FULL COST PRICING

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FOREWORD

This Working Paper is one of a series of eighteen studies carried out under the project: "Policies and Measures for Possible Common Action". The project was carried out by the OECD, together with the International Energy Agency, in 1996 and 1997 for the Annex I Expert Group on the United Nations Framework Convention on Climate Change (UNFCCC). The goal of the project was to assess a range of cost-effective greenhouse gas mitigation policies and measures for countries and Parties listed in Annex I to the UNFCCC. The eighteen working papers have been made widely available as analytical input to negotiations under the UNFCCC Ad hoc Group on the Berlin Mandate. The working papers may also provide input to national decision making processes on greenhouse gas mitigation policies. The measures analysed do not necessarily represent policy preferences of Annex I Parties.

The project benefited greatly from substantial input from delegates. Three successive chairmen of the Annex I Expert Group provided outstanding leadership for the project: Doug Russell (Canada); Ross Glasgow (Canada); and Ian Pickard (United Kingdom). The work was supervised by Jan Corfee Morlot (OECD). Fiona Mullins (OECD) drafted the initial framework which was used to structure the eighteen working papers.

The Annex I Parties or countries referred to in this document refer to those listed in Annex I to the UNFCCC: Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Czechoslovakia (now Czech Republic and Slovakia), Denmark, the European Community, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Lithuania, Luxembourg, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Spain, Sweden, Switzerland, Turkey, Ukraine, United Kingdom and United States. Where this document refers to "countries" or "governments" it is also intended to include "regional economic organisations," if appropriate.

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EXECUTIVE SUMMARY

Full cost pricing in the power sector as a possible policy for common action

Competitive markets maximise economic welfare if all costs of production are accounted for. Sometimes, however, prices do not include *all* the costs of production. This holds for sectors with unaccounted for environmental impacts. This leads to inefficiencies, since in the absence of additional measures, private actors do not take these costs into account. In order to eliminate these inefficiencies, instruments have been designed to include these environmental, or external, costs into private production and consumption decisions. This is referred to as "full cost pricing". Full cost pricing thus reflects *all* resource costs of the final product, be they traded commodities or public resources, such as the environment. In other contexts, full cost pricing is also referred to as the "internalisation of external costs".

Typical instruments to internalise external costs are emission fees (full cost adders) or the trading of emission permits. The height of the fee or the price of the permit then reflects the external costs, which, if added to the private cost of production, would achieve "full cost pricing". Full cost pricing as considered here has rarely been applied in practice. Instead, emissions control programs have more often imposed technical abatement measures through regulations or fees set at politically determined levels. These instruments have typically been applied in a manner that significantly reduces emissions, but does not duplicate the effects of full cost pricing.

The power sector has been chosen as a representative example for the potential effects of full cost pricing for three main reasons. First, it is, together with traffic, one of the two sectors in which the most authoritative studies and the most reliable values for hitherto *external* costs have been generated. Second, not only are these external costs non-negligible, but the regulatory set-up of the power generation industry makes the internalisation of external costs a real possibility. Third, models have been developed in which the power generation sector is represented in sufficient detail to allow to come to at least indicative conclusions.

Consideration of the power sector as a standalone example of the impacts of full cost pricing also faces some inherent limitations. First, the economic theory that provides the basis for full cost pricing assumes a competitive market. Since the electricity industry is heavily regulated in most countries, the benefits of full cost pricing must be balanced against the possible exacerbation of existing distortions. Second, full cost pricing that does not apply across all fuels can have perverse effects if end-users substitute direct use of primary fuels for purchased electricity. In MARKAL studies, *direct* competitors therefore have fees imposed to the same degree as the power generation sector.

Policy objective

The objective of full cost pricing is to reduce the emissions of CO_2 and other greenhouse gases through the full cost pricing of energy production, transmission and consumption, to the extent that local and regional effects on morbidity, mortality, and production are *fully* included in the final price through appropriate instruments. The full cost values used in this study do not reflect all existing or possible externalities connected with electric power generation. The potential costs of CO_2 emissions themselves are *not* included in this study. Although carbon taxes could in certain interpretations serve as the reflection of *implicit* perceptions of potential damage costs and thus achieve something akin to full cost pricing for CO_2 directly, this argument is not further pursued in this context. The reflection of full costs, for instance through emission fees on pollutants such as particulates, SO_2, NO_x has an effect on the relationship between inputs and outputs, on the choice of fuels, as well as on the specific technology of production processes. The primary objective is to reduce local and regional impacts. The strength of the impact on CO_2 emissions will depend on the degree to which CO_2 emissions and the emissions of local and regional pollutants are complementary, or to which degree local and regional pollutants can be reduced without affecting CO_2 emissions.

In cases in which the introduction of full cost pricing would lead to overall increases in energy efficiency, or to a general fall in energy demand, the reduction in local pollutants would also unequivocally reduce CO_2 emissions. However, in instances where the imposition of full cost pricing would lead to efficiency *decreasing* abatement measures, such as certain kinds of scrubbers, the imposition of full cost pricing for local pollutants might theoretically increase CO_2 emissions.

Approach, methodology and character of the study

The study proceeds on the basis of MARKAL models of three IEA member countries - the Netherlands, Italy and the United States. External costs, based on detailed marginal damage cost assessments for three local and regional pollutants (particulates, SO_2 and NO_x) were added to reasonable baseline scenarios reflecting the private costs of production under certain framework conditions. In order to keep with the framework of optimal internalisation, it was assumed that the marginal costs would not vary between the level of production in the baseline scenario and in the full cost scenario. For the Netherlands and Italy, the damage cost values were taken from the ExternE"-study co-ordinated by the European Commission, whereas for the United States, the, much lower, values were derived from the "Fuel Cycle Study" of the Oak Ridge National Laboratory commissioned by the U.S. Department of Energy.

The main difference between the two studies does not reflect methodological differences, but objective differences in the damages measured. The U.S. study, for instance, is calculated on the basis of lower population densities in the vicinity of newly sited plants than the EC study, reflecting the differing situations in the two regions. The damage values of the U.S. study, which are on average an order of magnitude lower than those estimated in the EC study, also reflect the role of an existing emissions cap with tradable allowances that already significantly internalises the costs from SO_2 emissions. Because of these objective differences, values derived from studies focused on one area cannot be extrapolated to other OECD or Annex I areas where conditions might differ significantly.

The baseline run of the country MARKAL models was compared to a run of the MARKAL models *including* the damage cost estimate for particulates, SO_2 and NO_x for all different processes which produce these emissions. In both cases, the emissions for particulates, SO_2, NO_x *and* CO_2 were computed. The difference between the two runs then established the results of the full cost pricing". The impacts on emissions reported in this study are measured against a hypothetical baseline in which current or planned regulatory, or other environmental policies are assumed not to exist. The baseline CO_2 emissions also deviate to some extent from the projections prepared for the official emission inventories under UNFCCC reporting requirements. It is important to keep in mind that, as with all kinds of modelling, the results are only roughly indicative of the potential order of magnitude of the *actual* impact of full cost pricing. Not only is the height of the damage costs open to discussion, although both studies serving as input are of a very high quality, but also the question of the appropriate baseline scenario on which the damage costs are imputed cannot be decided abstractly. The private costs of production, which are reflected in the baseline scenario, are dependent on parameters such as the state of technology, the policy framework and market conditions.

In certain cases, for instance, the policy framework has discouraged the use of a certain cheaper, and more polluting, technology in the past to the extent that its present use is inconceivable. In these cases, it would be unrealistic to use the cost data of this old technology to calculate the private cost of production, as the perception of what a "normal" power plant should look like, and therefore the nature of private costs of production, has changed. Undoubtedly, these are issues of judgement, as it has to be decided case by case whether elements of the policy framework reflect changed boundary conditions, or are already steps toward full cost pricing in themselves, and as such, they should be included in the "full cost pricing"-run of the model and not in the baseline scenario. While we would expect the discussion of the study to include this point, one should also keep in mind that agreement is often far easier to reach in the face of concrete, indicative examples than in the abstract.

Results - Impacts of the introduction of full cost pricing in the power sector

Impacts on emissions of local pollutants

As expected, the models showed substantial reductions of up to 70 per cent in the emissions of particulates, SO_2 and NO_x on which the full cost adders (the marginal damage costs) were levied. These reductions were achieved against a baseline case where existing emissions control policies were discontinued. These results are highly interesting in themselves concerning the effectiveness of environmental policy in the energy sector regarding local and regional pollutants. SO_2 and NO_x are only indirectly linked to climate change: NO_x leads to the formation of tropospheric ozone, a potent greenhouse gas, and sulfate aerosols originating from SO_2 have a cooling effect.

Impact on greenhouse gas emissions

The impact of full cost pricing on CO_2 emissions reductions was qualitatively established as positive in the context of two case studies of European countries. Using price adders based on the damage values from the EC study, CO_2 emissions reductions ranged from less than 1 per cent to 10 per cent, measured against a baseline in which current or planned environmental policies are assumed not to be implemented or are discontinued. It is very conceivable that continuation or reinforcement of these other policies could show equally positive side-effects on future CO_2 emission profiles. Moreover, significant variation in damage values across locations, as discussed above, precludes generalisation of the quantitative results to other countries. Impacts on other greenhouse gases were *not* analysed.

Impact on economic costs

Full cost pricing for local and regional pollutants to the extent that it also reduces CO_2 provides an added greenhouse benefit at no additional cost. Nevertheless, economic costs of “full cost pricing” do exist. Full cost pricing that raises electricity prices may increase economic costs caused by existing price distortions in electricity markets. Piece-meal schemes that focus *only* on electricity may promote welfare-reducing switching to primary fuels by end-users. In general, economic losses of full cost pricing consist of losses of producers and consumers through reductions in electricity demand due to higher prices. The imposition of full cost adders can be viewed as the public good equivalent of prices not levied before for private goods.

There are theoretical reasons to suggest welfare benefits from the imposition of full cost pricing. However, this assessment is sensitive to agreement about the height of externality measurements and the baseline definition. This is due to the fact that the internalisation of external costs reduces inefficiencies and increases total welfare, by reducing negative impacts on health, materials and the environment. Thus, if the full costs are calculated correctly, the losses in producer and consumer surplus and environmental rents are more than offset by the increases in quality of life and the reductions in health and maintenance costs. Thus economic costs of “full cost pricing” come, in principle, at zero total welfare cost (or even benefits), but any existing economic cost has to justified in advance by the verifiable merits of a reduction of particulates, SO_2 and NO_x alone. Thus total welfare impacts of the complete imposition of *correctly calculated* full cost adders imputed in a *generally accepted* baseline scenario should be unambiguouslypositive.

Linear optimisation models such as MARKAL are unable by their very nature to calculate economic costs, as they always minimise costs subject to a number of external constraints Thus MARKAL results always display zero economic costs and any real world economic cost have to be introduced by means of *externally* formulated constraints, such as, e.g., adjustment costs, which are then imputed into the model. In terms of the MARKAL model the economic welfare gain can be thought of as the difference between the cost of the externalities and the marginal cost increase in the *with* externalities MARKAL run, which due to optimisation will always be lower. The imposition of externalities will *raise* marginal costs of power production, but to a level which is lower than the sum of the *old* marginal cost *plus* the cost from the externalities due to the optimising properties of the model.

Other impacts

There are two additional issues which have to be considered. First, the imposition of full cost pricing might have, even in the case of an overall *improvement* of economic efficiency, distributive impacts which are policy relevant; and second, the imposition of full costs in one country could well make its electricity more expensive in comparison to another country. Concerning the distributional issue, full cost pricing will improve welfare for those, who are particularly exposed to externalities, such as for instance the elderly or the sick, or users of the environment in general at the expense of electricity producers and consumers. On a second level, producers of electricity with lower emissions, such as, e.g. the electricity produced with gas-fired combined-cycle turbines or renewable energy sources will gain at the expense of producers of electricity which is produced with higher emissions, such as, e.g. coal. Concerning international trade issues, the imposition of full cost pricing in one country could, in principle, lead to increased imports of higher emitting electricity from countries without full cost pricing. In practice these effects seem small, except in the case of specific industrial subsectors. Further study might be needed to decide the issue.

Implementation Issues

While full cost pricing is technically feasible, numerous large hurdles remain, including the consensus about the acceptability and validity of damage cost estimates. These damage cost estimates would have to be country or region specific. The issue, whether to adopt "full cost pricing" will invariably be mixed with public policy objectives other than environmental improvement such as security of energy supply, or regional and sectoral stabilisation, or trade and distributional issues. Thus implementation of full cost pricing is a highly complex problem of societal preferences, public choice and policy making.

Rationale for common action and conclusion

Full cost pricing as a common action could help to level the international playing field for the trade of electric power to the extent that it would equally reflect the full cost of production in each country. It would also contribute to the sharing of experiences. To the extent that full cost pricing provides a positive incentive for the development and adoption of emission reducing technologies, a wider introduction would provide a potentially larger market for these technologies. This would offer the possibility to exploit the decreasing costs of a wider production of these technologies. Beyond that, however, there are no intrinsic economies of scale in the implementation of this policy instrument which would make international (or Annex I-wide) adoption of this measure more effective than a country-by-country adoption.

From the standpoint of CO_2 emission reductions, the full cost pricing of local and regional emissions of particulates, SO_2 and NO_x would constitute a costless addition to other measures. However, the benefits from the reduction of local pollutants have to outweigh the costs in terms of economic output. The impacts on CO_2 emissions are likely to be small, or negligible at the Annex I level, but regionally they might be more positive. The effects of full cost pricing will differ according to national circumstances, recognising differences in damage values across locations and national environmental policies in the absence of full cost pricing. Adoption of such policies is appropriately based on a determination that their intrinsic benefits in terms of reductions in external costs from targeted emissions outweigh the economic costs. In the end, decisions have to be made taking account not only of the uncertainties connected with externality measurement and modelling, but also of the high number of additional considerations pertinent to the issue.

PLEASE NOTE: Current analyses are limited with respect to their implications for individual countries. Additional work now underway, including that in the United States, may help better assess the range of impacts and the range of externality values which reflect the different geographical, demographic and technical circumstances of each country.

EXTERNALITIES, FULL COST PRICING AND MARKAL MODELLING - THE PURPOSE, METHODOLOGY AND LIMITS OF THE "FULL COST PRICING" STUDY UNDER THE COMMON ACTION PROJECT

Introduction

The following remarks are designed to introduce the conceptual framework for the MARKAL case studies on full cost pricing and to answer any outstanding questions. In particular, they are designed to discuss three critical points: the range of externality measurements, the question of agreeing on a suitable "baseline"-case and the applicability and transferability of the case study results to other countries. It will be shown that the range of externality measurements can be high, that more than one acceptable "baseline" can be defined and that the transferability of the results of country case studies to other countries is low. All this underlines the indicative character of the country case studies. In fact, the insecurities with respect to the results of the case studies are too large that any general policy conclusions could be drawn.

Externalities and full cost pricing

Externality measurement as a basis for full cost pricing

What are externalities?

Externalities are unintended by-products of commercial activities such as power generation. As such, they are capable of influencing the well-being of people. Examples can be impacts on health, the loss of environmental quality or recreational facilities. The defining characteristic of externalities is that their creation lies outside the intention or concern of those who control the original activity and outside the control or influence of those who are affected by them. This leads to a situation in which too many negative externalities and too few positive externalities are produced. Dealing with this double asymmetry - lack of information and concern of the originators, lack of control or influence of those concerned - and to establish feedback mechanisms between the two is the main task of any attempts coming to terms with externalities, or, in technical language, to internalise them.

While externalities are easily felt as influences on well-being, their measurement in exact terms is difficult. The fact that they are not traded in markets prevents them from being priced like other goods. One approach to the problem defines the existence of an externality as equivalent to the non-existence of a market. Many externalities are linked directly to an inefficient overuse of the environment, which as a common property good, is not amenable to private trading. Economic theory has developed several techniques to overcome the information problem associated with externalities and to measure their impact in monetary terms. The measurement of "willingness-to-pay" or "willingness-to-accept" with the help of detailed data on dose-response functions, impacts and preferences has made great progress. Nevertheless, huge uncertainties - sometimes of the size of several orders of magnitude - remain. The present study restricts itself to those externalities (SO_2, NO_x and particulates) where, for a variety of reasons, research has progressed furthest. However, the internalisation of these externalities for their own reasons is also analysed with respect to its impact on CO_2 emissions.

How externalities relate to full cost pricing

Full cost pricing refers to the pricing of commercial goods - such as electric power - that would include into the final prices faced by the end-user not only the private costs of inputs, but also the costs of the externalities created by their production. This implies that the cost of the externalities is measured (with all the caveats, imprecisions and uncertainties therewith connected), calculated on a per unit of emissions basis and than added on top of the private costs of production. Of course, different production processes would, depending on their production of externalities, receive different externality adders, although the final end-product, electricity, would be the same. The externality costs should, ideally, be calculated as marginal cost at the point of production. This means that the optimal externality adder should be of the height of the marginal damage at the *optimal*, not at the actual, point of production. In practice, the two values are, under the assumption of linear damage functions, not calculated separately, but assumed to be the same.

The imposition of full cost pricing would create two kinds of impacts: first, more polluting (more externality producing) processes would become more expensive and overall electricity prices would rise. Evidence shows that in the MARKAL model used for the analysis of the effect of full cost pricing the substitution effect, i.e. substituting less-polluting for more-polluting processes, would be larger than the total demand effect. In theory, full cost pricing would achieve *full efficiency* and thus the maximisation of welfare. However, the valorisation of so far not calculated costs, e.g. health costs, can have negative impacts in terms of the original good and thus reduce traditionally measured GDP. For instance, due to full cost pricing health costs might be reduced, but less electricity might be consumed. If only, the latter shows up in GDP numbers, GDP will be reduced, although total welfare has gone up. Of course, this reasoning hinges on the correct measurement of the externalities, *if externalities are wrongly assumed to be too high, full cost pricing would lead to economic losses, as well as to total welfare losses.*

An additional consideration is often the distributional impact of full cost pricing. Full cost pricing in power generation would transfer resources from the electricity sector to governments. Even if the tax receipts were fully recycled, e.g. through a reduction of general income taxes or value added tax, the electricity sector and other sectors with high electricity consumption such as heavy or chemical industries would lose, in comparison with sectors such as banking, which would have relatively low electricity consumption per unit of output. This would happen even if total welfare were to be increased. In many instances these distributional impacts are considered undesirable, in particular if they regard export-oriented industries in structurally weak regions. Overall, these considerations show that a decision to introduce full cost pricing cannot be taken abstractly, but has to be considered in the full context of policy-making.

Related to the distributional issue is the question whether the imposition of full cost pricing in one country would lead to increased imports of electricity or electricity intensive manufactured goods from countries without full cost pricing. In the absence of detailed studies, only indicative statements on the basis of anecdotal evidence can be formulated on this issue. First, the height of the full cost adders seems small in comparison with the electricity losses due to transmission, and the problem might be theoretical rather than practical. Second, due to the fact that emissions in the exporting country might, due to transboundary pollution, affect welfare in the importing country, border tax adjustments proportional to emissions for compensation could be contemplated. In the abstract case of absolutely no transboundary pollution and no conceivable future side-effects, the importing country would have no issue with the exporting countries production methods and could import cheap energy at zero domestic emissions, and due to the absence of transborder effects, zero negative impacts.

The theory and practice of externality measurement

Since the correct measurement of externalities is the crucial point in full cost pricing, methods and techniques for correct measurement are briefly presented. There exist two main approaches to measure the damages from externalities. The first is the damage cost approach. The second is the control cost approach. The damage cost approach relies on the direct measurement of externalities, techniques for which are mentioned below. Other than by the direct measurement of damages and their evaluation in economic terms, damage costs can, in principle, also be determined by the cost of control approach. In this approach the damage costs are assumed to be equal to the marginal abatement costs at the point of the emission target. It therefore depends on an *a priori* defined emission reduction targets. The setting of emission caps depending on the costs of control is a frequently and successfully applied policy. However, it has to be kept in mind that it *cannot* provide useful values for a determination of optimal production level, since the *a priori* definition of this level is the essential driver of the resulting cost estimate.

In measuring the damage costs resulting from externalities, the researcher tries to estimate the "compensating variation" as the relevant measure of welfare loss from the imposition of the externality. This is the amount of money that if given to those affected by an externality would leave them exactly as well off as in the case in which no externality existed and no money was given. There exist five basic approaches to measure this "compensating variation". The first approach proceeds directly from observable prices for marketed goods, i.e. goods for which monetary valuations do exist. This can include the costs for medical treatment, the repair of painted structures from pollution, or the market value of damaged crops. The remaining four techniques fall into two groups. The first three are indirect valuation techniques that try to derive the damage from externalities by observing the behaviour of those affected in actual markets. The fourth is a direct valuation techniques and attempts to derive people's preferences concerning public goods through questionnaires.

The present study of full cost pricing has restricted itself to use estimated damage values for externalities from the emissions of SO_2, NO_x and particulates from the generation of electric power. In this particular area research has progressed furthest. Everything that has been said above about externalities in general would apply equally also to an externality, or a potential externality, such as climate change or the risk of an accident in a nuclear power plant. However, the dose-response functions, the impacts and the preferences are of such a high degree of uncertainty that the approach to damage cost measurement is not viable and other, more implicit, internalisation mechanisms have to be found. This does not mean that these damages are not considered important. They are just not amenable to a full cost pricing approach.

Three recent studies

In 1995 three major studies on the measurement of damage costs from externalities of electric power generation were completed. The first study is the *ExterneE: Externalities of Energy* study that was co-ordinated and financed by the European Commission. In a related effort the Oak Ridge National Laboratory undertook the study *Estimating Fuel Cycle Externalities* that was financed by the United States Department of Energy. The two studies began as a joint project, but then developed into separate efforts. Finally, the consultancy RCG/Hagler Bailly completed the *New York Environmental Externalities Cost Study* funded by a variety of energy agencies of New York State. Below are reported the main findings of the three studies:

Table 1. Damage cost estimates from three recent studies

($/ton)

Study	Characteristic	SO_2	NO_X	Particulates (PM_{10})
ExternE - EC1	High estimate	6 050	12 610	16 060
	Low estimate	4 140	0	16 060
Estimating Fuel Cycle Externalities - ORNL/DOE - Southeast reference site	High estimate	1002	2003	3 4004
	Mid estimate	60[2]	120[3]	1 900[4]
	Low estimate	10[2]	90[3]	850[4]
NewYorkEnvironmental Externalities CostStudy -Centralestimates	Urban	1200	1100	43800
	Suburban	800	900	7700
	Rural	700	900	3200

The reason for wide ranges and their implication

One can see easily that the differences between the damage cost estimates can differ by a factor of $6 \times 10_3$ even for studies that use comparable methodologies and conceptual approaches. Even if median or mean values are taken the results of two studies would still differ by a magnitude of 10_2. However unsettling these apparent differences might seem at first sight they reflect the need to be specific about the exact co-ordinates of each study rather than a fundamental questioning of the damage cost approach. First, the low values of the ORNL/DOE study reflect the fact that they explicitly only measure a subset of damages (see footnotes). The explanation of the remaining differences can be explained by two sorts of factors. Apart from differences in the valuation of human health and life (as the main component of all damage estimates are costs to human health and shortened life expectancies), differences in assumptions about dose-response functions and the pathways of harmful substances, the main difference is constituted not by *methodological* differences, but by *objective* differences of the damages measured in the different studies. The main parameter here is location and population density.

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1 Converted from ECU/tonne values at 1 ECU= 1,25 US$

2 No damages from acid precipitation or sulphate damage included. Acid rain precipitation may be significant in some regions.

3 Only damages from ozone, does not include nitrate aerosols.

4 Estimates are only for primary particulate emissions and do not include sulphate and nitrate aerosols.

The low damage values from the emissions of the reference site in the Southeast of the United States reflect the fact that the possibility to locate a given plant in a sparsely populated area, where damages are low, quite simply because there is hardly anybody there to suffer from emissions. On the contrary, the same plant in a densely populated area in Europe would create damages of two orders of magnitude higher. This fact is nicely demonstrated by the different estimates for damages from particulates in the "New York Environmental Externalities Study" where the damage estimates differ by more than an order of magnitude in the *same* study, in the *same* state according to the location of the plant.

Differences in damage costs can thus be explained even without referring to the nevertheless still existing methodological difficulties. However, this does not preclude that these differences *do raise some important questions* for the use of damage cost values in the modelling of power generation. The main implication is that **there do not exist generally applicable damage cost values**. In other words, any study of the internalisation of externalities will only have case study character. Even as a case study, the quality of a study will depend on the degree to which the damage cost values reflect the *specific* circumstances of the area (country, sector) under consideration. Under no circumstances can the damage cost values of the study of one country be transferred to the modelling exercise of another country. A transferral of the results of, say, the ExternE study to a MARKAL model run of, say, the United States would yield heavily distorted results. These factors have to be kept in mind in the drafting, as well as in the interpretation of the study results.

Introducing full cost pricing into MARKAL models of national energy sectors

Full cost pricing in linear programming models

Linear optimisation models such as MARKAL identify least cost solutions from a large number of linearly specified technologies subject to a number of external constraints. As such, by their very nature they do not work with real world commercial or economic data, but with exogenously specified engineering data. Only in a perfectly cost minimising world with no transactions costs and no frictions would a linear programming model yield "realistic results". However, one should keep in mind that economic models assume profit maximisation that is usually not considered an outrageous assumption, but is thought to reflect an essential determinant of real-world behaviour. To maximise profits under a given technological constraint will yield identical results as minimising costs for a given level of prices. Nevertheless, the working with stylised rather than actual statistical data remains the biggest drawback of linear programming models.

Full cost pricing is introduced into a linear programming model by *augmenting* the cost function of a given technology with the per unit of emission cost derived from the estimates of the damage cost of the externality. Although a linear programming model will not calculate economic costs (e.g. GDP increases or losses as macroeconomic models would do), there is a way in representing the overall welfare gains from the introduction of full cost pricing. In terms of the MARKAL model, the welfare gain can be thought of as the difference between the sum of the cost of an energy system without full cost pricing plus the total damage costs and the costs of an energy system with full cost pricing in which externalities are internalised. Due to the optimising properties, MARKAL will identify the lowest cost solution in each case. The imposition of externalities will *raise* marginal costs of power production, but to a level that is lower than the sum of the *old* marginal cost *plus* the cost from the externalities.

Thus while final electricity prices would be slightly higher which would imply welfare losses due to a reduction in consumer surplus, these losses would be more than offset through an increase in welfare as damage costs from externalities are reduced. But any existing economic cost has to be justified in advance by the verifiable merits of a reduction of particulates, SO_2 and NO_x alone. The accompanying reduction of CO_2 emissions in the reconfigured energy system would come at no additional welfarecosts.

Two ways of working with linear programming models

Two fundamental ways exist in which a MARKAL model of a country's energy sector can be used. For want of better expressions, they can be referred to as *optimised scenario building* and *mimicking the real world*. Keeping this distinction in mind is important, as the way in which the representation of an energy sector is pursued will strongly influence the modelling outcome of the imposition of full cost pricing. If "optimal scenario building" is chosen, the model will attempt to identify as many new, and possibly unproved, technologies and their cost characteristics as possible to develop scenarios that might give policy-makers indications of the characteristics of different stylised outcomes of policy choices.

"Mimicking the real world", obviously, will go into the opposite direction attempting to model a country's energy sector as realistically as possible. While it has been said that MARKAL works with technical and not with statistical data, there are a number of possibilities that a modeller can use to introduce real world features into the model. For instance, empirically observed barriers to market introduction, such as credit constraints due to high capital costs, can be reflected in higher linearised costs. Other *ex post* introduced conditions can relate to existing government regulations and institutional realities.

Other things being equal the introduction full cost pricing will have a larger effect in the more finely tuned, exclusively technology cost driven "optimal scenario building" case than in the "mimicking the real world" case, where a large number of other frictions have already been introduced and the energy sector will display a higher degree of inertia. Of course, there is no "good" or "bad" use of linear programming models, there is exclusively a need to clearly define and understand the purpose for which they are designed. In practice, most models will fall somewhere in between these two polar cases, however, it is important to keep in mind their relative position in order to understand the qualitative nature of the model runs.

The baseline issue

Another issue regarding the integration of the damage costs of energy externalities into a model of the energy sector is the question which *private cost* values shall be taken as the basis to which the damage costs are to be added. The intuitive response "of course the existing costs of producing electricity for the generator" might not, in fact, yield the correct results. This is due to the fact that in order to arrive at the economically efficient point of production, full costs shall be imposed. These full costs consist of the private costs of the generator, i.e. the costs of capital and labour, and the marginal damage costs of the externality which varies with the scale of production. However, it is not clear what exactly the pure private costs of the generator are. In fact, the real existing costs are more likely than not to include already some costs for compliance with government regulations, technical specifications and other measures designed to safeguard the environment.

In some countries, for instance the United States, even permit-trading schemes for harmful emissions might be in place. All these measures *raise* the private cost of production and *internalise* the externalities to some extent, and thus already constitute steps towards full cost pricing. An optimal permit-trading scheme would indeed fully internalise the externalities and establish full cost pricing by itself. To simply add the damage costs to the existing cost of production, without verifying that they are equivalent to the *pure private cost* of production could thus lead to full costs *higher* than the economically efficient level.

The problem facing the modeller is then to determine the accurate level of the pure private cost of production. This is more difficult than it sounds. The main reason is that outside action that might already constitute a certain degree of internalisation and technological progress go hand in hand. As wrong as it would be to take existing cost of production as the baseline, it would be equally wrong to take an arbitrary *past* cost of production as the basis for full cost pricing. Especially in a sector such as electricity generation that has been subject to a large number of direct and indirect incentives to develop new technologies it is very difficult to separate internalising government action from technological progress. This regards the present as well as the future. During a fifty-year time horizon, technological progress might lower the private costs of production as well as emissions *without* further action such as full cost pricing.

No clear-cut analytical way of establishing the correct baseline values exists. The judgement of the individual researcher or modeller is called for. As with all judgmental issues, they are open to discussion. Certain choices about baseline costs of production could probably have been made differently with equally justifiable reasons. The present study has attempted to steer a middle way in attempting to capture the *pure costs of production* as far as possible, while taking account of certain framework conditions such as the fact that there simply will not be built any more coal-fired steam boilers without low-NO_x combustion techniques in the Netherlands for the foreseeable future. In the end, the decision of what actually are the *private cost of production* is as much a political one, depending on a societal consensus, as an analytical one. However, it is also true that the more environmental costs are integrated (internalised) into the private costs, the lower emissions and external costs will eventually be. As with many issues, the possible agreement between researchers is presumably greater in the face of concrete technology choices and internalising measures than in an abstract *a priori* determination of what the private costs of production are supposed to be.

Full cost pricing as a policy option to reduce CO_2 emissions

From the preceding comments it is clear that quantitative results of a MARKAL model run which includes full cost pricing of environmental externalities have to be treated with great caution. In particular, **quantitative results should not be misunderstood as a one-to-one representation of reality**. While this is the case for any kind of modelling effort, it holds to a particular degree in the present case. This is due to the optimising property of MARKAL, as well as due to the impossibility to assure that the area of applicability of the damage costs estimates coincides exactly with the area of the policy case study. In addition, possible and justifiable disagreements over the establishment of the correct baseline are imaginable. The reasons for diverging damage cost estimates have been discussed above.

In any case, the decision to implement full cost pricing will have to be made in connection with the merits of emission reductions of SO_2, NO_x and particulates and corresponding economic costs and distributional impacts. The impact on CO_2 emission reduction is likely to be too small to influence any decisions regarding the introduction of full cost pricing. However, in an integrated strategy to reduce emission, and *if* full cost pricing can be justified on its own merits, it could provide some additional emission reductions at no extra cost.

The insecurities connected with a transferral of the results from a MARKAL modelling run to a political reality, i.e. to step from the analysis to actual internalisation and full cost pricing, have shown to be large.

However, the real question is not whether full cost pricing can yield exact, generally agreeable and certifiably welfare-optimising results. It cannot. The question is rather, whether the imposition of full cost pricing on the basis of intellectually honest analytical work, warts and all, will in all likeliness improve welfare over the existing situation. This is a question policy-makers ultimately will have to decide on the basis of study results, expert advice and additional information about policy preferences and distributional impacts. Considerations such as distributional and economic impacts show that decisions have to be made in the full context of policy-making. No model run will provide ultimate answers, but it can highlight the salient issues and thus promote the finding of a policy consensus.

FULL COST PRICING IN POWER GENERATION - MODELLING RESULTS

Background

The study aims to provide illustrative examples of the impact on carbon dioxide (CO_2) emissions from introducing full cost pricing in power generation. The full cost will cover the external costs of SO_2, NO_x and particulate emissions in addition to the commonly accounted direct cost associated with building and operating power stations (including fuel costs). In principle, several factors can contribute to lower CO_2 emissions as a result of the introduction of full cost pricing. First, power generation from fossil fuels will become more expensive, raising the price of electricity and thus induce conservation and savings at the consumers. For the same reason, non-fossil based power generation may become more competitive and further reduce the burning of carbonaceous fuels. More advanced types of power plants, offering lower acid and particulates emissions and a higher efficiency at the same time, will improve their position on the market in comparison with conventional equipment burning the same fuel. Finally, burning of inherently cleaner fossil fuels like light oil products and natural gas will become more attractive than using heavy oil and coal. In addition to lower specific CO_2 emissions per unit of energy content, in particular natural gas firing offers substantially higher conversion efficiencies.

This study identifies the compounded effect of the above factors by means of a comprehensive, technology-based process model applied to varying countries with strongly fossil fuel-based electricity supply systems. In accordance with the objective of this study, it is worthwhile to address the issue of possible synergies between reductions of pollutants like SO_2, NO_x and particulates from power plants, on the one hand, and lower emissions of CO_2, on the other hand. This question is of course largely independent from the question through which instrument(s) the reduction of said pollutants is to be achieved. Here we concentrate on the market-oriented approach of cost adders to reflect the full cost of power production.

It can be assumed that, if the cost adders associated with air pollution are higher, measures to reduce emissions will become increasingly attractive from an economic point of view (see Figure 1). The examples in the figure indicate that various types of countermeasures can be considered to reduce emissions, and thereby the level of costs added to direct generation costs. These direct costs are always accounted for and consist of capital costs, operating and maintenance costs and the cost of fuel as delivered at the power station. Capital costs and a variable part of operating and maintenance costs (permanent staff, insurances, etc.) are so-called fixed costs: they arise every year regardless of whether the plant is actively producing electricity or not. The remaining part of operating and maintenance costs and the fuel costs are variable: they depend on the amount of electricity produced from the plant. For units already in place the decision on which plant to operate, leaving aside technical considerations and constraints, depends on their variable costs: capital and fixed operating and maintenance charges cannot be influenced. Only for new units under consideration to replace older capacity and/or expand the total stock do all direct cost matter when it comes to deciding which type to build and operate in future. Existing units can be retrofitted with additional abatement technology, but typically at a higher cost than for new built plants, and the investment has to be written off in the smaller number of years remaining for the main components of the plant.

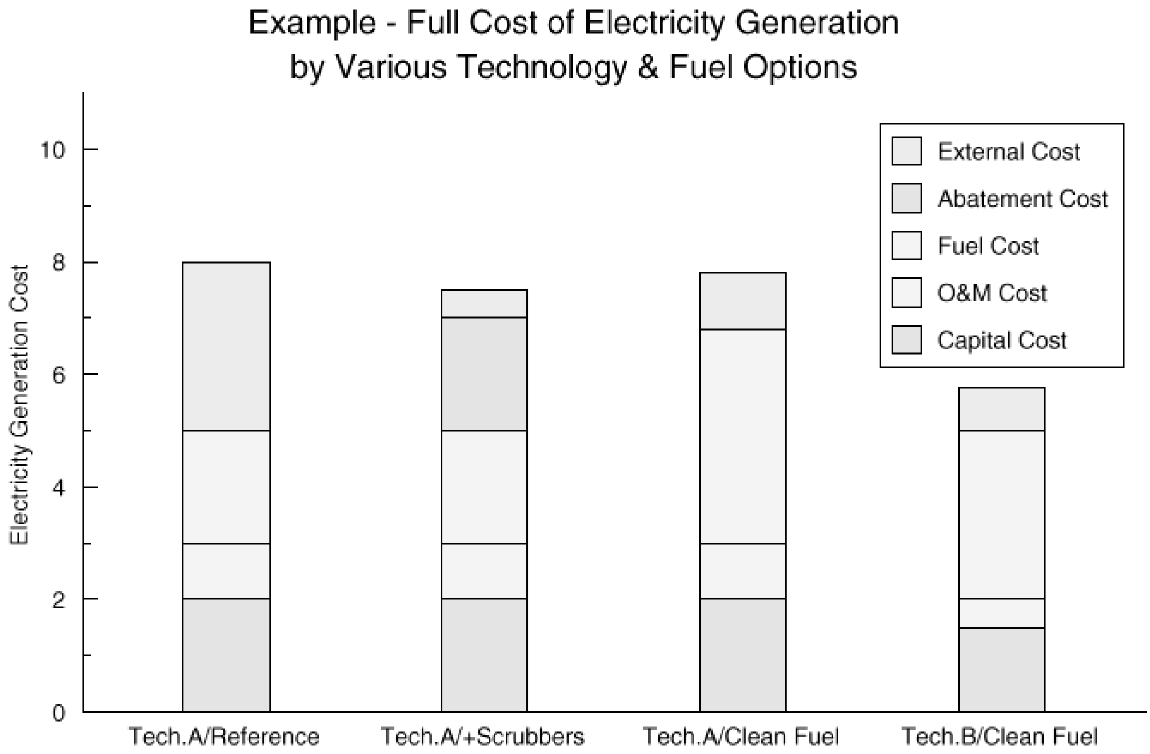

Figure 1. Example - Full Cost of Electricity Generation by Various Technology and Fuel Options

In Figure 1 it is shown that for the reference plant, using Technology A (say a conventional steam cycle) and a relatively cheap but polluting fuel (say coal), the total direct generation costs are relatively low. As the level of pollution is high, however, additional charges representing external costs are relatively high; (see the leftmost bar). Adding emission abatement equipment adds to direct costs, but cuts back emissions and thus external costs very efficiently. In the example "just sufficient to make up for the added direct costs", see the second bar to the left. But this will depend critically on conditions and assumptions. Alternatively, (as shown in the third bar), the same plant could switch to burning a cleaner fuel, like low-sulphur light fuel oil or gas, instead of adding technology. Again, it depends on conditions pertinent to the case at hand whether or not the more expensive fuel pays for itself by lowering external cost charges. Finally, if the choice of technology is still open, it can be considered to burn the cleaner fuel in a suitable, more efficient type of plant, such as a combined cycle, (see the rightmost bar). Typically, the choice of fuels and fuel qualities is not limited to just two; the number of viable technical abatement measures is even bigger, each with their own cost and characteristics; and many abatement technologies can operate with a variety of fuels.

It must be noted that of all pollution abatement options considered, many will show no direct beneficial effect on CO_2 emissions. Some can even have a --small -- negative effect as overall fuel cycle efficiencies are deteriorated. This holds, for example, not only for some flue gas clean-up processes, but also for oil products with reduced sulphur content that require additional (hydrogen) processing in oil refineries. Others can have a small positive side-effect on CO_2, e.g. a somewhat higher conversion efficiency from improved combustion intended to lower NO_x emissions. Discarding such secondary effects, basically 'CO_2-neutral' pollutant abatement measures include:

- Switching to essentially similar fuels with a lower sulphur content (e.g. HFO with 0.5 per cent sulphur to replace HFO with 4 per cent sulphur)

- Enhanced burners and furnaces (e.g. two-stage burners)

- Flue gas clean-up (dust collectors, dry or wet scrubbers, selective catalytic NO_x reduction) and enhanced combustion gas cleaning (e.g. in residual oil or coal gasification plants) as add-on to otherwise unchanged plants

Methodology and approach

The analyses are made with the MARKAL model, either operated in stand-alone mode or linked to a very simple economic growth model (MARKAL-MACRO). In both cases the outcome reflects a typical least-cost planning approach. The environmental cost adders to be considered are specified in monetary units per tonne of emission. As charging fees to emissions on a weight basis is one of the standard options in MARKAL, including the adders in MARKAL is very straightforward.

Less straightforward is the definition of a suitable baseline, against which to evaluate the impact of introduction of full cost pricing. Here it is assumed that current practices with regard to technological characteristics, developed in response to implemented standards, will be retained in future. This means that e.g. future steam boilers will be fitted with the low-NO_x combustion techniques as applied in modern power plants. Further NO_x emission reduction is then optional and can be accepted or rejected according to its cost-effectiveness after introduction of full cost pricing. Retrofitting of older existing units to similar performances as the most recent ones built, however, is not standard but an explicit abatement option. Similar guidelines are adopted for SO_2 and particulates.

For several reasons the resulting baseline CO_2 emission profiles will deviate from official projections as submitted e.g. as National Communication on Climate Change Policies [e.g. VROM, 1994] prepared for the Conference of the Parties under the UNFCCC. First, the baseline represents the strictly least-cost solution that matches future energy demands and supply under certain external constraints. Typically, official projections take into consideration a score of other factors and issues besides lowest cost at the macro level and will thus end up with different preferences and choices. Secondly, the baselines as defined and used in this study explicitly ignore existing and planned environmental policies in order to present as 'undisturbed' a reference situation as possible against which to measure the impact of full cost pricing. Clearly any official projection will at least assume continuation of already implemented environmental policies, and very probably also more ambitious measures and policies for the future.

Country case studies with MARKAL

As a first step, existing MARKAL databases were examined to assess their principal suitability for the purpose of this study. Criteria applied include: the extent to which current and expected future electricity systems rely on fossil fuels; the level of detail with which the electricity systems are modelled (e.g. generation options, emission factors, abatement options, fuel switching options); availability for the study. From the initially selected four candidates, Italy and the Netherlands are reported here. Additional contributions from the United States and the United Kingdom were requested, but could not be realised in time to be included here.

Estimates of full cost adders for SO_2, NO_x and particulates, derived from the EU's ExternE project [EU,1995] have been provided by a consultant on a per ton of emissions basis as follows [Eyre, 1995]:

Pollutant	External Cost [ECU/tonne]	
	Low[a)]	High[a)]
SO_2	3 310	4 840
NO_x	0	10 090
Particulates[b)]	12 850	12 850

a) The 'Low' cost level is associated with the highest confidence level and vice versa

b) Assumedtoapplytoparticulatesofupto10µm

Taking these adders into account, key options for fossil fuel baseload power generation in the Netherlands (fitted with/without optional abatement equipment) were compared at the individual technology level. This initial assessment indicated that structural changes in the electricity sector are expected from the introduction of full cost pricing, as the relative competitiveness of key candidate technologies was profoundly affected. As a rule, recent analyses with the MARKAL model include more or less severe policies with respect to emissions of SO_2 and NO_x. In order to obtain a baseline for the analysis of the impact of full cost pricing, a run was made in which emission constraints were lifted. Next, the above adders were introduced into the MARKAL databases and runs made includingthem.

It must be noted that, in line with MARKAL conventions, the electricity sector reported here covers all electricity produced, including industrial and other non-utility owned and operated power generation. In order to avoid unintended biases, it is assumed that the same full cost adders are charged to those non-utility power producers. Furthermore, corrections are made for fuel and emissions associated with co-generated heat (for industrial, commercial and residential CHP schemes), and directly competing heat supply options are also faced with the same full cost adders to maintain a level playing field.

CO_2 emission profiles

In the Netherlands the total CO_2 release in the baseline increases to about 260 mln tonnes by the year 2030; see Figure 2 At the same time, the net emission of CO_2 from the electricity sector grows even stronger, as the share of electricity in total energy consumption increases and the role for coal in electricity supply gets bigger at the expense of natural gas (see also below for more details). As a result, the contribution of the electricity sector to total CO_2 emission grows to over one third from its currentshare:justover20 percent.

Introduction of full cost pricing to account for external costs at the Low and High levels would lead to sizeable CO_2 emission reductions, in particular on the longer term after 2010. By 2020/30, a reduction of up to 10 per cent from the baseline results from the model analysis. It must be noted that the analyses are made with the extended MARKAL-MACRO model. The feedback mechanism inherent in this integrated energy/economy/environment formulation leads to price-induced reductions of electricity demand. As these reach up to around 4 per cent by 2020/30, almost half of the total CO_2 effect is explained by non-technicalfactors.

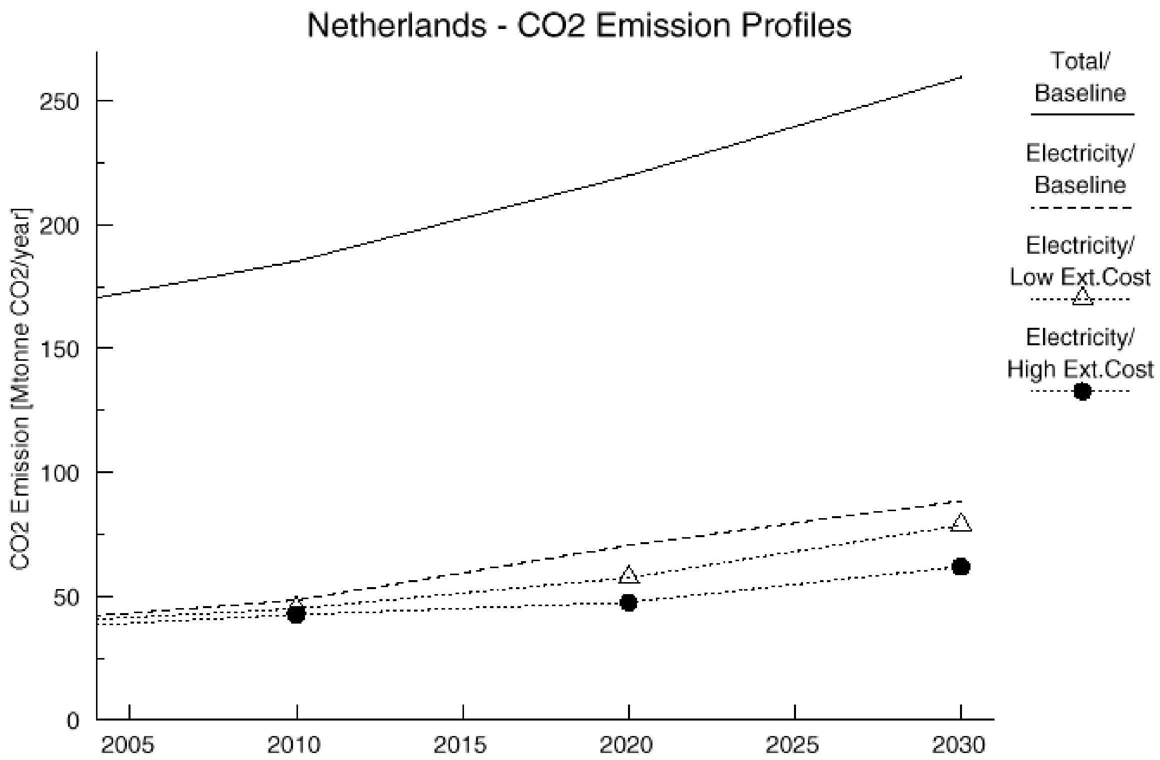

Figure 2. CO_2 Emission Profiles -- Netherlands

Technical changes relevant to CO_2 emissions include building much less conventional coal steam power plants. Instead, advanced, high efficiency and clean coal units (IGCC) are installed and more advanced gasfired CHP units with a high power-to-heat ratio are favoured for industrial co-generation schemes. Overall net efficiencies increase, and the share of gas in net fuel use for electricity generation increases. See also below for more details on the changes induced by full cost pricing in the Netherlands' electricity system.

For Italy also, an increase in total CO_2 emissions occurs in the baseline, reaching over 550 mln tonnes by 2010 (see Figure 3). Electricity's share thereof increases slightly over the shorter time span covered by the analysis: around 27 per cent in 2010 versus 24 per cent today.

Though many things change after application of full cost pricing, the compounded effect on CO_2 emissions associated with electricity generation is hardly affected. On the one hand, oil products are replaced by natural gas (less CO_2) for some multi-fuel conventional steam power plants and for many industrial installations On the other hand, once building of (retrofit) pollution abatement equipment is warranted to counter the full cost adders, the price advantage of coal over HFO becomes decisive for other multi-fuel units. Moreover, advanced, high efficiency and clean coal units (IGCC, PFBC) are favoured for capacity expansion, adding to the observed shift from oil products to coal (more CO_2).

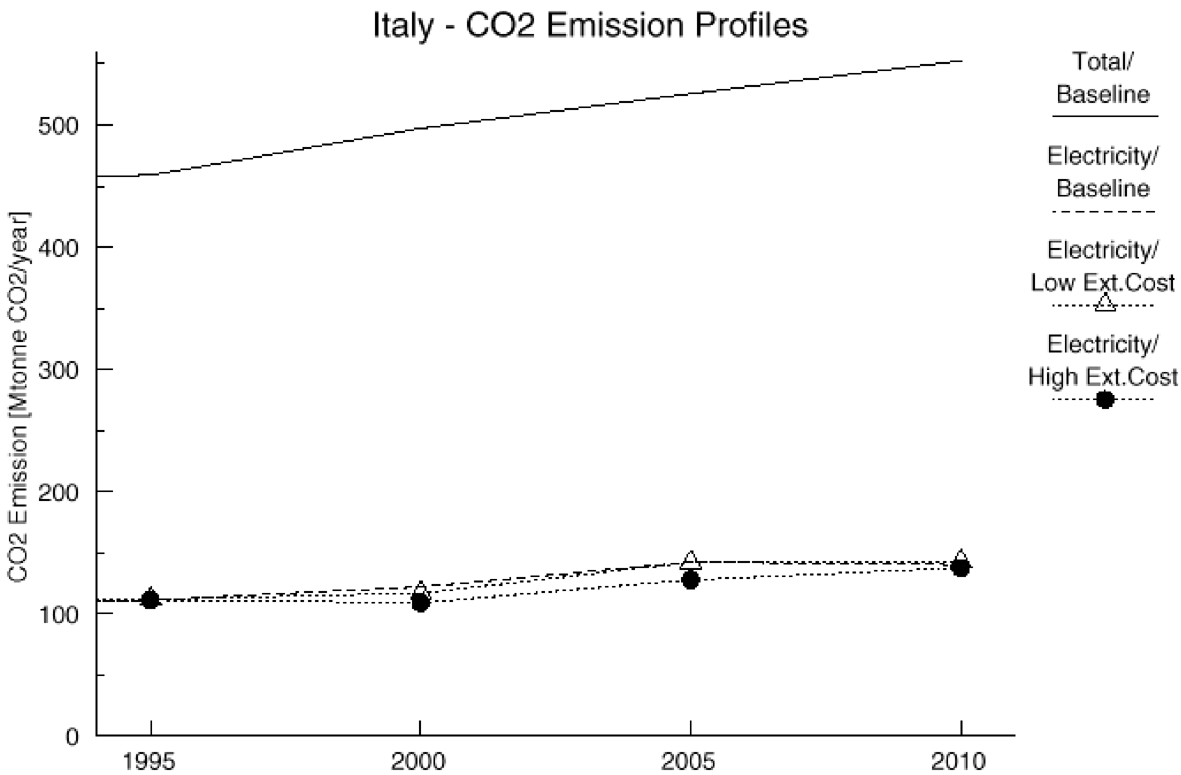

Figure 3. CO_2 Emission Profiles - Italy

Unlike the Netherlands' analysis, for Italy no demand feedbacks are evaluated. On the contrary, total electricity consumption rises slightly by up to 2 per cent due to elevated internal consumption by oil refineries (to deliver cleaner products) and by the electricity sector itself (for some types of abatement equipment).

Netherlands

The case study for the Netherlands concerns an analysis focusing on the medium to long term, primarily designed to assess the prospects for new energy technologies and fuel options under a variety of future conditions and constraints. In light of the current position of domestic natural gas and the still vast remaining resources, no obstacles for a continued widespread use of gas are assumed. As natural gas is imported and exported, the internal price is governed by international market developments. Coal and oil are imported at international market prices, assumed to increase on the longer run. In the scenario studied, expansion of nuclear power is not considered, and the two currently operating reactors will be closed before 2010. Modern coal power plants and gas combined cycles supply the bulk of electricity to the grid. In industry gas turbines with heat recovery boilers and/or steam bottoming cycles are most common.

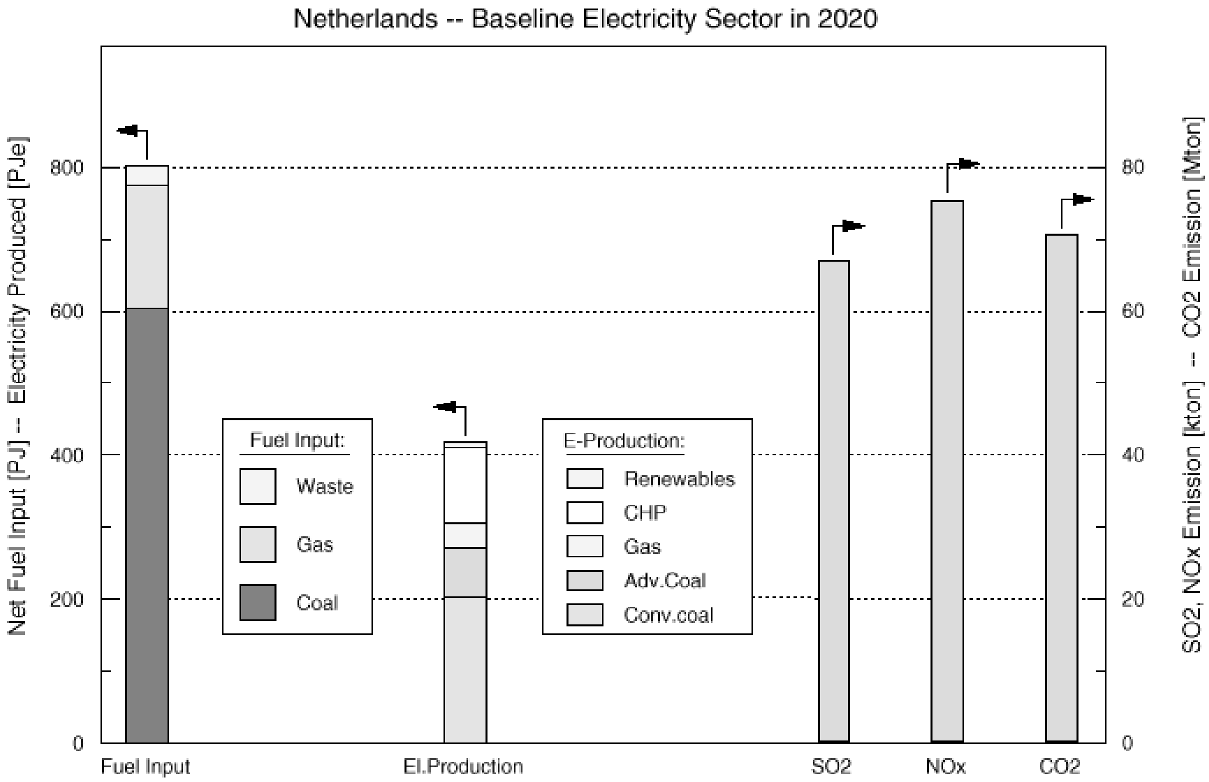

Figure 4. Baseline Electricity Sector in 2020

The electricity sector is characterised by the five bars displayed in Figure 4. The leftmost bar represents the net fuel consumption, broken down into coal, gas and (municipal) waste. The latter is included as the incinerators yield SO_2, NO_x and CO_2 emissions. The total input into the various plants is corrected for the heat generated (district heating; industrial and residential and commercial cogeneration), to obtain the net quantities used for electricity generation. In the absence of environmental considerations in the baseline, coal is the preferred fuel and covers 75 per cent of the total amount of 800 PJ. Taking the savings from coproduction of heat into account, the net input is converted into 420 PJ of electricity at an average efficiency of 52.2 per cent. As the second bar from the left shows, almost half of the electricity is produced in conventional, pulverised coal power stations. One quarter is supplied by modern combined cycles on natural gas or integrated with coal gasifiers (advanced coal). Renewables make a very small contribution, so that cogeneration (CHP) supplies the remaining quarter. The high share of coal and the absence of additional abatement technologies lead to substantial emissions from the electricity sector, as shown in the three bars to the right: 67 kton SO_2, 75 kton NO_x and 71 Mton CO_2.

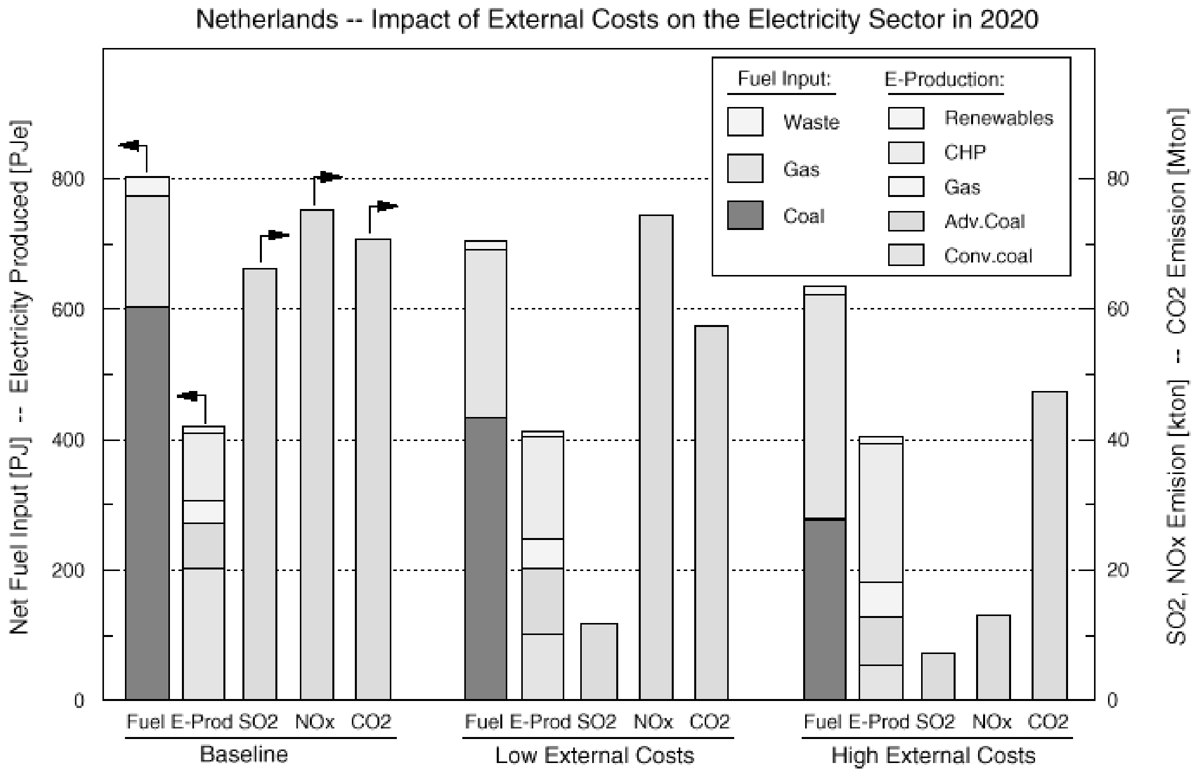

Figure 5. Impact of Charging External Costs on the Electricity Sector in 2020

Charging external costs according to the ExternE Low and High estimates adopted (see Table 1), induces a range of changes in the electricity sector, as illustrated here for the year 2020:

- the resulting increase in electricity prices reduces demand by less than 2 per cent (Low) to 4 per cent (in the High external cost case);

- CHP expands its share from one quarter in the baseline to 38 per cent in the Low, and even 53 per cent in the High external cost cases. This expansion is primarily attributable to a shift towards CHP technologies with a higher electricity-to-heat output ratio, and only marginally to a larger amount of heat being co-produced;

- The increase in CHP electricity goes at the expense of central coal power. The share of conventional coal power decreases from 50 per cent to 25 per cent (Low) and 13 per cent (High). This is only partly offset by an increase in advanced coal fired power generation. Centralised gas combined cycles increase their share slightly from 9 per cent (Baseline) to 11 per cent (Low) and 13 per cent (High);

- Coal fired plants are equipped with additional desulphurisation installations: enhanced FGD capturing 95 per cent (standard: 85 per cent) on pulverised coal plants and enhanced coal gas clean-up in IGCC plants to capture 99 per cent instead of 97 per cent of the sulphur in the coal;

- Only in the High external cost case is additional de-NO_X equipment installed. The level charged is sufficiently high to warrant investment in SCR (selective catalytic reduction) equipment and other very effective but costly de-NO_X options.

- The overall conversion efficiency, corrected for co-produced heat, increases from around 52 per cent in the baseline to 58.5 (Low) and 63.5 (High). Together with the -- modest -- decrease in consumption this makes that the fuel input drops by 12percent(Low)to21 percent(High).

The compounded effect of the changes in fuel mix, installed generating capacity and abatement technologies results in very drastic SO_2 and NO_x reductions (the latter only in the High external cost case). Fuel savings due to more CHP, more efficient plants and a larger share for gas imply reductions in CO_2 emissions. Compared against the baseline CO_2 emission from the electricity sector the reduction amounts to 18 per cent (Low) and 33 per cent (High). This corresponds to 6 per cent (Low) to 10 per cent (High) of the total national CO_2 emissions for the baseline in 2020. The total emissions associated with electricity generation are scaled to show their development over time per unit of electricity produced.

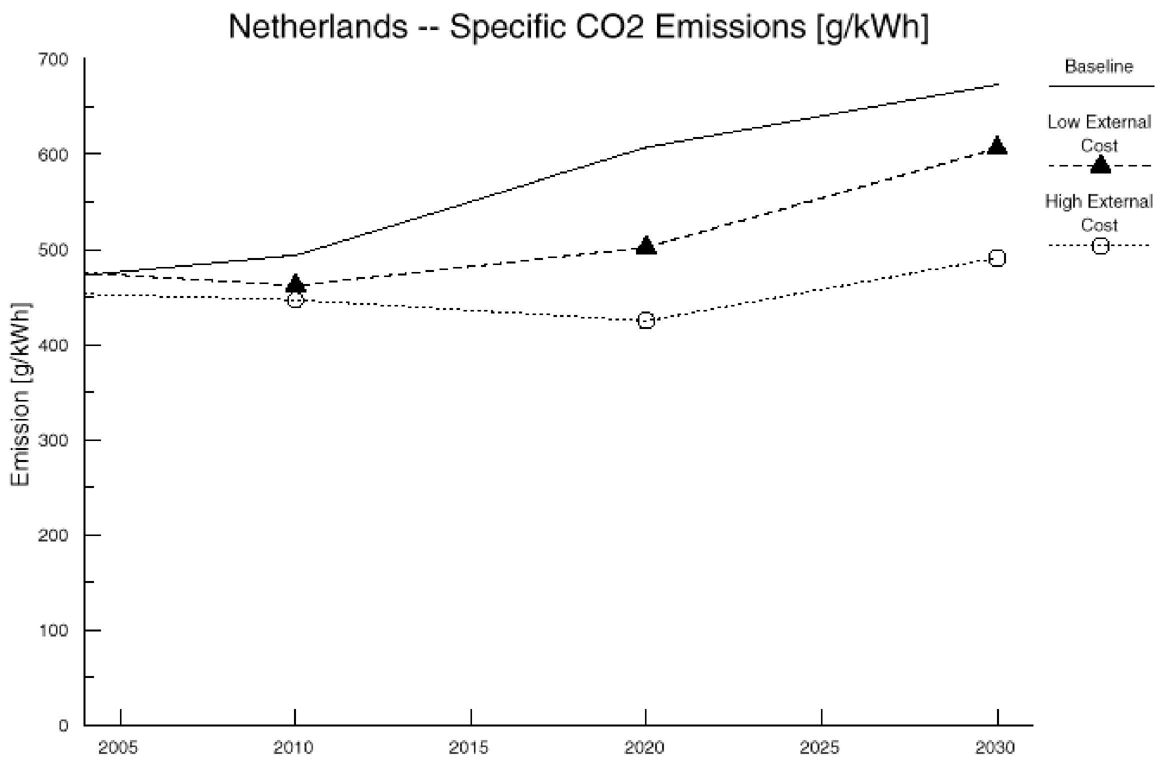

Figure 6. Specific CO_2 Emissions

In the baseline, a distinct increase in the amount of CO_2 emitted per unit of electricity produced can be observed, due to the already mentioned shift from gas to coal as the dominant fuel for power generation. Induced by the external costs the overall efficiency increases (more gas plants, more advanced coal plants, more CHP) and coal is replaced again by gas to lower the specific carbon emissions further from the baseline profile. However, in absolute terms, the specific emissions start to rise again sooner (Low, after

2010) or later (High, after 2020). The assumed growing wedge between coal and gas prices make advanced -- very clean -- coal power plants more cost-effective than gas fired plants despite the environmental cost adders.

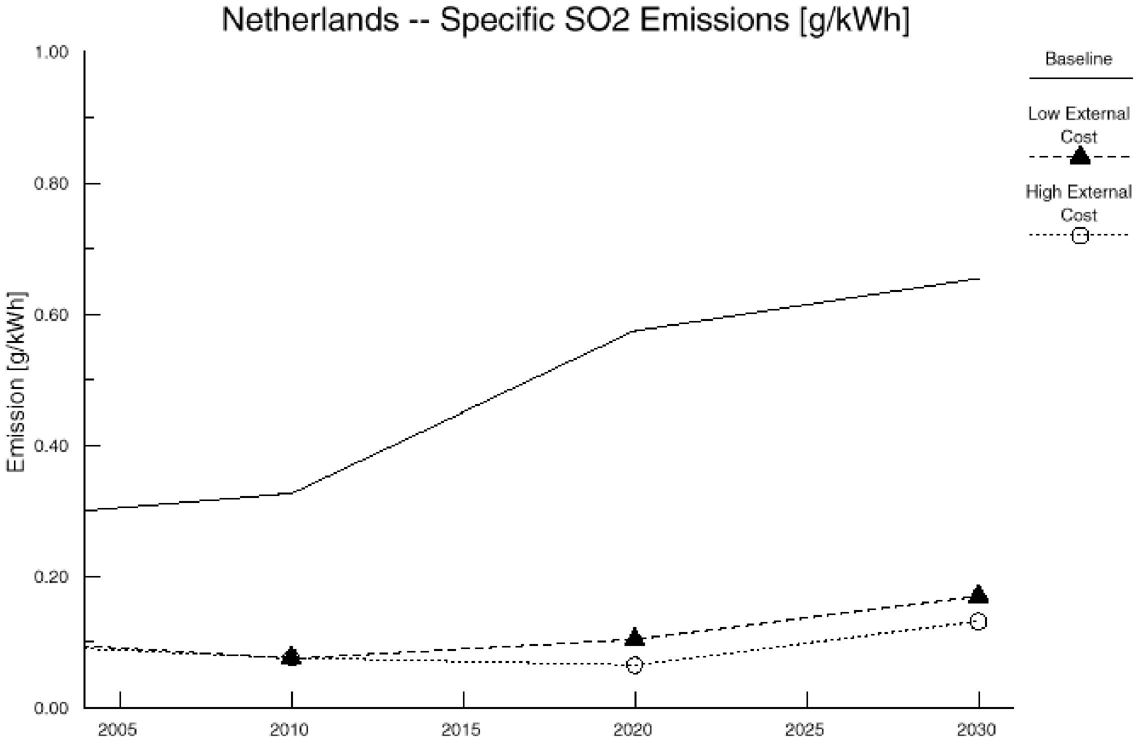

Figure 7. Specific SO_2 Emissions

Figure 7 shows that the baseline SO_2 emissions grow strongly due to an increasing share of coal in the input fuel mix. When charging external costs, the level decreases as (a) the share of coal decreases, and (b) enhanced desulphurisation equipment becomes cost-effective. The difference in specific SO_2 emission between the two external cost levels is relatively small because the difference in the cost levels themselves is not very large (see Table 1); and also because the lower level is already sufficient to induce deployment of the least SO_2 emitting options. With time, the gap between coal and gas prices is projected to widen, so that SO_2 emissions start to rise again despite deployment of modern technology fitted with up to99 percentefficientsulphurcapturingequipment.

The external cost levels for NO_x as derived from the ExternE project vary extremely, from zero to almost twice the highest level found for SO_2, (see Table 1), reflecting the uncertainty surrounding the estimates. Due to gradual penetration of new generations of equipment on the market with inherently lower NO_x emission factors than their predecessors, the average emission level decreases slightly in the baseline (see Figure 8). Naturally, the outcome for the Low case shows hardly any differences. By contrast, in the High case even relatively expensive abatement options like SCR become cost-effective and consequently the remaining NO_x emission level is decreased strongly. The emission level with SCR is relatively insensitive to the fuel type used, and therefore the switch from gas to coal over timehasalimitedimpact.

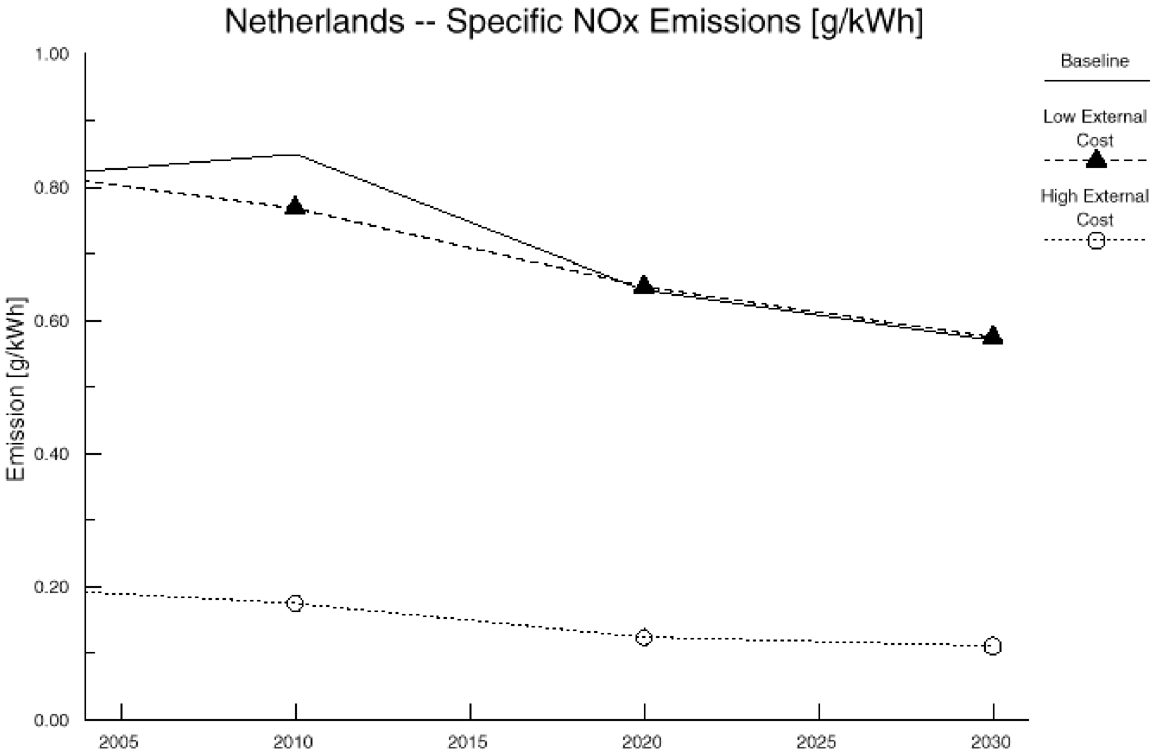

Figure 8. Specific NO_X Emissions

Italy

In Italy, the current electricity production is dominated by conventional steam power plants, the vast majority with multi-fuel firing capabilities (oil/gas; coal/oil). The actual mix can thus vary considerably following fuel cost, fuel availability and fuel acceptability considerations, the latter issue being strongly influenced by local environmental concerns hampering the use of coal. Heavy fuel oil is produced and used for power plants, in two qualities with different sulphur contents: 4 per cent and 0.5 per cent (by weight). Similarly, light fuel oil comes with 0.5 per cent or 0.1 per cent sulphur content. Due to additional refinery processing, the less sulphur containing oil products are more expensive. Furthermore, it is assumed that besides the standard quality of import coal with 1 per cent sulphur, up to 50 per cent of coal imports can shift to cleaner resources with 0.5 per cent sulphur at a higher price.

Contrary to the analysis for the Netherlands described above, the Italian case study concentrates on the short to medium term issues (up to the year 2010), e.g. associated with direct and indirect subsidies. Thus reactions to imposing environmental cost adders are to a large extent restricted to turning to cleaner fuels for existing plants, and/or retrofitting these with appropriate technical abatement equipment.

The key characteristics of the Italian electricity system in the year 2005 are displayed for the baseline and the two cases, with Low and High external cost adders considered in Figure 9.

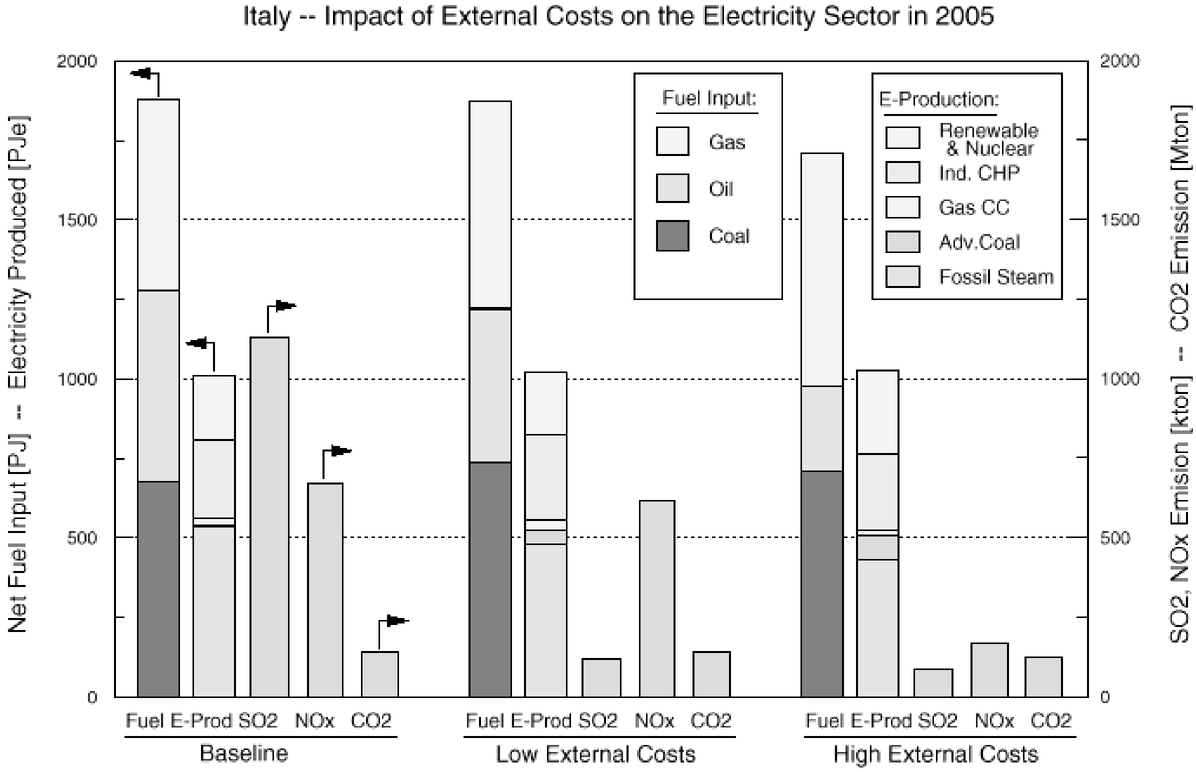

Figure 9. Impact of Charging External Costs on the Electricity Sector in 2005

In the baseline in 2005 coal, oil and gas each supply roughly one third of the total fuel requirements. Renewables, mainly hydropower, and (imported) nuclear power account for some 20 per cent of total electricity output. The remaining supply is dominated by conventional steam power plants (over 50 per cent) and various industrial producers (around 25 per cent). In the absence of abatement technologies and fuel quality constraints in particular SO_2 emissions are high at more than 1100 kton, but NO_x (675 kton) and CO_2 (633 Mton) emissions are also sizeable.

Under influence of external cost adders, non-fossil supply increases to 25 per cent (High case only) following the assumption that at higher prices more nuclear imports can be secured.5 Production from conventional steam power plants is further reduced by an accelerated deployment of advanced, clean coal units (IGCC, PFBC). In multi-fuel units accepting oil products or natural gas, a shift towards the latter is observed. However, as at the same time coal gets burned in advanced units, replacing HFO in other multi-fuel units, the share of coal also increases at the expense of oil. Together, coal and gas each cover over 40 per cent of the net fuel requirements in the High case, while the role of oil shrinks from one third in the baseline to 25 per cent (Low) and just 15 per cent (High). The simultaneous shift from oil to coal and from oil to gas implies that the net effect on CO_2 emissions remains small (see also Figure 10).

5 It should be noted that nuclear imports will not reduce overall CO_2 emissions, unless these imports come from incremental capacity in the exporting country. If this is not the case, all that is being achieved is a shifting of emissions from the importing to the exporting country.

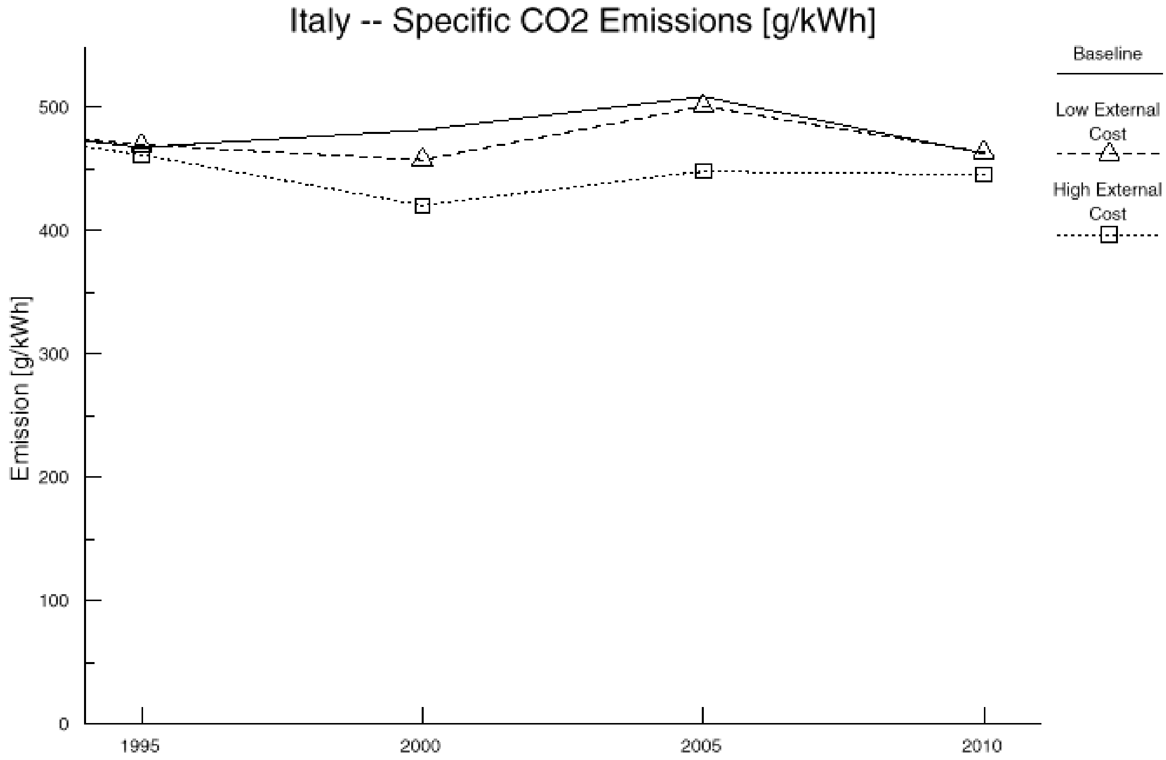

Figure 10. Specific CO_2 Emissions

Specific SO_2 emissions are reduced very drastically (see Figure 11) in the first instance, to the extent possible by substituting low sulphur quality fuels for their more polluting counterparts (HFO from 4 per cent to 0.5 per cent; LFO from 0.5 per cent to 0.1 per cent and import coal from 1 per cent to 0.5 per cent).

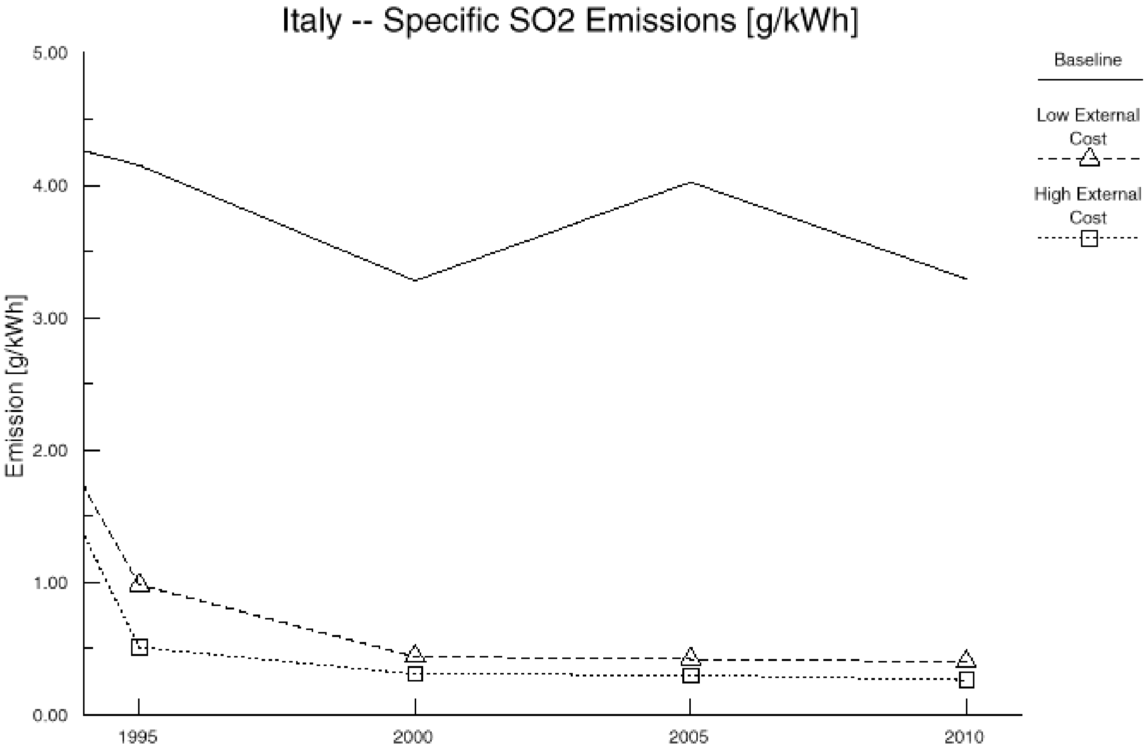

Figure 11. Specific SO_2 Emissions

Secondly, by expanding the number of units with desulphurisation equipment of various kinds, the combination of low sulphur fuels and the most efficient SO_2 scrubbers becomes economically viable in the High case, pushing down the emission level even further than in the Low case.

As NO_x emissions are largely independent from the fuel type of choice in a certain plant, and as except for a few exceptions SO_2 abatement technologies have little or no impact on NO_x formation, specific NO_x emissions are only significantly reduced in the High case (see Figure 12). There a relatively high external cost charge is assigned to NO_x emissions, inducing the widespread introduction of low-NO_x burning equipment and SCR.

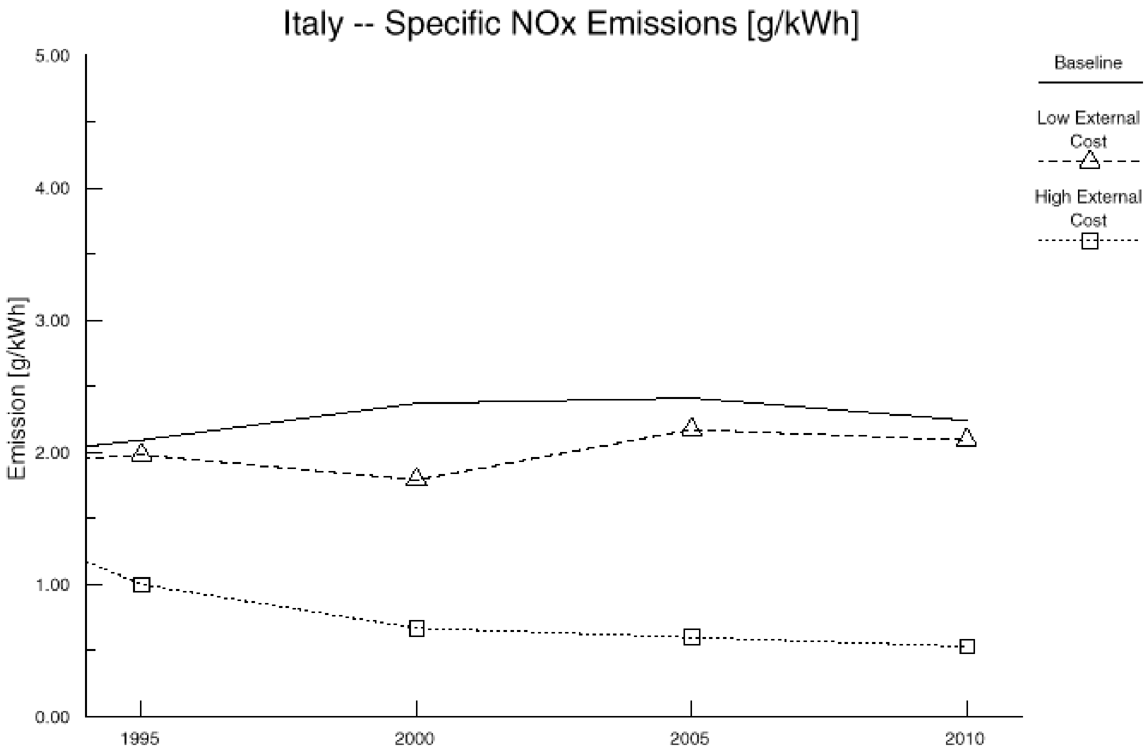

Figure 12. Specific NO_x Emissions

Overall conclusions and discussion

- Accounting for environmental cost adders associated with emissions of SO_2, NO_x and particulates as derived in the EU/ExternE study would induce much cleaner electricity production systems on the grounds of overall, full cost considerations.

- In practical electricity systems, varying subsets of a wide range of viable countermeasures will achieve these lower emission levels.

- Some of the countermeasures called upon in the case studies lead to reduced emissions of CO_2: e.g. switching from coal to oil products or to natural gas; introduction of new, high-efficiency-generating equipment. Others are essentially CO_2 neutral: adding flue gas scrubbers; buying low sulphur qualities of the same fuel type; etc. Sometimes adverse effects on CO_2 emissions occur also: e.g. switching from high-sulphur HFO to low-sulphur coal.

- Depending on the time frame considered, the starting point in the reference case, and specific future conditions (such as energy resource availability and prices) pertinent to individual electricity systems, very different mixes can yield the lowest overall cost in a full cost framework.

- Consequently, both distinctly lower CO_2 emission levels as well as practically unchanged levels are reported after introduction of environmental adders for SO_2, NO_x and particulates.
  With greater flexibility regarding fuel availability and power generating equipment, so typically in the longer run and/or with more market-oriented utility structures, the chances for positive side-benefits on CO_2 emission levels become better.

- Especially on the shorter term, the impact on CO_2 emissions will at best be small. Under specific circumstances with regard to installed generating equipment, prices and availability of fuels at the point of power production, even adverse effects like higher CO_2 emissions cannot be precluded. Expansion of the environmental cost adders to include carbon emissions explicitly would be an effective way to prevent such less desirable trends.

- In particular on the short term, the possibilities to adapt to the introduction of full cost schedules are limited. Too sudden, too quick and/or too rigid introduction therefore will lead to transition periods with much higher electricity prices that may be undesirable or even unacceptable for reasons of economic competitiveness and/or distribution of income.

It must be noted that the impacts on emissions of CO_2 and the various air pollutants reported here as a result of introducing environmental cost adders are measured against hypothetical baseline developments, in which current or planned regulatory and other environmental policies are assumed to be never implemented or discontinued. It is very well conceivable that continuation and/or reinforcement of current policies may show equally positive side-effects on future CO_2 emission profiles.

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