Implementing the flexible mechanisms of the Kyoto Protocol : lessons from a simulation of trading CO_2 and electricity in the Baltic Sea Region

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Introduction :

The implementation of the Kyoto Protocol raises interesting questions about the possible behaviour of Parties to the Protocol : how will governments approach their mitigation and trading strategies under price uncertainty ? The simulation organised by the International Energy Agency in March-April 2002 intents to provide some insights, to learn about the interaction between a CO_2 emission trading system and a fully open electricity market and to explore the so-called flexibility mechanisms of the Kyoto Protocol to the United Nations Framework Convention on Climate Change (UNFCCC).
The governments of ten States in the Baltic Sea area and 20 electricity and energy companies of this region have been involved in this simulation. Unlike previous exercises of this kind that focused either on industry or on the inter-governmental dimension of the Protocol[1], the BASREC trading simulation combined three elements that are critical to its realism and relevance for future policy:

- government targets – i.e. Annex B greenhouse gas (GHG) emission objectives except for the United States;
- company targets, based on allocation by governments;
- a fully-open market for electricity and extensive trading of CO_2 within – and possibly outside – the region.

It also included recent features of emission trading agreed by the Parties to the UNFCCC in Bonn and Marrakech, such as the commitment period reserve. Joint Implementation projects were also simulated in this exercise.

The simulation relied on several simplifying assumptions related to both the technicality of electricity and CO_2 trading and the policy aspects of a CO_2 trading regime (including the allocation of emission objectives). For this reason, the simulation results are not meant to be accurate projections of what could happen in the Baltic Sea region under the Kyoto Protocol.

[1] See in particular simulations organised by Eurelectric (GETS, GETS2), Eurelectric, IEA, ParisBourse (1999), Eurelectric, EuroNext, PriceWaterhouseCoopers (2000).

We present in this article the lessons learned by this exercise. The first section draws the main features and the steps in the simulation. Section 2 outlines the lessons learned. Finally, section 3 envisages the limits of such an exercise.

1. How it unfolded: actors and steps in the simulation

The simulation unfolded as indicated in Table 1. This step-by-step approach created some sense of real time in the simulation: decisions taken in a year engaged players for the rest of the simulation, even though future developments (e.g. the price of CO_2 or electricity) could undermine the rationale of these decisions.

Table 1: Simulation Schedule

Session	Preparation	11March	18 March	2 April		8 April	15 April	24 April
Years	**2001-2002**	**2003-2004**	**2005-2006**	**2007**	**2008**	**2009-2010**	**2011-2012**	**2014 (grace period)[2]**
GHG target[3]								
CO_2 market[4]								
Electricity market								

The simulation spanned the years between 2001 and 2014, although trading started in the year 2003. Prior to the first session, governments and generators had provided their starting point, including:

- assigned amounts allocated to each generator;
- electricity generation during 2001-2002 and corresponding CO_2 emissions;
- possible investment decisions taken in these two years;
- GHG emissions of sources outside the generation sector and countries' overall GHG inventories.

Every week (two-year period), the electricity market opened first and generated prices for all generators and buyers (box 1). A generator that had submitted a generation schedule with fossil-based

[2] Because there will be a delay between 31[st] December 2012 and the production of Parties' 2012 GHG inventories, Parties with excess allowances were allowed to transfer them to other Parties that may need them for compliance with their 2008-2012 commitment, during a so-called grace period. The electricity market was no longer open during that last session.

[3] Emission targets and timetables were not defined beyond 2012, but participants were told to assume that objectives would be more stringent than those under Kyoto for 2008-2012.

[4] Emission trading started in 2003, assuming that all Parties would be eligible to trade that year – a rather optimistic assumption, since very few Annex B Parties currently possess the necessary elements to be eligible.

facilities would know on Tuesday how much it should supply from each type of facility. This determined each player's CO_2 emission level and allowed it to adjust its CO_2 trading strategy (table 2).

Box 1 - The electricity market: day-ahead auction and regional pricing

The simulation offered the opportunity to test the basic mechanisms of electricity trading. In current markets such as Nord Pool, buyers (sellers) bid (offer) quantities of electricity for each hour of the day, every day for the next day. Once all bids (proposals to buy) and offers (proposals to sell) are given to the exchange, the market solves for a unique market price, which is then adjusted to take into account physical constraints related to transmission. The exchange therefore produces a price for each area of the region.[5]

Information on existing transmission constraints in the Baltic Sea region was used to make the simulation more realistic from a geographic and transmission standpoint. It was possible to change such constraints during the simulation – as changes in transmission capacity happen frequently in the real world. However, it was decided not to change capacity numbers in order to provide more stability in the market. Transmission prices were not reflected in electricity prices received/paid, but congestion management cost was indirectly reflected through the use of area prices.

Because every session in the simulation spanned two years, generators and buyers submitted their demand and supply schedules at the beginning of every week for 6 periods of four months: Winter (January-April), Summer (May-August), and Autumn (September-December). Presumably, electricity demand would be lower in the Summer period. These periods rendered parts of the seasonal activity of power generation.

Every Monday, generators submitted step functions (i.e., six supply schedules) indicating willingness to produce MWh for one season based on offered prices. These schedules were binding: once submitted, generators had to supply the quantity corresponding to the price announced by the exchange. Buyers – simulated – submitted step functions for electricity demand on a country by country basis, i.e. a single buyer for each country.

It was assumed that all generated electricity would be sold on the exchange. Nord Pool indicated that a large number of generators on the market would improve the realism of the simulation through better market liquidity. For some generators, this required adjustments as they currently export electricity outside the Baltic Sea Region. For the purpose of the simulation, the market was restricted to the Baltic Sea, and exports to countries outside were simulated as local demand instead.

This market structure, well suited for simulating a long time period, necessitated considerable adjustments from the reality of current electricity markets. Bidding generation for four month periods as opposed to an hour could seriously affect the economics of generation: the received price, high or low, applied to electricity sales over four months. In some circumstances, a generator could receive a price for a four-month period, which corresponded to a plant operated for only a few hours.

On the other hand, the peak demand was considerably reduced, and so was the use of plants that are sometimes the most CO_2 intensive. This should have facilitated compliance with CO_2 objectives.

Other critical assumptions included: the sale and purchase of all power on a single market and the ability to use all available transmission capacity between countries.

For these reasons, the results presented below can hardly be interpreted as projections of future developments in the region's electricity market(s).

[5] See Nord Pool (2001) for a summary description of how the spot market is operated in real world conditions.

Table 2: A Week in the Simulation

	Operations
Monday*	Generators and buyers send their supply and demand curves to Nord Pool before noon
Tuesday	Prices are given to all electricity players in the afternoon
Wednesday	CO_2 market is open for 1½ hours
Thursday	Reporting (electricity, emissions, trades**)
Friday	Feedback

** JI transactions could take place at any time as they are not contingent on the electronic markets.

Box 2 - The CO_2 market: continuous trading and Joint Implementation projects

The market for CO_2 emission reductions consisted of: (i) an exchange for emission trading, provided by Nord Pool; (ii) bilateral transactions for reductions from joint implementation projects.

Emission trading on the exchange relied on a double auction, or continuous trading: each participant proposed quantities for sale or purchase at a price of their choice. At any point in time, the exchange displays the best bid (highest proposed price for purchase) and offer (lowest price asked to sell) – other offers are also displayed, but cannot lead to a transaction at that point. A transaction can only take place when two participants agree on one of these two prices. With this principle, the double-auction system offers a competitive pricing mechanism.

Transactions on the exchange were anonymous – certain markets disclose the identity of buyers and sellers, but this was not the approach taken here. Trading sessions took place once every week over a period of 1½ hour. These design choices were intended to generate a more transparent, competitive and liquid market. If the market had been open constantly over 6 weeks, there would have been a risk of supply and demand not being present on the market at the same time, making it difficult to generate price movements.

In the simulation, the traded unit was 1,000 tonnes of CO_2 – a million tonnes could have been too large a unit for participants with low assigned amounts.

Who are the actors and what guides their behaviour ? :

Two kinds of actors were represented in the simulation, with distinct activities and responsibilities as shows the table below:

Tasks	Governments	Electricity generators
Objective	• Ensure that the country's total emissions over 2008-2012 will not exceed their assigned amount (see table 3).	• contractual obligation to supply electricity to the grid, if they had submitted a supply schedule to Nord Pool. • a CO_2 emission objective for 2008-2012, as part of the country's commitment under the Kyoto Protocol.
Obligations : allocation and generation	• Allocate emission objectives to electricity generators according to a simple principle: the country's assigned amount would be distributed according to the respective players' 1999 emission levels[6]. • allocate the tradable amount to the generators, once the commitment period reserve has been calculated[7]. • managing others sectors' GHG emissions : once allocation to electricity generators had been made, the government player needed to manage the rest of the country's GHG inventory[8].	• for each country, the IEA gathered power generation statistics together with corresponding CO_2 emissions. Participants agreed to include heat generated by combined-heat-and-power plants. In order to bring the electricity market to a realistic size, it was proposed that generators for a given country in the simulation share among themselves the totality of generation and corresponding CO_2 emissions. Most companies did not play on the basis of their current generation[9].
Compliance	• If a government emissions were well above its amount, it needed to take action to reduce them domestically and/or acquire allowances from the market. • Alternatively, it could launch a joint implementation (JI) project in another country, or agree to acquire emission reduction units (ERUs) from JI projects, after approval by the government of the country that hosted the project.	• Generators had several options to reduce their CO_2 emissions : - lower generation from CO_2 intensive plants and increase generation from others plants accordingly. Use a less CO_2 intensive fuel in plants with dual-firing capacity - lower overall generation - invest in less CO_2 intensive generation to substitute to fossil-based plants between 2008-2012. Any investment should be described at the moment it is launched. • In addition, generators could acquire CO_2 emission allowances and

[6] If a generation company emitted 15 per cent of the country's total GHG emissions, its constraint would be defined as 15 per cent of the country's assigned amount under Kyoto. A generator that relied entirely on hydro, nuclear or wind resources, if it decided to invest in a combined-cycle gas turbine, would need to cover every single ton of CO_2 emitted by this plant with purchases of allowances on the market. With the same rule, a generator in a country with a significant surplus of allowances would receive a share of this surplus, available for sale or banking without incurring any additional cost. This rule would have considerable impacts on the competitiveness of generation in the region, as some would start with significant "head room" to increase their emissions or sell their excess allowances, at a profit.

[7] The reporting framework provided by IEA included various methods to allocate the reserve across generators, governments could also define alternative options. One simple method was to distribute the tradable amount according to the entities' initial share of the country's assigned amount; if an entity is responsible for per cent of the assigned amount, its reserve would be 20 per cent of the country's reserve. For countries with the reserve set by the last inventory, each entity's reserve could simply be five times it latest inventory. The tradable amount is simply the difference between an entity's reserve and its assigned amount.

[8] A simple country module was distributed to each government player to project future GHG emissions outside the power generation sector, to test policies to reduce emissions (simulated as a tax in €/tCO_2), and quantify the cost of these policies. There can a significant difference between the level of a tax and the actual marginal cost of emission reductions. Participants needed to assess the marginal cost of various emission paths in order to decide on a cost-effective emission reduction strategy. The model's aim was to allow government participants to test various paths of policies between 2001-2012 and to measure exactly the difference between their inventories and their assigned amount, which should guide trading.

[9] These virtual companies provided a description of their initial capacity, underlying technologies and efficiency and corresponding CO_2 emissions, based on coefficients provided by IEA. They also needed to provide a break-down of generation among various plants for each season.

		ERUs from other participants.
Reporting	• At the end of every session, governments reported on the Parties' total emissions for the two years of the session, including CO_2 emission inventories from power generators. The government players reported emission levels projected by their model, together with the policy cost that they has applied in the model to reach that level. • each Party reported on its acquisitions and transfers for both allowances under emission trading and ERUs for Joint Implementation projects[10].	• Generators had to provide to both their governments and IEA: - their supply profiles for the six seasons of every period, matching the quantity asked by NordPool. - Their biannual CO_2 emissions, which governments used to complete the country inventory - The summary of their CO_2 transactions, including JI projects - Their investments decisions, if any taken on those years. The description of planned additions to capacity should include data on technology, capital cost, capacity, efficiency and fuel type.
Implementing the commitment period reserve	• The Marrakech Accords set a limit on how much a Party can transfer during the commitment period, so as to avoid overselling (excessive transfers of allowances that don not match actual reductions by the seller). Until the 2012 inventory of a Party's has been produced and reviewed, it should not allow its assigned amount to fall below the lowest of two levels: option 1: 90% of its assigned amount, option 2: 5 times its latest available reviewed inventory.	
Approval JI projects	• governments also had to approve joint Implementation projects that could be proposed by their power generators, and to report corresponding transfers of ERUs as they took place.	
Establish a domestic compliance regime	• Governments could establish a domestic compliance regime : financial penalties for non-compliance (Norway and Sweden imposed a €100/tCO_2 penalty, annual GHG objectives for each year of the commitment period, or renewable electricity goals for generators[11].	

[10] A simple reporting framework was provided for that purpose, with details on each player's emissions and transactions.
[11] These domestic policies were not monitored in the simulation. Feed back from participants indicated that options such as an annual target were not implemented. Some generators self-imposed a renewable energy quota to test the implication of such measures on the cost of CO_2 reductions.

2. Lessons learned:

2.1 Domestic mitigation policies, electricity generation and CO_2 objectives : irreversible policy and technology choices

2.1.1 Domestic mitigation strategies

In the simulation, the only lever that governments could use to reduce emissions outside the power sector was a tax on CO_2 emissions. They had full flexibility to choose a tax path over the simulation period but were also bound by past choices.

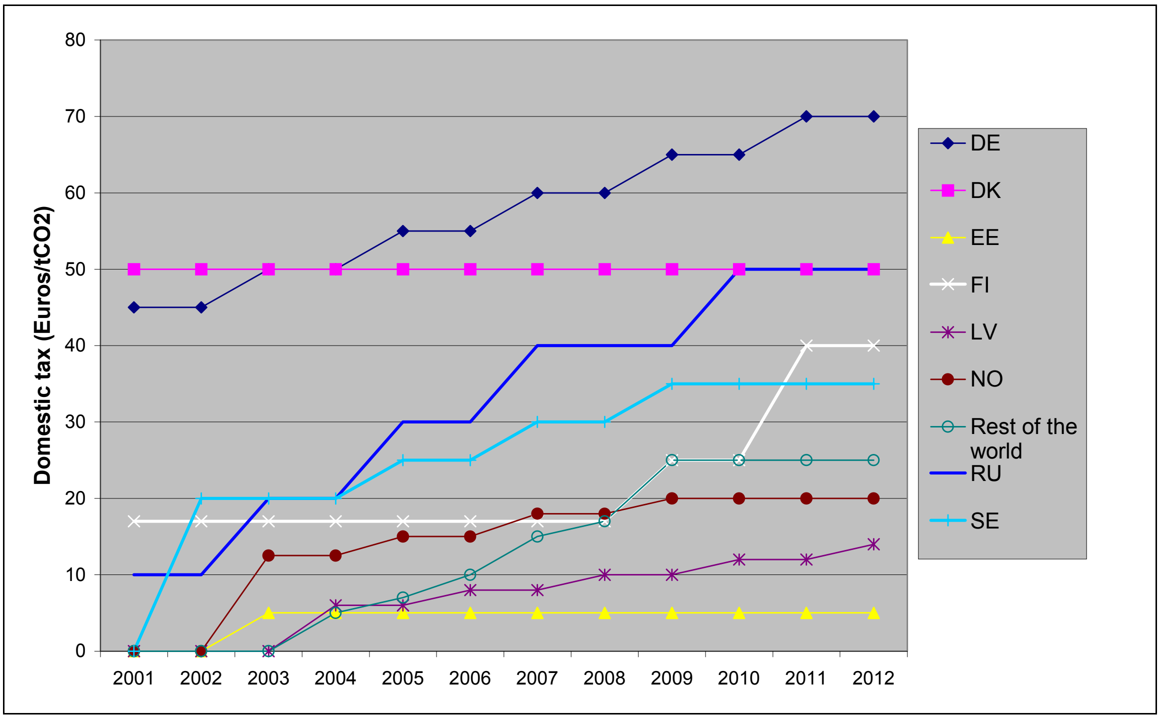
Figure 1 shows the tax levels used by various governments in the simulation to reduce their emissions. For the most part, the trends show coherent approaches: a stable tax rate or steady growth, with only one exception (FI[12]). Once a policy course has been set, it is unlikely to be radically altered in the course of the commitment period.

Some players noted that the early indication of the price of allowances made it possible to adjust their domestic policy to minimise cost. In the case of DE, the domestic policy objective of reducing emissions further than the domestic target under the EU agreement would have driven the tax rate to an unacceptably high level. The availability of allowances at a lower cost on the market made it possible to avoid this politically difficult outcome.

Countries with a surplus fall in two distinct categories in this simulation. On the one hand, RU, LV and EE implemented domestic measures to further reduce their emissions. PL and LT took no measures to contain emissions, other than the cap on the power generation sectors – in the case of PL: the government had to purchase allowances to achieve compliance during the grace period.

[12] These tax levels allowed the government to maintain emissions at a stable or slowly increasing level, and minimised the trading needs.

Figure 1: Increase in CO_2 Taxes in the Simulation



Source: Simulation participants, based on IEA country emission and cost modules; Norway used its own model and statistics.

Note: Some countries in the regions had implemented CO_2 taxes prior to 2001; hence the above figures would represent *increases* from their existing domestic tax levels.
Countries not represented in this picture (LT, PL) did not apply any cost on their domestic emissions over the period.

RU's policy choice may seem peculiar – but partly explains its pricing behaviour on the market. In spite of a very significant amount of allowances above its projected 2008-2012 emissions, the government decided to introduce an aggressive policy to contain the growth of its emissions. RU participants explained that they sought to simulate the effect of early investments in domestic mitigation – and could only reduce emissions in the simulation through a tax increase. In that sense, the tax level recorded in RU has no direct meaning. One could of course question the realism of high CO_2 taxes in transition countries: government officials often make the point that the compliance situation of their countries – i.e. their ability to comply without taking immediate action – makes it difficult to promote climate change on the list of priority for government action[13]. In that sense, the "no-tax" approach observed in LT and PL may be a more likely scenario, even if an economically rational behaviour would suggest otherwise, in presence of an allowance market.

[13] Participants from Central and Eastern European countries to the OECD/IEA/IETA workshop on "National systems for flexible mechanisms: Implementation issues in countries with economies in transition" (13-15 May, Szentendre) reiterated this point.

2.1.2 Power generators: managing uncertainties

The electricity side of the simulation proved very insightful, even if the development of the electricity market was considered rather unrealistic by a number of participants.

Generators were not constrained in their investment or trading behaviour, which, some players thought, facilitated their task.

Participants almost unanimously recognised that the data generated by the simulation as "virtual". But the scenarios generated by the simulation, trends and behaviours bring very interesting information on power generation under a greenhouse gas constraint.

a. Generation and CO_2 objectives: diversity of starting points

Table 3 provides a summary of where various generators stood at the outset of the simulation. We show in particular the gap between their 2002 emissions and their allowed emission level during the commitment period.[14]

The more or less ambitious environmental goals were largely determined by the country of origin. The suggested allocation rule was to define the generation sector's obligation in proportion with its share in the country's emissions in 1999. Generators in countries with excess assigned amounts had therefore objectives well above their 2002 and projected emission levels.

In SE and DE, generators adopted an identical starting point, in contrast with the FI, PL, NO generators whose profiles were divergent. In NO, two companies that had no generation capacity in 2002 indicated their intention to install natural gas-based capacity during the commitment period. These generators had no allowances and needed to acquire them on the market to cover the totality of their emissions in 2008-2012.

[14] A more detailed description of the virtual generation companies is provided in the Appendix.

Table 3: Output, Emissions and Objectives of Virtual Generation Companies

	Output in 2002 (TWh)	Share in total regional output (2002)	Emissions in 2002 (MtCO2)	Difference with assigned amount
DE1	276.9	25.6%	160.7	19.66%
DE2	276.9	25.6%	160.7	19.66%
DK1	20.9	1.9%	16.1	55.78%
DK2	14.8	1.4%	4.1	56.16%
EE1*	7.1	0.7%	8.5	-63.17%
FI1	21.9	2.0%	2.1	-8.89%
FI2	7.7	0.7%	4.7	10.87%
FI3	42.1	3.9%	21.6	17.01%
LT1*	13.8	1.3%	1.2	-84.94%
LV1*	3.9	0.4%	0.7	-52.14%
NO1	0.0	0.0%	0.0	NA
NO2	0.0	0.0%	0.0	NA
NO3	121.2	11.2%	0.0	NA
PL2*	40.5	3.7%	38.0	-23.62%
PL4*	22.3	2.1%	25.1	-9.14%
PL5*	28.3	2.6%	28.9	-35.03%
RU1*	44.5	4.1%	22.5	-50.55%
SE1	46.8	4.3%	1.9	0.54%
SE2	46.8	4.3%	1.9	0.54%
SE3	46.8	4.3%	1.9	0.54%
Total	1083.2	--	500.4	-2.17%

Source: Simulation data.
Note: * Indicates a generator in a country with an excess of assigned amount.

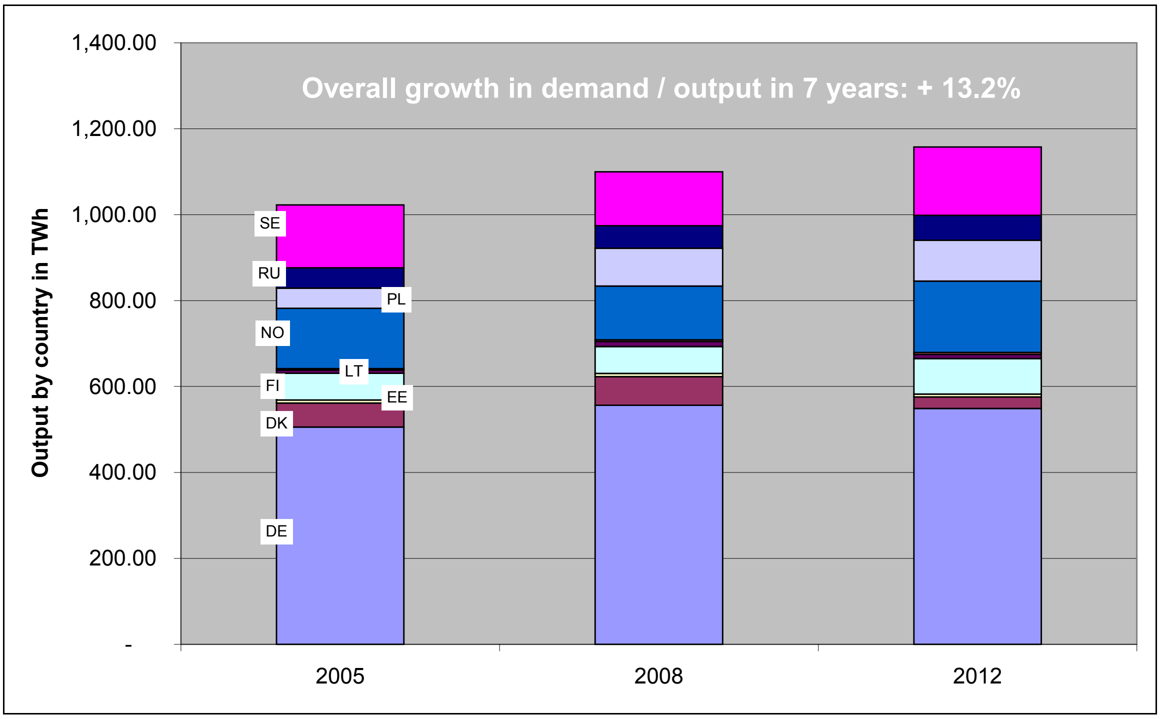
Some external policy factors were also taken into account by participants:

- The decision to invest in 1,000 MW of nuclear generation in FI, shared across all three players;
- The de-commissioning of the Barsebäck nuclear plant in SE, Ignalina nuclear plant (two reactors) in LT, and phase-out of nuclear capacity in DE;
- In some cases, participants assumed participation in a green certificate system where additional renewable energy could be sold at a premium (SE), or a mandatory target to provide a certain percentage of renewable electricity by 2010 (DE).

At the outset, it is clear that the chosen allocation rule and the additional assumptions would have widely different implications on these companies' cost to meet their emission objectives. Such contrasted, even extreme, picture made it somewhat easier to distinguish generation and electricity pricing strategies under a CO_2 constraint.

b. Electricity market evolution 2005-2012

Figure 2: Growth in Electricity Output by Country – 2005-2012



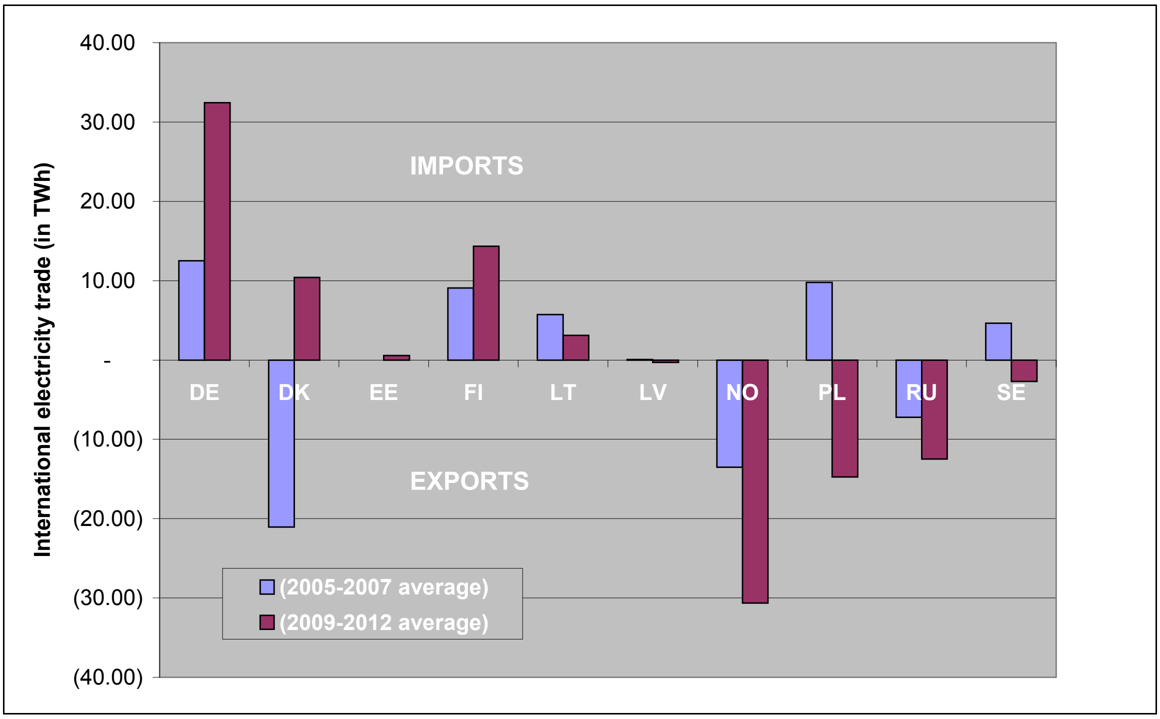
Source: Nord Pool data from the simulation.

After the trial session (2003-2004), the market started out at a fairly low overall volume – 1,022 TWh against 1,083 TWh in 2002 – and it took a few sessions for participants to adjust their bidding behaviour and to bring overall demand to a more realistic level. 2008 was a "dry" year for Scandinavian countries, resulting in lower generation volumes in NO and mostly SE, while DK, RU and PL increased their output to make up for the shortfall in SE.

A detailed look at the market results shows significant swings in the electricity trade balance of countries through time.[15] These reflect shifting supply/demand imbalances within countries resulting partly from the addition of the value of CO_2 in the supply curves of generators.

[15] As stated earlier, the Nord Pool electricity trading platform assumed full access to the transmission capacity across countries.

Figure 3: Electricity Imports and Exports in the Baltic Sea during the Simulation



Source: Nord Pool data from the simulation. Data for 2008 was not included as it was assumed to be a dry year for Scandinavia.

As an example, DK generators had the possibility to export large amounts of electricity to neighbouring countries without being affected by the CO_2 constraint, in 2005-2007. The situation was reversed during the commitment period. LV, PL, RU companies also increased their exports during the commitment period, as their CO_2 objectives allowed for significant growth in output.

How did electricity prices evolve over the period? Were they significantly affected by the constraint on CO_2 emissions? The economically-rational behaviour would be that each generator fully reflects the cost of carbon attached to its own generation, regardless of its position as a buyer or a seller of allowances. A generator that sells electricity based on fossil fuels must cover these with allowances; if it is in a position to sell these allowances but higher electricity sales (and emissions) prohibit such transaction, it should be compensated for the foregone allowance sale. If it must buy allowances to cover increased emissions, it will lose financially by not reflecting this cost on the price of its electricity.

From what can be read in market clearing prices, participants did not always reflect the full cost of CO_2 emissions in their offered electricity prices. Table 4 provides a preliminary analysis of the possible influence of CO_2 allowance prices on the market clearing prices of electricity in different countries. We find that:

- In most countries where generators were, on the whole, buyers of CO_2 allowances, the cost of carbon was probably fully reflected in the offered prices; the residual price increase is explained by higher level of demand;

- For generators with an excess of allowances (in transition economies), the market clearing price increased less than the carbon mark-up. In other words, these generators did not price their generation with full account taken of the CO_2 cost – this finding was confirmed by feedback from participants after the simulation. The fact that a "generous" allocation was distributed to them for free can be a justification for this behaviour even if they could have optimised their strategy through more cost-reflecting prices and active trading on the CO_2 market.

Table 4: Influence of the CO_2 Allowance Price on Electricity Prices

	Market clearing price in 2005 (Euro/MWh)	Market clearing price in 2011 (Euro/MWh)	Price increase (2011-2005) (Euro/MWh)	Carbon content of generation (2011) (tCO2/MWh)	CO2 "mark-up" in 2011 (Euro/MWh)	Residual price increase (Euro/MWh)
DE	26.41	40.26	13.86	0.5273	9.24	4.62
DK	23.96	37.85	13.89	0.2823	4.95	8.94
EE	26.43	34.56	8.13	0.9906	17.36	-9.22
FI	23.96	36.13	12.17	0.3259	5.71	6.46
LT	26.43	31.56	5.13	0.5705	9.99	-4.86
LV	26.43	31.56	5.13	0.1261	2.21	2.93
NO	23.66	35.80	12.14	0.0094	0.17	11.98
PL	27.72	37.79	10.08	0.9935	17.41	-7.33
RU	26.43	31.56	5.13	0.4807	8.42	-3.29
SE	23.96	36.13	12.17	0.0478	0.84	11.33

Source: Nord Pool and IEA data from simulation.
Note: The CO_2 "mark-up" is equal to the average carbon content of generation in the country multiplied by €17.5, the average price of carbon in the simulation.

c. Compliance strategies of generators : investing in lower carbon generation and the role of other energy policy choices (nuclear, renewable energy certificates markets…)

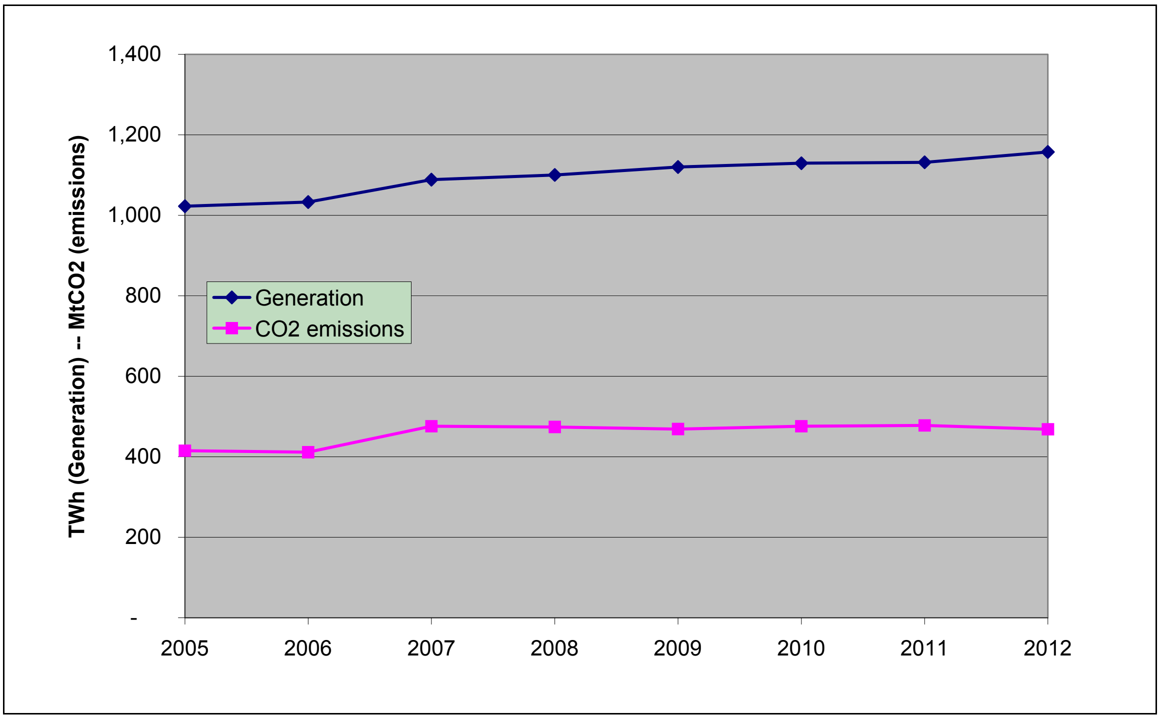
Generators all managed to meet the CO_2 emission objectives assigned in the simulation. Their strategies to achieve these goals varied remarkably, even for virtual companies with identical generation profiles in 2012 (in DE and SE). To a large extent, this reflected participants' assumptions about other policy goals that would apply to power generation – e.g. renewable energy requirements, nuclear phase-out, etc. – and shows that the cost of meeting CO_2 constraints will hinge on other policy priorities. We can't go into a detailed cost analysis of generators' compliance strategies, but we provide, when available, orders of magnitudes that may be useful to understand the major factors affecting compliance costs.

The trends in electricity supply and CO_2 emissions over the period show a slight de-coupling between electricity output. This is confirmed by data on the carbon content of generation before and after the commitment period: CO_2 emissions per MWh of generation declined by 12.5 per cent on average between 2002 and 2012 (Figure 4).

This trend reflects significant investment in new, low-CO_2, generation capacity (19 GW) and retrofitting of existing plants (6 GW) over the simulation period, in the case of generators with emission objectives that required reductions from current levels. This would amount to some €20 billion over the period. Out of the 19 GW of new capacity, 6 GW are in wind power. One player assumed that it would be subject to a green power obligation, under which part of its renewable energy power would be sold at a premium (SE2). This would affect the economics of wind and other renewable sources – and of CO_2 mitigation more generally, even if wind power does not appear to be one of the least-cost options to abate CO_2; a green certificate regime that would improve the economics of wind would nevertheless have direct benefits on CO_2 emissions.

It is important to note, however, that about 3,000 MW of carbon-free nuclear capacity were phased-out by DE1, where they were replaced by 4,500 MW of wind, 600 MW of biomass. Because wind power supply is intermittent, new base-load gas capacity was also installed (3,600 MW). The corresponding increase in emissions was partly offset by coal-to-gas retrofitting in existing plants. In all, part of the investment cannot be attributed to the need to reduce CO_2 emissions, but rather by the early retirement of some nuclear power plants. In an opposite direction, FI generators shared new nuclear power capacity from 2011 onward.

Figure 4: Electricity Output and Related CO_2 Emissions 2005-2012



Source: Simulation data

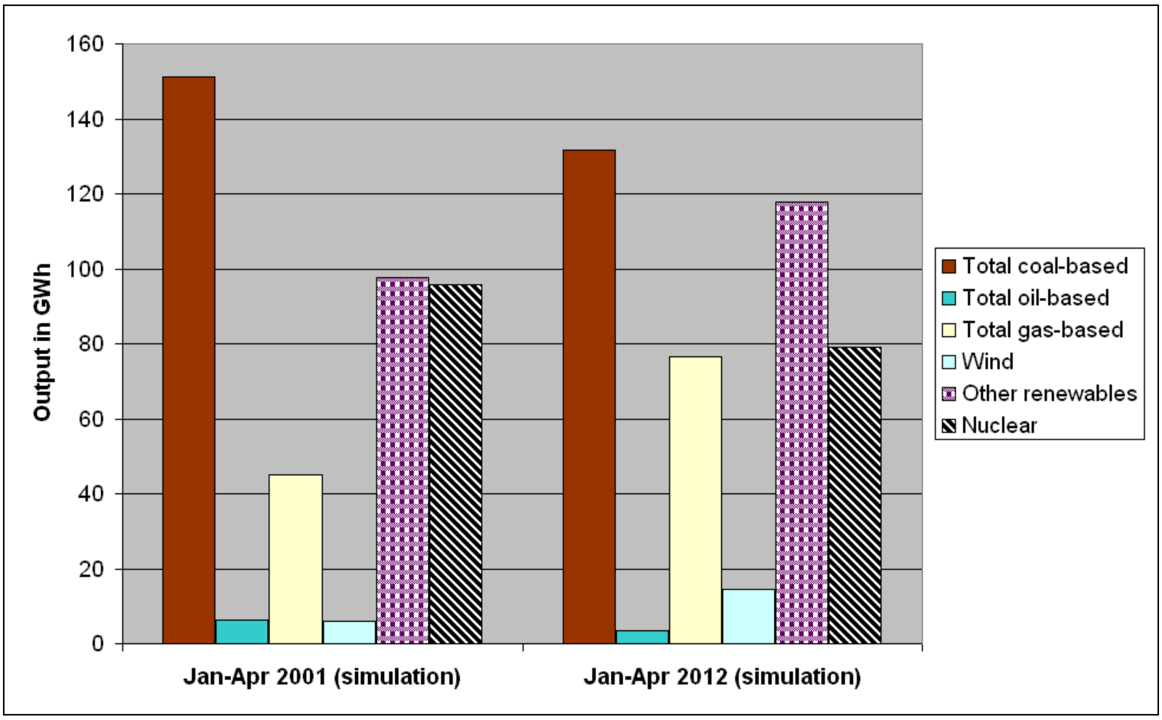
Table 5: Investment in New Capacity – Generators in "buying countries"

	2002-2004	2005-2007	2008-2012	Total
Hydro	0	1110	450	1560
Biomass	0	666	350	1016
Wind	1533	3200	3670	8403
Nuclear	0	0	1150	1150
Gas & CCGT	10	3700	2300	6010
Retrofit (coal to gas / biomass)	0	3518	2900	6418
CHP peat/coal	0	50	190	240
CHP gas	0	0	200	200
CHP biomass	0	180	500	680
CHP misc. Fuels	0	220	90	310
Total				25987

Source: Generators reports during the simulation.

The simulation also highlighted the important role of heat generation. It was assumed that all fuel consumption, whether for heat or power, would be subject to the emission cap in the simulation. But since all electricity was sold on the market, a price that was too low for CHP plants stopped heat generation. It is not clear whether this is an artefact of the simulation design or if this points to a real problem of a fully-open electricity market.

Figure 5: Electricity Output by Fuel/Technology (Winter 2001 and 2012)



Source: Simulation data

Generators with emission targets well above their emissions were of course less prone to invest in new capacity, except for those who agreed to Joint Implementation projects. In all, a total capacity of 1,700 MW was installed or retrofitted over the 2002-2012 period. Here again, the closing of nuclear plants in LT – Ignalina I and II amounting to 2,600 MW – required investment in substitution capacity, in this case combined-cycle gas turbines and some wind generation. Because the country had significant over-capacity, only 350 MW were installed to make-up for the loss of nuclear generation. It also started to import electricity from neighbouring countries – see Figure 3 above. As a result, the LT generator recorded a large increase in CO_2 emissions, at 5.4 $MtCO_2$ against 1.5 Mt in 2001, while output declined from 13.5 TWh to 12 TWh in the meantime. It is clear that the generous allocation of CO_2 objectives allowed the LT generator to make a generation choice that would otherwise have direct cost repercussions. In a single year of the commitment period, the 4 Mt increase in emissions would add € 66 Mn to operating costs, with the allowance price level observed in the simulation, had the allocation been based on 2001 emission levels.

Figure 5 illustrates the change in technology and fuel over the simulation period for two winter periods (January to April): the reduction in coal-based generation is offset by increases in gas-based, wind, and other renewable generation (hydro and biomass). Both years were assumed to be "normal": a dry year would show a very different profile, as lower hydro generation would need to be offset by other capacity in the region. For this and other reasons presented at the beginning of this section, this picture cannot be taken as a forecast for the region's power generation under a carbon constraint, but simply as a one-off scenario.

2.2 Governments and generators trading

2.2.1 Government trading

By design, government-level trading was a major element in the simulation. While it is likely that governments would take some part in international emission trading and other flexibility mechanisms, the simulation gave governments an overly significant role in the emission trading market. In a more realistic picture, other industry outside power generation would be engaged in emission trading, contributing to more liquidity and a more competitive market. Last, governments had no budgetary constraint on their trading activity.

All governments traded allowances during the simulation (see Table 6), although with varying intensity. Some governments had a rather small emission gap to bridge with domestic reductions and did so cheaply, while others had a clear interest to acquire a portion of their compliance needs on the market (DE, DK, NO, PL and ROW).

For some net buying countries, compliance did not stop at an exact coverage of 2008-2012 emissions: some portion of the unused assigned amount was banked (DE, SE). One government player indicated that a higher market price would have persuaded the government to sell banked allowances during the grace period.

Governments with an excess of allowances adopted two very distinct behaviours: while RU sought to maximise trading revenues, others were more restrained in their trading strategies. The latter indicated that they would also have sold more, had the price reached higher levels in the grace period, but that keeping allowances in the bank was also a valid strategy from their standpoint.

It was expected at the outset that governments would seek to cover their needs on the market as early as feasible. In fact, most of government purchases occurred during the commitment period; the largest trading volume was observed in the grace period.[16] No firm conclusion can be drawn, however, as some of the large buyers (DE) did not have access to the trading platform in the early sessions. The comment was made that leaving most transactions to the very last years of the commitment period (or to the grace period) could be economically risky, as the ability to control emissions, and to respond to higher prices, would be minimal at that point.

[16] Three players conducted bilateral transactions after closure of the market as they had not managed to acquire all the necessary allowances to achieve compliance while the market was open.

Table 6: Government Sector Compliance and Trading

	Initial assigned amount (AA) Mt CO2	2008-2012 emissions Mt CO2	Adjusted AA Mt CO2	Net trades ('+': bought) Mt CO2	Surplus after trading Mt CO2	Share of surplus traded %
DE	3431.3	3344.1	3517.9	86.6	173.7	
DK	207.9	231.0	232.9	25.0	1.9	
EE	60.3	37.6	53.1	-7.2	15.6	32%
FI	251.0	248.1	250.0	-1.0	1.9	
LT	179.9	100.2	179.4	-0.5	79.2	1%
LV	135.8	58.0	124.9	-11.0	66.9	14%
NO	262.6	277.0	277.1	14.5	0.1	
PL	1635.7	1653.0	1653.0	17.3	0.0	
RU	11651.7	8510.6	9107.1	-2544.5	596.5	81%
SE	338.4	316.3	346.4	8.0	30.1	
RoW	33729.0	36584.6	36585.7	2856.7	1.1	

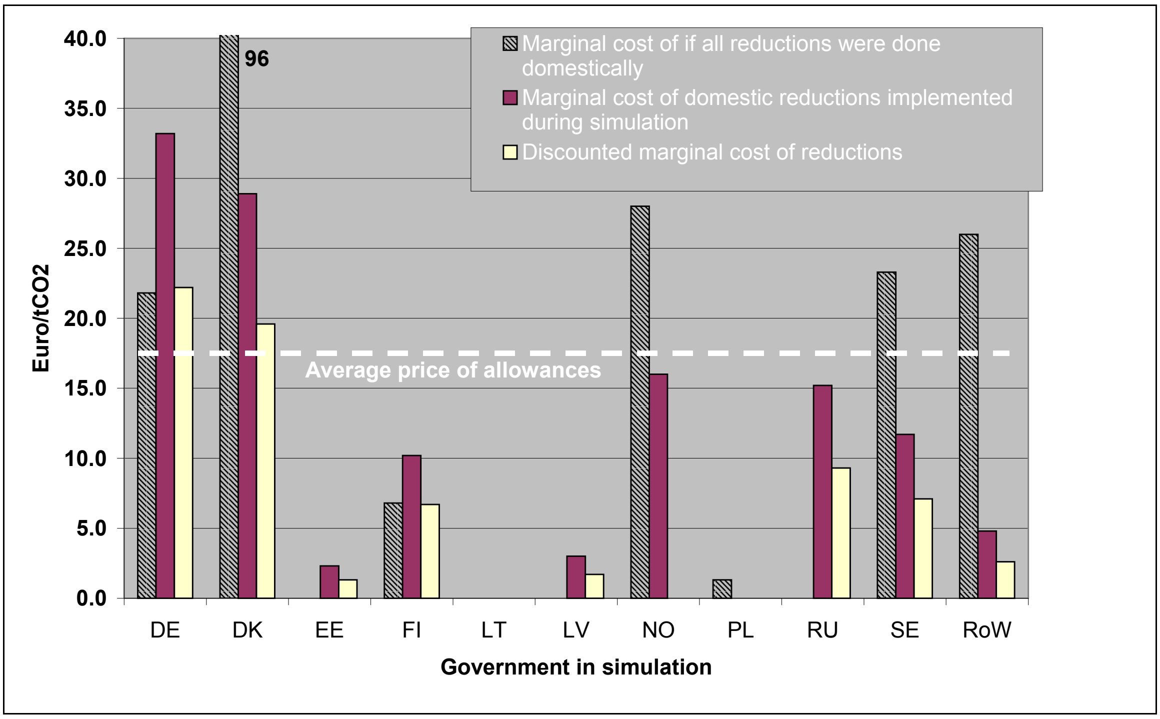
Source: BASREC simulation data

In the end, were governments economically efficient in their mitigation strategies? Economic theory suggests that the marginal cost of domestic reductions should match the price of allowances, so that no reduction is achieved at higher cost than what is available on the market. Figure 6 shows an ex-post evaluation of the domestic marginal cost of reduction for the government sectors in the simulation. It confirms that few governments have matched their domestic marginal cost with the international price, which is not surprising. Governments sought to reflect the national priorities (e.g., ambitious domestic reductions for DE), the political feasibility of raising higher carbon taxes. They were also faced with uncertainties on the future price of allowances and emission trends[17] (e.g., RoW expected a drop in allowance prices later in the simulation).

The figure sheds also an interesting light on the pricing behaviour of RU: its domestic marginal cost – not discounted – reached €15/tCO_2. With that assumption, the sale of allowances at €17.5 is somewhat more rational than if RU had not undertaken any further reduction. In theory of course, the price level should match the marginal cost exactly and the €2-3 "mark-up" between the marginal cost and the allowance price is a sign that RU was able to exert some monopolistic power on the allowance market.[18] The extent of market power is even more conspicuous if we compare the discounted marginal cost– less than €10/tCO_2 – with the allowance price.

[17] In the end, only RoW was subject to a significant and unexpected shock on its emissions – a major drop in 2011-2012 as a consequence of a severe economic recession, but all participants were aware that deviations from their baseline emission trend could happen.
[18] See OECD/IEA (2000) for a discussion of market power in international emission trading.

Figure 6: Marginal Costs of Mitigation for Governments during the Simulation



Source: IEA simulation data

Note: * These costs reflect *ad hoc* GHG projections for sources outside power generation, simulated for this exercise. These data should not be used outside the context of this simulation. The costs are computed from the IEA modules, looking at the additional cost necessary to reduce emissions by one more tonne, through an increase in domestic tax. The observed marginal cost differs from the tax rate for a number of reasons including the recycling of tax revenues in the economy, structural changes brought by early action, etc. The discounted cost refers to the marginal cost discounted to 2001, assuming 8 per cent as a discount rate. NO relied on a Norwegian model.

On the other side of the market, the presence of a very large buyer (RoW) was not enough to balance RU's monopolistic power. Had it been the case, the buyer would have depressed the international price by achieving more significant reductions domestically, this was clearly not the case in the simulation. But the rising emissions of RoW, known to all participants as years went by, indicated clearly that this player's demand for allowances would be significant.

As stated in the section 3.1.1Caveat: the price of CO2 and what it really means, the observed price level should therefore considered as an artefact of the simulation, not a projection of expected prices. One could, for instance, question the ability of the government of RU to undertake aggressive reductions at a cost that could justify the pricing behaviour observed in this simulation. The addition of competing supply of allowances from other Central and Eastern European countries and the Clean Development Mechanism could also undermine its monopolistic power, if it decided to exert it.

Governments' behaviour in summary

In closing, we note that the above observations concur with insights from an earlier simulation that involved government participants[19]:

- Government policies are likely to remain fairly stable – or follow a predictable path – in the course of the commitment period. Unless CO_2 prices become prohibitive, emission trading would be used to cover excess emissions – or sell surplus allowances;

- Banking plays a crucial role in governments' strategies (no trade is always safer than a bad trade);

- The perception today is that drastic efforts to reduce emissions in countries where emissions are substantially below 2008-2012 targets are not likely, as political momentum for such action is lacking.

In the particular framework adopted here – a very large seller on the market – the risk of monopolistic power cannot be excluded. The reporting of countries' GHG inventories will provide crucial indications on overall supply and demand. Countries with emissions well above target during the commitment period will have little bargaining power, because CO_2 emissions – especially energy-related – are subject to significant inertia. Sellers will know that these buyers have limited margin to reduce emissions.

2.2.2 Generators : Trading CO_2 for compliance – and more

Generators were quite active on the CO_2 market even if their share of the traded volume is of course small, when compared to RU-RoW transactions that dominated the market. Some players also used the CO_2 allowances market as a business opportunity – acting as both buyers and sellers. This proved risky in some instances, given the limited predictability of prices during the simulation.

Table 7 shows the net transactions and the total trading activity of generators during the simulation. Focussing on net trades and their contribution to compliance, we find a variety of different strategies – beyond the distinction between buyers and sellers. As an example, DE1 and DE2, with identical generation profiles, followed completely different compliance strategies:

- DE1 achieved most of its reductions "in-house", through investment in new capacity, and this in spite of the phase-out of part of its nuclear capacity;

- DE2 relied a lot more on the market to cover its increased emissions but also sold more electricity during the commitment period. DE2, however, continued to use its nuclear capacity in full, which would have brought a significant competitive advantage.

In SE, two different patterns also emerge:

- SE1 and SE3 bought allowances for more than 30 and 47 per cent of their emission objectives, respectively, to cover increased emissions in 2008-2012;

- SE2 reduced its emissions much more than needed and sold the unused allowances on the market. This was made possible by significant investment in new capacity (1,500 MW of wind, 500 MW of new gas-based combined heat-and-power, and fuel-switching in CHP from coal and oil to biomass). SE2 recorded a net profit from their investment and CO_2 trading strategy, because it assumed that its new renewable energy capacity would generate sales of "green" power at a premium over wholesale electricity prices.

With two exceptions (DK2 and LT1), very few generators retained allowances for banking. Generators with excess allowances at the start of the simulation raised therefore some non-negligible revenues from their CO_2 transactions. As we mentioned above, they did not reflect the value of CO_2 in their electricity marketing strategies. Further analysis could reveal whether the gains achieved through higher electricity sales was more profitable than full-cost electricity pricing – and the possibility to sell more CO_2 allowances as a result.

Table 7: Trading and Compliance of Virtual Companies

MtCO2	Net trades incl. JI reduction units	Net trades as % of commitment	Banked units (% of initial assigned amount)	Trading activity	
				Bought	Sold
DE1	0.8	0%	0.4%	41.1	41.1
DE2	103.7	15%	0.0%	330.7	227.1
DK1	2.1	4%	1.3%	20.0	18.0
DK2	33.4	252%	195.4%	45.4	12.0
EE1*	-79.6	-69%	0.1%	-	80.1
FI1	-1.1	-10%	0.0%	2.5	3.7
FI2	1.0	5%	0.2%	1.3	0.3
FI3	1.1	1%	0.0%	5.1	4.0
LT1*	-6.8	-18%	33.8%	0.0	6.8
LV1*	-3.9	-55%	0.1%	0.0	2.5
NO1	5.1	N.A.	N.A.	5.1	-
NO2	5.0	N.A.	N.A.	5.6	0.7
NO3	0.0	N.A.	N.A.	-	-
PL2*	-51.5	-21%	0.0%	5.0	56.5
PL4*	-54.8	-40%	0.0%	-	54.8
PL5*	-22.2	-10%	0.2%	0.0	22.2
RU1*	-90.1	-40%	1.7%	-	89.0
SE1	2.8	31%	0.0%	4.2	1.5
SE2	-3.1	-34%	0.0%	-	3.2
SE3	4.3	47%	0.1%	4.0	0.3
RU2* **	-291.0	-9%	1.2%	-	290.4

Source: Simulation data provided by generators and Nord Pool.
Note: * indicates generators with excess allowances; ** RU2 did not take part in the electricity market, and was allocated a portion of RU's assigned amount, in line with the power generation sector of Russia operating outside the Baltic Sea region.

The above table also shows that players were ready to "play the market" to generate revenues – DE1 did not rely on trading to comply, but bought and sold 41 Mt CO_2 during the simulation. DE2 needed 103 $MtCO_2$ to achieve compliance but bought a total of 330 $MtCO_2$ from the market and did 147 trades. Those who traded actively stated that this activity was rather risky in the simulation, as price dynamics was largely driven by one player and therefore impossible to forecast with the available data.

[19] See Baron (2000) and IEA (2001)

The role of Joint Implementation projects

The number of JI projects implemented in the course of the simulation was rather low although all those with a full description lead rapidly to a project and a transfer of ERUs. So it was rather a matter of supply than one of demand.

In total, nine Joint Implementation projects were concluded, most of which initiated by RU1 (RAO-UES). No JI projects were implemented in Lithuania. The role of JI in the simulation strongly depended on the initiatives of the participants. Particularly, RU participants played a very active role, facilitated by an existing list of actual and well-documented JI projects.

The total volume of ERUs transferred was much smaller than the volume of allowances traded. The following project types were implemented in the simulation: five wind parks (3 to 60 MW), two small hydro projects, the installation of expander units at a power plant, and, finally, a portfolio of small biomass projects. The prices for ERUs ranged from €11 to 15 per tCO_2, cheaper than the price for allowances on the simulation exchange. One Russian project also involved a transfer of allowances at a discount. The general opinion was that the ERU price was determined by the allowance price in the trading simulation. No economic and risk analysis of JI projects was made. Most participants do not think the simulation prices were "realistic" in that sense.

For investor/buyers the main motivation for starting JI was: 1) the lower price for ERUs, 2) to gain experience and establish contacts, and, 3) JI as a investment/business opportunity. The most important reason for not starting JI was the time constraint. Negotiating JI projects took more time than simply buying allowances on the electronic trading platform in a few seconds.

On the learning benefit from the simulation on JI, opinions differ. Some found it useful while others argue that a simulation can not do justice to those characteristics that would determine the competitiveness of JI on real markets.

3. Limits, interpretations:

3.1 CO2 allowances price: the tip of the iceberg

This section provides tentative explanations for the peculiar CO_2 price evolution during the BASREC simulation. Readers should first be aware of the limits of such an exercise before drawing conclusions about the future price of CO_2.

3.1.1Caveat: the price of CO2 and what it really means

The BASREC simulation provides some very interesting insights on how an international GHG allowances price could evolve, although all participants agreed that the price level in itself couldn't be taken as a meaningful forecast for the following reasons:

- The business-as-usual projections used in IEA models are rough extrapolation of past trends; marginal costs of abatement generated by the IEA models were also not meant to be realistic (a single price of carbon applied to a single energy good);

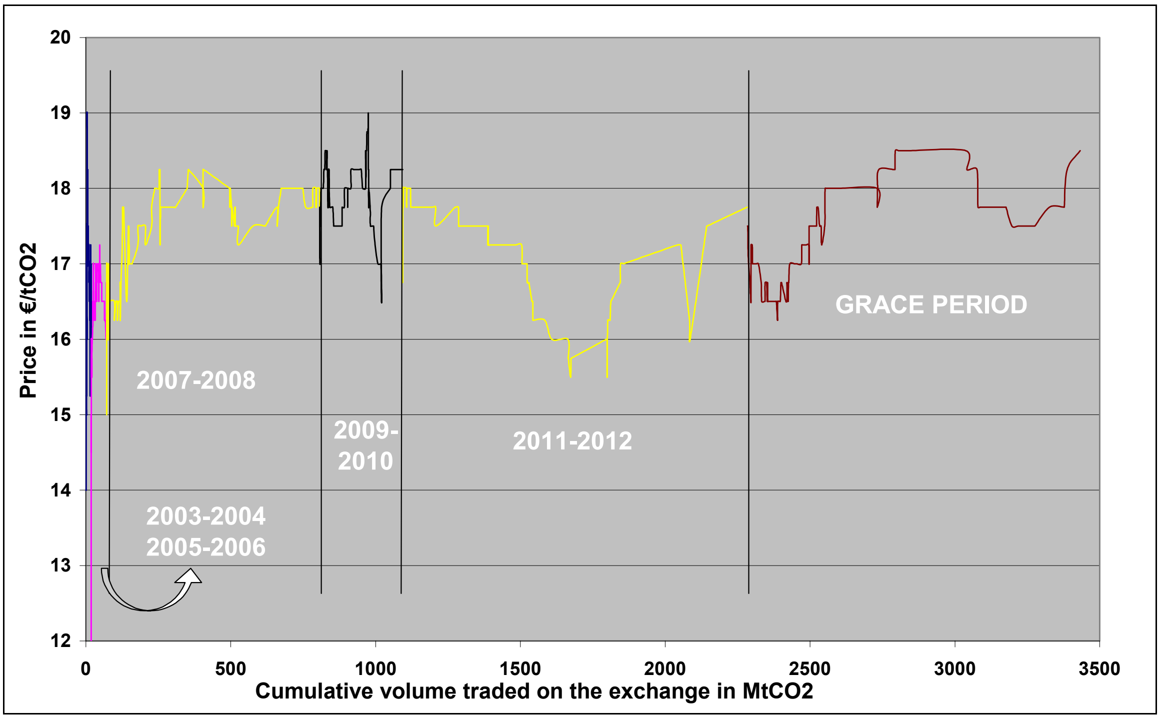
- One player – the rest of the world – played as a bloc, while it included both potential buyers (EU countries outside the Baltic Sea region, Japan, Canada, Australia, New Zealand) and sellers (Ukraine and Central and Eastern European countries outside the region);

- The rule for the allocation of allowances to power generators implied large windfall profits for generators located in countries with economies in transition;

- Other industrial sectors were embedded in the government sector; they would be acting as independent buyers and sellers in the market. Their mitigation and trading strategies would be driven by more accurate cost analyses than made possible here;

- Some players tested radical policies that could be difficult to implement in the real world – in particular a rather aggressive GHG mitigation policy in RU.

Figure 7: Evolution of the allowance price in the simulation



Source: Nord Pool data.

3.1.2 A relatively stable price

The price of CO_2 in the simulation was rather stable throughout the 10 years of the simulation (see Figure 7 and Table 8).[20]

[20] The CO_2 price in other simulations of this kind was much more volatile (IEA, 2001).

Table 8: CO_2 Trading Statistics

	2003-2004	2005-2006	2007-2008	2009-2010	2011-2012	Grace period
Average price (Euro/tCO2)	16.58	16.51	17.67	17.90	17.09	17.82
Price range	14.00-19.00	12.00-17.25	15.00-18.25	16.50-19.00	15.50-18.00	16.25-18.50
Traded volume (MtCO2)	18.36	52.30	736.16	287.26	1,189.07	1,149.25
Number of transactions	103	147	173	114	116	126

Source: Nord Pool data.

Many factors explain this outcome:

- The market was dominated by a large seller (RU government player) and a large buyer (rest of the world); all other actors on the market were of a much smaller magnitude and could not influence prices to any great extent;[21]

- The seller did not adjust supply conditions to changes in demand during the simulation. News announcing an unexpected decline in emissions in the rest of the world did not affect the market price. An attempt by RoW to depress demand by staying outside the market in 2009-2010 had no effect: the CO_2 price was even higher in that session than in any other. The fact that supply is overly abundant compared to demand is a misleading indicator since sellers always have the possibility to bank allowances that are not sold in the first commitment period. Some governments with significant surplus allowances did not sell their full potential.

- Other sellers (potential or actual) were small: they could sell the quantities they wanted without depressing prices;

- Emission inventories and trading positions of all Parties were known to all after each session, as would be the case in the real world. Sellers were therefore fully aware of other players' compliance situation. As soon as allowances remained in high demand and the market price seemed acceptable, there was no pressure to reduce the price;

- The competition of Joint Implementation projects, as an alternative means to comply with objectives, was extremely limited.[22] CDM projects were not included in the simulation;

- Buyers had no means of negotiating the price separately with sellers: the vast majority of transactions took place through the competitive pricing mechanism of the exchange. In the real world, negotiations could take place, especially during the grace period;

- Some technical problems on the CO_2 platform prevented participants from trading as actively as they would have during the first sessions. By postponing part of the demand until later years, when mitigation options became more costly, this probably contributed to reinforcing the dominant position of the seller.

[21] One player observed that news affecting the power generation business – weather changes, changes in fuel prices, etc. – could have triggered more price movement. While this may be true, the contribution of the power sector's emissions to the total market size was small. These price moves, had they occurred, would therefore not have reflected market fundamentals: power generators *in the simulation* were price-takers, not price-makers.

[22] The total transfer of ERUs in the simulation was smaller than the transactions already contracted by the government of the Netherlands in its first round of the ERU-PT programme.

Not all of the above are of equal relevance when it comes to climate change policy choices, but most raise interesting questions about the possible behaviour of Parties to the Protocol in the future: how will governments approach their mitigation and trading strategies under price uncertainty? What are the implications of government-level trading dominating the market?

3.2 On governments and trading

Governments had the possibility to project ahead their future emissions, subject to some uncertainties, and the path of policies that they would need to take to reduce these emissions. The cost of these measures was also derived in a relatively simple fashion. The notion that such analytical tools would be readily available and that governments will be able to adjust their mitigation strategies – in particular the balance between trading, JI, CDM and domestic action – so as to minimise cost is not a realistic one at this stage. If governments remain responsible for a large share of their countries' emissions – which is probable, with few exceptions – they will need new tools to consider the many and complex cost elements of their abatement strategies. Otherwise, the efficiency gains that emission trading is meant to introduce in countries' collective response to global climate change may not materialise to the extent that it was projected by economic models.

In the simulation, government players have been keen to reflect some of their existing policy priorities (nuclear phase-out, reduction goals going beyond Kyoto). These reflect a number of factors, going beyond the value of avoided CO_2 and how it compares with an allowance price on the international market. Governments, however, should be eager to adopt an economically sound approach to emission trading. Furthermore, early reductions will give governments more flexibility to adjust to price signals during the commitment period. The risk is otherwise to rely on the allowance market as a "provider of last resort" and to be left with no choice but to accept a price entirely set by early players – or fail to comply. This simulation tells us that early reductions are a sound risk-management approach.

The same can be said of the selling side of the market – countries in transition. They are likely to bank significant amounts, either because the price will not seem high enough to sacrifice the possibility of raising emissions in the future, or because they may not be equipped to handle such transactions. That is not to mean that emission trading requires substantial government resources, but rather that countries for which compliance is not an issue may not be inclined to allocate these resources to international climate change policy. There is definitely a need to raise the importance of this issue in transition economies, and the simulation organisers hope that they contributed to that aim.

3.3 On electricity and CO2 trading

Already in the past, the power generation sector has shown that it can master the complexity added by the introduction of a new market, the market of CO_2 allowances and the underlying constraint of a CO_2 cap.[23] From a technical standpoint, meeting emission objectives at minimum cost will be easier in the real world than it was in this simulation, where prices were definitive and given for four-months periods without a clear idea of future demand growth, and no hedging instruments such as electricity and CO_2 futures were available. Risk management was one of the missing elements of the simulation, at least for the more experienced electricity market players.

[23] The cost and acceptability of emission reduction objectives are issues of a political nature that can not be neglected of course. The simulation has little to bring to this discussion except the obvious conclusion on the positive effects of a generous allocation.

What became clear in the simulation is the influence of external parameters such as the treatment of CHP in the market and other market developments (renewable electricity that could be sold at a premium). Any analysis of the implications of a CO_2 constraint on power generation must take these into account in the future, as they can affect the cost of achieving reduction objectives.

3.4 On simulations

Participants were faced with a number of unresolved questions and, in some cases, technical problems that prevented some from maximising the learning brought by the exercise. Could the simulation have been improved? Certainly, although some degree of simplification will remain necessary – participants also stressed the significant time commitment that this simulation represented. Beyond solutions to problems of a technical nature, such as blocked computers during trading sessions, participants made the following suggestions for improvements:

- A more realistic electricity market picture. The assumption of a single fully-open market for all countries in the region created a chaotic situation, as participants had no time to learn about their respective positions in this "new world". A proper simulation of peak-load generation would also increase realism;

- More detailed assumptions about the cost structure of various generation options would also help players that are reluctant to use their own data, given their strategic nature;

- A coherent set of assumptions on external factors such as a market for renewable energy (and whether related cost can be absorbed by the market), national energy policy choices (is nuclear an option?), but also on future fuel prices, so that all participants are in fact subject to similar conditions;

- The introduction of external factors to add to market volatility of the CO_2 market, allowing to test more elaborate hedging strategies. These factors could include long-lasting weather changes (with feedback on electricity demand and resource availability), variations in the economic activity, variations in fuel prices, estimates of the contribution of sinks to countries' assigned amounts, possible mistakes in countries inventories revealed by UNFCCC in-depth reviews, etc.

In conclusion, the simulation brings the following lessons:

- The initial allocation of allowances seemed to affect the competitiveness and pricing behaviour of power generators – especially as the simulation assumed allocations beyond utilities' needs for countries in transition, resulting in windfall gains. In the end, however the possibility to acquire CO_2 emissions from the market contributes to a more level playing field;

- Other policy aspects of power generation affect the cost of meeting CO_2 constraints – e.g. decisions to retire nuclear capacity early and the possibility to market renewable electricity at a premium;

- For a number of reasons, not all countries with assigned amounts for sale would necessarily sell them on the international CO_2 market in the first commitment period. In addition, the existence of a price for allowances may not be enough to convince them to take drastic measures to reduce their emissions further;

- The (very few) JI projects in the simulation led to transactions at prices that were lower than the international trading market price. This low price could reflect a risk premium or the transaction cost attached with JI projects. However, no thorough analysis of the projects could be conducted by buyers, which should be a central element in defining the price of reductions in a JI transaction;

- The international CO_2 market could be dominated by a large seller. CO_2 prices have remained remarkably stable before and during the commitment period as a result of the pricing policy of the largest seller. A close look at the market showed some degree of market power;

- The CO_2 price, whether it was deemed too high or too low, did somewhat alter government strategies towards compliance. It also changed their banking/trading behaviour.

Nevertheless, the data generated by the simulation (electricity generation and prices in the region, CO_2 allowance prices, projected emissions) are the result of a number of simplifications, strong assumptions, and ultimately of participants' behaviour that were not always realistic. The data should therefore not be used outside the context of this exercise.

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