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SCENARIOS ON THE INTRODUCTION OF CO_2 EMISSION PERFORMANCE STANDARDS FOR THE EU POWER SECTOR

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Table of contents

Executive Summary

In this paper, the introduction of Emission Performance Standards (EPS) as a means for potential emission reductions in the European power sector was assessed. EPS in the power sector can already be found in California, USA, since 2007 as well as in the US states of Oregon, Washington and Montana, which introduced EPS schemes following the example of Califonia.

EPS scenarios and associated emission reductions

For the assessment 18 scenarios with varying level of EPS, scope of installations covered and point of time of introduction were compiled. Scenario emissions were projected for the timeframe 2005-2030 and compared to a reference case, broadly based on the current EU policy targets.

Reductions between 2006-2030 varied between 0.3 % (resp. 104 Mt CO_2) in the case of an EPS of 500 gCO_2/kWh only for new installations from 2020 onwards and 34 % (resp. 10,885 Mt CO_2) when using an EPS of 350 gCO_2/kWh for all installations with a capacity of more than 100MW from 2010 onwards.

Of course the earlier the point of introduction for an EPS, the more stringent the EPS level and the broader the scope of installations covered, the higher are the resulting reductions. With regards to the scope there was a clear signal that both existing and new installations should be covered, as EPS scenarios covering only new installations resulted in reductions of maximum 7 %. At the same time, there is room for improving cost-efficiency by leaving smaller installations, e.g. below 100 MW capacity, out of the scheme, as 70 % of reduction potential lies with installations >300 MW capacity. With regards to the point of time of introduction it was found that an earlier introduction of a less stringent EPS resulted in higher emission reductions than a more stringent EPS introduced at a later point in time. Introduction of a 500 gCO_2/kWh level EPS in 2015 resulted in 53% higher emission reductions than in the case of a 350 gCO_2/kWh introduced in 2020. In order to take into consideration the various necessities – security of supply, availability of technology, cost-efficiency – a staged approach covering both new and existing installations seems preferable. This approach could start with an EPS for new installations in the medium-term (e.g. 2015), which is then made more stringent on the long-term (e.g. 2025). For existing installations, an EPS demanding retrofit activities could be introduced on the long-term (e.g. 2025).

Consideration of biomass and CHP

In the following, the use of biomass and CHP in the framework of an EPS system was discussed. With biomass the question is mainly supply related and a first assessment indicated that sufficient biomass would be available for coal-fired power plants to reach a co-firing share of 50%, but the issues of sustainability, technical feasibility and availability of biomass at the regional level remain to be assessed in detail. With regards to CHP a separate EPS approach considering the production of heat seems advisable. It was briefly discussed whether instead of installation-based EPS, utility-wide averages could be used, as this could increase cost-efficiency e.g. in a starting period. It was found that, while the latter was generally true, the clear signal of an EPS system might be lost and increases of cost-efficiency would mainly occur with larger utilities with a suitable mix of installations, but not for smaller or even one-installation utilities.

EPS for non-power sectors

When assessing the feasibility of introducing EPS for the iron and steel as well as the cement sector, it was found that the uniformity of the product necessary for an EPS, and which can be found in the power sector, is of course not given for the mentioned sectors with their strongly varying product qualities. Furthermore difficulties arise due to the complexity of the production process especially for the iron and steel sector. It was found that in general a rather moderate EPS could help drive very inefficient installations out of the market, but it was considered questionable whether an EPS can be designed to support new best-practice development or enforce the implementation of most efficient technologies.

Conclusions

Overall it was found that EPS approaches could help to considerably lower emissions in the European power sector if a comprehensive and suitably staged approach is applied. Further assessment is of course needed to determine what kind of staged approaches would be technically feasible to cover the desired scope as well as optimizing cost-efficiency and ensuring security of supply. Furthermore, projections beyond 2030 would be necessary, as substantial CCS and retrofit activities are considered to only be available after 2020.

1 Introduction

1.1 Background

With the introduction of the European Emissions Trading System (EU ETS) in 2005, the European Union and its member States have set in place environmental legislation requiring larger emitters of greenhouse gases (GHG) to achieve emission reductions, and setting incentives for the application of less-emissive technologies and processes.

The sector with the highest share of emissions in the EU ETS is the energy sector. In theory a system like the EU ETS should lead to significant changes in the energy sector towards a less-emission intensive, more sustainable generation. Such changes are essential if ambitious mid- and long-term GHG reduction targets are to be achieved. However, such changes have not been observed so far. If, for reasons of supply stability, grid parity and limitations to rapid renewable growth, fossil power generation is still needed, a fuel shift from highly-emissive lignite and coal to less-emissive natural-gas should occur. Nonetheless the amount of hard coal-based electricity has even slightly risen from 2004 to 2006[1]. A survey among utilities indicates that currently in the EU 263 new fossil-fuelled power plants with a capacity of more than 300 MW are being built or planned[2]. The capacity of these plants totals to nearly 200 GW, equivalent to 25 % of the total current operational capacity in the EU. 33 % of this capacity will be coal-fired, the largest part of the remainder gas-fired and a marginal fraction of oil-fired.

In the bigger picture, the International Energy Agency forecasts a global resurgence of coal-based energy generation until 2030. By then, worldwide electricity production will have risen from 18,921 TWh to 33,265 TWh, and coal-based generation increased its share from 41 % to 44 %. Accordingly, this will lead to a 59 % rise in energy-related CO_2 emissions from coal to 18.6 Gt in 2030.[3]

One way to further allow the use of coal and other fossil fuels while achieving emission reductions is the development and implementation of carbon capture and storage (CCS) tech-

[1] Source: Eurostat 2007a
[2] Source: Graus et al. 2008
[3] Source: IEA, World Energy Outlook 2008

nology in power plants. Currently it is still being discussed, whether the incentives provided by the EU ETS will be sufficient to make CCS economically viable and thus allow for significant GHG reductions in the fossil fuel-based electricity sector. The timeframe for full deployment of CCS is another issue of discussion. It is generally not expected before 2020, i.e. CCS is not considered a major short or medium-term solution.

Based on these facts and in order to ensure that mid- and long-term reduction targets can be met, a need can be seen to put additional policies and measures complementing the EU ETS and leading to the development and application of low-emissive power generation technologies in place. An instrument currently discussed at EU-level is the introduction of Emission Performance Standards (EPS). These standards set maximum thresholds for the emission-intensity of power generation (e.g. gCO_2/kWh) and could thus pave the way for more efficient and sustainable energy production.

1.2 Objective

This paper is meant to deliver input into the political discussion on EPS in the EU power sector. The paper will explore the effects of the introduction of an EPS on electricity sector emissions until 2030 and discuss various EPS related implementation issues.

Regarding emission effects, the consequences of different EPS designs will be compared to a reference scenario which includes the EU's targets for 2020 as described in the Energy and Climate Change Package proposed by the European Commission in January 2008.

Furthermore, the study will deliver qualitative assessments of key implementation issues: EPS and the use of biomass, the inclusion of combined heat and power plants as well as EPS applied at utility rather than at installation level. Furthermore an indication on costs that can be associated with the introduction of EPS is given and the general potential to introduce EPS for two non-power sectors, the iron and steel as well as the cement industry, is assessed.

2 Emission Performance Standards

2.1 Existing and Comparable Performance Standards for Energy Industry

An introduction of EPS for power plants would not be the first case of quantitative thresholds in environmental legislation in general, but also not concerning the power sector. With the introduction of policies regulating emissions of sulphur dioxide (SO_2), nitrous oxides (NO_x) and other substances, the EU has gained useful experiences on the introduction and implementation of EPS, which are known as 'emission limit values' in existing legislation.

2.1.1 Comparable Regulations – Californian EPS

California has introduced an EPS for public baseload electricity supply in 2007. It was first established as an interim policy until the introduction of a cap and trade-system, but it is now under discussion, whether the EPS system should not be maintained even if a cap and trade system is introduced. One of the reasons for the introduction of an EPS was to prevent Californian power consumers from high cost increases by the time an emissions trading system (ETS) is introduced. Furthermore the EPS was intended to guide innovation and investments in sustainable energy supply early enough, to increase the industry’s competitiveness in a GHG-constrained future.

The EPS level is 1,100 pounds of CO_2 /MWh (498.95 gCO_2/kWh), which was found to be the average emission rate of a combined-cycle natural gas power plants. The EPS applies for electricity procured by local publicly owned utilities, whether it is generated within state borders or imported from plants in other states. The standard applied to all new long-term electricity contracts after June 30, 2007.

Relevant lessons learned

Regional Impact: Shortly after the adoption of the EPS scheme in California, Washington, Oregon and Montana followed with similar schemes.

Coexistence of EPS and emissions trading systems: The fact that California applies EPS, at least on an interim basis, while as part of the Western Climate Initiative being a forerunner for emissions trading in the US, shows that both policy instruments are believed to be able to co-exist together. The same applies to Washington, Oregon and Montana, which are also part of the Western Climate Initiative.

Security of Supply: It was found that California's situation with regards to security of supply has improved since the introduction of the EPS system.

2.1.2 Comparable Regulations - LCP Directive

The regulation most comparable to an EPS is the Large Combustion Plants (LCP) Directive, which first entered into force in 1988 (Directive 88/609/EEC) and was significantly amended for the last time in 2001.

The LCP Directive was intended to control and reduce the emissions of SO_2, NO_x and dust. It sets limit values for combustion plants having a capacity of 50 MW and more.

In 2001, these limit values were amended to reflect technological development and cost reductions in pollution control technologies. The LCP Directive is now part of a broader regulative framework on air pollution that consists of several Directives on ambient air polluters (now integrated into Directive 2008/50/EC) and the Integrated Pollution Prevention and Control (IPPC) Directive 2008/1/EC. While the LCP Directive sets maximum limits on pollution concentrations in emissions, the IPPC Directive includes requirements on the application of best available technologies for new as well as existing plants. Additional to their modest levels, the LCP Directive's limits are fuel- and country-specific and include several exemptions and transition rules as well.

As an effect of the LCP Directive in combination with other pollutant regulations mentioned, European power plants apply pollution control technologies on a broad range and at a relatively effective but still cost-efficient level. Negative economic effects could be avoided because of the consideration of cost-efficiency in the legislative development as well as the possibility of utilities to pass through respective costs onto customers.

Relevant lessons learned

Combination of policies: An important aspect of the LCP Directive is its being part of a partly overlapping legislative framework of air quality and pollution control that is directed towards Member States as well as installations. An introduction of a CO_2 EPS would also be part of a policy network on climate change that includes Member States' effort sharing under the UNFCCC, the EU-ETS Directive and renewable energy policies.

While this effort increases the amount of regulative burden and is a potential drawback for cost-efficiency, it can ensure the environmental effectiveness in areas where one single over-arching instrument (like the EU ETS) might fail to provide effective long-term incentives.

Command-and-control minimum standards: Like the LCP Directive, EPS would define minimum standards for electricity generation. Minimum standards do not necessarily incentivise innovation or application of best available technology. But they ensure that minor shares of worst-performers do not contribute heavily to overall emissions and that tested and available techniques reduce their costs by forcing their application on a large, cost-efficient scale.

Economies of scale and power market design: In general, by creating demand for pollution control technologies like desulphurisation or CCS, the costs for these technologies and associated installation, maintenance, monitoring and reporting services decrease faster and stronger than estimated beforehand. Additionally, by forcing similar requirements onto the power sector, distributional or competitive effects are very low, as all utilities face similar costs increases and can pass them through to customers.

2.1.3 Comparable Regulations – Air pollution limits for motor vehicles

The first European-wide limits on air pollutants from motor vehicles were introduced in 1970. By then only emissions of carbon monoxide (CO) and hydro-carbons (HC) were regulated, which was part of a process to define uniform standards on various design and functionality aspects of vehicles. Coverage widened through the next two decades by amending the framework to apply to nitrogen oxides (NO_x) as well as buses and trucks. In 1992, the first so-called Euro norm was established, setting the limits for CO and HC+NO_x emissions from new cars at 3,160 mg/km and 1,130 mg/km, respectively.

During the last 15 years, the limits have been tightened to reflect technical advancements. Nowadays, new cars have to fulfil Euro 4, which allows 1,000 mg/km of CO and 180 mg/km of HC+NO_x. This means a reduction by 68 % and 84 %, respectively compared to Euro 1. Future limits of Euro 5 and 6, to become effective in 2009 and 2014, respectively, have already been adopted, decreasing the allowed emissions from NO_x and especially particulate matters considerably.

Perhaps controversial to intuition, the tightening emission regulations probably helped the automotive sector to sell more new cars. This is because in line with emission regulations and an increased focus on environmental policy in Member States, many countries included the emission level of a car type into the taxation system. In effect, maintaining an old car got more expensive, as higher taxes had to be paid compared to a new car with better emission performance. Additionally, a second market for retro-fitting one's car with newer filtering technologies developed, which opened a new market for respective manufacturers, suppliers and service providers.

Relevant lessons learned

Financing through demand-side regulation: As with filter technologies for vehicle emissions, there will probably not only be regulations on the manufacturer/ generation side, but also on the demand side. Financial incentives - e.g. through taxation, as in the case mentioned above - on clean energy for consumers could not only maximize the effectiveness of CO_2 emission policy in the electricity sector, they could also help to finance the R&D costs of technologies like CCS. A necessary condition is that limits are gradually tightened and incentives adjusted accordingly.

2.1.4 Comparable Regulations - Summary

The analysis of these approaches provides us with the insight that EPS have already been implemented successfully in the past if the right framework conditions were created. Of special interest is the EPS in California, which resulted in further US States adopting comparable legislation. All of these states, including California, are part of the Western Climate Initiative, cooperating on cap and trade systems, which indicates that a coexistence of EPS and ETS is deemed possible by the respective authorities.

Partly EPS stakeholders were supported in bearing the costs through incentivizing legislation, e.g. tax breaks. In certain cases they were able to create and successfully market their own "low emission"-products by even exceeding the EPS requirements. Supportive to the introduction of an EPS is the involvement of the general public as an increased information level leads to a higher acceptance of the mechanism.

2.2 Methodological Approach

In the following, the methodological approach regarding the development of the reference scenario as well as the EPS scenarios and the underlying assumptions are presented.

a) The reference scenario

The reference scenario is based on a database portraying the largest part of the European power sector in detail. It includes plant-specific technological as well as historic emission data. Detailed data for the year 2005 is available for the 319 largest CO_2 emitters, representing 72 % of all EU-ETS Emissions and approx. 60 % of gross electricity production according to Eurostat. This database was compiled using the register of the EU-ETS registry as well as the European WEPP power plant database provided by Platts. The WEPP database contains extensive information on over 25,000 power generation units with technological (i.e. fuel type, boiler technology, steam temperatures, manufacturer) as well as statistical data (i.e. start of operation, status of deployment).

This data is especially useful to develop a scenario on the closure and replacement of power plants. For each technology and fuel type specific assumptions were made based on this information. The result is a detailed database regarding the demand for new power generation capacity for the EU25. This gap is replaced with new power plants following their respective share of generation in 2005. The assumptions on the lifetime of the individual power plants are given in table 1.

Table 1: Default lifetimes per plant type

Fuel type	Technology	Lifetime [years]
Hard coal	Steam turbine	50
Lignite	Steam turbine	50
Natural gas	Combined cycle	35
Natural gas	Gas turbine	30
Natural gas	Steam turbine	50

Based on this data, a reference scenario is developed, taking into account the EU's targets for a 20 % decrease in GHG emissions relative to 1990, a 20 % decrease in energy consumption relative to business-as-usual, and 20 % share of renewable energy, all to be met in 2020.

As little information is available on the legal framework after 2020, the trends in overall emissions, energy efficiency and renewable energy are continued for the timeframe of 2020-2030. The results are validated in order to avoid extreme developments resulting from this continuation of trends.

Furthermore, it is assumed that national plans to phase-out nuclear power generation until 2020 are implemented. From 2020 onwards and where no such plans are available, the absolute level of nuclear power generation (total MWhs) is kept constant until 2030.

The final reference scenario delivers data on EU power generation and associated emissions per fuel-type for each year until 2030. Figure 2 shows the share of the individual fuel types in the electricity mix up to the year 2030 as described in the reference scenario.

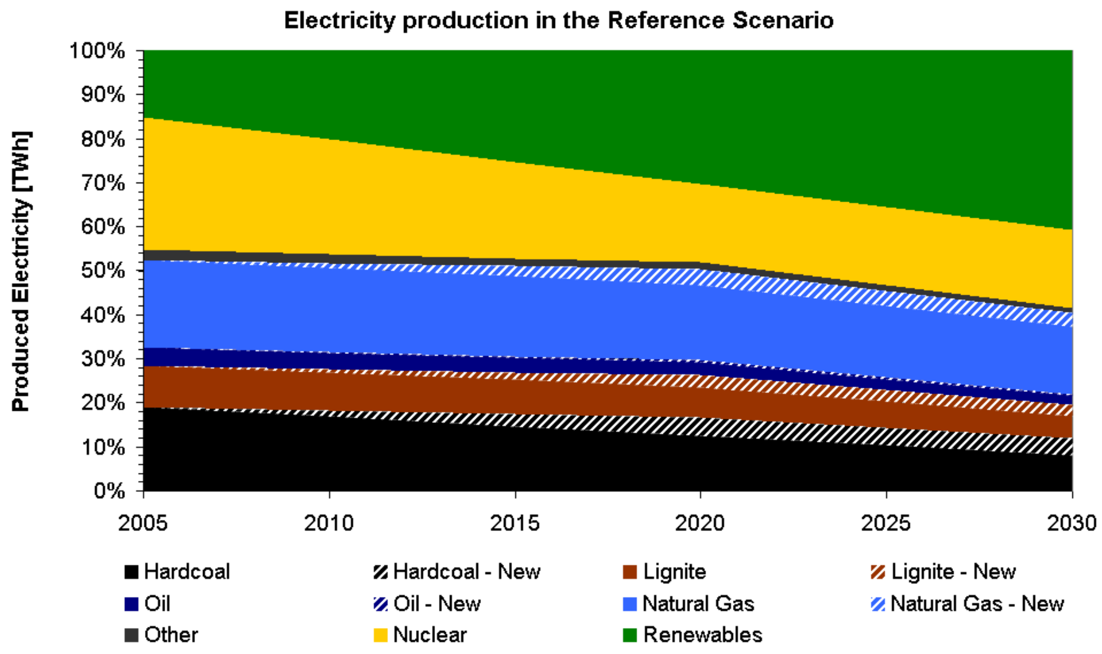

Figure 1: Electricity production in the reference scenario

Figure 3 shows the development of CO_2 emissions in the reference scenario according to fuel types and stock/new power plants. In addition the respective emission reductions until 2020 / 2030 from 2005 are included. Compared to 2005, an emission reduction of 14 % and 35 % respectively is achieved for 2020 and 2030.

It is important to note that the planned 200 GW additional capacity from fossil fuels, with around 33% coal/lignite exceeds the additional capacity needed until around 2015 in the reference scenario. The extent to which the need is exceeded can only be judged with difficulty, because the planned workload of the new capacities is of course not known. Expert estimation roughly indicates that the planned capacities might exceed the need for additional capacity in the reference scenario due to closure of older plants and increased power demand by around 25%. While quantification is not easy, this generally indicates that there is a deviation between the developments needed to achieve the EU-targets and the actual developments in the power sector.

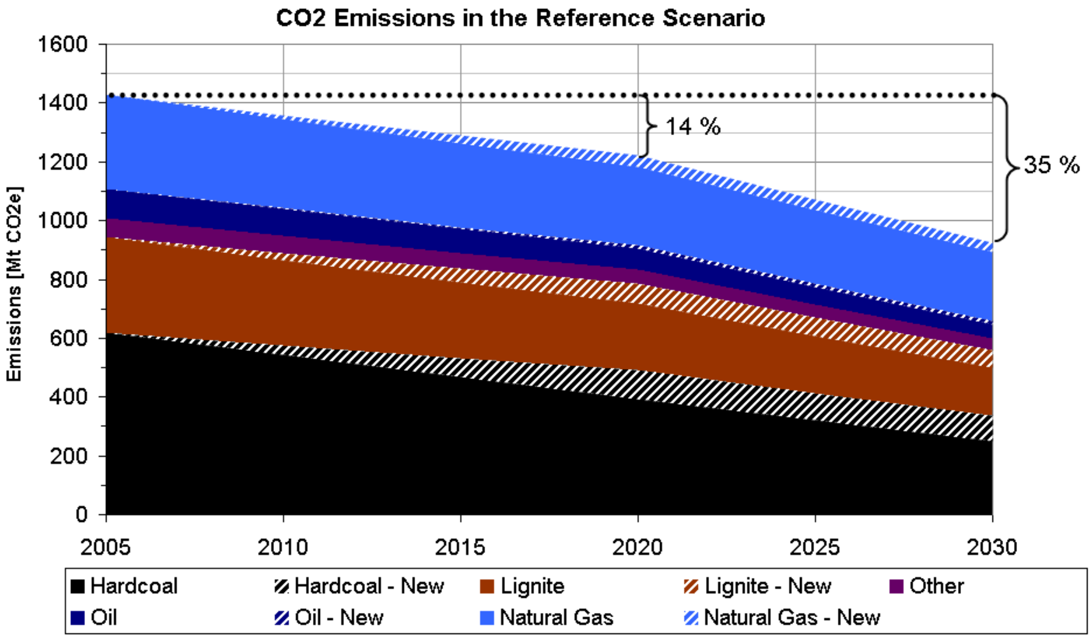

Figure 2: CO_2 emissions in the reference scenario.

b) Consideration of EPS Values

Three EPS values were chosen and briefly assessed with regards to their implications for the power sector.

- 500 gCO_2/kWh: This threshold can easily be achieved by existing as well as newly built plants using natural gas. If oil, hard-coal or lignite is used, co-firing of a sufficient amount (minimum 30 %) of biomass or CCS would be necessary to achieve this threshold.

- 350 gCO_2/kWh: This threshold can be achieved by newly built plants using natural gas. If oil, hard-coal or lignite are used, a very high level of co-firing biomass (minimum 50 %) or CCS would be necessary to achieve this threshold
  This threshold can only be met by newly built installations using natural gas. Finding sufficient biomass for co-firing is an issue to be considered.
- 150 gCO_2/kWh: This threshold can only be achieved by using biomass or by combining fossil fuel use with CCS.

While the 500 gCO_2/kWh EPS could be implemented for newly built plants already in the short term, more time would be necessary for the lower EPS thresholds, as respective technologies need to be in place and respective markets developed. Therefore it seems helpful to use a staged approach with thresholds becoming lower over time and existing installations being subject to EPS at a later point in time.

c) Development of EPS Scenarios

For the quantitative assessment of different EPS design options, 18 scenarios have been chosen, differing in the following aspects:

- EPS level
- Year of introduction
- Coverage of new and existing plants
- Coverage threshold for plant capacity (where nothing is mentioned, all plants are included)

The different scenarios are shown in table 2 below:

Table 2: EPS scenarios

EPS Scenarios	
1.	**350 gCO_2/kWh** for all new installations from **2010** onwards, **150 gCO_2/kWh** from **2015** onward
2.	**500 gCO_2/kWh** for all new installations from **2010** onwards, **150 gCO_2/kWh** from **2015** onwards
3.	**150 gCO_2/kWh** for all new installations from **2010** onwards
4.	**350 gCO_2/kWh** for all new installations from **2015** onwards
5.	**500 gCO_2/kWh** for all new installations from **2015** onwards
6.	**350 gCO_2/kWh** for all new installations from **2020** onwards
7.	**500 gCO_2/kWh** for all new installations from **2020**onwards
8.	**350 gCO_2/kWh** for all new installations from **2010** onwards plus **350 gCO_2/kWh** for all installations having started operation before 2010 in **2015**
9.	**150 gCO_2/kWh** for all new installations from **2010** onwards plus **150 gCO_2/kWh** for all installations having started operation before 2010 in **2020**
10.	**150 gCO_2/kWh** for all new installations from **2010** onwards plus **150 gCO_2/kWh** for all installations having started operation before 2010 in **2025**
11.	**350 gCO_2/kWh** for all new installations from **2010** onwards plus **350 gCO_2/kWh** for all installations having started operation before 2010 in **2020**
12.	**350 gCO_2/kWh** for all new installations from **2010** onwards plus **350 gCO_2/kWh** for all installations having started operation before 2010 in **2025**
13.	**500 gCO_2/kWh** for all new installations from **2010** onwards plus **500 gCO_2/kWh** for all installations having started operation before 2010 in **2020**
14.	**500 gCO_2/kWh** for all new installations from **2010** onwards plus **500 gCO_2/kWh** for all installations having started operation before 2010 in **2025**
15.	**350 gCO_2/kWh** for all installations with a capacity **> 100 MW** from **2010** onwards
16.	**350 gCO_2/kWh** for all installations with a capacity **> 200 MW** from **2010** onwards
17.	**350 gCO_2/kWh** for all installations with a capacity **> 300 MW** from **2010** onwards
18.	**150 gCO_2/kWh** for all new installations from **2020** onwards plus **150 gCO_2/kWh** for all installations having started operation between 2010 and 2020 in **2025**

Scenario calculation is done as follows: Generic emission factors in the database are replaced by the respective EPS values, depending on the scenario conditions. The annual electricity production is kept constant for all scenarios including the reference scenario.

A number of assumptions had to be made for scenarios 15 and 16. These scenarios include capacity-specific thresholds of 100 MW and 200 MW. The database used only contains capacity related data for around three quarters of CO_2 emissions from the EU power sector. While installations >300 MW capacity are well covered, assumptions had to be made regarding the power production within the various capacity categories (between 300 and 200 MW, between 200 and 100 MW, below 100 MW). Based on data for historic production, emissions and plant sizes, the following assumptions with regards to the power production were taken for Scenarios 15 and 16:

- For existing lignite and coal installations, the higher the capacity category, the higher the shares of total power production coming from these fuels
- New lignite and coal installations will be built with capacities > 200 MW, with the majority of power production coming from plants with capacities > 300 MW
- Oil plants are generally assumed to have capacities lower than 100 MW.
- For existing gas plants the majority of power production was assumed to take place in the category < 200 and >= 100 MW while gas plants above and below that range have about equal production shares.

For validation purposes, a sensitivity analysis for these assumptions was carried out. Distribution of power production for the various fuel types and across capacity categories was assumed to be radically different than expert knowledge indicates. The following assumptions were made, leading to two new sub-scenarios for Scenario 15 and 16:

a) Power production is distributed equally over the categories for all installations
b) Power production is concentrated with capacities between 100 and 200 MW for hard coal and lignite, while for gas concentration is assumed to be with capacities between 200 and 300 MW

In these sub-scenarios emission values in 2030 as well as reductions 2005-2030 showed a variation below 5 % compared to the main scenario.

2.3 Scenario Results for EPS

In the following, the key findings from the development of 18 EPS scenarios and their comparison with the reference scenario are presented. This is not done for every single scenario, but for groups of scenarios, based on the main parameters varied within these scenarios. Absolute and relative emission reductions compared to the reference scenario are presented in Annex I.

The parameters varied in the different the EPS scenarios are the following:

- The EPS level: 500 gCO_2/kWh, 350 gCO_2/kWh, 150 gCO_2/kWh
- The year of introduction: 2010, 2015, 2020, 2025, including staged and non-staged approaches as well as with or without retrofitting
- The coverage: existing and new plants, only new plants
- The capacity: For all plants, for plants > 100 MW, > 200 MW, > 300 MW

2.3.1 Variation of EPS Level

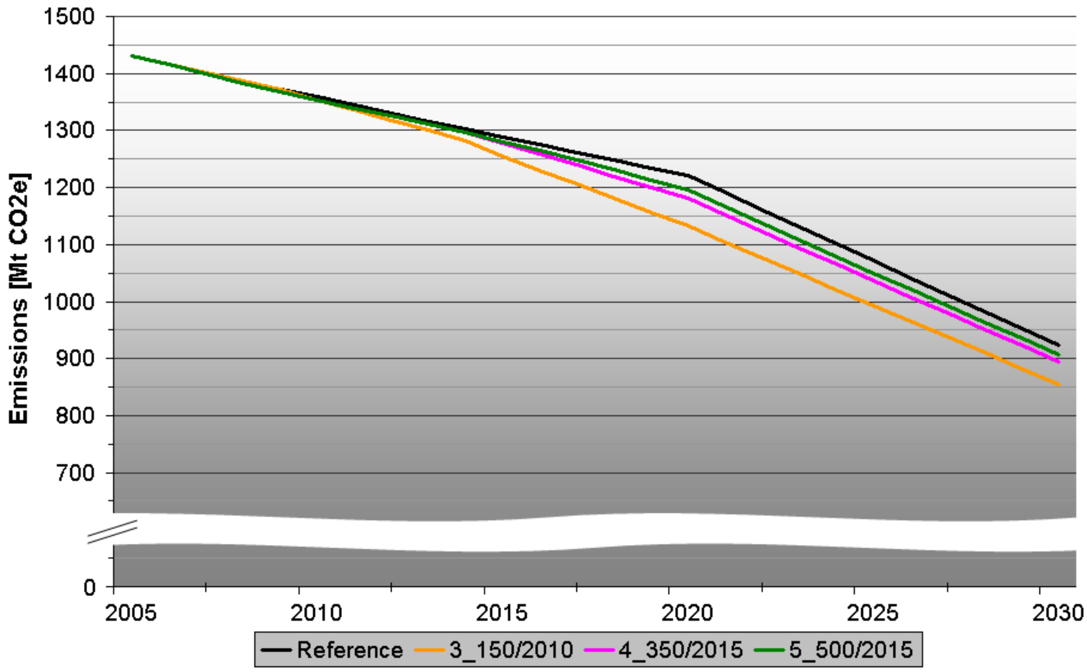

Figure 3: Impact of EPS Level I

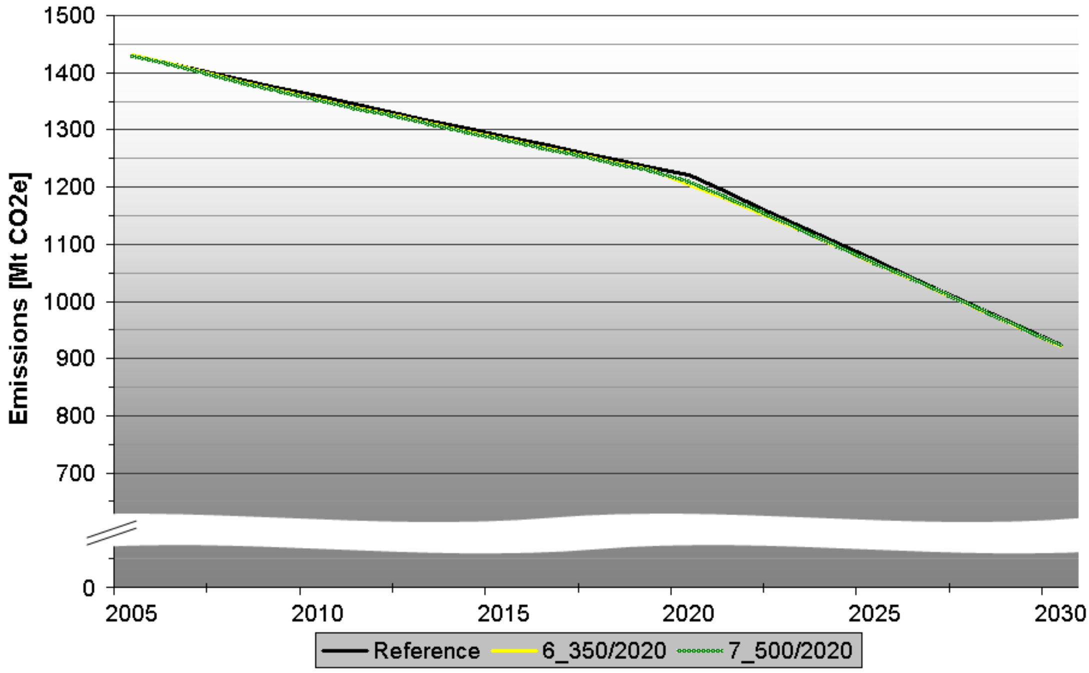

Figure 4: Impact of EPS Level II

The figures 4 and 5 show the reference scenario as well as the scenarios 3-7. The EPS-level as well as the year of introduction can be seen from the scenario names. EPS only applies to newly built installations. The highest impact is of course achieved with the EPS of 150 gCO_2/kWh introduced already in 2010: total emissions between 2005 and 2030 are around 6.3 % lower than in the reference scenario. The choice between a 350 gCO_2/kWh and a 500 gCO_2/kWh level has a more modest impact, especially when the EPS is introduced five years later, total reductions compared to the reference scenario are 1.7 % and 1.1 %, for an introduction in 2020 the reductions are marginal both being below 0.5 %.

This shows clearly that EPS only for new installations will lead to rather small reduction potentials. To access larger potentials it is clearly necessary to include existing installations and to introduce EPS as early as possible.

2.3.2 Variation of Year of Introduction

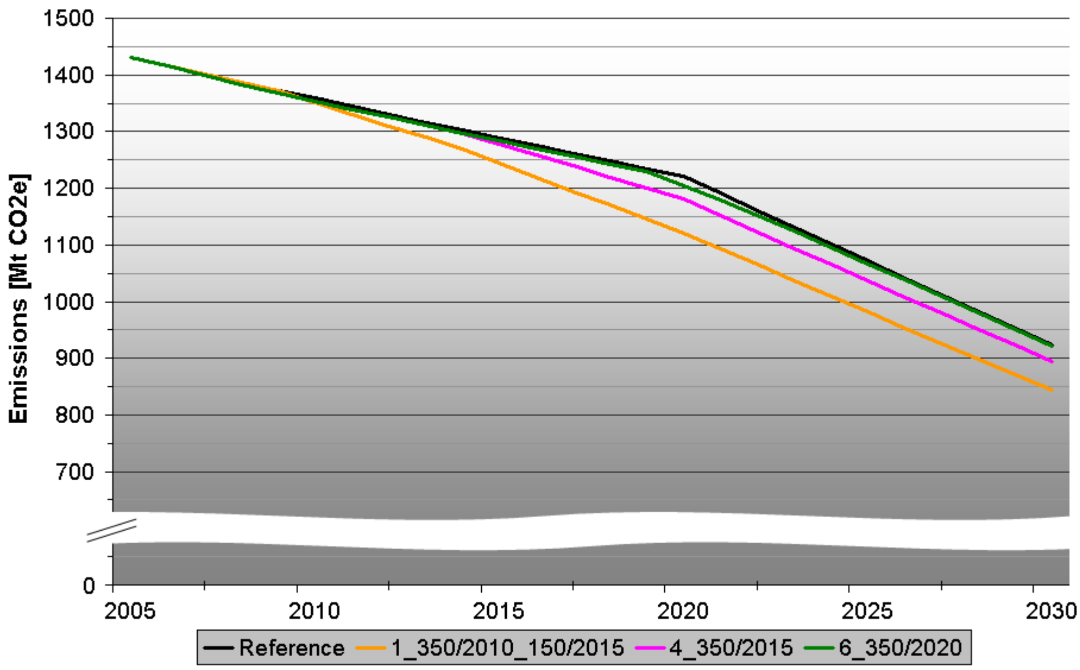

Figure 5: Impact of Introduction Year I

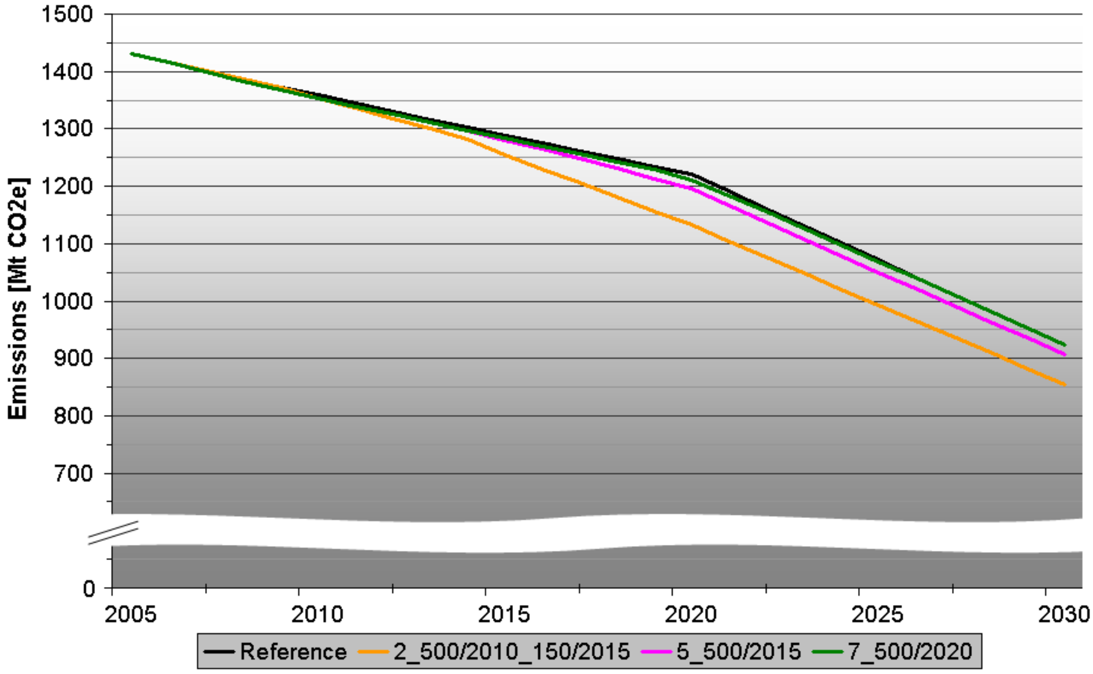

Figure 6: Impact of Introduction Year II

The effects of different introduction years are shown in Figure 5 and 6. Again only new installations are taken into consideration. Scenarios 1 and 2 represent a staged approach. As total reductions are small due to the fact that only new installations have to comply with the EPS, these differences stemming from variations to the year of introduction remain modest: E.g. considering an EPS of 350 gCO_2/kWh, reductions are only 1.3 % greater than if the EPS is introduced in 2015 (Scenario 4) instead of 2020 (Scenario 6). For an EPS of 500 gCO_2/kWh and the same years of introduction, the difference amounts only to 0.7 % in total reductions (Scenarios 5 and 7).

2.3.3 Variation Staged Approach

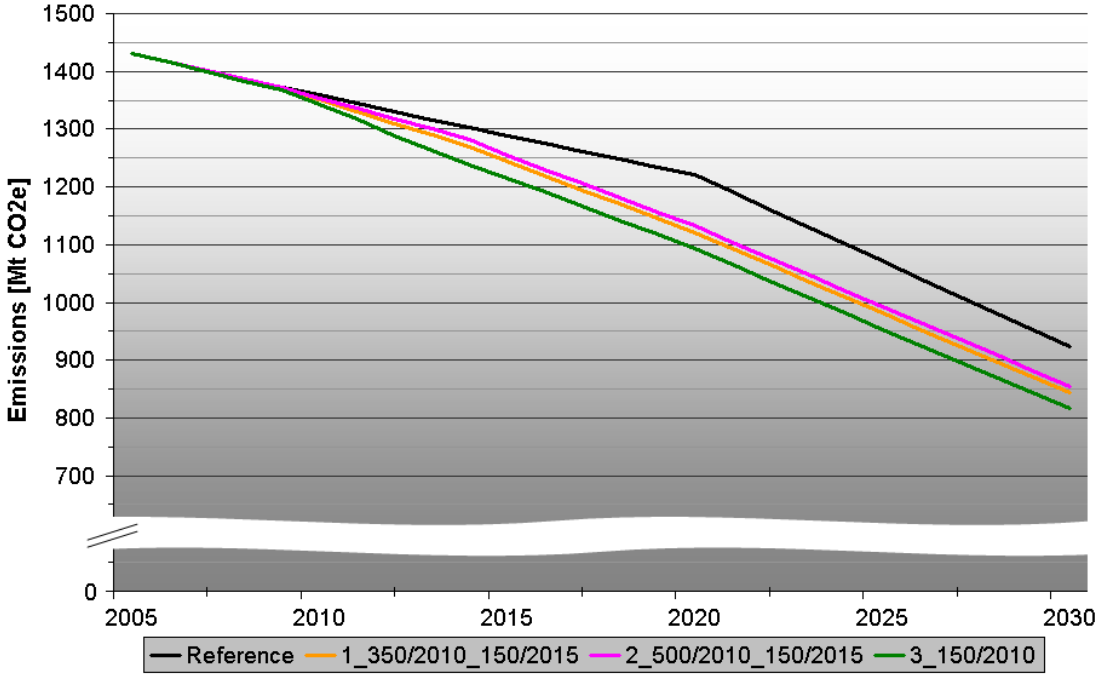

Figure 7: Impact of Staged Introduction

Figure 7 displays the impact of a staged introduction of EPS levels. This means that an EPS is first introduced at a modest level and a more ambitious EPS is set at a later stage. As only new installations are considered, the overall emission reduction compared to the reference scenario does only differ slightly through the scenarios: 4.5 % (Scenario 1), 3.8 % (Scenario 2) and 6.3 % (Scenario 3).

2.3.4 Variation Retro-Fitting

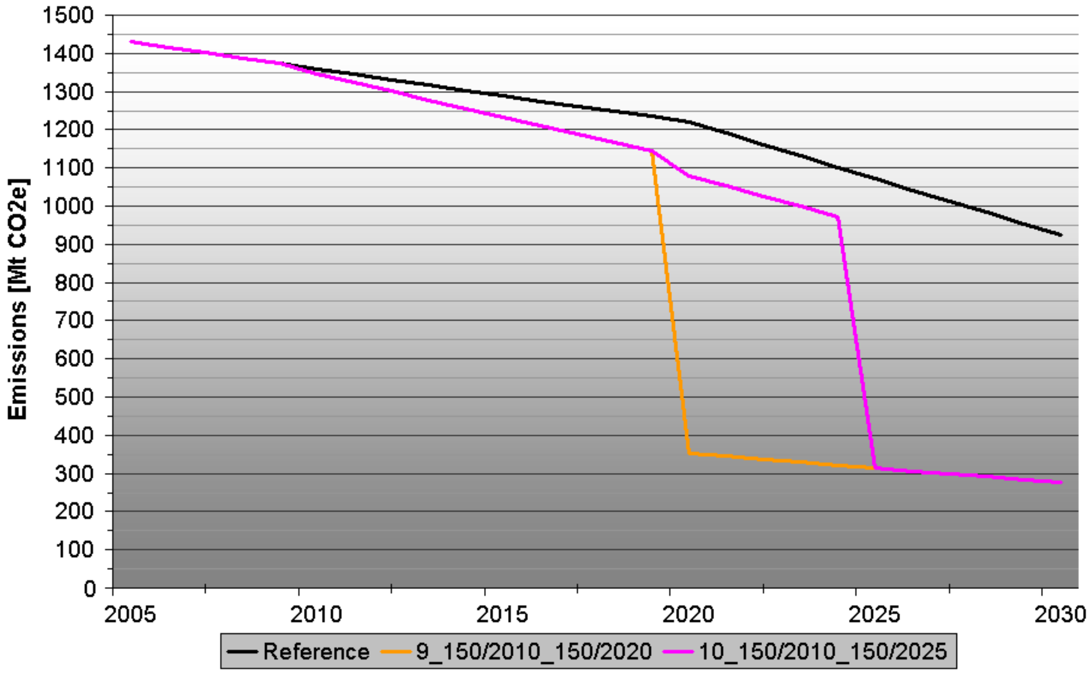

Figure 8: Impact of Retro-Fitting I

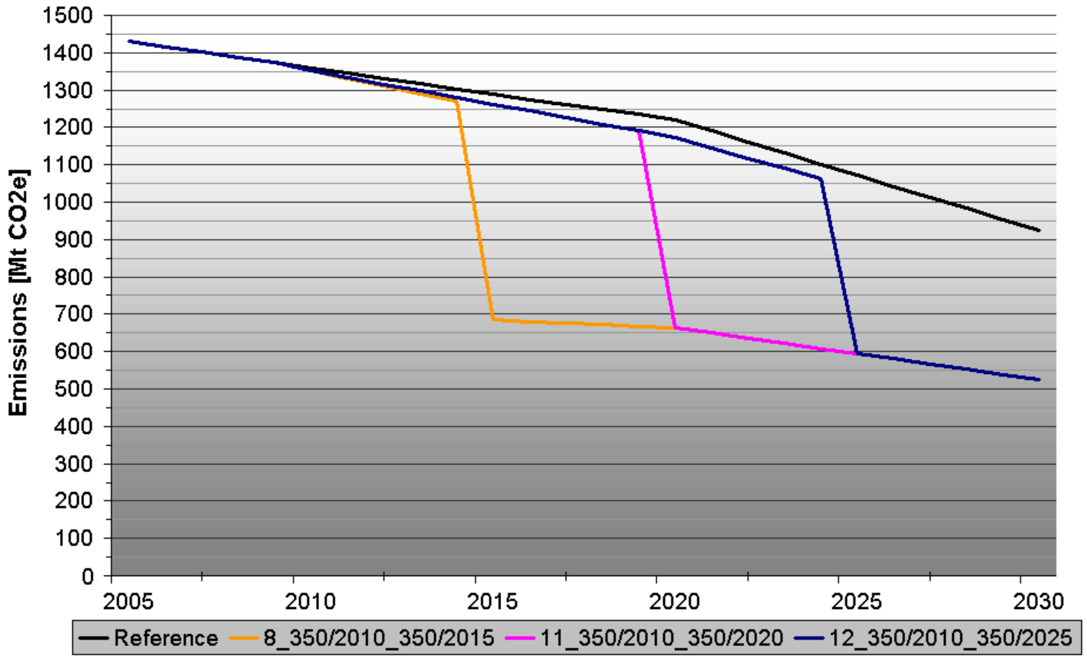

Figure 9: Impact of Retro-Fitting II

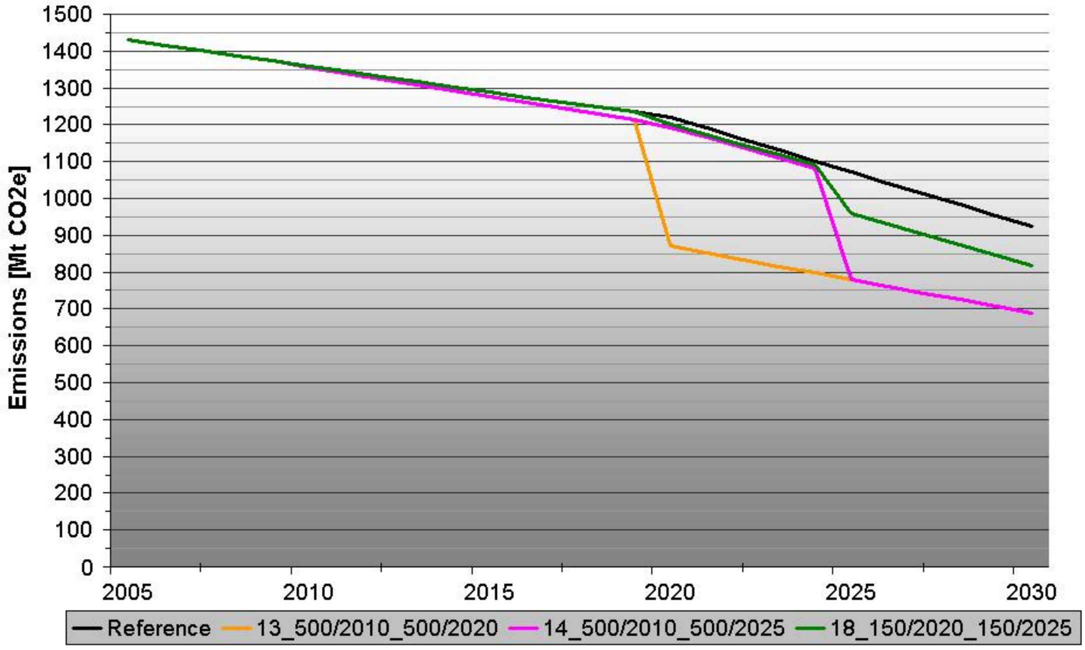

Figure 10: Impact of Retro-Fitting III

If EPS are also applied to existing power plants as displayed by Figure 8, Figure 9 and Figure 10, significantly higher emission reductions can be achieved. This effect is of course the highest if an ambitious EPS level of 150 gCO_2/kWh is set (Figure 8), leading to overall reductions between 28 % (Scenario 9) to 17 % (Scenario 10) compared to the reference scenarios. Reductions are respectively lower when an EPS level of 350 gCO_2/kWh (Figure 9) is introduced – 26 %, 17 % and 10 % for Scenarios 8, 11 and 12 - than when an EPS of 500 gCO_2/kWh (Figure 10), with reductions of only 10.5 % and 6 % in Scenarios 13 and 14 is used. It also becomes apparent that with taking the larger reduction potential of existing installations into account, the year of introduction becomes much more relevant. Retrofitting in 2020 instead of 2025 leads to 11 % higher reductions for the 150 gCO_2/kWh EPS, and to 7 % and 5 % higher reductions for EPS of 350 gCO_2/kWh and 500 gCO_2/kWh respectively.

Scenario 18 in Figure 10 shows a very specific retro-fitting approach: retro-fitting in 2025 is only applied to plants that were built after 2010. As this would include a much smaller share of existing plants and, additionally, would only cover already more efficient plants, the achieved reductions of 2.3 % are considerable smaller compared to the other retro-fitting scenarios.

2.3.5 Variation Capacity Limits

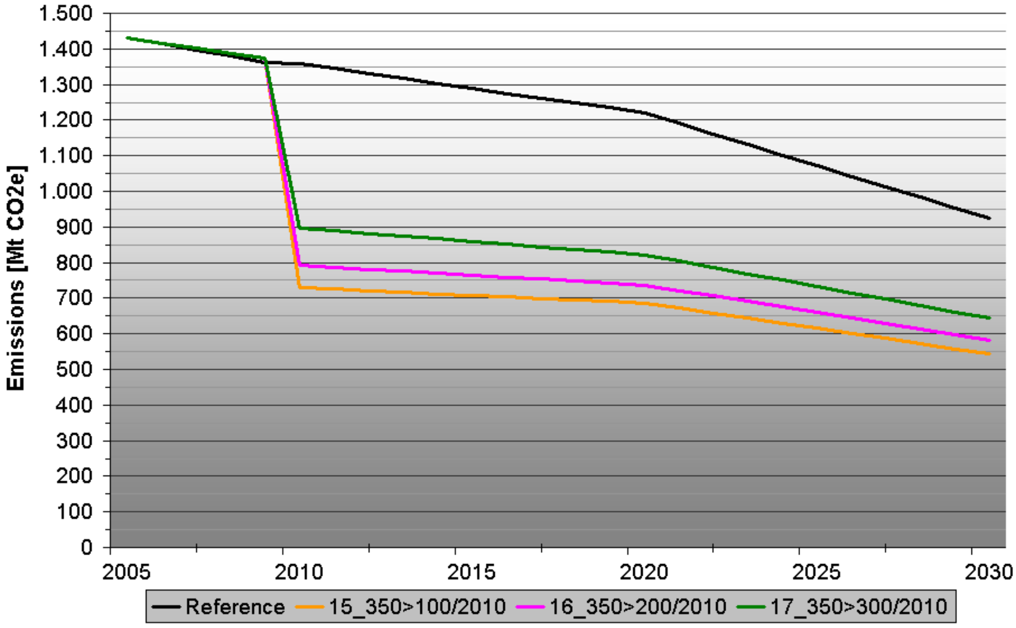

Figure 11: Impact of different Size Limits for Capacity Threshold

The impact of different capacity thresholds is shown in Figure 11. Scenarios 15-17 all use an EPS of 350 gCO_2/kWh. Both new and existing installations are covered. Overall reductions are of course highest, where the highest reduction potential is included. This is the case in Scenario 15, including all installations >100 MW. Here emission reductions of 34.3 % can be achieved. Scenario 17, including only installations >300 MW provides reductions of 25.4 % over the whole period 2005-2030.

Reductions in Scenario 15 are 3.4 % higher than in Scenario 16, while the difference is 5.5 % for Scenarios 16 and 17. This can partly be explained by the assumptions made, e.g. the fact that in the range 100-200 MW as well as in the range 200-300 MW, existing coal-fired plants will reduce emissions, but emissions from new coal fired plants are assumed to occur only for capacities > 200 MW.

As it is assumed that the majority of gas-fired power plants is in the range <300 MW, a lower EPS of 150g CO_2/kWh might lead to greater differences between the emissions for the three size categories.

2.3.6 Summary of Key Findings

A number of key findings can be drawn from the different scenarios and associated parameters:

- For a suitable comparison of different scenarios it is necessary to consider overall emission reductions over the whole time period and not only the final emission level.
- Both existing and new installations should be included in an EPS scheme in order to achieve substantial emission reductions. Reductions remain below 7 % in the timeframe 2005-2030 if only new installations are included.
- Introducing an EPS at a later point in time will lead to lower overall emission reductions, but of course depending on the overall reduction potential. If the latter is small, e.g. in case only newly built installations have to comply with an EPS, the year of introduction becomes less relevant
- Over 70 % of the reduction potential lies with installations >300 MW. In order to fully understand the impact of EPS for the capacity ranges >100 and >200 MW, additional research seems necessary as currently not all required information is available.
- A staged approach seems to suit the necessities of setting a climate relevant signal while involving both existing and new installations and best ensuring security of supply as well as leaving time for availability of necessary technologies

It is of course most important to consider the fact that these findings are only related to reduction potentials, but not to reduction costs.

3 Implementation Issues

Regarding the implementation of Emission Performance Standards several additional issues regarding the energy sector and its environmental effects should be considered. For their provision advanced measures would then be required depending on the set objectives. However any measures taken should be reviewed for their effect on the main strategic objectives in overall energy politics as shown below.

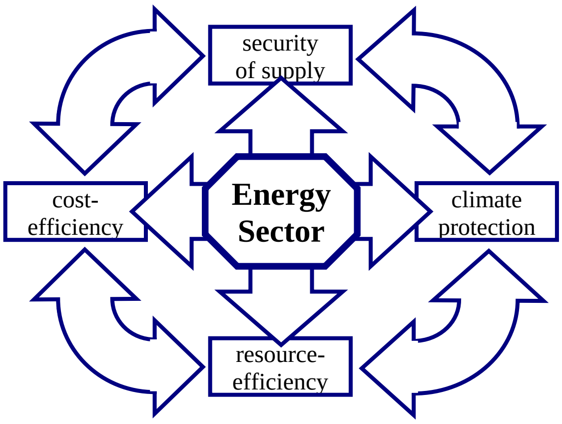

Figure 12: Strategic objectives of energy politics

Three possibly important issues are discussed in the following sections regarding the utilisation of biomass as fuel, the generation of combined heat and power (CHP) and the application of EPS per plant or per utility.

3.1 EPS and Biomass

Raising the share of biomass as a renewable fuel supports the aim of lowering fossil fuel emissions. Especially the use of solid biomass pledges to be used in classical power generation technologies through co-firing in existing coal-fired power plants in order to significantly reduce CO_2 emissions in the sector of power generation.

Biomass co-firing involves procedural and possibly constructional adjustments. In general coal-fired boilers can also handle a fuel combination of coal and biomass. Nevertheless a range of technological issues remain to be solved due to the inherent differences in the physical and combustion properties between biomass and coal.

Whether the use of biomass is feasible or not and to which extend largely depends on the combustion technology and the required fuel specifics (calorific value, grading, moisture content etc.). Estimates for the possible ratio of biomass in co-firing ranges from 5 to 20 % of heat input for existing plants and up to 40 % in newly built plants. Although the overall performance and long-term operability still has to be finally proven, the use of biomass as a fuel in coal-fired power plants is adopted by an increasing number of plants all over the world.

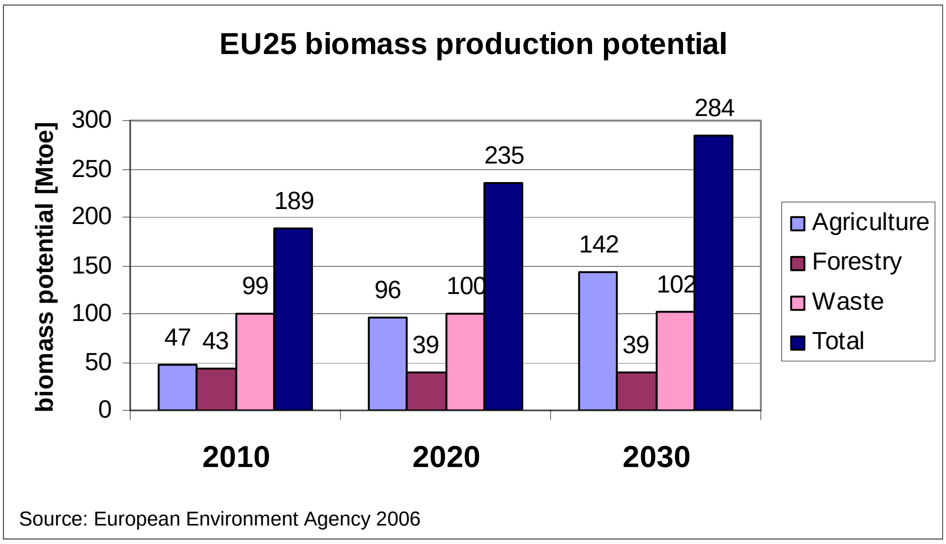

Figure 13: EU25 biomass production potential

According to the European Environment Agency there is an overall potential of biomass production of about 295 Mtoe in 2030 for the EU25[4]. Compared to about 217 Mtoe of coal and lignite used for electricity and heat production in 2005 in the EU25 there would be enough biomass available to achieve a (theoretical) co-firing ratio of 50 %, while still having an appropriate supply for other areas where biomass is used as a fuel or input material, e.g. in cement and in paper production.

Compared to fossil fuels however biomass as a fuel has a few draw backs regarding mainly:

- seasonally and geographically limited availability
- material properties and processing
- environmental effects due to cultivation
- possible competition to food plant cultivation

Regarding the actual utilisation the first two bullet points will determine the economical and technical degree of usability and the latter two the regulatory admissibility. The proportion of

CO_2 neutral emissions from biomass can be deducted based on the heating value of the biomass input or they can be directly measured by continuous emission measurement .

Regarding the chosen scenarios in chapter 2 the accreditation of biomass as a CO_2 neutral fuel could be especially important for reaching the ESP of 500 gCO_2/kWh for coal-fired plants, allowing a more cost-efficient compliance with not only CCS but also biomass use available. However reaching this standard through co-firing of biomass would already necessitate intense technological efforts.

3.2 EPS and CHP

In order to raise the overall efficiency of power plants the proportion of purposefully used heat is crucial. Hence it makes sense to implement measures which motivate the use of heat to the largest possible extent.

The most prominent challenges for an implication of promotional tools are the definition of purposeful heat utilisation and the accounting. A general exemption of CHP plants from EPS might be difficult because it could open a possible loop hole and cause a distortion within the energy market.

To establish an integration of the promotion of CHP technology into EPS, which is both fair and manageable, two main instruments present themselves as most viable. The first and very simple way would be to additionally introduce an EPS for heat and add this one to the overall calculation of allowed emissions based on the amount of purposefully used heat (exemplary calculation: $EPS_{cum} = EPS_{el} \times kWh_{el} + EPS_{th} \times kWh_{th}$). Another possibility to promote CHP generation would be to introduce an efficiency factor by which the electricity-based EPS is multiplied to account for the lower electrical efficiency which is caused by heat extraction (exemplary calculation: $EPS_{cum} = EPS_{el} \times 1$ / proportion of efficiency decrease).

Whereas the first instrument can be defined freely to constitute a motivation for the use of CHP to a greater or lesser extent, the latter proposal only represents a mere compensation of disadvantages caused by heat extraction. Following the objective of lowering the overall CO_2 intensity in the energy sector possibly a separate EPS for heat is preferable. In this regard the effort of implication (additional metering and monitoring) has to be weighted against the desired effects.

[4] Source: European Environment Agency 2006

3.3 EPS and Plant-based vs. Utility-based Application

As a variation of a plant-based introduction of an EPS there is the option of a utility-bound EPS which means that looking at the overall mix a utility is not allowed to emit more than a certain average of CO_2 per kilowatt hour of its produced electricity. This means for example that it still can run an emission intensive coal-fired power plant if at the same time there is enough capacity of low or no-CO_2-emitting power generation. Therefore this approach implies a shift from administrative regulation to a more market-based solution because each utility is free to decide on the means to comply with the standard. Of course, this approach is more realistic with higher EPS values like 500 gCO_2/kWh. Under certain circumstances and using a mix of CCS, gas-fired plants, potentially biomass co-firing and coal, even the 350 gCO_2/kWh might be achievable.

The suggested concept would give utilities more flexibility since there are various considerations to be taken into account when deciding about the appropriate power generation technology. Besides the emissions other important factors determine such a decision:

- the electricity portfolio of the utility (generation and procurement),
- the function as base or peak load power plant,
- the availability and price (including its forecasted development) of fuel,
- the access to an appropriate plant site,
- the investment costs and the sustainability of the investment.

All these issues can be given consideration more easily if a utility would have to fulfil the same emission requirements as an average and not every single plant . This means that a utility has more (cost-efficient) possibilities for compliance within its portfolio and there is less danger of an unbalanced shift towards a single low-emission technology. In the latter case, security of supply is clearly an issue to consider.

On the other hand a major draw back of granting greater flexibility through a utility-based EPS could be the fact that it takes the pressure to introduce low emission technologies off certain plant types. The higher cost-efficiency is thus bought with at least a time-delay in emission reduction in this case.

Applying an EPS to the overall power generation of an energy company requires adequate accounting and monitoring which additionally could lead to an increase in transparency of the composition of the electricity market depending on the designated coverage and public availability.

Another considerable effect of a utility-wide EPS should be taken into account: Single-focused utilities can be affected disproportionately and either have to diversify or might be driven out of the market. Smaller utility companies also might have difficulties fulfilling such an EPS because of a lack of diversification possibilities or financial means. Since the national structures of the sector of utility companies can differ widely the means should fit to the desired effects and therefore must be established very carefully.

Introduction of a utility based EPS could theoretically be an option for an introductory EPS phase, with a switch to an installation based EPS at a later stage. Looking at the difficulties in implementation especially with regards to smaller utilities, an installation based approach with decreasing EPS-levels over time and taking installation size into consideration might be easier to implement and more fair, as the difference between the range of reduction options between large utilities and one plant utilities is not so large.

4 Reduction Costs of EPS

In the framework of this paper it was not possible to calculate precise reduction costs for the various scenarios. The approach required would have meant to optimize each scenario with regards to EPS compatible reduction options over time.

In order to give an indication, costs have been roughly estimated for scenario 3 (150 gCO_2/kWh from 2010 onwards) and scenario 5 (350 gCO_2/kWh from 2015 onwards). Data was taken from the Ecofys database which also delivered the basic data for the scenario calculations. The reduction related values in the database are cost value per unit of energy produced [EUR/MWh] during an installations lifetime, based on reduction figures from various literature sources. In this installation lifetimes are assumed as described under section 2 of this report, average operating hours based on the evaluation of Eurostat data.

It was assumed that scenario 3 is achieved by using CCS technology for all new installations. Costs per MWh produced with CCS technologies are around 41 % higher for coal and 37 % for lignite fired installations. No suitable literature values could be found for CCS with gas-fired installations, but it was assumed that the cost increase per MWh with CCS is about the same for gas as for coal, i.e. around 40 %. In 2030, an emission reduction of 112 Mt CO_2 is achieved at an overall additional cost[5] of around 1,930 Mio EUR or 39 % compared to costs for new installations in the reference scenario.

In scenario 5 it is assumed that all new installations from 2015 onwards are gas-fired combined cycle installations. In 2030 a reduction of 30 Mt CO_2 is achieved at overall reduction costs of 840 Mio EUR or 24 % compared to the reference scenarios.

These are of course only very basic considerations. For simplification it was assumed that the EPS values are complied with by using only one specific technology and that both sufficient investment capacity with operators as well as building capacity with service providers is there to implement this technology at the time needed. Especially for CCS in 2010, this might not be considered realistic. Also the issue of security of supply has not been taken into consideration. Costs for retrofit of existing plants, e.g. to accommodate CCS or a higher share of biomass co-firing were not an issue in the scenarios considered, but are surely one of the major

[5] At 2000 EUR prices.

issues in the implementation of an EPS. We feel that these factors should of course be considered, when deciding about both cost and feasibility of an EPS approach.

5 EPS in Non-Power Sectors – Exemplary Analysis

In order to set up an emission performance standard for a sector, the more uniform the product qualities of the main product produced by this sector, the better. This is rather unproblematic for the power sector, but more complex for other industry sectors. This chapter considers the general feasibility to implement emission performance indicators in other sectors than the power sector. Two energy-intensive industry sectors are assessed: The iron and steel sector as well as the cement sector. In both cases only the energy related emissions as influenced through the energy intensity of the production process are considered. Emissions from the transformation of non-fuel input materials in the production process have not been taken into consideration.

For an emission performance standard both energy intensity values and the used fuels need to be considered. Energy intensity values for the iron and steel as well as for the cement sector can be found in literature. While energy efficiency only changes substantially if respective measures are taken, the type of fuels used can differ considerably depending on framework conditions, e.g. in the case of cement. As the assessment to be made in the following sections is only qualitative and for the sake of simplification, only the energy intensity issue is considered in detail, while more generic considerations are made with regards to fuel use.

5.1 EPS in the Steel Sector

In the iron and steel sector, outputs and their intrinsic energy intensity can vary considerably based on the desired product qualities. Furthermore, a number of production approaches need to be distinguished. Here differences stem both from the input materials used (e.g. primary vs. secondary steel-making) as well as the technologies (e.g. blast furnace vs. smelt reduction) employed. Furthermore, a number of generic process steps partly offering alternative routes need to be differentiated. Figure 14, taken from Worell et al., 2007, gives an overview of world best practice energy intensity values for these process steps and technologies. Phylipsen et al, 2003 indicates that energy intensity for most EU-15 is somewhere between 0-30 %

higher than a best available technology value. The report indicates that these values are from 1998, i.e. that the deviation from best available technology is rather underestimated.
Literature values can differ considerably based on the assumptions taken, e.g. on distribution and transmission losses and the emission factor of the power consumed. Worrell et al, 2007 states that “Totals for process routes depend on the feedstock and material flows and differ from plant to plant; totals should not be used to compare individual plants.” Careful consideration is thus needed when developing potential EPS values for the iron and steel sector.
Another issue to be kept in mind is the feasibility of monitoring, which is necessary to show compliance with an EPS. Monitoring data is currently collected for plants in the iron and steel sector under the EU Emissions Trading Scheme (EU ETS). This is usually done by using a mass balance, i.e. considering all carbon inputs and outputs to the installations. This approach only determines overall emissions over a reporting year, but does not necessarily allow to allocate emissions to specific products or production steps. Introduction of an EPS might thus lead to the necessity of additional monitoring which might not be straightforward. Again the question arises, whether results will be comparable.

		Blast Furnace – Basic Oxygen Furnace		**Smelt Reduction-Basic Oxygen Furnace**		**Direct Reduced Iron – Electric Arc Furnace**		**Scrap - Electric Arc Furnace**	
		GJ/t	**kgce/t**	**GJ/t**	**kgce/t**	**GJ/t**	**kgce/t**	**GJ/t**	**kgce/t**
Material Preparation	Sintering	2.2	74.3			2.2	74.3		
	Pelletizing			0.8	25.7	0.8	25.7		
	Coking	1.1	36.3						
Ironmaking	Blast Furnace	12.4	423.7						
	Smelt Reduction			17.9	610.2				
	Direct Reduced Iron					9.2	315.6		
Steelmaking	Basic Oxygen Furnace	-0.3	-9.5	-0.3	-9.5				
	Electric Arc Furnace					5.9	202.9	5.5	187.7
	Refining	0.4	13.0	0.4	13.0				
Casting and Rolling	Continuous Casting	0.1	3.9	0.1	3.9	0.1	3.9	0.1	3.9
	Hot Rolling	2.4	80.4	2.4	80.4	2.4	80.4	2.4	80.4
Sub-Total		**18.2**	**622.0**	**21.2**	**723.7**	**20.6**	**702.7**	**8.0**	**272.0**
Cold Rolling and Finishing	Cold Rolling	0.9	32.1	0.9	32.1				
	Finishing	1.4	48.4	1.4	48.4				
Total		**20.6**	**702.5**	**23.6**	**804.2**	**20.6**	**702.7**	**8.0**	**272.0**
Alternative: Casting and Rolling	Replace Continuous Casting and Rolling with Thin Slab Casting	0.5	17.3	0.5	17.3	0.5	17.3	0.5	17.3
Alternative Total		**16.3**	**555.1**	**19.2**	**656.8**	**18.6**	**635.8**	**6.0**	**205.1**

Figure 14 World Best Practice Primary Energy Intensity Values for Iron and Steel (values are per metric ton of steel). Source: Worell et al., 2007

Fuels used are mainly coal and natural gas. It has to be taken into consideration that energy from fossil fuels might be substituted by electricity also for other elements of the production chain than the furnace. Considerations with regards to energy efficiency do not largely change by this fact, but emissions attributed to the respective installation from the iron and steel sector will.

A potential EPS would thus need to take into consideration the respective process steps and technologies in order not to rule out a specific technology from the start. An EPS aiming at developing new best practice technologies or constellations seems difficult to develop due to the need for strong differentiation. At the same time, a rather moderate EPS value which can easily be achieved by recent installations e.g. built in the last 10 years could be used to drive very inefficient installations out of the market. It is difficult to estimate, what this level could be for the EU and what its potential reduction effects for the EU would be, as a database offering a sufficiently high level of detail about the iron and steel industry is currently not available.

5.2 EPS in the Cement Sector

As in the case of the iron and steel sector, the output is not uniform, but varies depending on its desired product characteristics. Options to reduce energy intensity vary with the production boundaries considered. If cement as a product is considered, a main option to reduce emissions is to reduce the amount of clinker per ton of cement by using additives. If clinker as a product is considered, reduction options mainly relate to technical energy efficiency measures and fuel use. There is some flexibility in fuel use (including wastes and biomass), allowing the operator to choose based on market prices.

Figure 15 gives an overview on the energy intensity of the cement production process using coal as fuel. In contrast to the iron and steel sector only one basic production technology needs to be considered, making the development of a potential EPS less complex. Data available under the EU-ETS currently only relates to the amount of clinker produced, i.e. additional monitoring would be necessary to determine the amounts of cement produced. Here a careful accounting is necessary, as many cement production plants also buy and sell cement from other facilities, i.e. the amount of cement sold per year can strongly deviate from the amount produced.

		Product unit	kWh/t product	kgce/t product	GJ/t product	kWh/t clinker	kgce/t clinker	GJ/t clinker	kWh/t cement	kgce/t cement	GJ/t cement
Raw Materials Preparation	Electricity	t raw meal	13	1.6	0.05	23.0	2.83	0.08	22	2.7	0.08
Solid Fuels Preparation	Electricity	t coal	18	2.2	0.06	1.75	0.22	0.01	1.8	0.20	0.01
Clinker Making	Fuel	t clinker					97	2.85		92	2.71
	Electricity	t clinker				22.5	2.8	0.08	21.4	2.63	0.08
Additives Preparation	Fuel	t additive		26	0.75						
	Electricity	t additive	55	6.8	0.20						
Finish Grinding											
325 cement	Electricity	t cement							25	3.1	0.09
425 cement	Electricity	t cement							27	3.3	0.10
525 cement	Electricity	t cement							30	3.7	0.11
625 cement	Electricity	t cement							31	3.8	0.11
Total											
325 cement		t cement							**70**	**101.0**	**2.959**
425 cement		t cement							**72**	**101.2**	**2.967**
525 cement		t cement							**75**	**101.6**	**2.977**
625 cement		t cement							**76**	**101.7**	**2.981**

Figure 15 World Best Practice Final Energy Intensity Values for Portland Cement with 5% Additives

As Figure 15 shows, world best practice allows reaching an energy intensity of around 2.9 GJ/t cement. At the same time, Phylipsen et al. (2003) finds energy intensities of 3.5 - 4 GJ/t cement for most of the EU15.

For the cement sector an EPS generally seems easier to be implemented than in the iron and steel sector, at least for newly built installations. For existing installations an EPS might be designed in a way to simply give a signal for an increased additive use in cement – a signal which is currently not included in the EU-ETS, as there are only emissions from clinker production considered.[6] At the same time it has to be kept in mind that energy intensity per ton cement can vary considerably based on the desired product qualities. Therefore, an EPS would need to somehow accommodate the production of energy intensive cement types for special uses, for which to date no alternatives exist.

[6] At the same time, an indirect signal through increased clinker prices needs to be considered.

6 SUMMARY

Methodology and approach

In this paper, the introduction of EPS as a mean for potential emission reductions for the European power sector was assessed. This was done by compiling 18 scenarios with varying level, scope and timing of EPS. Scenario emissions were projected for the timeframe 2005-2030 and compared to a reference case, broadly based on the current EU policy targets.

Furthermore, experiences from existing EPS schemes or similar measures were compiled and additional issues like biomass use, CHP and reduction costs were discussed. A brief consideration was also given to the potential for introducing EPS in the iron and steel as well as the cement sector.

Assessment of emission reductions for EPS scenarios

EPS levels used in the scenarios were. 150 gCO_2/kWh, 350gCO_2/kWh and 500 gCO_2/kWh. An EPS of 500 gCO_2/kWh could easily be achieved by gas-fired, combined cycle plants and/or by substantial co-firing of biomass in coal-fired plants. An EPS level of 350 gCO_2/kWh can only be complied with by new combined cycle gas fired plants or by using CCS in coal-fired plants. Finally, an EPS of 150 gCO_2/kWh can only be achieved by using mainly biomass and/or CCS. Due to the expected time horizon for CCS, this seems to be rather difficult to achieve even in the medium term.

The quantitative results for the modelled EPS scenarios as well as the qualitative assessments on key aspects provide valuable information on the important design options that have to be taken into consideration when implementing an EPS. Reductions between 2006-2030 varied between 0.3 % (resp. 104 Mt CO_2) in the case of an EPS of 500 gCO_2/kWh only for new installations from 2020 onwards and 34 % (resp. 10,885 Mt CO_2) when using an EPS of 350 gCO_2/kWh for all installations with a capacity of more than 100 MW from 2010 onwards. Of course the earlier the point of introduction for an EPS, the more stringent the EPS level and the broader the scope of installations covered, the higher are the resulting reductions. The most important factor was found to be the scope: if only new installations are subject to an EPS, reductions of at maximum 7 % can be achieved. This means that if substantial reductions are to be achieved, also existing installations need to be covered by an EPS. At the same time it was found that around 70 % of achievable emission reductions lay with installations having a capacity of more than 300 MW, meaning that there is room for increasing cost-efficiency by excluding smaller installations, e.g. below 100 MW, from an EPS scheme. Further research would be necessary to fully quantify the effects.

With regards to the point of time of introduction it was found that with the expected situation of installations being closed down and new capacities being built to replace these as well as to cover increased power demand, with a peak between 2010 and 2020, an earlier introduction of a 500 gCO_2/kWh level (in 2015) resulted in 53% higher emission reductions that a an EPS level of 350 gCO_2/kWh introduced in 2020. In order to take into consideration the various necessities – security of supply, availability of technology, cost-efficiency – a staged approach covering both new and existing installations seems preferable. This approach could start with an EPS for new installations in the medium-term (e.g. 2015), which is then made more stringent on the long-term (e.g. 2025). For existing installations, an EPS demanding retrofit activities could be introduced on the long-term (e.g. 2025).

Lesson learnt from emission limits in comparable contexts

To date experiences with EPS mainly were made with regards to other pollutants like SO_x and NO_x, but examples of CO_2-related EPS in the power sector can already be found in California since 2007. Oregon, Washington and Montana also introduced EPS schemes following the example of California. As all of these states are part of the Western Climate Initiative, with the aim of cooperating on the introduction and operation of cap and trade-systems, there is a clear indication that the fruitful co-existence of EPS and ETS schemes is considered feasible. In general it was found that EPS schemes were implemented successfully, especially if the right framework conditions were created, e.g. by helping operators to bear the costs of EPS compliance through incentivizing legislation (e.g. taxation related). In the EU this could also be supported by a more stringent EU-ETS with higher certificate prices.

Implementation issues: Biomass, CHP, utility-based approach

Earlier the use of biomass and CHP in the framework of an EPS system was discussed. With biomass the question is mainly supply related and a first assessment indicated that sufficient biomass would be available for coal-fired power plants to reach a co-firing share of 50 %. At the same time, technical feasibility of this as well as sufficient availability of biomass at the regional level and sustainability of biomass use remain to be assessed in detail. With regards to CHP a separate EPS approach considering the production of heat seems advisable. In the EU Emissions Trading Scheme a similar approach has successfully been taken with benchmarks for allocation of certificates at the national level. In any case an EPS system needs to be carefully designed to take into consideration existing and EPS related incentives for the use of biomass and CHP.

Furthermore, the issue of allowing utilities to comply with an EPS by using the average emission intensity of power production in their various plants was briefly discussed. It was found that, while this was generally a cost-efficient approach for the medium term, the clear signal of an EPS system could be lost. Additionally, only larger utilities with a suitable mix of installations would profit from this, while smaller utilities would be in disadvantage.

Costs of EPS

Only basic considerations could be given to the issue of costs. The issue is of course crucial for the feasibility of an EPS system. Reduction costs were calculated in a simplified approach for two scenarios: Scenario 3, demanding an EPS of 150 gCO_2/kWh for new installations from 2010 onwards, and scenario 5 with an EPS of 350 gCO_2/kWh for new installations from 2015 onwards. In the first case, the use of CCS for all new installations is assumed, in the second, new plants are all built as gas-fired combined cycle plants. Compared to the reference scenario, costs for new installations rose by 39 % for scenario 3 and by 24 % for scenario 5. In general, costs for the retrofit of existing plants are considered more problematic than costs for newly built plants.

EPS for non-power sectors

When assessing the feasibility of introducing EPS for the iron and steel as well as the cement sector, it was found that the first sector with its very complex production process would be difficult to assess and monitor. Here a rather moderate EPS could help drive very inefficient installations out of the market, but it is questionable whether an EPS can be designed to support new best-practice development or enforce the implementation of most efficient technologies. For cement with a less complex production process, allowing also for easier monitoring, the case is more – but still not completely - straightforward. Here an EPS related to the amount of CO_2 per ton of cement instead of per ton of clinker could support the increased use of additives in the cement, allowing to reduce the use of energy-intensive clinker. Nevertheless, the level of the EPS remains an issue, as cement types and their energy intensity can vary considerably based on the desired product qualities. Designing an EPS would thus need to accommodate for the case of more energy-intensive cement types for special uses.

Conclusions

Overall it was found that EPS approaches could help to considerably lower emissions in the European power sector if a comprehensive and suitably staged approach is applied. Further assessment is of course needed to determine, what kind of staged approaches would be technically feasible to cover the desired scope as well as be cost-efficient and ensuring security of supply. Furthermore, projections beyond 2030 would be necessary, as substantial CCS and retrofit activities are considered to only be available after 2020.

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Figure 16 Overview Reference Scenario + Scenarios 1-18

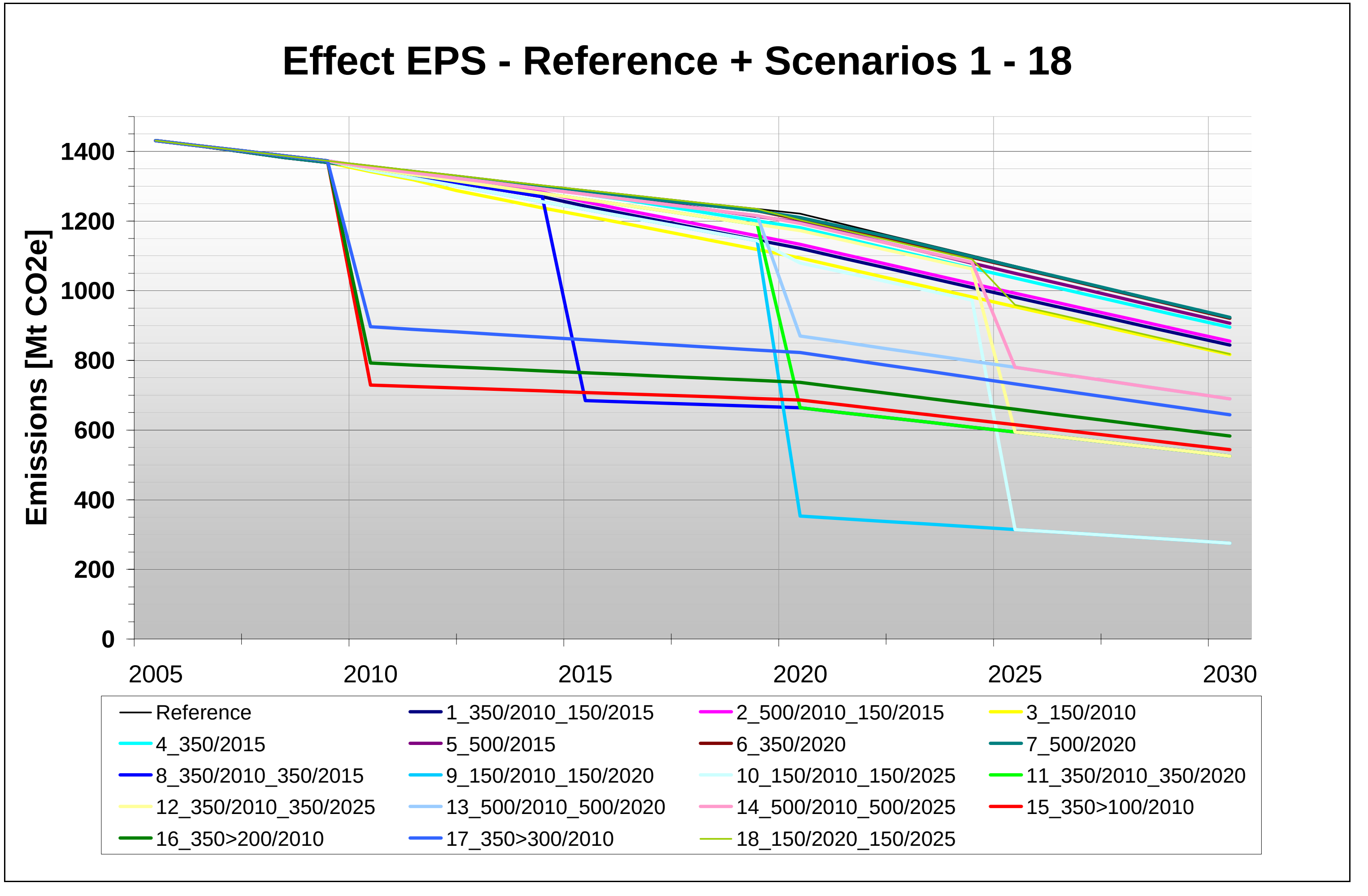

Figure 17 Reference Scenario and Scenarios 1-7

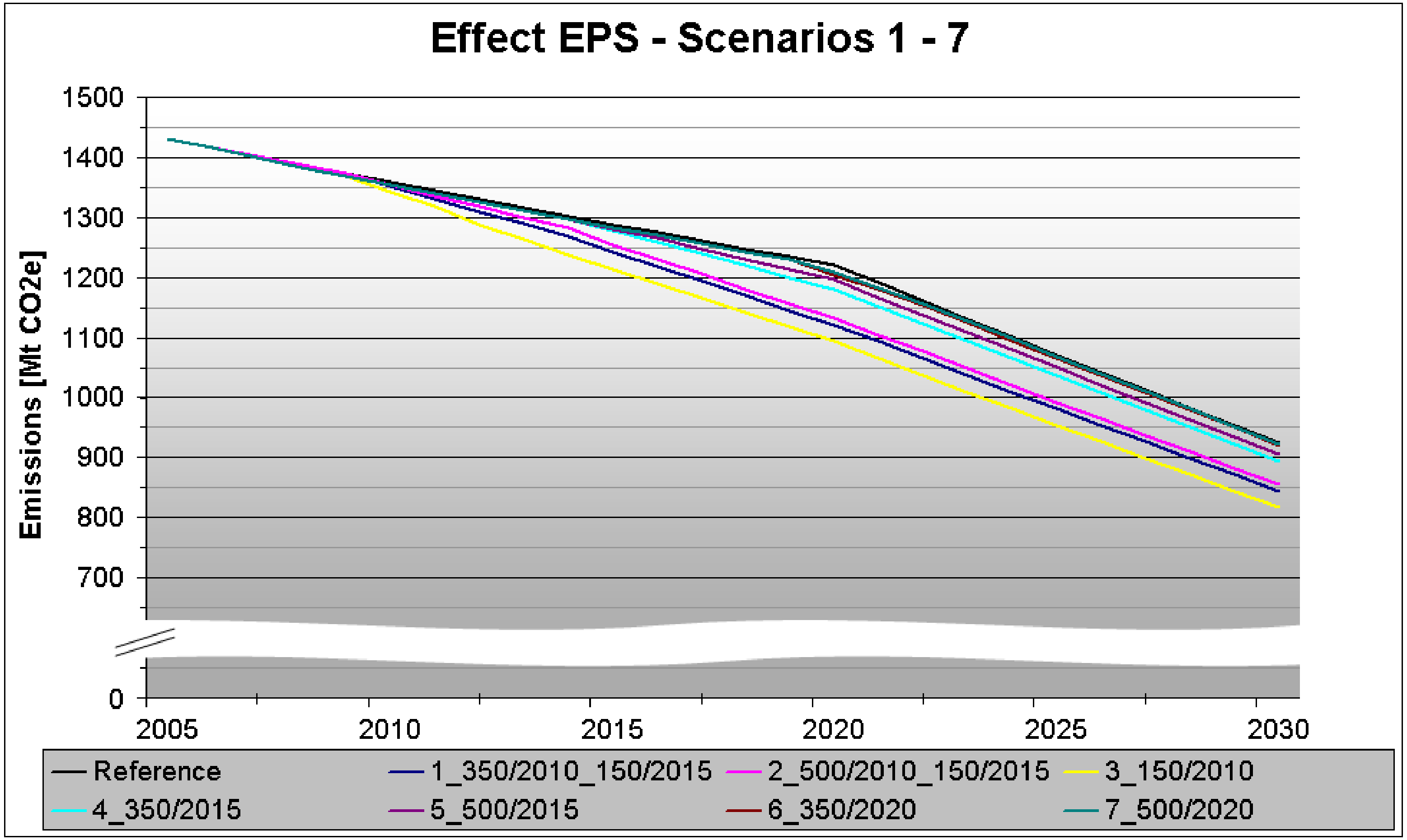

Figure 18 Reference Scenario and Scenarios 8-14 + 18

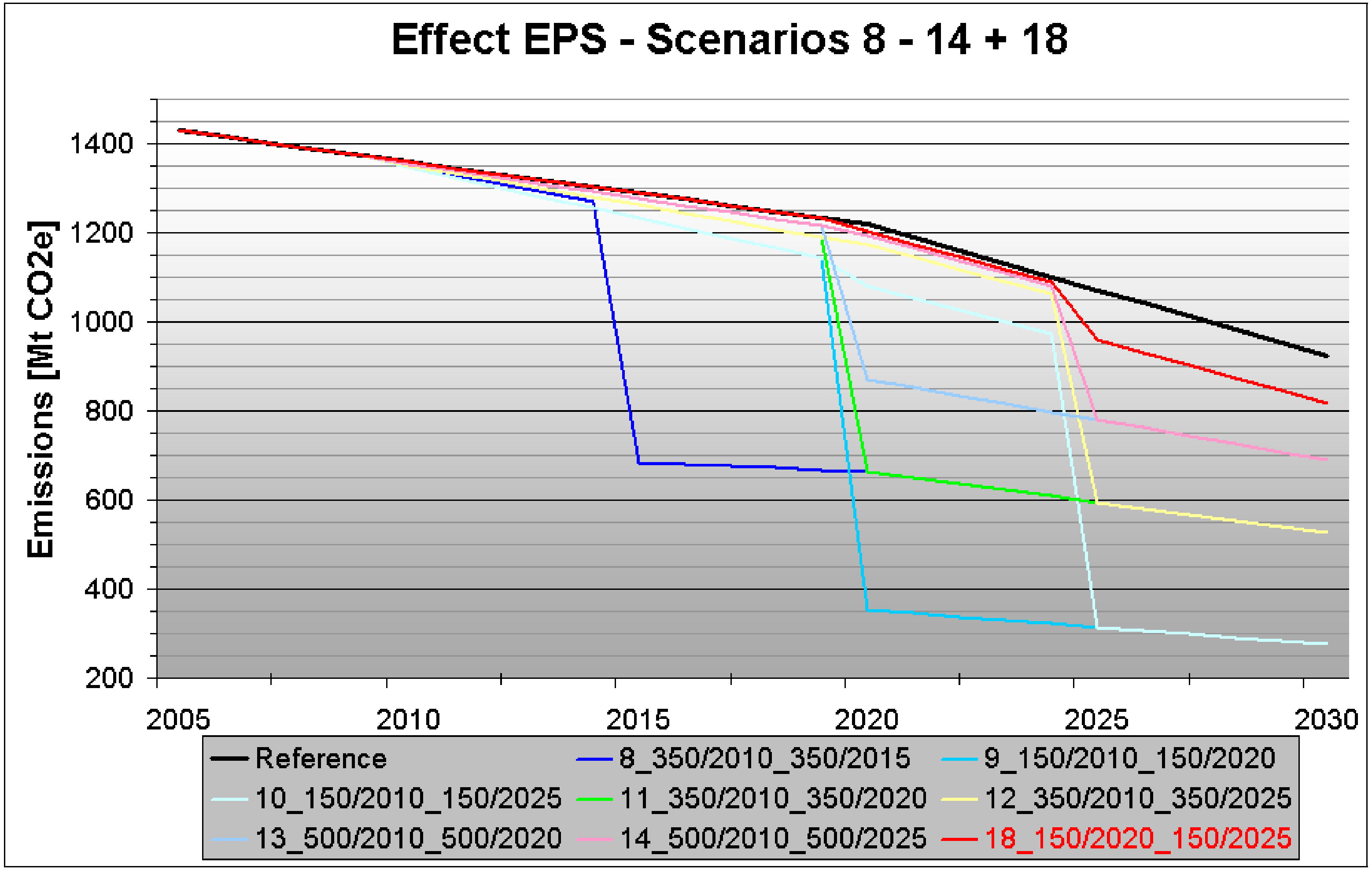

Table 3: Scenario Emissions, absolute emission reductions and reduction in relation to reference scenario in EPS scenarios

Scenario Emissions	2005	2010	2015	2020	2025	2030	Total Emissions 2005-2030	Reduction against Reference Scenario 2005-2030	Reduction contra Reference Scenario 2005-2030
	[$MtCO_2$]	[$MtCO_2$]	[$MtCO_2$]	[$MtCO_2$]	[$MtCO_2$]	[$MtCO_2$]	[$MtCO_2$]	[$MtCO_2$]	
Reference	1,431	1,359	1,289	1,221	1,071	924	31,760		
1_350/2010_150/2015	1,431	1,351	1,243	1,121	981	844	30,331	1,429	4.50%
2_500/2010_150/2015	1,431	1,354	1,255	1,133	993	855	30,553	1,208	3.80%
3_150/2010	1,431	1,342	1,214	1,094	954	817	29,773	1,987	6.26%
4_350/2015	1,431	1,354	1,277	1,181	1,036	895	31,225	536	1.69%
5_500/2015	1,431	1,354	1,281	1,196	1,050	907	31,420	341	1.07%
6_350/2020	1,431	1,354	1,284	1,205	1,067	921	31,626	135	0.42%
7_500/2020	1,431	1,354	1,284	1,210	1,069	923	31,657	104	0.33%
8_350/2010_350/2015	1,431	1,351	685	664	595	525	23,481	8,280	26.07%
9_150/2010_150/2020	1,431	1,345	1,233	353	314	276	22,910	8,850	27.87%
10_150/2010_150/2025	1,431	1,345	1,233	1,079	314	276	26,354	5,406	17.02%
11_350/2010_350/2020	1,431	1,351	1,262	664	595	525	26,255	5,505	17.33%
12_350/2010_350/2025	1,431	1,351	1,262	1,173	595	525	28,663	3,097	9.75%
13_500/2010_500/2020	1,431	1,354	1,277	870	780	689	28,432	3,328	10.48%
14_500/2010_500/2025	1,431	1,354	1,277	1,193	780	689	29,949	1,812	5.70%
15_350>100/2010	1,431	729	708	686	615	544	20,876	10,885	34.27%
16_350>200/2010	1,431	792	764	737	660	583	21,938	9,822	30.93%
17_350>300/2010	1,431	897	859	822	733	644	23,699	8,061	25.38%
18_150/2020_150/2025	1,431	1,359	1,289	1,203	959	818	31,032	728	2.29%