-scale.[1] Global climate change can be considered a 'Tragedy of the Commons' for which no effective global coordination, regulation or enforcement has been developed yet (1968). This has not happened for a variety of reasons. First, CO_2 is a global, not a regional pollutant such as SO_2 or NO_x, which implies that the regulation of local emissions needs to be coordinated worldwide. Second, fossil fuels have become the lifeblood of industrialized economies: reducing or replacing their consumption is difficult and costly. While the cost of abatement is high, doing nothing will eventually be much more expensive (cf. Stern (2006), and the growing consensus that CO_2 emissions need to be stabilized and then reduced in the course of this century has led to much interest in achieving cost-efficient emission reduction through incentive-based instruments, rather than command-and-control regulation.

Incentive-based policy instruments such as the European emission trading system (ETS) and carbon taxation (CT) use market signals to influence decision-making and behavior (Egenhofer 2003). A market in which emission rights can be traded is expected to yield an economically optimal distribution of emissions among polluters. It remains to be seen, however, whether it creates sufficient investment incentives for electricity producers, because the price of emission rights is volatile and the time horizon of the ETS is limited. A carbon tax represents a more stable price signal but it is difficult if not impossible to establish *ex ante* which tax level would be required to achieve the desired emission reduction.

In this chapter, we will compare these two policy instruments, addressing the following question:

[1] See the chapter by Lackner *et. al* in this volume for a detailed discussion of carbon capture and sequestration.

> What are the effects of taxes and emission trading upon CO_2 emissions, electricity prices and the technology portfolio for electricity generation and CO_2 abatement?

We address this question by developing and using an agent-based model of a competitive electricity production sector in which non-coordinated decisions are made within a common framework of an electricity market with either no carbon policy, with and ETS or with a CT.

In this chapter, first the technology and policy options for CO_2 emission reduction are summarized and the impact of both instruments explored. Second, these insights are translated into an agent-based model. Its structure and approach are described, the scenarios and assumptions that are used for comparing the policy instruments are given and the agents' behavior and technology options are introduced. Third, the simulation results are presented and interpreted for a large variety of exogenous conditions. Finally the conclusions are summarized.

2 Options for CO_2 emission reduction

While the European CO_2 emission trading scheme (ETS) is the largest in the world, similar systems have been established in at least six states in the US and several large companies have implemented internal trading schemes. Carbon taxes have been implemented in Scandinavia. Table 1 presents an overview of the main types of carbon policy.

Table 1: Characterization of carbon policies

policy instrument		*price*	*volume of emissions*	*allocation of emission rights*	*implemented in practice*
carbon taxation		set by government	not limited	can shift between sectors	yes
emission trading	cap-and-trade	market-based	capped[2]	grandfathering/ auction[3]	yes
	Performance-standard-rate	market-based	not limited	benchmarking & performance	no
command-and-control		no price	regulated per source	by government, per source	only for other pollutants

"Economic theory tells us that if cost and benefit functions are known with certainty, then a price based policy (such as a tax) and a quantitative policy (such as tradable permits) are equivalent from an efficiency point of view" (Hovi and Holtsmark 2006: 141). However, one of the key issues in climate policy is that cost and benefit functions are uncertain. Weitzman (1974) argued that given uncertainty, the slope of the supply and demand functions should determine the choice. Grubb and Newberry (2007) summarize this argument and apply it to CO_2 policy. They conclude that in principle taxes are superior, but observe practical obstacles such as political acceptability. An advantage of a tax is that it creates less investment risk than emission trading because there is

[2] In the ETS, the total amount of rights granted is capped to reach a certain emission target. This cap has been divided between Member States. As of January 2008, inter Member States trade is possible. Member States also can increase the volume of rights via the Clean Development Mechanism.

[3] An alternative strategy is to ration carbon allowances per capita. The chapter by Meyer *et al.* in this volume discusses this alternative.

no market and thus no price volatility. A risk to investors is, however, that the tax level may be reduced during the economic life of the investments.

In Europe, electricity generation accounts for one third of CO_2 emissions (Cozijnsen 2005; Cozijnsen and Weijer 2005). The success of an emission trading scheme therefore depends for a significant part on the reduction of emissions from the power sector. Will these materialize via operational adjustment or investment? Let us briefly analyze carbon policies and their effects. Three types of effects of incentive-based carbon policy instruments can be discerned.

The first effect is that the pricing of CO_2 leads to higher energy prices, which in turn leads to a reduction of demand and supply substitution. In the short term, the price-elasticity of electricity demand is notoriously low, but in the long term higher prices will cause consumers and industry to invest in less energy-intensive equipment. "We need only look back to the oil price shocks of the 1970s to see how well the price mechanism works. Higher fossil fuel prices dampen total energy consumption" (Manne and Richels 1993). The lower energy-intensity of the European economies as compared to North American economies provides evidence of the impact of structurally higher end-user prices, which are largely due to higher taxes.[4] However, given the fundamental importance of electricity in our society, the potential for demand reduction alone is limited, compared to the CO_2 emission reduction needed.

The second effect of carbon policies is that CO_2-intensive electricity production becomes less attractive. Higher fossil fuel prices also make fossil fuels less attractive relative to other supply-side alternatives. Hence, carbon taxes create incentives to switch away from carbon-intensive fuels. However, at the level of an individual power plant the options for fuel switching are limited, because the technical designs differ too much to make a switch from coal to, for instance, natural gas in an existing installation economically attractive. A single option that is economically feasible is to co-fire biomass in a coal-fired power plant, to a maximum of 15% fuel input. At the sector level, fuel switching takes place through changes in the merit order: plants switching from base load operation to peak load operation and vice versa. With any merit order change, the fuel diet of the sector changes.

The third effect of carbon policies is to induce investment in CO_2 abatement. Investment options are retrofitting existing installations or extending them with carbon capture and sequestration (CCS), or investing in new, more efficient facilities and carbon-free technologies such as wind power.

Changing the merit order and co-firing at best will reduce CO_2 emission by 10-15%. Over time, investment decisions will tend towards less CO_2 intense technologies, reducing the average CO_2 intensity of the electricity generation portfolio. The dynamics of process innovation in mature capital-intensive industries are characterized by high risks and long time spans (cf. Dijkema (2004)). The main impact of carbon policies therefore must be achieved through the investment decisions of electricity producers.

Electric power generation is a capital-intensive industry and assets have life cycles of decades. The capital cost of a full scale, state-of-the art coal-fired power plant in the EU is around 1000-1200 €/kW, which means more than a billion Euros for a 1040 MW plant such as currently planned by E.On. A coal gasification plant cost another 600-800 €/kW more. Investment levels for wind parks or biomass-firing are similar. These generation technologies are proven and

[4] For an overview of electricity price elasticity, see for instance (Lijesen 2007).

commercially available, but under which conditions will carbon pricing cause power companies to invest in these low carbon technologies?

Carbon taxation provides a clear price signal by increasing the variable costs of fossil fuel-based electricity production (Lowe 2000). It is a classic Pigouvian tax, the ideal level of which should be equal to the marginal social damage (Pigou 1947). The positive cost of CO_2 emissions provides a monetary incentive for reducing emissions (Pizer 1999: 2). An issue with a carbon tax is that the total emissions volume is not constrained. A tax is expected to shift the portfolio balance from coal to more natural gas and perhaps renewables and CCS. Such a shift is the aggregate result of many separate investment decisions regarding the choice of energy source, electricity generation technology, plant scale and CO_2 abatement technology. A possible second-order effect of a carbon tax is that it reduces the demand for coal and increase the demand for alternatives such as natural gas, which could cause coal to become relatively cheaper, partly undoing the effect of the tax. At which level fuel prices, volumes and CO_2 emission level the market would stabilize is difficult to predict, because they not only depend the fuel markets dynamics but also on the availability and price of alternatives such as CCS and renewable energy sources. This is one of the reasons why the effect of a tax upon the CO_2 emission level is difficult to estimate *ex ante*.

This would not be a problem if we knew the optimal tax level; then, by definition, the resulting emission level would also be socially optimal. However, a fundamental problem with a Pigouvian tax is that we do not have a reliable measure for the social damage, so it is impossible to establish *ex ante* the correct level of the tax (Bimonte 1999). As Grubb and Newberry (2007) argue, we do not know which tax level would reduce CO_2 emissions sufficiently to stabilize the atmospheric concentration at a certain level.[5] A possible solution is to start with a relatively low tax and to adjust it over time in response to observed emission reductions. If a firm commitment is made that the tax will not be lowered during the life span of existing investments in less carbon-intense power generation or CO_2 abatement, this would provide significant certainty to investors regarding the minimum level of return on their investment. This way, investment risk can be limited while preserving policy flexibility.

Emission trading relies on a price signal for internalizing a negative external effect of production (Ekins and Barker 2001). A major argument for tradable emission rights is that "the invisible hand" of the market would lead to least-cost emission reduction (Smith 1776; Svendsen 1999; Ehrhart *et al.* 2003; Svendsen and Vesterdal 2003). Both within a sector and between sectors transactions will occur until a CO_2 price develops where total emissions equate to the emissions cap and where no emitter will invest in further emission reduction. “There is a broad consensus that the costs of abatement of global climate change can be reduced efficiently through the assignment of quota rights and through international trade in these rights” (Manne and Stephan 2005). Box 1 presents an overview of the experience with the European ETS.

The main difference between trading and taxation can be summarized as follows: with trading, the total quantity of CO_2 emissions is set but the price is unknown and volatile. Under taxation, the price of CO_2 is set, while the volume of emissions is not.

[5] Stern (2006) argues that this level should be around 500 ppm.

Box 1: Experience with the European emission trading scheme

In January, 2005, the European emission trading scheme (ETS) was implemented (CEC 2003).[6] In the ETS at least 90% of emission rights are grandfathered: they are allocated to emitters for free, in volumes based on past emissions. This led to a highly politicized process in which companies, industrial sectors and European countries vie for emission allowances in order to minimize the financial consequences of the CO_2 cap. Over allocation of allowances was the consequence. Initially, market parties did not know this, but when in April of 2006 the European Commission communicated that they had issued too many emission rights, the price collapsed to nearly zero (Cozijnsen 2005). Between 7 and 8 billion Euros in emission rights value vaporized overnight. The grandfathering of emission rights also led to substantial windfall profits for power producers. They passed the marginal costs of CO_2 on to the consumers (in perfect accordance with economic theory), which they had largely had obtained at zero cost. In addition, with respect to emission reduction, the low-hanging fruit could still be picked no or limited cost. To solve this problem, in the second phase of the ETS between 2013 and 2020, all emission rights for the power sector and in other sectors an increasing percentage of the rights will be auctioned.

In the first phase of the ETS (2005 – 2007), the prices of tradable CO_2 emission credits were highly volatile. In retrospect, this was due to the limited time horizon of this phase, the highly politicized process for determining the emission cap, uncertainties regarding the cost and availability of abatement options, the mismatch between the actual and forecast demand for emission rights and the inelasticity of the supply of emission rights. Using the first phase as a learning period, the European Commission proposed improvements to the ETS. The most important change is to set a predictable cap that is to be reduced by 1.7% each year to achieve a 20% reduction between 2013 and 2020. The Commission also made it clear that ETS will continue beyond 2020 and at least become more stringent. Meanwhile, an extensive program to develop and demonstrate CCS is being developed. Funding of R&D on innovative energy technologies has been increased, and regulation and research to reduce energy consumption is back on the agenda. As in any market, a certain amount of price volatility remains inevitable, but both the design of the ETS and its context are improved to reduce uncertainty.

3 An electricity market model with carbon policy

3.1 Description of the model

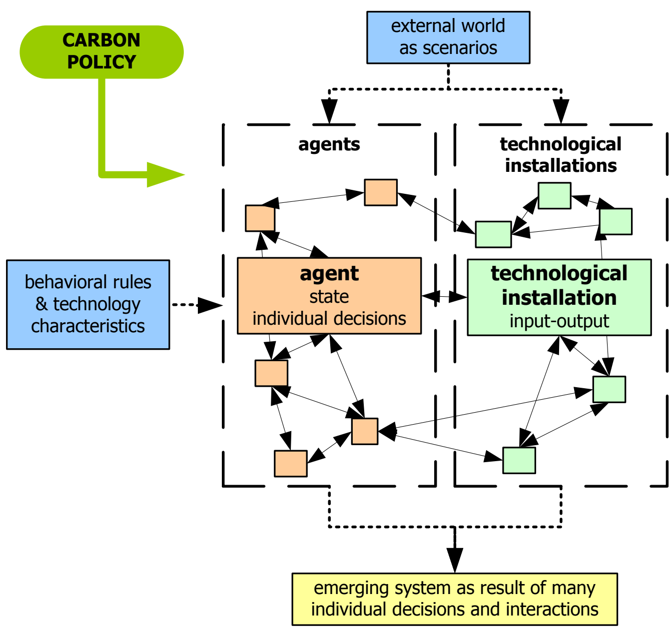
The electric power production sector may be considered as a large-scale socio-technical system, in which a variety of stakeholders (agents) interact with each other and with the physical infrastructure for the production and transport of electricity (Chappin and Dijkema 2008a; 2008c; Nikolic *et al.* 2008). While the technical infrastructure is governed by the rules of nature, the social network is governed by informal and formal social rules and regulations. The combined system is complex and exhibits chaotic behavior. The long life cycle of power plants and electricity networks cause strong path dependence in the development of this system. Consequently, quantitative static equilibrium analyses, as are common in economics, only provide limited insight into the long-term impact of policy interventions such as a carbon tax or emissions cap.

[6] An elaborate discussion of the EU ETS is given in the chapter by Musier *et al.* in this volume; for an overview of the results of Phases 1 and 2 and a discussion of the proposed changes for Phase 3 see for example the report by Carbon Trust (2008).

A quantitative *agent-based model* (ABM) therefore was developed to simulate the evolution of the structure and performance of a hypothetical electricity market in the next 50 years using insights from microeconomics, market design, agent theory, process system engineering and complex system theory (Chappin and Dijkema 2008a; 2008c; Nikolic *et al.* 2008). An ABM represents a set of interacting 'agents' with certain properties who live in an external world whereupon they have no influence – a modeling paradigm that matches the electric power production sector, where independent power producers, governments and consumers can be considered agents that compete and interact via markets. Each agent has a set of goals, a working memory, a social memory and a set of rules of social engagement.

The model reflects the real-world situation of six independent electricity producers who have different generation portfolios and who make different decisions regarding the operation of their generators, investment and decommissioning. A schematic overview of the ABM is presented in Figure 1. The model contains two subsystems: agents and installations. The external world is represented by exogenous scenarios. The agents in the model, the power producers, need to negotiate contracts for feedstock, the sales of electricity and, in the case with emissions trading, emission rights. In the longer term, the agents need to choose when to invest, how much capacity to build and what type of power generation technology to select. Agents interact through negotiated contracts and organized exchanges and the physical flows and their constraints and characteristics are modeled. The characteristics of the modeled system are emergent: the generation portfolio and merit order, fuel choice, abatement options, as well as electricity and CO_2 prices and emissions emerge as a result of the decisions of the agents. The model has been run for three cases: no carbon policy, ETS or CT.

Figure 1. A schematic overview of the model



Adapted from Chappin *et al. (2008b)*

The electricity demand profile consists of 10 steps per year that reflect a typical load-duration curve, to reflect the different emissions levels, costs and operating hours of the different power plants. Markets for CO_2 rights, power and fuels are modeled as exchanges in which 100% of the product is traded every time step. The time step of the model is one year and the simulations span a horizon of 50 years.

The main policy variable of the ETS is the emissions cap. In the model the cap is set to reflect the likely design of Phase 3 of the EU ETS in which the CO_2 cap is reduced every five years by 3 Mton for a market with the size of the Netherlands. With an initial cap of 50 Mton, a 50% reduction is achieved in little more than 40 years. Another important policy variable is how many emission rights can be obtained through the Clean Development Mechanism (CDM)[7]. This is set to 5 Mton/year over the entire simulated time period.

The only CT policy variable to be set is the tax level. To allow a fair comparison between ETS and CT, the tax level in our model has been calibrated to the average CO_2 price that emerges in the simulated emission market. The initial tax level equates to 20 €/ton, which reflects current CO_2 price under ETS. With time, tax level increases to 80 €/ton (See Figure 5.)

3.2 Scenarios and assumptions

The electricity producers – the agents – operate in a dynamic world which is represented as exogenous trends: time series of fuel prices, electricity demand and carbon policy parameters (emission caps or tax levels). We assume that the electricity producers have no market power, neither in fuel markets nor in the electricity or CO_2 markets. In Table 2 an overview of the scenarios and carbon policy parameters, values and trends used is provided.

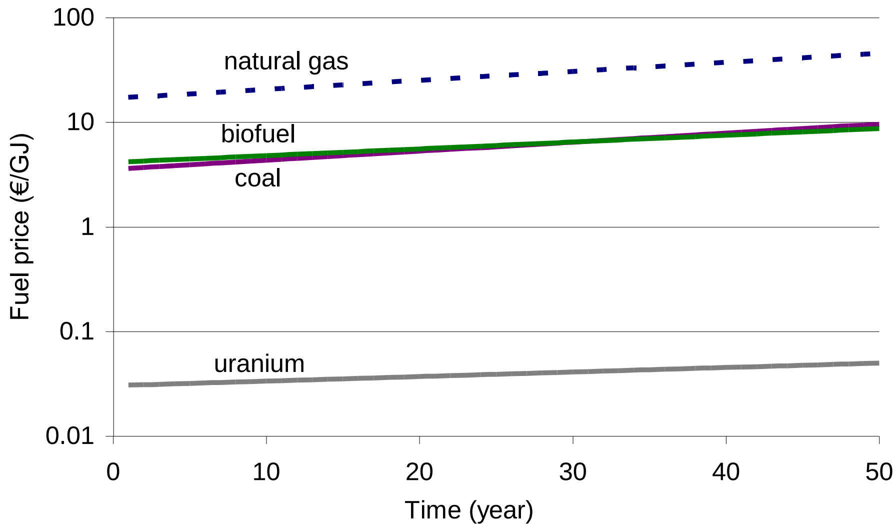
Table 2. Exogenous parameters: scenario and carbon policy settings

Domain	*Parameters*	*Initial value*	*Trend*
Fuel markets	Natural gas price	0.61 €/Nm^3 [8]	+2 % / year
	Coal price	103.3 €/ton[9]	+2 % / year
	Uranium price	17 €/kg[10]	+1 % / year
	Bio-fuel price	120 €/ton	+1.5 % / year
Power market	Electricity demand	140 TWh/year	+2 %/year
Emission trading	Cap	50 Mton CO_2/year	-3 Mton / 5 year
Carbon taxation	Taxation level	20 €/ton	Rising from 20 to 80 €/ton, with the average equal to the average CO_2 price in emission trading

The fuel prices in the simulation start at October, 2008 market levels and develop as depicted in Figure 2. The figure presents the *average* fuel prices used. In individual runs, fuel prices vary randomly around these averages.

[7] Under pressure of the industry, the Dutch government acquires additional emission rights through the Clean Development Mechanism. In the Dutch ETS allocation plan, it was announced that government reserved 600 million Euros for this purpose, equivalent of 20 Mton CO_2 rights. Source: (Ministry of VROM and SenterNovem 2005)
[8] World average gas price in 1984-2007 (BP 2008).
[9] World average coal price in June 2008 (GlobalCoal 2008).
[10] World average uranium price in June 2008 (UxConsultingCompany 2008).

Figure 2. Average development of fuel prices



The rationale for these choices is as follows:

- *Natural gas* is and remains relatively expensive because it is a clean fuel, the conversion efficiency (MWh produced per GJ fuel) is high (55-60% for new plants), the capital costs of natural gas plants are relatively low and natural gas can be used for home heating and combined heat and power generation, also in small facilities. With increasing demand, the production of existing fields leveling off and a limited amount of new production underway, an increasingly tight supply-demand balance is expected for the coming decades, which leads to continuously increasing prices.
- *Coal* has a much lower price per energy unit than natural gas, because it is a polluting fuel that only can be used in large power plants or gasification units at relatively high investment costs, while the conversion efficiency (MWh produced per GJ fuel) is relatively low (40-45%). World coal resources suffice for over 400 years of present consumption, or even 2500 years of present consumption if all known coal deposits are developed. Therefore the marginal cost of coal production will only gradually increase and average prices are only expected to rise moderately.
- *Biomass* for use in power generation is expected to be traded at a somewhat higher price than coal, because while biomass can be fired in similar installations as coal, it is a more desirable product because we assume that it does not lead to net CO_2 emissions.[11] On the other hand, biomass demand is limited by the higher handling costs, the more expensive installations and the fact that it is converted at a lower efficiency (35-40%). We assume that biomass production can keep pace with demand, so price reflects cost rather than scarcity. The possibility of switching from biomass to coal is an effective cap on the biomass trading price.
- *Uranium* costs per GJ are assumed to remain near their current low levels.

The following assumptions underlie the models:

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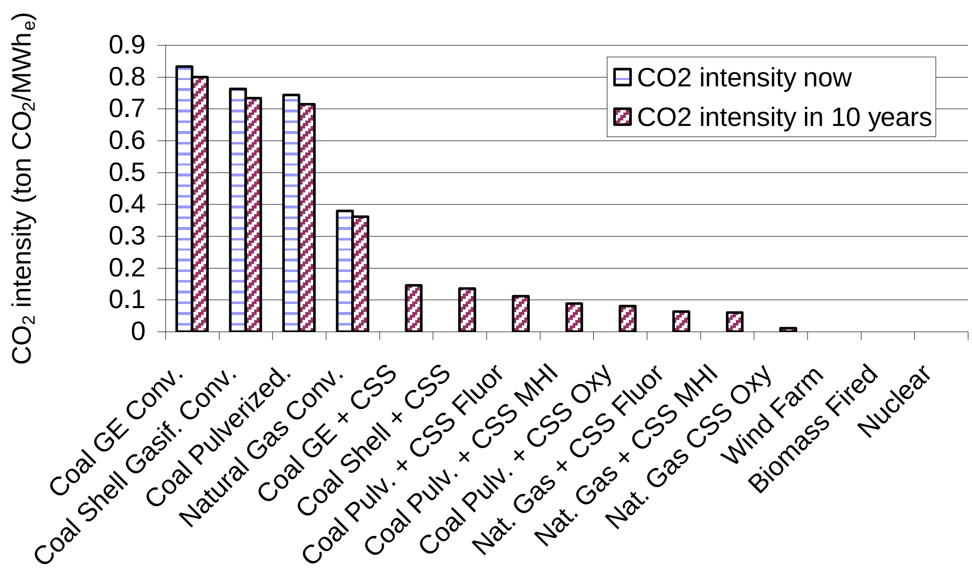
[11] Currently, the net CO_2 emissions associated with biomass production are a heavily debated. Some biomass sources appear to have a negative CO_2 impact - the emissions associated with the production chain exceed the emission avoided. The high-level Cramer committee concluded in its advice to the Dutch Government that 30 to 70% of the direct CO_2 emission from burning biofuel is compensated for in the biological cycle (Cramer Commission 2006).

1. Fuel is always available. There is an unlimited supply of biomass and natural gas.
2. Fuel prices are exogenous and reflect the relative scarcity of fuels. The modeled system is too small to impact world fuel prices.
3. Biomass is assumed to be 100% carbon-neutral[11]. In our model, biomass represents the general characteristics of renewable energy: carbon-free, but more expensive.
4. The main characteristics of Phase 3 of the EU ETS (2013 and beyond) are included: 100% of emission rights are auctioned and the cap will decrease over time.
5. The effect of inter-sector emission trading is assumed to be negligible compared to intra-sector trade.
6. Innovation is limited to learning; available technologies gradually improve in terms of cost and performance, entirely new technologies do not become available in the model.
7. The generation portfolio, size of the market, CO_2 cap, the number of players and the attitude towards nuclear power reflect the current (2008) Dutch power sector.
8. All costs and prices are in constant 2008 Euros. Electricity prices are wholesale prices; taxes and network fees are not included.

Figure 3. Overview of CO_2 intensity of the modeled technologies, today and in 10 years



3.3 Power generation technologies

In the model, power plants are characterized by their fuel type, costs, technical life span and fuel usage (conversion efficiency). The model includes an extensive set of 'state-of-the-art' power generation technologies as well as technologies that are expected to be commercially available within 10 years time, most notably CCS. In Figure 3 the carbon intensity, currently and in ten years, is summarized for the different technologies. The data in Table 3 on coal and gas plants – with and without CO_2 capture – are taken from Davidson (2007), the other data sources are cited in Chappin (2006). The effect of learning and incremental innovation is included by gradually increasing the efficiency and reducing the investment costs of new facilities. Carbon capture and storage options are only available after the first ten years of the simulated period.

Table 3. Power plant characterization

Power plant type	Efficiency (%)	Efficiency modifier	Investment (€/MW)	Investment modifier	Fixed operating cost (€/MWh)
Coal Pulverized	44	0.4%	1,144,715	1.0%	7
Coal Pulv. + CSS Fluor	35	0.5%	1,608,943	1.0%	7
Coal Pulv. + CSS MHI	35	0.5%	1,660,976	1.0%	7
Coal Pulv. + CSS Oxy	35	0.5%	1,792,683	1.0%	12
Coal Shell Gasif. Conv.	43	0.4%	1,311,382	1.0%	12
Coal Shell + CSS	35	0.5%	1,791,870	1.0%	12
Coal GE Conv.	38	0.4%	1,169,919	1.0%	9
Coal GE + CSS	32	0.5%	1,475,610	1.0%	13
Natural Gas Conv.	56	0.4%	405,691	0.5%	2
Nat. Gas + CSS Fluor	47	0.5%	706,504	0.5%	4
Nat. Gas + CSS MHI	50	0.5%	721,138	0.5%	4
Nat. Gas CSS Oxy	45	0.5%	1,245,528	0.5%	6
Biomass	35	0.4%	1,250,000	1.0%	4
Wind	35	-	1,150,000	2.0%	3
Nuclear	-	-	2,000,000	0.0%	5

3.4 Agent definition and behavior

The key agents in the model are the power producing companies. Their tactical decisions consist of offering their output to the power market. They bid their power based on marginal costs, which includes the cost of CO_2 emissions in the cases with a carbon policy. Thus markets are simulated in which power producers negotiate the electricity, fuel and CO_2 prices. Their strategic decisions cover investment in and decommissioning of power plants. Each agent's decision process is as follows:

1. Decide per power plant whether it should be dismantled. The decision to dismantle is taken when the technical lifetime of a power plant has expired (after 20 years for wind farms, 30 years for gas and coal plants and 40 years for nuclear) or if the plant caused continuous operational loss for over 5-9 years.
2. Estimate whether there is a need for new generation capacity in three years. The estimate of the demand for capacity in three years is based on an extrapolation of the electricity demand trend of the past three years. Capacity expansion decisions take into account investments and decommissioning already announced by competitors. Continuous operational losses will cause unannounced decommissioning; thus the planning of agents is not perfect and investment cycles can occur. Limited overinvestment is modeled to dampen those investment cycles.
3. If step 2 results in an investment decision, the agent needs to select a technology for its new plant. Its decision is based on the lifecycle cost per MWh_e produced. The lifecycle CO_2 cost is based on current CO_2 taxation levels or, under emission trading, the three year average CO_2 auction price. The total lifecycle cost must be recovered by electricity income or else the investment is cancelled. In the latter case another agent will get the opportunity to invest. The order in which the agents make their investment decisions varies randomly. In addition to financial aspects, an agent's conservativeness, aversion to nuclear power and risk attitude affect its decisions. Despite the large weight of financial considerations, these individual style aspects have an effect, especially when financial differences between options are small. Conservativeness is modeled as 'preferring more of the same'; risk attitude translates to different responses to historic variance of CO_2 and electricity prices.

In the case of emission trading, electricity producing agents complete the following actions concerning the operation of their power plants each year:

1. Purchase emission rights in the annual auction. The auction bids are based on the ‘willingness to pay’ per installation, which is determined as the expected electricity price less the marginal costs of each unit, divided by the CO_2 intensity. The bid volume equals the expected electricity sales volume times the CO_2 intensity of the power plants that are expected to be in merit.
2. Offer electricity to the market (which is modeled as a power pool). Each plant’s capacity is offered at variable generation cost (fuel cost, variable operating and maintenance cost and CO_2 cost). The CO_2 costs of a generator equal the CO_2 price times its CO_2 intensity. In case insufficient CO_2 rights have been obtained, CO_2 cost equals to the penalty for non-compliance.[12]
3. Acquire the required amounts of fuel from the world market, which are calculated from the actual production and fuel usage.
4. Bank surplus CO_2 rights or pay the penalty in case there is a shortage of CO_2 rights. Surpluses and shortages are calculated from the actual production levels and the volume of emission rights owned by the agent.

A difficulty with this procedure is that the CO_2 and electricity markets are mutually dependent. While there is only one CO_2 price per year, the use of a load-duration function with 10 steps means that 10 different electricity prices are developed for each year. Therefore we need to model arbitrage between these 10 periods. As the demand for CO_2 credits is different at every step in the load-duration curve, we had to develop an iterative process in which arbitrage between the demand for CO_2 in these markets takes place, in such a way that total annual demand for CO_2 satisfies the emissions cap and a single annual CO_2 price develops. We adopted the following procedure. Since the outcome of the CO_2 market is input to the power market and vice versa, steps 1 to 2 are computed via an iteration that is complete when stable prices have been established for the entire year. In each simulation interval, we start with the prices of the previous year. In each iteration, first the CO_2 auction is cleared (step 1), which results in a CO_2 price. This price is then used to calculate power market offers and for each of the ten sections of the load-duration curve this market is also cleared (step 2). This new clearing price for electricity is fed into the bids for the CO_2 auction as the expected price of electricity (step 1) and so on. Upon completion of this iteration, emission trading (step 1) has effectively been completed.

Under carbon taxation, step 1 is skipped; in step 2, the CO_2 cost is the carbon tax times the CO_2 intensity. In this case, the CO_2 price is exogenously determined. The electricity market bids simply incorporate this price. No iteration is necessary. Step 4 is replaced by paying carbon tax to the government. In case there is *no carbon policy*, the calculation procedure consists of step 2 and 3 with a CO_2 price equal to zero.

4 Simulation results

Where the model design and the technology representation are generic, results are presented for a CO_2 market that is modeled after the European ETS and for generation portfolio and market data that reflect the Dutch power sector. In reality and in the model, carbon policy is only one of several factors that affect emissions. The evolution of the system is also determined by: (1) the scenarios (exogenous factors such as fuel prices and electricity demand), (2) the system’s components and properties, (3) and the starting conditions. To provide a good representation of

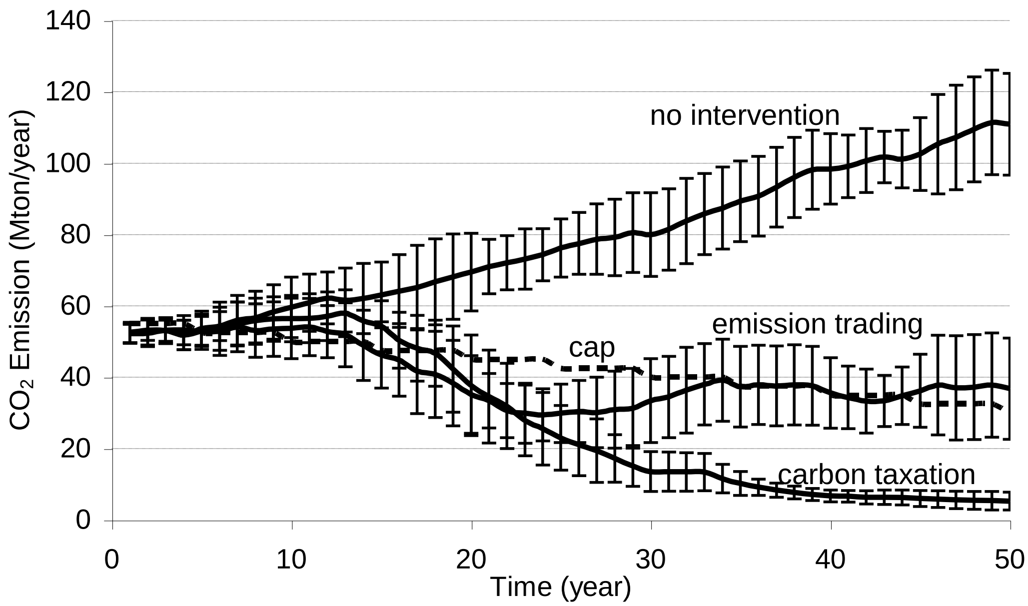
[12] When the CO_2 price exceeds the penalty level, agents will rationally choose to pay the penalty rather than purchase more CO_2 credits. Consequently, this penalty level functions as a price cap for the CO_2 market.

the possible development of the system over 50 years, we present the aggregated results of 60 simulation runs in which the scenario parameters were varied evenly across the entire scenario space and the initial set of power plants is randomly distributed amongst the agents.

4.1 Average total CO_2 emissions

Figure 4 shows what carbon policies deliver in the long run. Emissions are lowest under the carbon tax. In the long run, emission trading generally leads to emissions close to the cap. This may not come as a surprise, but in some simulation runs the cap is not met at all. In these cases abatement investments are made too late, given their long lead time and the fact that the cap continues to decrease. High CO_2 prices result. Despite the spread in outcomes (indicated by the error bars in Figure 4), the difference between the trajectories caused by the three carbon policies is statistically significant.

Figure 4. Average CO_2 emission levels for three carbon policies



The results reflect the tremendous inertia in capital-intensive energy systems. Without intervention, emissions continue to rise indefinitely and neither carbon policy guarantees a rapid decrease of emissions. To the contrary, emissions increase in the first 10-15 years in all scenarios, due to the system's inertia: even at high CO_2 prices, it is not attractive to replace relatively new power plants, even if they emit much CO_2.

4.2 Electricity prices

The pressure that carbon policies put on the power generation system is reflected in the electricity prices (Figure 5), since power companies ultimately pass through their CO_2 cost to consumers. The prices shown are outcomes of the simulated negotiation between the six operating companies and simulated demand. Three important observations can be made:

- The three carbon policies cause significant, structural differences in the electricity prices.
- Under emission trading, CO_2 prices are highly volatile for the first three to four decades.
- Under emission trading, the CO_2 price is strongly correlated with the electricity price, while the correlation between a carbon tax and electricity prices is much weaker.

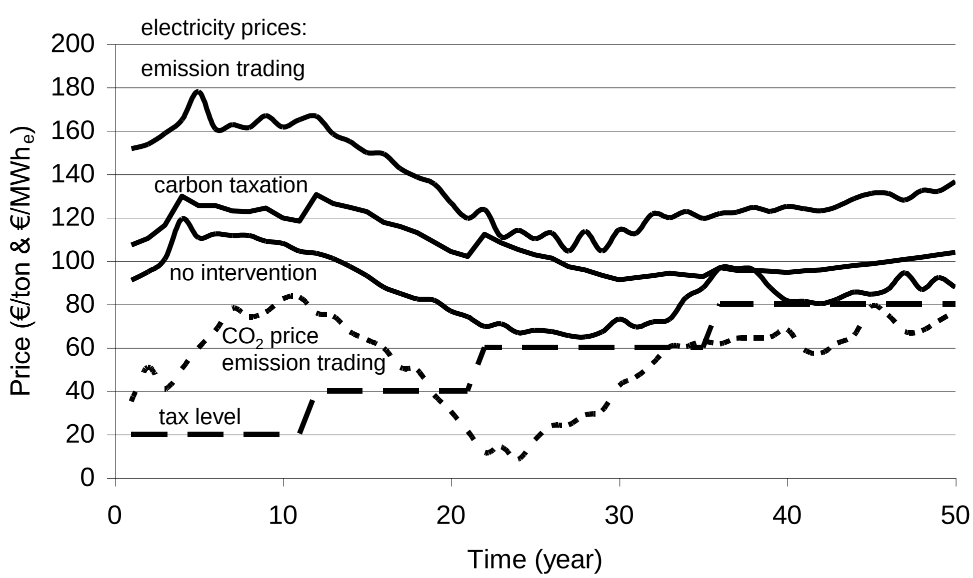
Electricity prices drop during the first two decades, which appears to be counterintuitive when an ETS or CT is introduced. In all three cases, however, the power plant portfolio at the start of the simulation is not economically optimal for existing market conditions. With time, generators invest, adjusting their portfolio and lowering their marginal cost of electricity production.

In the case without intervention, coal becomes increasingly dominant because it is more attractive. Innovation leads to further cost reductions. Towards the end of the modeled period, electricity prices begin to rise again due to the assumption that fuel prices will gradually increase.

In the case of an emission trading scheme, both the price of emission rights and the CO_2 emissions remain high for the first 15 years, which leads to extremely high electricity prices. These can be explained by the inertia of the generation portfolio and risk aversion. Inertia results from the economic rationale for keeping existing power plants and the lead time for building new ones. Power producers exhibit risk aversion towards the capital-intensive investments required for CO_2 abatement due to CO_2 price volatility. The high prices lead to an abatement overshoot in most runs, which causes a CO_2 price collapse in the third decade. This discourages further abatement measures and emissions creep back to the cap and stabilize.

Under emission trading the CO_2 price is volatile (Figure 5). It contributes to an already high investment risk. The consequence for abatement efforts are a delay of investments and a bias towards less capital-intensive abatement technology, many of which are more costly in the long run. A carbon tax does not have the disadvantage of volatility and thus minimizes the price risk of abatement measures, provided there is no regulatory uncertainty about the tax level – the risk of later governments backtracking on earlier taxation decisions. However, there is also regulatory uncertainty with emissions trading as later governments may decide to loosen the cap. Regulatory uncertainty increases investment risk under both policies.

Figure 5. Electricity and CO_2 prices, averaged over all runs, under different carbon policies



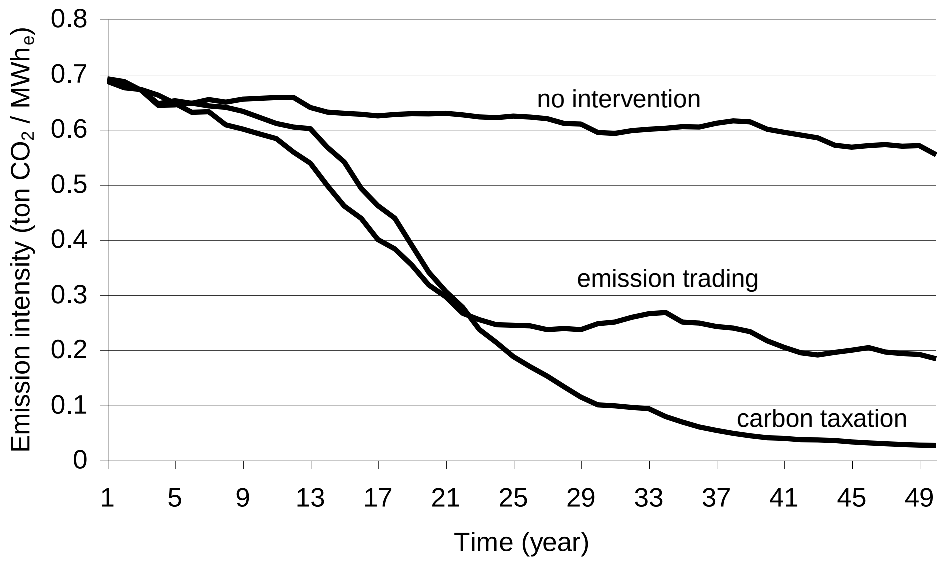
The impact of carbon taxation on the electricity prices is relatively small. The tax starts at a fairly low level of 20 €/ton. When the tax level rises, investment in abatement reduces the CO_2 intensity of electricity generation, which reduces the impact of the tax upon electricity prices. Clearly, one cannot simply add the cost of CO_2 under the two carbon policies to the electricity prices under no intervention. The price is determined by CO_2 price and the CO_2-intensity of the portfolio, which evolves differently under each policy option (see Figure 6).

4.3 CO_2 intensity

Given the continuous rise in electricity demand, CO_2 emissions can only be reduced significantly by changing the generation portfolio, i.e. by shutting down existing facilities and by investing in new ones. Figure 6 presents the CO_2 intensities of the carbon policies, averaged over the runs. This figure shows that the absolute emission levels shown in Figure 4 are achieved via a dramatic reduction of the CO_2 intensity of the generation portfolio. Without intervention, CO_2 emissions rise, but the CO_2 intensity is relatively stable – natural gas is replaced by coal while its fuel efficiency increases through innovation.

The impact of CO_2 prices on the variable cost of installations may change the merit order of generation. At higher CO_2 prices, CO_2-intensive installations may move from base load to peak load. Under all scenarios, including no intervention, a merit order shift takes place from CO_2-intensive towards CO_2-extensive base load facilities.

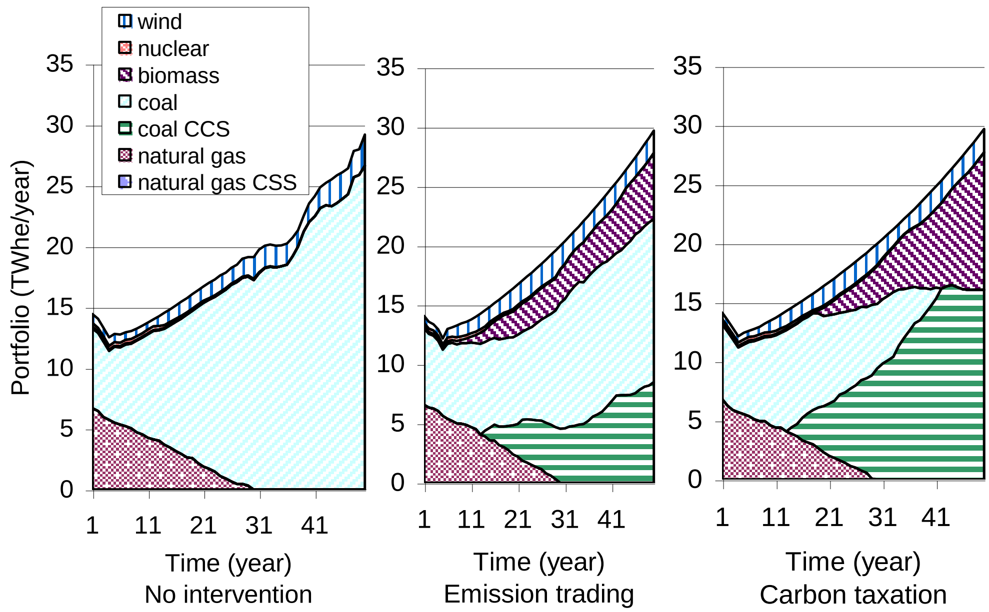
Figure 6. Average CO_2 intensity of capacity and supply under the different carbon policies



4.4 Generation portfolio development

The simulation results clearly show that different carbon reduction policies profoundly affect the generation portfolio. Without a carbon policy, the economics favor coal, which replaces natural gas, nuclear and biomass. Under emission trading, the generation portfolio becomes more diverse. Coal without CCS remains important, but its share stabilizes. Coal with CCS emerges in the second decade and replaces natural gas, because of the declining cost of CCS and the increasing price of natural gas. The introduction of carbon-free biomass is the second largest source of emissions reductions. An increasing carbon tax prompts an almost complete switch to carbon-free electricity generation in the long run. Coal with CCS first replaces natural gas capacity and later coal without CCS, with biomass taking a far greater share than under emission trading. Traditional coal is phased out. The volumes of wind energy are stable and small under all three policy instruments. Nuclear energy does not appear in any of the cases due to its substantially higher cost (see Table 3). In Figure 7 the evolution of the average portfolio of technologies is displayed.

Figure 7. Average generation portfolio evolution for the three scenarios



The portfolios in Figure 5 are diverse, while one would expect economic rationality to lead to a single preferred technology. However, other factors also affect investment decisions. Especially when the costs of options do not differ much, secondary criteria can be decisive. These include greenness (measured in CO_2 intensity) and conservativeness (a preference for proven technologies, which is measured by the current adoption level of the technologies). The adoption of wind – in continuous but limited amounts – offers a typical illustration. In the simulations there is one agent who is relatively conservative and green. Since wind often is close to the cheapest option, it is sometimes adopted by this agent. And in some runs, early adoption combined with the agent's conservativeness will cause it to adopt wind again. Via the same mechanism, wind gradually may disappear in other runs. When the runs are averaged, this produces a gradual and limited share of wind in the portfolio.

4.5 Sensitivity to the assumptions

However complex a model may be, it remains a simplification of reality. The results are influenced by the following types of assumptions:

- The way in which the carbon policies are modeled;
- The assumptions regarding the model's inputs: the (relative) prices of natural gas, coal, biomass and uranium, the set of available generation technologies and the demand for electricity;
- The structure of the energy market that was modeled;
- Assumptions regarding investment behavior and the way in which prices are formed in the market.

A cap and trade scheme is more complicated than a carbon tax, as it involves more design variables. Choices need to be made about the method of allocating the emission rights (auctions are theoretically superior but not always politically favored), about credit issuing and continuous registration, banking and borrowing credits and whether to issue negative credits to CO_2 sinks. In both systems, emissions must be monitored and verified, the scope of the system (which sectors and countries to include) must be decided upon, where to place the obligation to obtain credits or pay tax (at the consumer, the power producer or further upstream), etcetera.

A difficult choice is how to model fuel prices, because structural changes (such as China's economic emergence) may create lasting price effects. We assumed prices to be exogenously determined. This assumption holds for a small system, e.g. a single country or state, but if carbon policies are widely implemented, this may decrease the demand for carbon-intensive energy sources worldwide, making them cheaper and hence economically more attractive, reducing the effectiveness of the reviewed carbon policies.

We did not assume any technological revolutions. The existing technologies, including carbon capture and sequestration (CCS), would continue to be available and gradually improve in terms of cost and performance. We assumed that a technology's maturity determines its pace of improvement, with learning being exogenous to the market. In reality, adoption and improvements reinforce each other, so technological learning is endogenous. A second technical issue is that most existing coal plants are not suitable for running peak load (in case high carbon prices cause them to shift their position in the merit order). This could lead to block bidding and reduced flexibility of the power system. Future technologies, such as coal gasification, will probably be more flexible[13].

The abatement options differ per country. In most countries, only a limited amount of CO_2-free generation options such as hydropower or geothermal energy are available. In these countries, the options that were reviewed in this chapter are the main ones. But there are exceptions, like New-Zealand, Canada, Brazil and Norway, since they have an abundance of hydro.

Electricity demand is modeled exogenously, without price elasticity. One may assume that there is, in reality, some price elasticity, which would dampen price swings. Perhaps price elasticity will be improved through applications that make use of the digital electricity meters that are beginning to be installed across the world. Finally, it may not be a correct assumption that electricity demand will grow perennially; perhaps there is a saturation point, or conservation efforts may outweigh natural demand growth.

The acceptance of a carbon policy by society may be affected by the way in which the revenues are spent. Stoft (2008) favors returning revenues (both from a tax or an auction of emission allowances) to the people on a per capita basis. This avoids a net income transfer from consumers to government while maintaining the incentive to reduce emissions. The revenues may also be returned to the affected industry sector to maintain an international competitive position. Other options are to use the revenues to finance CCS infrastructure, support R&D or to let them flow to the treasury. This question of political acceptability and allocation of the revenues, however, is outside the scope of this chapter.

The market is modeled with a limited number of generating companies, which is realistic, but they act as perfect competitors, which is not realistic. Oligopolistic behavior is likely to be observed in electricity markets, given the regional nature of the product, and may lead to different

[13] See for instance the chapter by Williamson et al in this volume, geothermal as base load renewable.

investment behavior. Oligopolistic rents may offset investment risks, allowing companies to invest more proactively in an emissions market than the model suggests, but it will be uncertain whether they choose to do so.

5 Conclusion

Taxation and CO_2 emission trading schemes should yield similar results in theory. In this chapter, we analyzed, for a hypothetical electricity sector, the effects of both instruments under realistic circumstances, such as policy uncertainty, risk aversion by investors and long construction lead times.

Both carbon policies are effective in reducing CO_2 emission in the long run, provided that the tax or cap level is set at an ambitious level. The first 10-15 years, CO_2 emissions from power generation continue to increase under all three policies (no intervention, CT or ETS). Operational adjustments, which both CT and ETS can be expected to invoke in the short term, do not have sufficient potential. A substantial change in the generation portfolio is needed to obtain the policy goals for emission reduction. Under emission trading, natural gas is replaced by coal with carbon capture and sequestration (CCS) and biomass. Conventional coal retains a certain share. An increasing tax leads to a complete phasing out of natural gas and conventional coal, leading to a portfolio with almost only coal with CCS and biomass. No new nuclear capacity is developed under any of the three policies. In the absence of intervention, absolute emission levels grow dramatically (50%), even though the CO_2 intensity of electricity generation is stable due to technological improvements.

A key result is that given a certain CO_2 cost to producers – whether it is due to a tax or the price of CO_2 emission rights – carbon taxation leads to lower electricity prices than emission trading. The explanation is the difference in investment risk: a tax is predictable, whereas CO_2 prices are volatile. This uncertainty leads to an investment cycle under emission trading that is absent under carbon taxation. High CO_2 prices frequently occur when the CO_2 intensity of electricity generation is high. This cyclical behavior is a significant disadvantage of emission trading. In contrast, under taxation, high tax levels occur only in the second half of the simulated period. At that time, they do not cause large income transfers, because the CO_2-intensity is already low, so the impact upon the electricity price is limited. Predictability is a key advantage of taxation, which allows investors to minimize cost over a longer time horizon. Given the capital-intensiveness of many of the abatement options, this leads to substantially lower overall cost as well as lower emissions in the long term. This confirms the ideas of Grubb and Newberry (2007).

Both trading and taxation are instruments that create current pain, while yielding significant results in the future. When these policies are kept in place for decades, their long-term impact is significant. From the modeling exercise, however, we also conclude that for both instruments to have an effect, affordable and competitive low-CO_2 electricity generation options must become available on a large scale. In our simulations, options included were CCS, nuclear and renewables biomass and wind. In practice, other technologies such as solar power may also be part of the solution. While it cannot be concluded that the very portfolio shifts that were observed in the model are the most likely to occur in practice, it is safe to conclude that carbon policies do deliver in the long run.

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