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Electricity scenarios by country and primary fuel for 2010-20-30

OME - ECON - COPPE/UFRJ - ERI - IIMA - MRCEI

Table of Contents

1. Summary 2

Existing models for EU 2
ECON model for EU 2
Non-EU countries 3

2. Existing models for EU countries 5

Model description 5
Comparison of main assumptions 7
Main results 8

3. Electricity scenarios in EU countries 11

Background 11
The Econ Classic model 13
Input / assumptions 13
Results 15
Conclusions 34

4. Electricity scenarios in Brazil, China, India and Turkey 35

Brazil. 35
China. 46
India. 64
Turkey 68

1. Summary

This deliverable is divided in 3 parts. First the common used model for EU are described and compared. Then the ECON model assumptions and results are explained in details. And the third part deals with bases and alternatives in Brazil, China, India and Turkey.

Existing models for EU

Energy models produce forecasts for the future global energy situation, especially in terms of energy demand, energy mix and security of supply. A range of organisations issue regular projections that serve a variety of political and economic purposes and with different emphases and methodologies. This variety means that the forecasts are often difficult to compare.

On the basis of selected parameters, the first part compares the points of view of three well-established models regarding electricity sector scenarios for the EU-25, namely the European Commission's (EC) DG-Tren (PRIMES), EC's DG-Research (WETO-H_2) and IEA (WEO).

ECON model for EU

The second part of the report aims at specifying the impacts of external costs internalization in the European electricity market.
The study uses the results and data from other CASES studies and other works from DG TREN. The economic model used is the classical ECON model, which takes as basic hypothesis that the demand is always satisfied, and which clearly defines the hypothesis of work (projection of demand growths, fuel prices, data on infrastructures, electricity price, rate up-date of 5%…).
The logic of the model is that the investment level of new generation capacities is determined by the growth of the demand and that the type of technology to be used is determined by the technologies relative competitiveness (i.e. long term marginal cost of production).
The external costs are caused by the electricity generation indirect consequences on:

- The human health,
- The environment, for example the loss of bio-diversity,
- The radionuclide, which can cause radioactive contamination,
- Gas emissions.

This study uses the hypothesis of a 20€/tCO2 cost, constant for 2010, 2020 and 2030.

To resume, the comparison between both scenarios "A- without external cost" and "B- with external costs" gives for 2030 the followings principal results for Europe:

- The investment level of the scenario B is much higher than the scenario A one, because in one hand, wind farms have a factor of load lower than the thermal plants, and in the other hand, the high exploitation costs of the thermal plants accelerate the replacement programs.

- In the scenario B, the new investments are realized in majority with means using natural gas (CCGT) and wind energy. There is no investment in coal plants anymore, due to their exploitation costs comparatively very high.

- The exploitation costs being higher, the wholesale market would increase from 45-50 euros/MWh (scenario A) to about 70 euros/MWh (scenario B), so around 40% more.

- The electricity demand of the scenario B would be 7.5 points lower than the scenario A one.

- The CO2 emission would be reduced by 50%, from 1500 Mt (scenario A), mainly due to the coal generation, to 750 Mt (scenario B) mainly due to the natural gas generation. This decrease is obtained with a 20€/tCO2 cost.

The distinctive cases in the UK, Germany and Bulgaria are treated and are in correlation with the general tendency of the two scenarios.

Non-EU countries

Brazil, China, India and Turkey have each one their scenarios. The assumptions concerning the base scenario and the alternative scenarios are not the same for the 4 countries due to their specificities.

Brazil

With respect to CO_2 emissions, Brazil has a favorable scenario thanks to its energy structure, with a predominance of renewable sources. As a result, Brazil has one of the lowest rates of emissions from the energy sector, with respect to GDP, in the world. Nevertheless, in the last few years there has been a strong increase of fossil energy in the energy supply mix. This is mostly due to the recent restructuring of the power industry, which seeks to attract private capital for building new plants. Therefore, renewable energy sources, such as hydropowers, are losing ground, leading to an increase in energy based CO_2 emissions.
Two scenarios are presented: the *baseline scenario* for the Brazilian energy sector which has been simulated using the MESSAGE model, and the *alternative scenario* for the expansion of the generating capacity of the power industry which has been built taking into account penalties for greenhouse gas emissions.
The alternative scenario shows a reduction in emissions in 2030 from 112 $MMtCO_2$ to 84 $MMtCO_2$, which means a reduction of 25%. An increase in the cost of expansion can also be seen in the alternative scenario.

China

In order to analyze future energy demand and emissions in China, three scenarios have been built. Primary energy demand in the *baseline scenario* could go to 2.1 billion toe in 2020 and 2.7 billion toe in 2030. The annual growth rate from 2000 to 2030 is 3.6%, while energy elasticity of GDP is 0.58. Coal will be the major component energy in China (1.5 billion toe in 2030), with a

58% share in total energy demand. There is a rapid increase for natural gas demand in China, with its share in total primary energy use increasing from 4% in 2000 to 17.3% in 2030 (average annual growth rate: 10%). Electricity demand increases from 112 million toe in 2000 to 451 million toe in 2030. Oil use in transport will increase from 74 million toe in 2000 to 410 million toe in 2030.

For the *high demand scenario*, primary energy demand in 2030 is 2.9 billion toe, which is 250 million tons higher than the baseline scenario. Of the total primary energy demand, coal provides 59.1%, oil 16.1%, natural gas 17.8%, and nuclear 1.2%. Because this scenario assumes better integration in international markets, there is greater reliance on imported energy such as natural gas and oil.

By assuming the adoption of energy and environmental policy measures, for the *policy scenario*, compared to the *baseline scenario*, there is nearly 245 million toe energy demand reduction in 2020, 280 Mtoe in 2030. By exploring the policy options, it has been found that there is big pressure to apply these policy options in order to reach the lower energy demand scenario, and also need to be introduced at early time because of long life span of energy technologies.

With the calculation of energy demand, several pollutant emissions were calculated. SO_2 emission will keep increasing before 2010 with the rapid increase of coal use in China. After 2010, more and more desulphurization technologies will be used and therefore SO_2 emission will be reduced from fossil fuel use. Compared with *high demand scenario*, SO_2 emission for *baseline scenario* in 2010 is 4.5 million tons lower, but still increase 9.45 million ton from 2000. This will be big challenge for government target. Because of lack of policy to control NOx, its emission keeps going up. Same trend is seen for TSP emission.

Concerning the effects for policy options used in the *policy scenario*, by comparing with *baseline scenario* and *high demand scenario*, it has been noticed that there are a package of policy options could be adopted now to reduce the growth rate of energy demand. For example policy to promote penetration rate of high energy efficiency technologies, fiscal energy and environment policies including vehicle fuel taxes, subsidies for renewable energy, emission taxes, resource taxes etc., and policy to promote public involvement, are important for China to go to a low energy demand scenario.

India

The power generation in the *baseline scenario* is primarily coal driven with different types of coal power plants contributing by 61% to the total power generation at the end of 2050. Super critical technology slowly makes its way from year 2010 onwards and finally captures a share of 22% in the terminal year 2050. From the year 2030, the conventional coal plants are replaced by advanced coal like integrated coal gasification combined cycle (IGCC) taking a share of 12.4% in the year 2050. The other competitive system in 2050 is the CCGT, which contributes more than 24% of total power production. Approximately 15% of the electric power would be supplied by the nuclear and renewable energy sources in the year 2050.

After the internalization of external costs into baseline cost, the structure of the power generation mix has altered considerably. In this alternative scenario, the overall power generation gets reduced by 13% (in absolute terms 780 TWh) in the year 2050 as compared to the baseline scenario. In the externality scenario, although coal remains the major contributor to

total power production, however, its share is reduced from 61 per cent in baseline scenario to 44 per cent in externality scenario in the year 2050.
Some of the advanced coal technologies like IGCC plus CCS also make its way along with only IGCC power plant technologies. Combined together these two contributes 15 per cent of generation in the externality scenario as compared to nil in the baseline scenario. Share of renewable energies including hydro and biomass also gets increased in the externality scenario. With the introduction of external cost into the total production cost of electricity, emissions get reduced quite considerably. Within the period, the emissions reduction of CO2, SO2, and NOx happens because of the premature retirement of coal plants without SO2/NOx control.

Turkey
In the study, a Reference Case was developed to compare alternative scenarios. Greenhouse Gas (GHG) Reduction scenarios analyze options in form of technologies and policies that are primarily oriented toward the reduction of CO2, CH4, and N2O. This analyze has a projection up to 2020.

In the Reference Case a total capacity of 4500-5000 MW nuclear units would be added to the power system until the year 2015. Limitations on natural gas and import coal used to produce electricity would affect the system adversely, however, they would make import dependency increase. Final energy demand increases from 68 Mtoe to 177 Mtoe in the study period. Industry has the highest share, then residential and transportation. Oil products, electricity, and coal are the most important players. Demand of electricity and hard coal more than triple while that for oil products more than double. As for the final demand, primary energy supplies also about triple and reach 223 Mtoe (from 84 Mtoe in 2003) at the end of the study period. Overall energy imports are estimated to increase from 61 Mtoe to 157 Mtoe between 2003 and 2020. The total economic cost of the Reference Case is $350.4 billion of which $167.9 billion is going to meet import requirements.

The DSM scenario is a “win-win” option compared to the Reference Case. Under DSM scenario, the economic cost of energy supply and the cost of energy imports will be lower, as well as the emissions of CO_2/GHG. In addition, there are substantial ancillary benefits involved in terms of PM, SO_2, NO_X. The reduction in CO_2/GHG emissions from DSM is about 7.0% over the period 2003–2020 and the potential may be even higher as this analysis only concentrated on the residential and industrial sector but excluded the transportation sector for lack of country-specific information.

2. Existing models for EU countries

Model description

a) PRIMES

The European Commission’s (EC) DG-TREN[1] published the latest set of PRIMES[2] scenarios in 2005 and 2006. PRIMES is a modelling system for energy supply and demand in the EU member states up to 2030. The following three distinct scenarios are developed:

[1] *European Commission’s Directorate General for Transport and Energy.*

The ***Baseline (reference) scenario*** takes into account a higher energy import price environment (50 to 60 US$ per barril over the forecasting period) compared to the former baseline. It includes policies and measures implemented so far in the Member States and assumes a continuation of policies on economic reform (Lisbon Agenda) and the completion of the internal energy market. It incorporates current policies on energy efficiency and renewables, without assuming that specific targets are necessarily met.

The ***Medium gas and soaring oil prices*** case assumes a higher economic growth in parts of Asia (China, India and other Asian developing countries) in combination to relatively less abundant resources than in the Reference scenario. Oil prices are expected to increase to US$ 100 per barril by 2030 while gas prices, no longer linked with the oil price, experiences a slower pace.

In the ***Soaring oil and gas prices*** case, the assumptions as regards economic growth and availability of fossil fuel resources are identical to those of the "Medium gas and soaring oil prices" case with gas prices remaining linked to the evolution of the oil price, thereby increasing stronger.

b) WETO

The EC DG-Research also published the 'World energy, technology and climate policy outlook' (WETO-H_2) in 2006. The POLES model[3] is a world partial equilibrium simulation model for the energy sector, with endogenous international energy prices. Two scenarios are compared, namely:

- The WETO-H_2 ***Reference scenario*** which: i- assumes the continuation of existing economic and technological trends but with a minimum degree of political initiative in climate policy in all regions of the world; ii- adjusts to constraints on access to oil and gas and on emissions of CO_2.

- The ***Carbon constraint scenario*** sets stricter limits on CO_2 emissions[4] such that carbon values are at €10 per tCO_2 in 2010, increasing linearly to €105 and €200 per tCO2 in 2030 and 2050, respectively.

c) WEO

The International Energy Agency (IEA) model uses its World Energy Outlook (WEO)[5] to carry out long-term energy projections up to 2030. There is a strong focus on concerns about the security of energy supplies, investment in infrastructure, the environmental damage caused by energy production and use and the unequal access of the world's population to modern energy. In this model, a Reference scenario is compared to an Alternative policy scenario.

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[2] *This section is based on European Energy and Transport. (May 2006). Trends to 2030 – Update 2005. http://ec.europa.eu/dgs/energy_transport/figures/trends_2030_update_2005/energy_transport_trends_2030_update_2005_en.pdf*

[3] *Quoted from: http://webu2.upmf-grenoble.fr/iepe/textes/POLES12p_Jan06.pdf "Poles – State of the Art", LEPII-EPE, CNRS Grenoble, January 2006.*

[4] *Factor 2 reductions in 2050 compared to 1990 (650 ppmv CO_2 eq.).*

[5] *International Energy Agency. World Energy Outlook 2004 and 2006.*

The ***Reference scenario*** (business as usual) is based on: i- policies enacted by mid-2006 and no new policy are introduced for the forecasting period; ii- increasingly efficient energy supply and end-use technologies; ii- energy prices remaining relatively stable throughout the forecasting period.

In the ***Alternative policy scenario***, additional measures related to energy security and climate change are introduced.

Comparison of main assumptions

While the models' reference scenarios have similar population and GDP growth rate assumptions, their main differences lie in the prices of the different fuels and the value attached to carbon which are all presented in the next table.
Whereas the IEA scenarios are characterized by a constant energy price environment over the forecasting period, the PRIMES reference scenario is based on a slight progression. The other two PRIMES as well as the WETO scenarios assume a stronger increase in energy prices.
Concerning the future power generation fuel mix, the most important element is the price differential between natural gas and coal. This differential remains more or less constant in the IEA scenarios and is slightly higher in the PRIMES reference scenario, followed by the medium gas and soaring oil price scenario and the two WETO scenarios. The differential grows most rapidly in the soaring oil and gas scenario.

Table 2.1 : Main assumptions for the scenarios

		Primes reference	Primes medium gas & soaring oil prices	Primes Soaring oil & gas prices	WETO reference	WETO Carbon Constraint	IEA reference & alternative
OIL							
($ per bbl)	**2010**	44.6	61.9	61.9	38.7	38.5	51.5
	2020	48.1	75	75	53.5	50.4	
	2030	57.6	98.5	98.5	66.7	61.1	55
GAS							
($ per Mbtu)	**2010**	5.8	5.8	6.5	4.7	4.7	5.9
	2020	6.4	7.2	8.9	8.3	8.2	
	2030	7.7	9.5	12.9	11.0	10.3	6.5
COAL							
($ per ton)	**2010**	59.5	59.5	64.8	57.5	57.5	55
	2020	67.1	67.1	76.2	69.0	65.2	
	2030	71.0	71.0	94.3	80.5	75.9	60
CO2							
(€ per tCO2)	**2010**	5	5	5	10	10	
	2020	5	5	5	15	58	
	2030	5	5	5	20	105	

As far as carbon is concerned, PRIMES considers a relatively low carbon value environment while WETO's is higher, in particular for the carbon constraint scenario which sets stricter limits on CO_2 emissions[6] such that carbon values increase linearly to 105 € per tCO_2 in 2030. The

[6] *Factor 2 reductions in 2050 compared to 1990 (650 ppmv CO_2 eq.).*

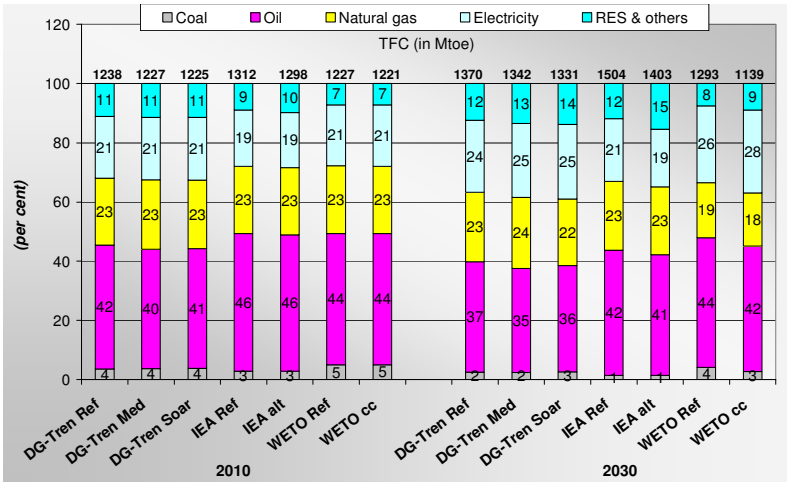
IEA's trends in CO_2 emissions are based on improved efficiency of energy use and increased use of nuclear power and renewables[7]. It is important to note how increasingly "carbon" has become an essential part of energy forecasting.

Main results

a) Total final consumption

This section provides some of the main results concerning the electricity sector. The figure below shows that the share of electricity in total final consumption (TFC) will increase between 2010 and 2030 as we increasingly move towards a service society. Strongest growth is observed in both WETO scenarios. Also, the share of renewable energy sources (RES) increases mainly due to the various policy measures introduced through the EU-Directives and/or individual countries. Both increases in the shares of electricity and RES occur at the expense of oil. In the case of WETO, natural gas also sees its share diminish.

Figure 2.1: Total final consumption (all scenarios)



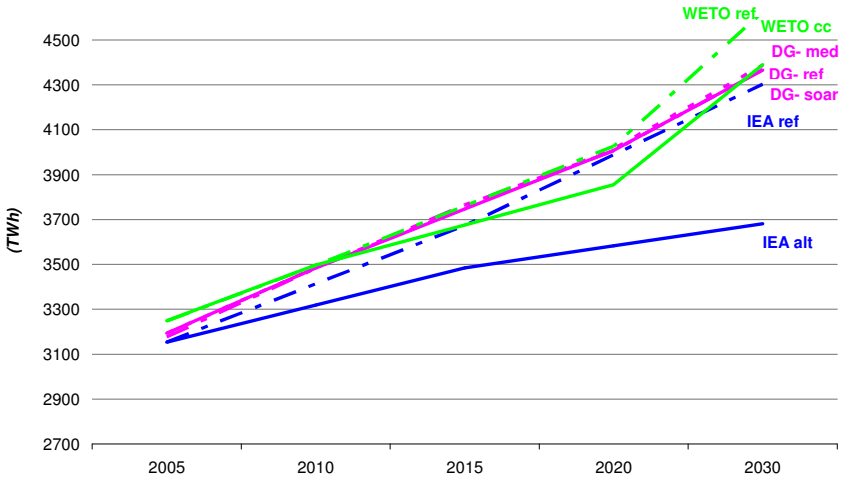
Source: OME.

b) Total power generation

All scenarios show a sustained growth in electricity generation based, among others, on the assumption of the shift development of electricity intensive information and communication technologies ("third industrial revolution"). This development is even more pronounced in the case of the WETO reference scenario. The WETO carbon constraint electricity demand is slightly lower as a result of a higher carbon value and higher electricity prices which improves end-use efficiency. The IEA alternative scenario falls well below all others due to major efficiency and energy intensity improvements in energy use.

[7] *According to the alternative scenario, just a dozen specific policies in key countries account for 40% of the reduction in global CO2 emissions.*

Figure 2.2: Total power generation to 2030

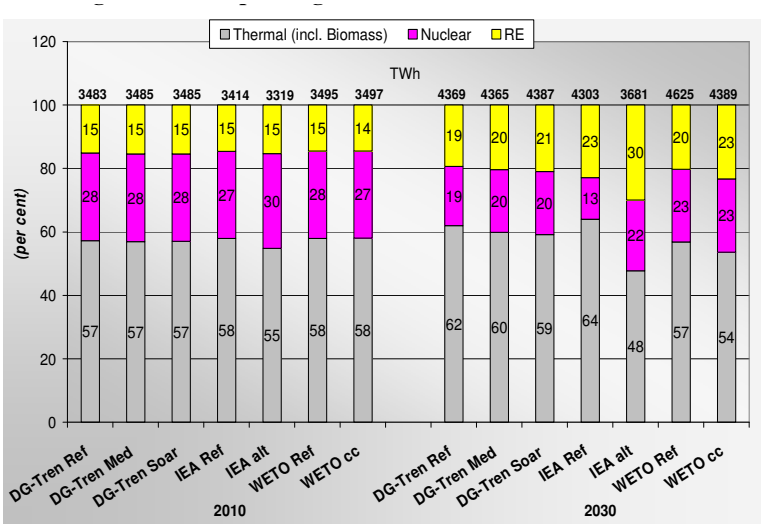


Source: OME based on all the different scenarios

c) Power generation mix

Concerning the fuel-mix in power generation, RES gain a greater share over the forecasting period (2010 to 2030). RES-based power generation doubles in most cases. Nuclear decreases slightly in volume in most scenarios, except for WETO's modest increase. The share of nuclear, however, falls in all scenarios. Thermal power production[8], in general, shows a sustained growth, with its share increasing (even if marginally in some scenarios), except in the case of the IEA's WEO.

Figure 2.3: Total power generation, by source



Source: OME based on all the different scenarios

The more detailed data is provided by the PRIMES model where the fuel input breakdown to power generation is given. In the Reference scenario, the natural gas/coal price differential

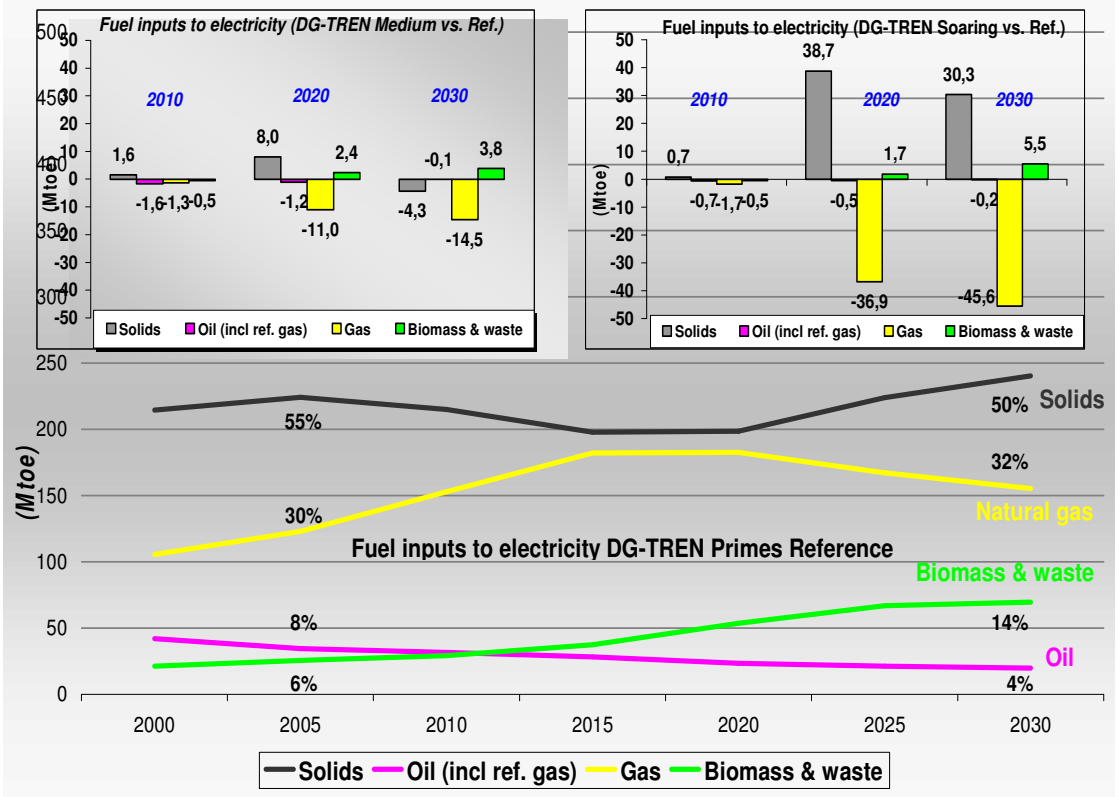
[8] Thermal includes biomass and does not have a more detailed breakdown for the fuels in all models.

remains almost constant between 2000 and 2015, thereby continuing the gas penetration. The price differential increases thereafter, and gas starts losing in terms of volume.

Medium gas and soaring oil prices (Medium) vs. *Reference scenario*: gas and coal prices in 2010 are almost identical leading to a similar fuel mix in power generation for both scenarios. By 2020, the natural gas/coal price differential is higher in the Medium scenario which leads to a decrease in gas consumption at the benefit of coal and some renewables. In 2030, this price differential is even more pronounced leading to a stronger decrease in gas consumption. At this point in time, the fall in natural gas should be compensated by the stronger penetration of nuclear, wind and biomass at the expense of coal.

The *soaring oil and gas price scenario* has a higher gas/coal price differencial than the Medium scenario to the *Reference scenario*. A similar use of energy sources to the Medium scenario in 2020 can be expected – albeit more pronounced. By 2030, the gas/price differential gets so important in this scenario, that the strong penetration of nuclear and renewables is not sufficient to compensate for the fall in gas consumption. This leads to the increase in coal use.

Figure 2.4: Fuel inputs to power generation in the DG-Tren PRIMES scenarios

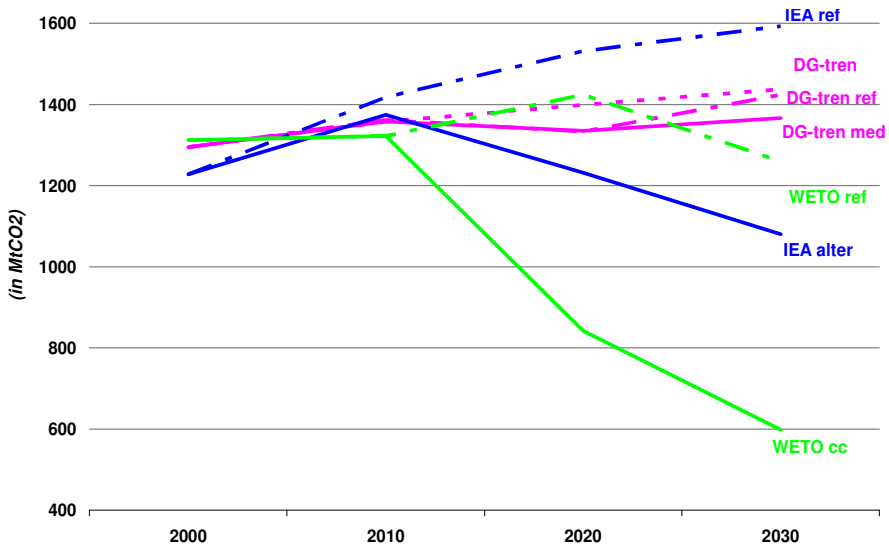


Source: OME based on the 3 DG-Tren scenarios

d) CO_2 emisssions from power generation

It should be noted that both the WETO carbon constraint scenario and the IEA alternative policy scenario show a sharp decrease in CO_2 emissions since they were designed to exactly achieve this important cut - albeit less so for the IEA scenario. In the case of WETO's carbon constraint, the model is designed to achieve a 50 per cent reduction of the 1990 TPES emissions by 2050 (factor 2 reduction). It is interesting to note that in the electricity sector, this reduction would already be achieved before 2030.

Figure 2.5 : CO2 emissions 2000 to 2030



Source: OME based on all the different scenarios

3. Electricity scenarios in EU countries

Background

Efficient use of energy, security of supply, reduced CO2 emissions and promotion of renewable technologies comprise the most important focus areas for the electricity generating industry in

Europe today. While various policies may promote efficiency and security, and also accelerate development of renewable technologies, private investment decisions are a necessary supplement to said policy drivers in ensuring sufficient capacity growth. Interests from the private sector may not always tally with government policies, as non-public stakeholders tend to base investment decisions on capital costs and other financial costs rather than on externalities. If investment decisions are driven by financial costs alone, promotion of renewable technologies and analogously reducing CO2 emissions will in all likelihood slow down. The adverse situation is expected to prevail if the full external costs are included in the total costs of generation, as external costs outweigh the relatively lower capital costs of conventional electricity generating technologies.

WP1 of CASES involves assessing the outcome of investment decisions if the full social costs of electricity generation are taken into account, in addition to the development in demand. Econ Pöyry's chief contribution to WP1 in CASES has in this context been to model investment decisions under private costs and full social costs, based on cost assessments from the other work packages in CASES. This is analogous to analysing the difference between private and social investment decisions and thus assessing the full impact of policy measures on environment, security of supply and efficient energy development.

The key issue is how the structure of European electricity generation would develop if the full social costs (private costs, environmental costs, life cycle costs, etc.) were internalized in investment decisions. The analysis is carried out using Econ's Classic electricity market model as the main analytical tool. Econ has run altogether eight model runs; the base year (2007), the private cost case for 2010, 2020 and 2030 and the full cost case for the same years.
On the demand side Econ's base case and other scenarios are based on DG Tren's Baseline 2005 report, which is an update to the *Trends to 2030* report published in 2003, where 2030 projections are derived from the PRIMES model. In this report, demand projections from the DG Tren study are used. On the supply side, cost assessments are based on the NEEDS study.

The Econ Classic model

The Econ Classic model is an optimisation model for the electricity market that maximises welfare (and minimises costs) subject to a set of conditions, the most important one being supply equals demand. The Classic model is solved for a set of chosen years. Classic covers all EU27 regions as well as Norway and Switzerland.
In Classic certain variables such as fuel prices, costs of production, income growth and transmission capacities are exogenous. Regarding capacity, known capacity developments including decided or ongoing investments, refurbishments, mothballing and retirements are entered exogenously into the model. In addition, investment in new capacity and in refurbishments is endogenous. Endogenous investment decisions are based on long-term marginal costs and projected demand. Demand is endogenously determined based on GDP growth projections and (endogenous) electricity price development. Hence, investment levels are determined by demand growth while types of investment in terms of technology are determined by the relative competitiveness of different technologies (long term marginal costs), subject to potentials and transmission capacities.
The Econ Classic model regularly undergoes improvements and updates. For the CASES project, the version of the Classic model used is based on the most recent update from Q-3 2007. This model version contains the latest available macro and growth estimates from October 2007, while fuel prices are based on forward prices for 2008. Generating capacities for non-renewable technologies are derived from the March 2007 Platts database, while transmission capacities are derived from the Union for the Coordination of Transmission of Electricity (UCTE).

Input / assumptions

Econ makes consistent use of various public sources regarding exogenous inputs. For instance, capacity assumptions are normally derived from the Platts database for most countries in Continental Europe, while those for Nordic countries are based on the regions' respective statistics provider. Also, transmission capacities are usually based on data from UCTE and Nordel.

Future generation capacity is based on planned new-build as well as plant developments ECON deem as considerably likely. The same rationale applies to decommissioning and mothballing of existing capacity. Platts remains our main source for planned new-build and decommissioning, though we also apply our own assumptions and judgements, particularly for the Nordic countries.

ECON use a substantial number of sources for the exogenous input variables in Classic. For CASES, Econ was requested to use input sources consistent with other analyses undertaken in the work package. These specific inputs, and their sources, are listed in the remainder of this chapter.

a) Demand growth

Income growth is one of two factors that determines demand growth in Classic (the other factor being price), and is set as an exogenous variable in the model. In WP 1 it was decided to use GDP growth figures from the DG Tren Primes Study as the source for income growth. Using DG Tren figures ensures consistency in the reference scenario modelling in CASES.
Income growth in Classic is set as an average growth from the base year (2007 in this case) to the given scenario year. Hence, the average growth rates from Primes have had to be converted in order to fit the Classic framework.

b) Fuel prices

Fuel prices are the same as the fuel prices used in NEEDS:

Table 2: Fuel price assumptions

Constant 2005 prices	2010	2020	2030
Oil (€/GJ)	5.425	5.786	7.233
Gas (€/J)	4.535	4.605	5.581
Coal (€/GJ)	1.57	1.753	1.858

These energy prices are also in line with the reference scenarios of DG Tren Primes, and of the IEA and WETO. For biofuels, nuclear and lignite prices, we have used the same price assumptions as for the original Classic version.

c) Carbon assumptions

Carbon values, or CO2 prices, have been set to 20€/tCO2 consistently for years 2010, 2020 and 2030. Free allocation shares for CO2 emissions have been set to zero for all scenarios.
Hence, unlike the other environmental costs of power generation, the estimate for CO2 costs are not based on CASES assessments. Rather, the thinking is that the external cost of CO2 emissions is indirectly determined by the marginal abatement cost. Here we use the price of 20€/tCO2 as the starting point: Assuming this is the price of CO2, one important question of this study is whether adding the other external costs of generation will achieve the emissions reduction target. The project has defined a 50% reduction of CO2 emissions from the power sector as a likely target for 2030. If the full cost scenario were to yield higher CO2 emissions, there would be an option to run a Carbon-restrained scenario, investigating to which levels the CO2 price would have to increase in order to reach the 50% reduction target.

d)

e) Renewables capacity

The scenarios contain a fixed minimum level of power generation based on renewable energy sources (RES-E) in order to take account of a voluntary EU policy of RES-E promotion. This minimum RES-E generation level is identical to the DG Tren scenarios for all years modelled in Classic. This input is calibrated so that the share of RES-E generation is approximately 28% in 2030 in the base scenario. This exogenous input gives a "floor" of renewable capacity.

f) Investment Costs

Investment costs are obtained from the assessment of private and external costs of power generation undertaken by the New Energy Externalities Development for Sustainability (NEEDS) project. The NEEDS project has been used as it examines both the private and the external costs in one framework. Moreover, both the sets of costs are dynamic – i.e. they are changing over time, as technologies develop, knowledge about impacts of energy use n the environment increases and individual preferences for certain environmental and other values change. Hence, using estimates from the NEEDS project allows us to build on the integration of private and external costs within one framework

The NEEDS project includes cost estimates for so-called new-entrant technologies such as CCS and fuel cell generation. These technology categories have not yet included in Econ Classic, so cost estimates for these technologies have been omitted from this study.

g) Investment restrictions

The CASES project does not provide assessments of the potentials for different technologies in different countries. It is however necessary to restrict investments in wind power capacity particularly. If potentials and system costs are not taken into account, wind investment could grow to implausible levels. The restrictions used in the model have been derived from the Green-X database, and adjusted for the exogenous wind capacity from DG Tren. As wind investment potentials in Green-X are defined as technical potentials, this potential has been adjusted downwards somewhat to increase the realism of the potentials.
The restrictions to potential renewable (or any other) generation development are be added exogenously to Classic. This is done by constructing a "ceiling" for investment capacity by technology.
In terms of nuclear, only five countries are assumed to make new investments; Finland, France, Sweden, UK and Bulgaria. This restriction is based on the national policy attitudes towards nuclear in different countries. For Sweden the nuclear investment is restricted to upgrades in existing capacity.

Results

In this chapter we present the main results from the model runs. In order to save space, and for clarity, we only present total results for the EU27 area (+Norway and Switzerland) and for a selection of individual countries, namely Germany, UK and Bulgaria.

a) Scenario description

In addition to the simulation of the base year, 2007, two different scenarios, consisting of six model runs, were carried out for this project. Table 2 lists the different runs:

Table 3: List of scenarios.

Scenario	Name of runs	Description
1	Base Case	Econ Classic base model from Nordic Power Quarterly Q3 - base year 2007
2	2010	2010 with private costs of generation
	2020	2020 with private costs of generation
	2030	2030 with private costs of generation
3	2010_ExtCosts	2010 with full costs of generation
	2020_ExtCosts	2020 with full costs of generation
	2030_ExtCosts	2030 with full costs of generation

Investments are only endogenous in the 2020 and 2030 runs. No investment is permitted in the 2010 scenarios as the lead time between 2008 and 2010 is perceived to be too short to get new, not yet decided, generation on stream. The main difference between the sets of scenarios, Private cost and Full cost, is the cost of production. In the Private cost scenario, marginal production costs are equal to the private costs, ie external costs. In the Full cost scenario, marginal production costs equal the full social costs. The external costs included in the Full cost scenario are:

- Human health costs, except those relating from radio nuclides
- Environmental costs, such as loss of biodiversity, crops and material
- Radio nuclides, causing radioactive contamination
- Marginal costs of greenhouse gases

Including these external costs in the costs of generation makes conventional technologies more costly. Hence, this could lead to a shift in the composition of supply side technologies, encouraging more investment in renewables.

Next figures show a cost comparison for different generation technologies for average EU cost estimates. Based on private costs alone, hard coal would be preferable to onshore wind power, while this is reversed when external costs are included (external costs are the sum of all four costs listed above). Nuclear is the cheapest option regardless of cost composition. It should be observed, though, that the capital costs are fairly low as the discount rate has been set to only 5%. This would favour investment in capital intensive capacity like nuclear.

Figure 3.1: Composition of marginal costs for nuclear and thermal technologies 2005-2010 (Eur/MWh)

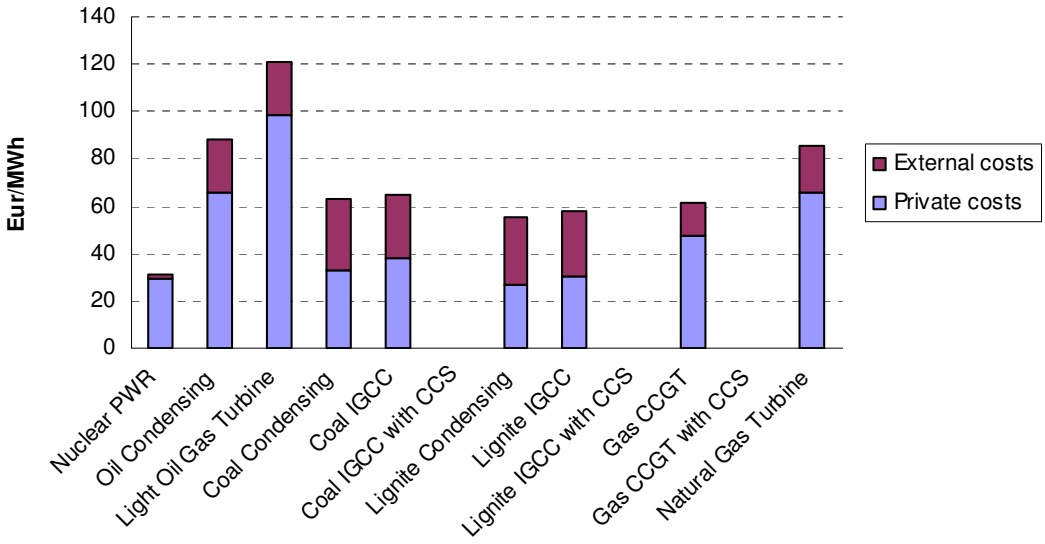
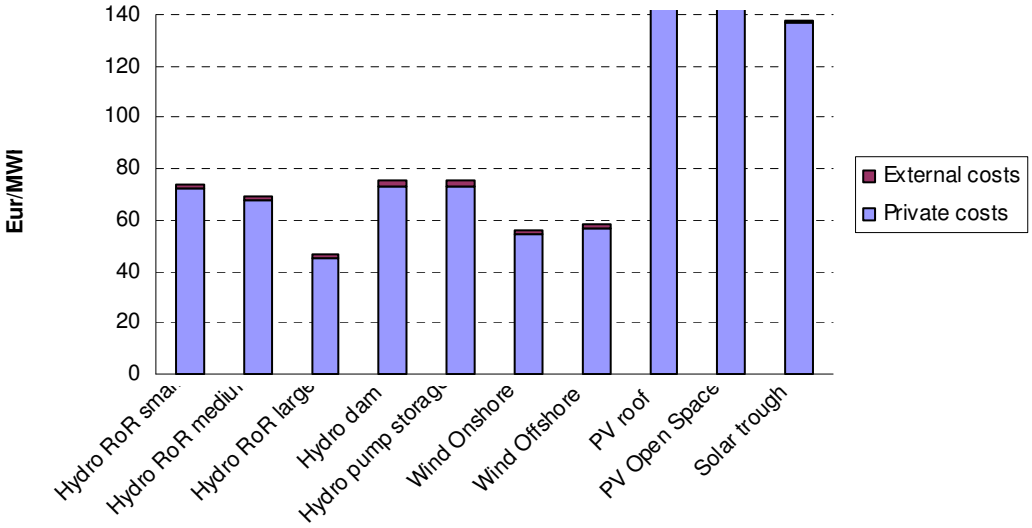


Figure 3.2: Composition of marginal costs for renewable technologies 2005-2010 (Eur/MWh)



The external costs displayed in the figures above are average costs for the EU. However, external costs vary between countries due to different emission levels and different dispersion. For instance, the marginal damage costs of electricity generation are higher in traditional fossil-fired countries.

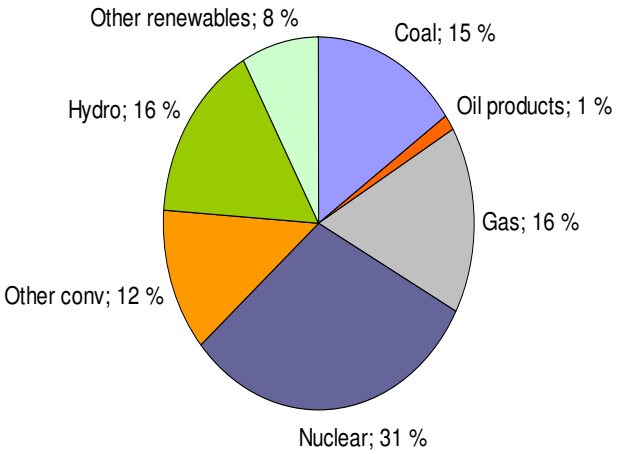
The scenario "Carbon Constrained scenario" put forward as a suggestion by CASES has been omitted from this study. The reason is that the intention of this (optional) scenario was to set the CO2 price so that CO2 emissions related to power are reduced by 50% compared to the 1990 levels. Aggregate CO2 emissions from power generation (and district heating) in EU27 plus Norway and Switzerland was approximately 1500 mtCO2 in 1990, which would have implied setting a CO2 price so a total level of 750 mtCO2 in the power sector could be achieved.

However, it will transpire later in the report that this saving is achieved in the 2030 scenario with full costs. As a consequence, the Carbon Constrained Scenario has been left out.

b) Investments

The current aggregate capacity in the EU27 is distributed on different technologies, though coal-fired, gas-fired and nuclear generation account for most of the generation. This is shown hereafter:

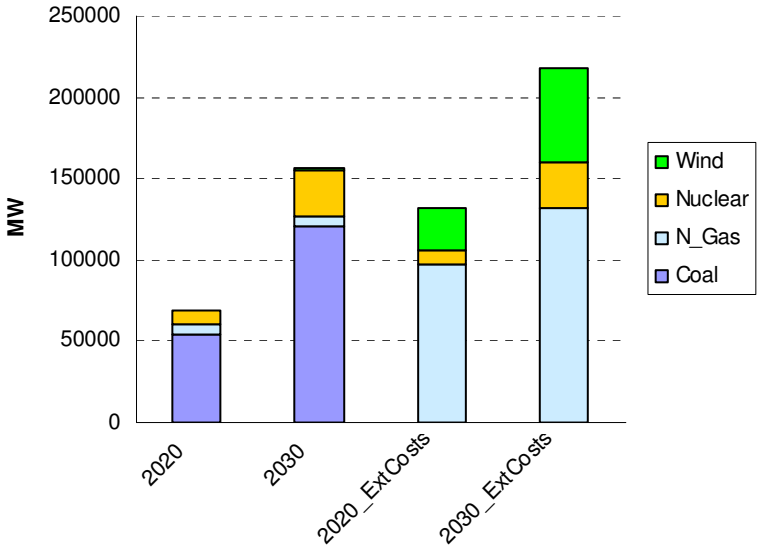
Figure 3.3: Shares of electricity generation by fuel for EU27 in 2007 (%)



The shares of fuel types used for electricity generation change as investment in capacity are carried out. The results show that investments, and hence fuel shares depend strongly on whether external costs are included or not. As expected, including external costs makes renewable technologies relatively cheaper, which in turn leads to phase-out of conventional technologies such as coal and gas-fired generation. This hypothesis is confirmed as shown in

Figure 3.4, where it emerges that investments in coal capacity are replaced by wind and natural gas when external costs are included. It should be noted that the figure only shows endogenous investments.

Figure 3.4: Total endogenous investments in generation capacity in the EU area



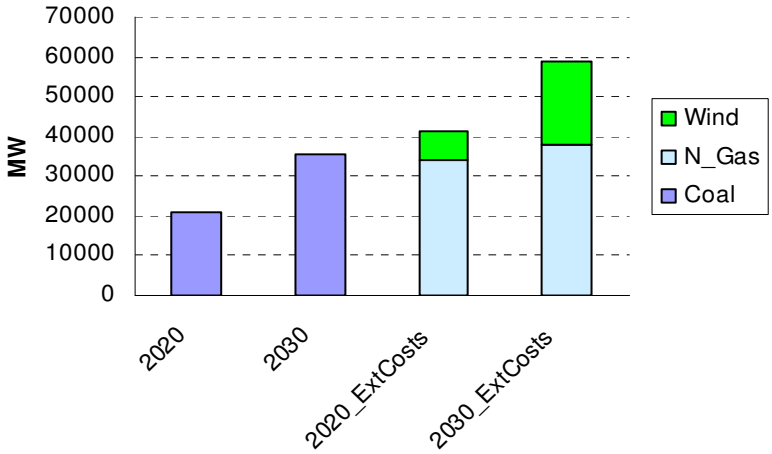
(MW)

For the scenarios with private costs investment decisions are dominated by coal, which due to relatively low fuel prices has the lowest marginal costs. Coal accounts for 90% and 80% of the investments in 2020 and 2030 respectively. When external costs are included investment decisions shift in favour of natural gas and wind. Investment in nuclear are relatively identical between the two sets of scenarios as nuclear consistently has the lowest marginal costs, and investments are restricted by the applied capacity ceilings.
It is also evident that total capacity investments increase between the two scenario sets. It does so for two reasons. The first reason is that wind power generally has a lower load factor than coal generation, and hence more capacity is needed to meet energy demand. The second reason is that higher operating costs for thermal technologies means that less fossil generation is refurbished, while coal plants are retired earlier. So in effect, higher operating costs displaces coal power in favour of wind and marginally less expensive natural gas generation.

Figure 3.5, Figure 3.6 &

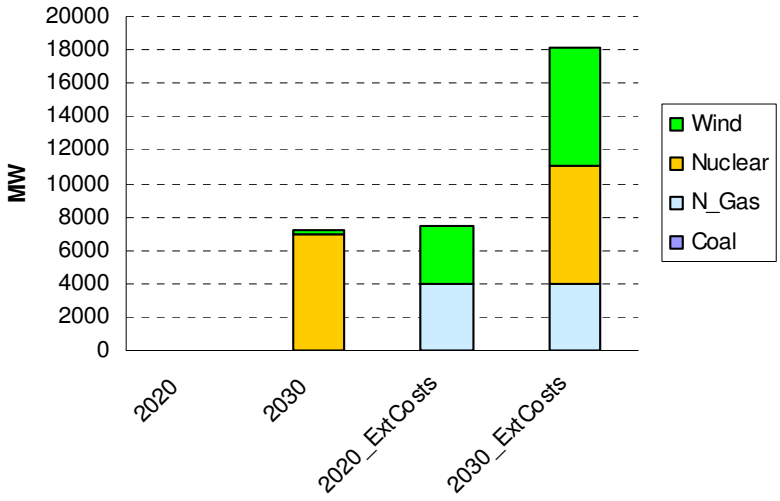
Figure 3.7 show investment in Germany, UK and Bulgaria respectively.

Figure 3.5: Endogenous investments in power generation in Germany. MW.



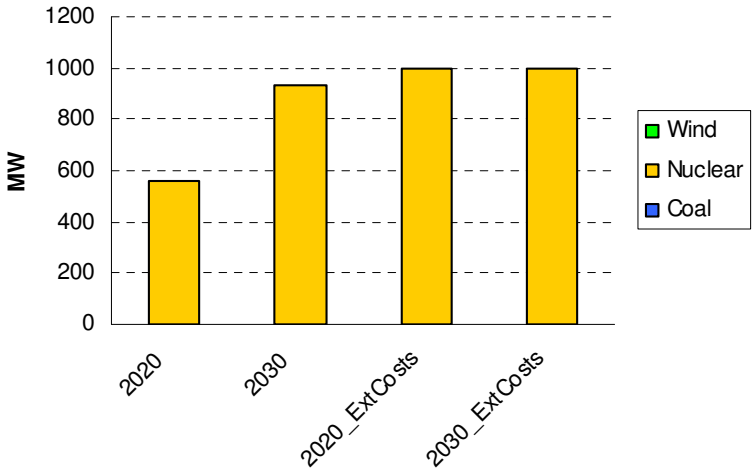
There is a significant shift in investments in Germany following the inclusion of full costs of production. This is evident in both 2020 and 2030. In the Private cost scenario, which does not include external costs, investment in coal prevails as coal has the lowest marginal costs. When external costs are included marginal costs of coal (and lignite) increase markedly, and investment shifts in favour of natural gas and wind. With full costs there is also considerably more investment in 2020 and 2030. Part of this is explained by the relatively lower load factors for wind, but the main reason is related to the many aging power stations in Germany. Including external costs of coal production curbs refurbishments and speeds up the retirement process of old coal plants, inducing higher investment to replace this phase-out.

Figure 3.6: Endogenous investments in power generation in the UK (MW)



Including external costs also has significant implications for investment decisions in the UK. Unlike Germany, however, the generation park in the UK is of newer date, implying fewer investments overall. In 2020 without external costs, significant capacity and relatively low operating costs imply that plants get refurbished rather than replaced. Also, in 2020 electricity prices are relatively low, making investments unprofitable. With full costs, however, higher operating costs curb refurbishment and also squeeze out existing capacity, inducing investments in wind and natural gas. For both 2030 scenarios, nuclear investments are equal to the perceived limit of 7000 MW assuming nuclear interest in the private sector triggers investments. There is also more wind investments in 2030.

Figure 3.7: Endogenous investments in power generation in Bulgaria (MW)



Energy policy in Bulgaria does not restrict nuclear investments. As a result, all capacity investment in Bulgaria is nuclear due to the low investment and operating costs. This endogenous investment has, however, been restricted to 1 GW for both 2020 and 2030 so as to stay within plausible levels given expected growth in demand. Bulgaria initially has surplus capacity, and therefore the nuclear investment in the private cost scenarios does not reach the

restriction level. In the full cost scenarios, however, some aging coal and lignite capacity is scrapped, and replaced by additional nuclear investments.

c) Demand

From the base year (2007) the demand levels in the model years 2010, 2020 and 2030 increase according to the specification of the demand curves, the GDP growth rates from Primes, and the development in prices. GDP growth and price parameters differ between demand sectors, of which there are five in Classic; Households, Services, Other (non-energy-intensive) industry, Energy-Intensive Industry and Electrical Boilers[9].

Figure 3.8 shows the total demand for EU27 (and Norway and Switzerland). For the scenarios without external costs, demand is consistently higher than in the scenarios with full costs. This is because the higher electricity prices resulting from higher costs of production in the full cost scenarios curb demand by 7.5% in 2030. Including external costs curbs demand by 10% in 2010 as the price difference for this year is higher. This is due to the generation park being similar in the two 2010-runs, and that higher operational costs of capacity have not yet been mitigated by investments in relatively cheaper technologies. The model probably overestimates the demand response in 2010 since long-term price elasticities are assumed.

Figure 3.8: Total demand in the EU area. TWh/year.

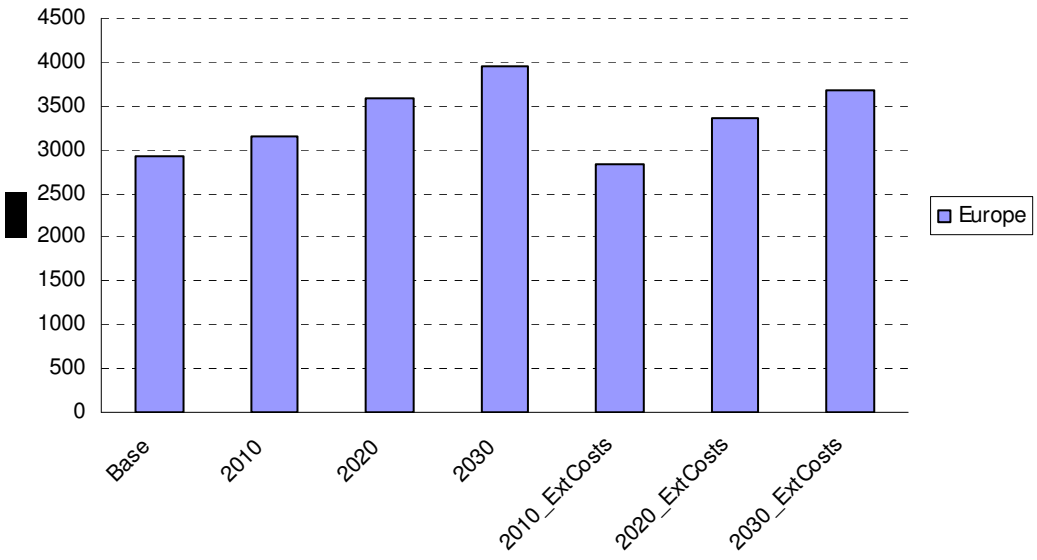
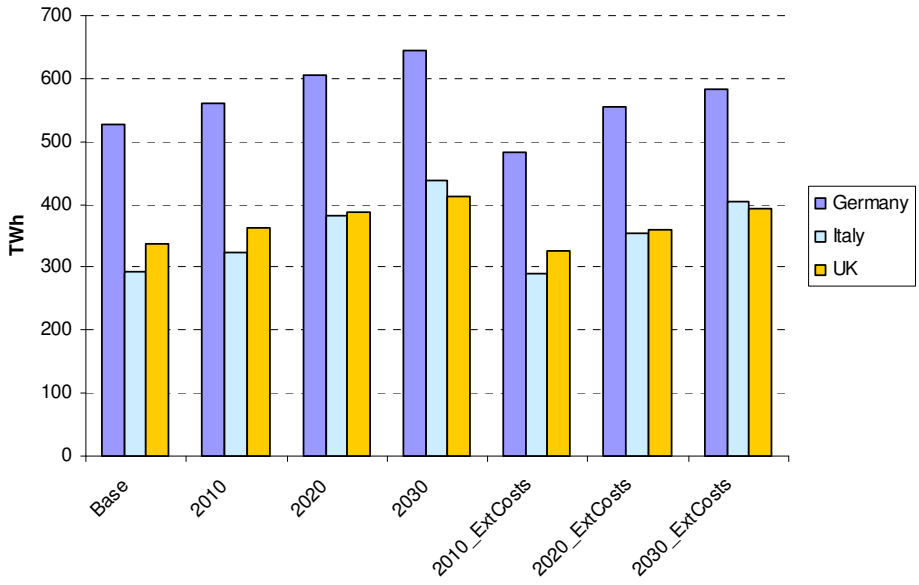


Figure 3.9 displays demand for the three selected countries Germany, Italy and the UK.

Figure 3.9: Demand in Germany, the UK and Italy TWh/year.

[9] Electrical boilers can switch between oil and electricity and are only significant in Norway and Sweden.



As similar price elasticities are assumed in these countries, the overall demand growth figures in the regions bear some resemblances. However, there are some evident differences in the demand patterns. For instance, in 2010 with full costs demand in Germany falls relative to the base case, whereas this does not appear to happen in the UK and Italy. This can be attributed to Germany's relatively sizeable power-intensive industry. Due to the energy-intensity per se, this sector has stronger price elasticity than other demand sectors for all the regions in the figure, inducing a greater decrease in electricity demand in Germany compared to the UK and Italy.

Another noticeable feature of the demand results is that electricity demand in Italy overtakes that of the UK in 2030 for both scenarios. This can again be explained by elasticities, as households and services, who have greater price elasticites, account for a relatively larger share of electricity use in the UK.

d) Generation

Developments in generation are closely linked with investments and demand. Total generation distributed by fuels in the EU area is displayed in
Figure 3.10 and Figure 3.11. These figures indicate that higher operating costs through the introduction of external costs have significant implications for the generation mix.

Figure 3.10: Total generation by fuel in the EU area – Private cost scenario. TWh.

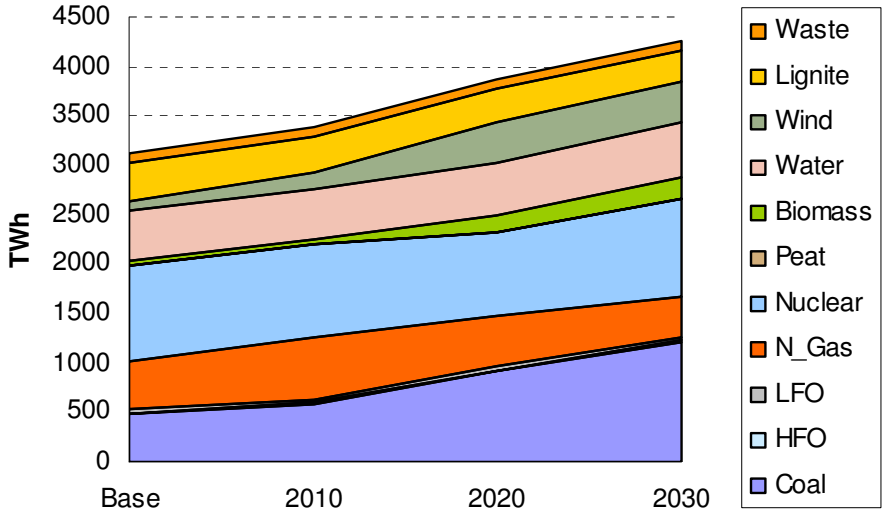
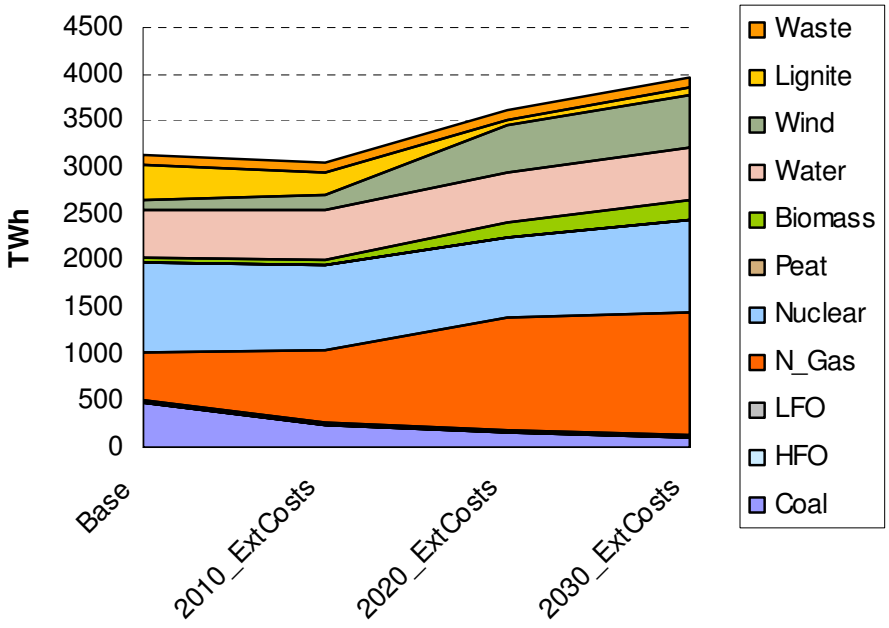


Figure 3.11: Total generation by fuel in the EU area – Full cost scenario



With costs of generation reflecting private costs alone coal generation is, given the fuel price assumptions, the cheapest technology, and will thus cover base load demand for many EU countries. By the same reasoning, wind investments are relatively restricted. Hence, wind generation, with an assumed fixed load factor accounts for roughly 10% of overall generation in 2030. This share can be attributed to exogenous wind investment according to the DG Tren study, meaning that investments in wind are driven purely by policy.

In the Full cost scenario, wind generation accounts for 15% of total generation. Adding external costs to investment and operating costs thus yields an extra 5% of wind generation generated by private sector investments. Coal and lignite generation, which have high external costs conversely become more expensive and are replaced by natural gas and wind subject to the applied restrictions. Nuclear generation remains relatively similar between scenarios as explained above. It is also worth noting that total generation levels are lower in the Full cost

scenarios due to lower demand, since higher overall marginal costs yields higher prices and hence demand cuts.

Generation in Germany is shown in

Figure 3.12 and Figure 3.13.

Figure 3.12: Total generation by fuel in Germany – Private cost scenario. TWh.

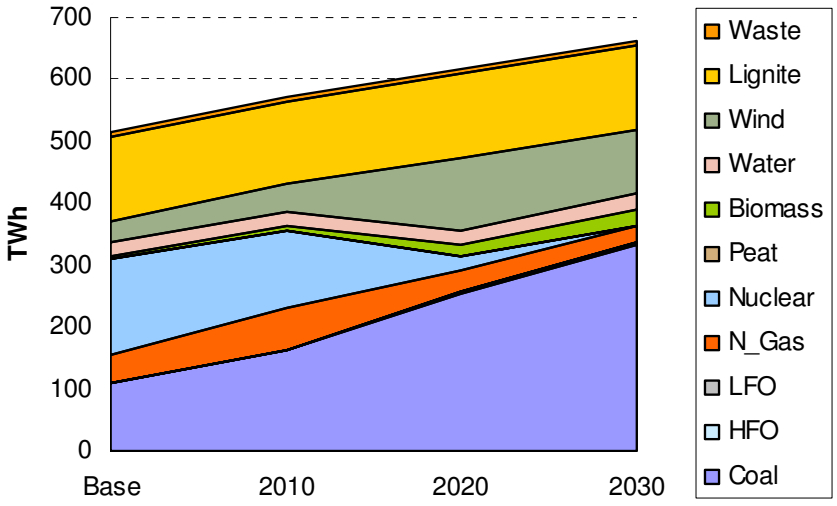
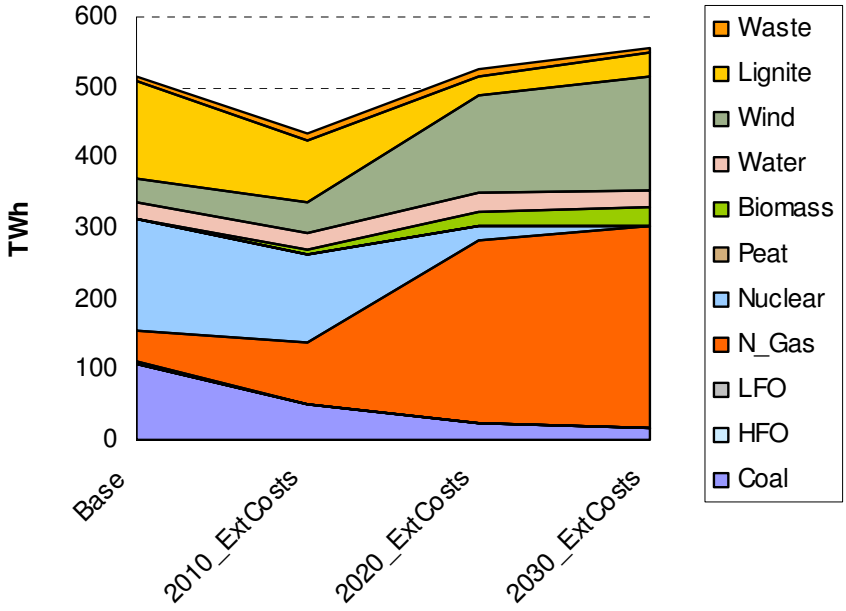


Figure 3.13: Total generation by fuel in Germany – Full cost scenario. TWh



Generation output for Germany verifies the hypothesis that the inclusion of external costs in the marginal cost of production will significantly change the fuel mix. Between the two scenarios, the most striking difference is the coal/natural gas level of generation. In addition to replacing coal as base load generation, CCGT investments replace peak load technologies such as LFO-fired plants. Natural gas is also supplemented with new wind generation, though wind investments are restricted by limits in potentials.

UK generation is displayed in Figure 3.14 and Figure 3.15. Through the same mechanisms as in Germany, natural gas and to some extent wind replaces coal up to 2030.

Figure 3.14: Total generation by fuel in the UK – Private cost scenario. TWh.

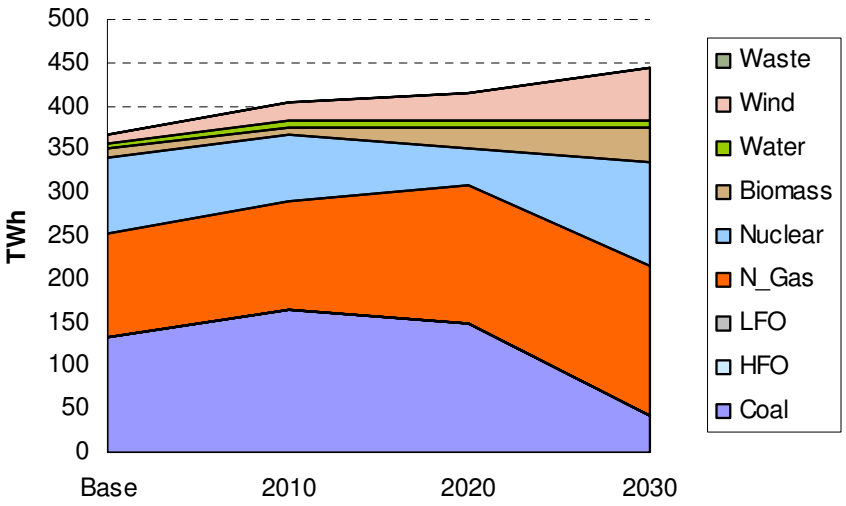
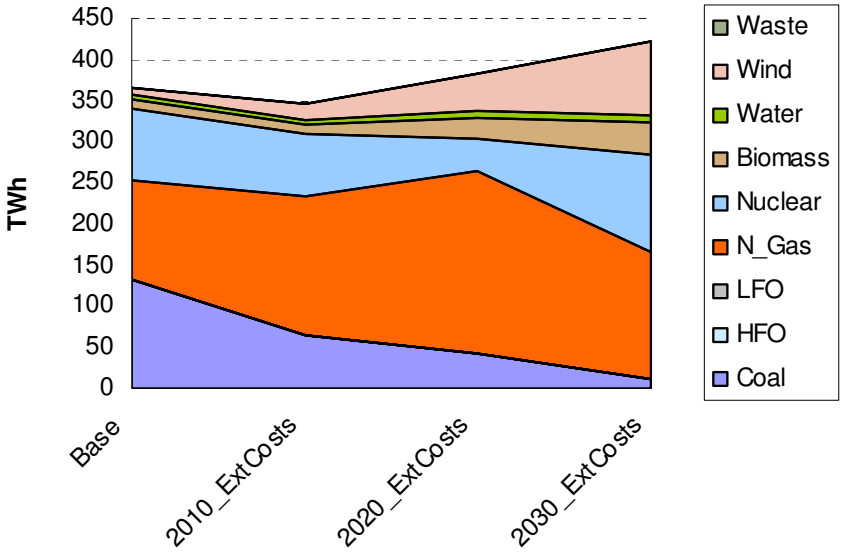


Figure 3.15: Total generation by fuel in the UK – Full cost scenario. TWh.



Generation based on private costs in the UK is different than that of Germany as there is considerably less coal investment in the UK. The reason for this is nuclear power. The model results show that nuclear investment will amount to 7.000 MW in the UK by 2030. This is reflected in the generation mix, and coal-fired generation is replaced by nuclear and to some extent wind power in 2030.

The assumption on UK nuclear investment also applies to the Full cost scenario. Here, the higher costs of generation curbs refurbishment of existing coal plants, and thus induces added investments in CCGT stations and some wind. This is particularly the case in 2020 where gas-fired generation is almost 40% higher than in the Private cost scenario. This share decreases, however, when new nuclear capacity is built.
Generation in Bulgaria, displayed in Figure 3.16 and Figure 3.17, shows some of the same features as Germany and the UK. Bulgaria is one of the regions in which investment in nuclear is an available option.

Figure 3.16: Total generation by fuel in Bulgaria – Private cost scenario. TWh.

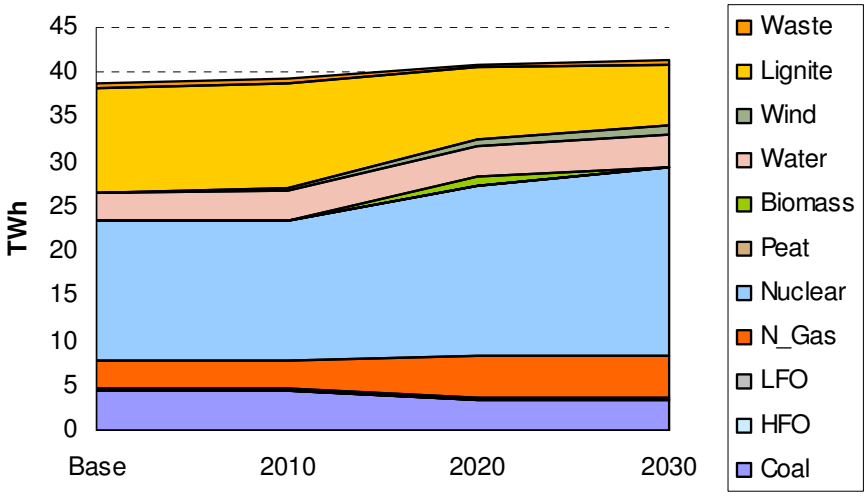
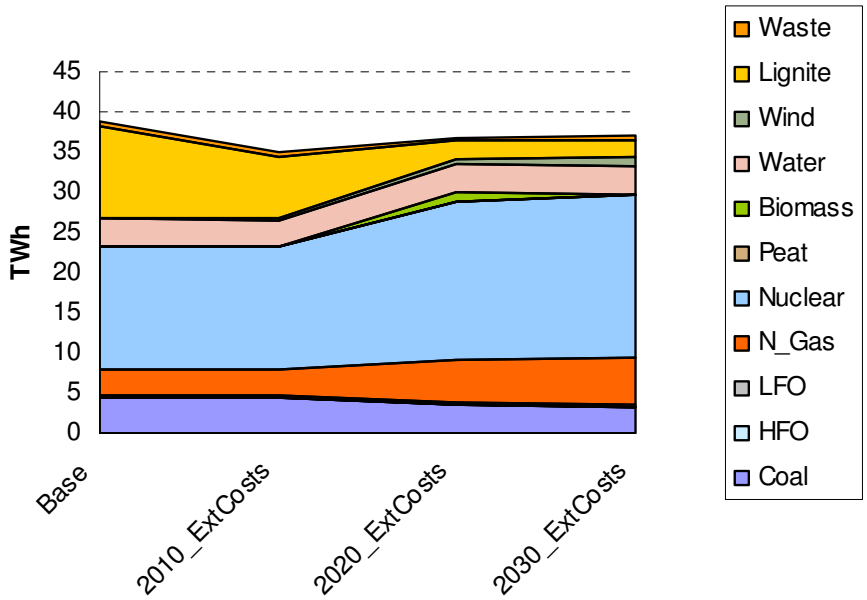


Figure 3.17: Total generation by fuel in Bulgaria – Full cost scenario. TWh.



Nuclear generation accounts for over 50% of total generation in Bulgaria in both scenarios. In the Full costs scenario the marginal cost of lignite increases substantially and thus lignite-fired generation is to some extent replaced by gas.

e) Fuel use in the electricity sector

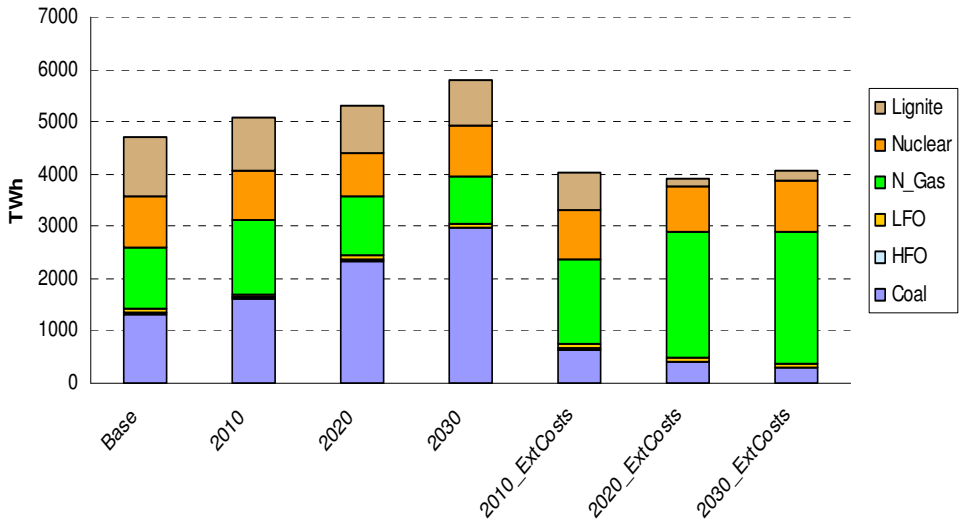
Inputs of various fuel types follow analogously from the generation mix. Fuel use intensity naturally depends on the efficiency assumptions of the various plants, and these are outlined in Table 4 below.

Table 4: Plant type efficiencies. %.

Plant type	Fuel type		Efficiency	
	Operating	Start-stop	Full load	50% load
New GT (CO)	Light Fuel Oil	Light Fuel Oil	33 %	16 %
New CCGT (CO)	Natural Gas	Natural Gas	54 %	27 %
New Scrubbed Coal (CO)	Coal	Heavy Fuel Oil	43 %	22 %
New IGCC Coal (CO)	Coal	Heavy Fuel Oil	47 %	24 %
New Lignite (CO)	Lignite	Heavy Fuel Oil	40 %	20 %
New IGCC Lignite (CO)	Lignite	Heavy Fuel Oil	40 %	20 %
New nuclear	Nuclear	Nuclear	100 %	100 %

The efficiency of these plant types determines the economics of investment decisions. In the Private cost scenario, the assumed coal plant efficiency makes coal the least expensive option given the investment costs, operating costs and the fuel prices. Including external costs increases the operating costs of coal plants relative to gas-fired plants, and this is verified through the fuel use of the various fuel types in Figure 3.18 below.

Figure 3.18: Fuel use in electricity generation by fuel type. TWh.

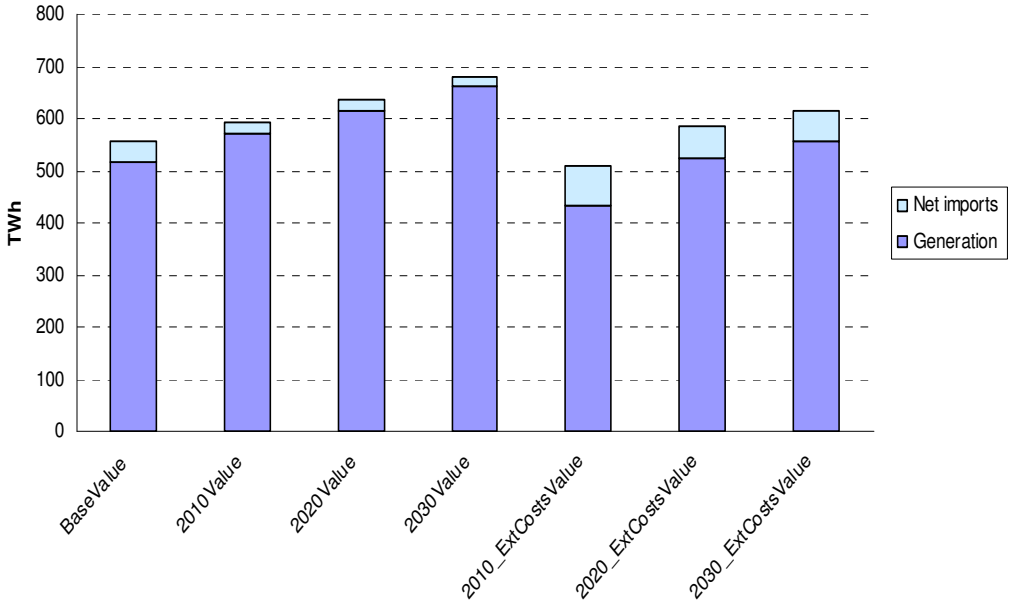


The gap in total fuel use between the Private and the Full cost scenario is largely explained by differences in renewables, bearing in mind, however, that overall generation is lower in the Full cost scenario.

f) Electricity trade

There are a number of interconnectors linking electricity markets to one another in Europe, and there is substantial electricity exchange across many of these links. In the model simulations, the flow of capacity from one country to another follows price differences, ie from a region with low prices to a region with high prices, as should be the case in a functioning market.
Germany is linked with various other European countries, and tends to be a net importer of electricity due to a relatively old and expensive thermal-dominated generation park. German domestic generation and net imports are shown in Figure 3.19.

Figure 3.19: German domestic electricity generation and net imports

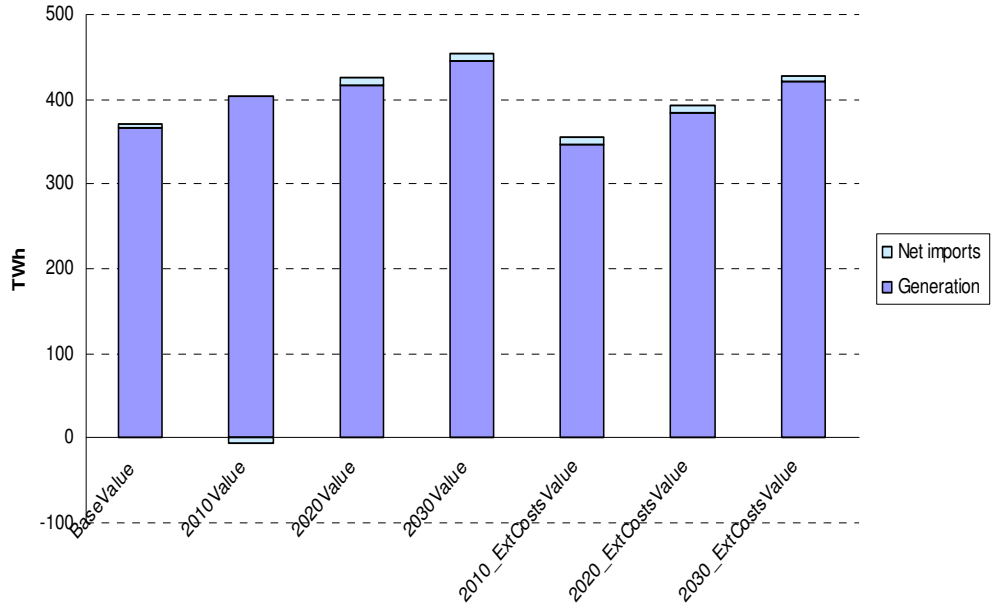


In Germany, wholesale electricity prices increase substantially with external costs due to higher marginal costs of production. As a result, net imports to Germany are higher in the Full cost scenario as imports from France and Denmark increase. The share of net imports is highest in 2010, as the operating costs in this year are at their highest.

The UK has a much more restricted transmission capacity than Germany. In effect, only two interconnectors connect the UK to Continental Europe; the Anglo-French Interconnector and the BritNed interconnector. UK domestic generation and net imports are displayed in

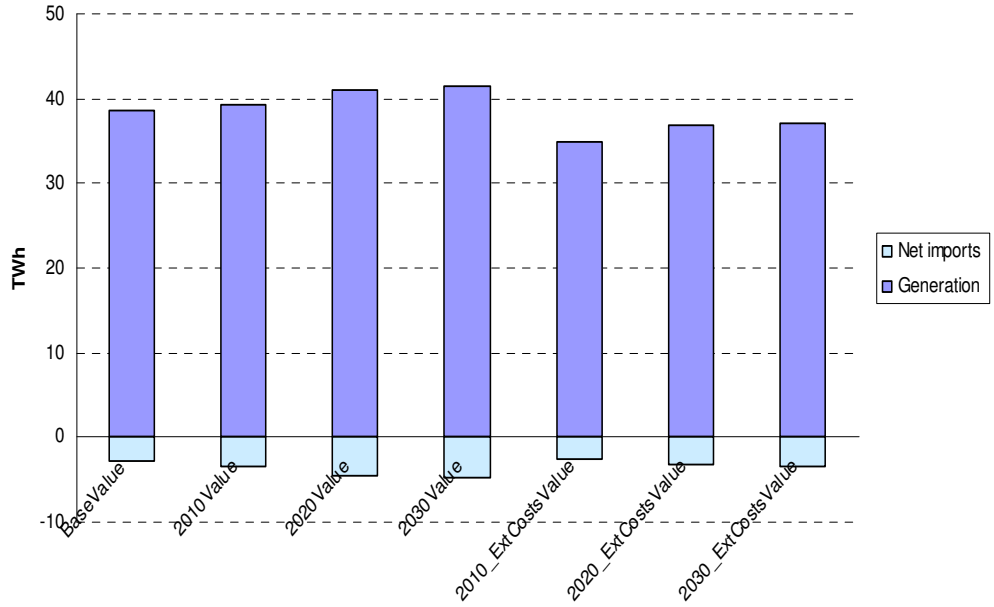
Figure 3.20

Figure 3.20: UK domestic electricity generation and net imports. TWh.



The share of net imports of overall electricity consumption in the UK is much smaller than in Germany. However, net import shares of overall electricity consumption increases in the UK as well, as nuclear-dominated France has lower costs of generation.
Unlike UK and Germany, Bulgaria's generation mix is dominated by nuclear, yielding relatively low costs of generation. As such, Bulgaria is a net exporter of electricity to its connected regions, Romania and Greece. This can be seen in
Figure 3.21.

Figure 3.21: Bulgaria domestic electricity generation and net imports. TWh.



As Bulgaria is a net exporter of electricity, its share of exports in the full cost scenario declines slightly along with total generation.

g) Wholesale price of electricity

The wholesale price of electricity reflects the costs of producing electricity, implying that higher marginal production costs will lead to higher wholesale prices of electricity. This is evident in

Figure 3.22 and Figure 3.23:

Figure 3.22: Wholesale price of electricity – Private cost scenario. €/MWh.

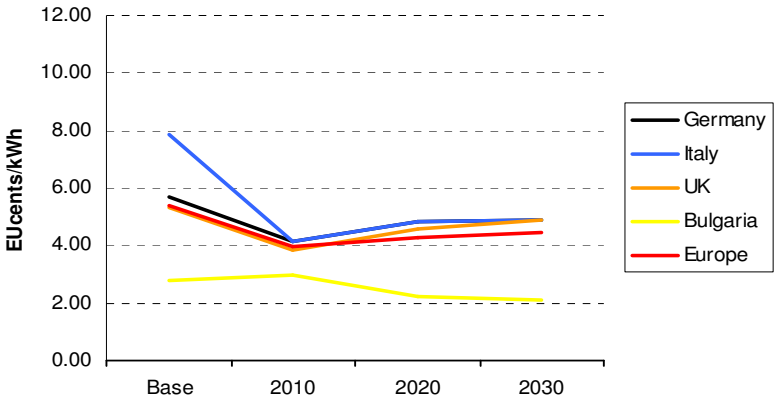
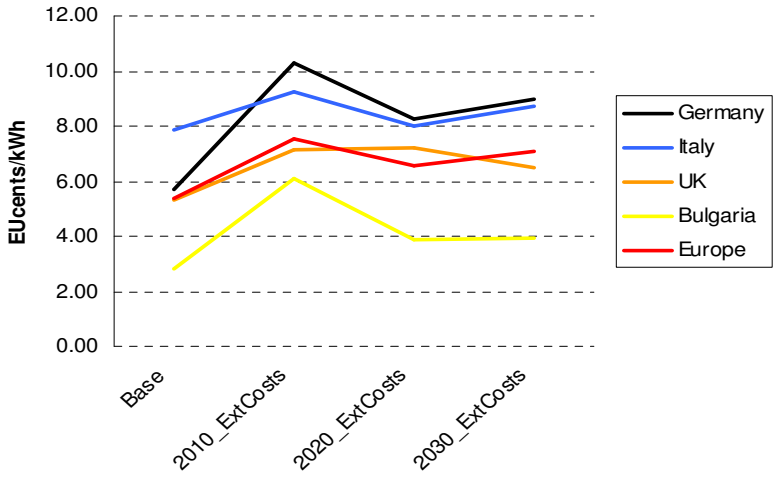


Figure 3.23: Wholesale price of electricity – Full cost scenario. €/MWh.



In the Private cost scenario, prices decrease significantly from the base year (2007) to 2030. The pronounced drop between 2007 and 2010 is chiefly due to a substantial amount of exogenous new-build for most countries, while some expensive old power stations are either mothballed or decommissioned over the same period. There is moreover constrained capacity in the base year. From 2010 to 2020, prices pick up in non-nuclear countries due to imposed wind investments and increasing demand.

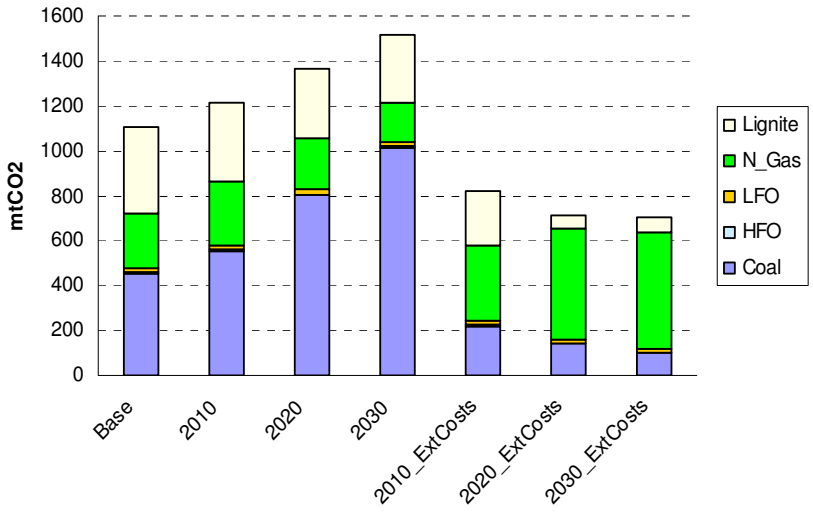
For the Full cost scenario, the picture is markedly different. The inclusion of external costs increases the cost of production significantly in 2010, pushing up electricity prices to over 10 €cents/kWh for many countries as the external costs are passed through to the wholesale

prices. When moving towards 2020, new investment in CCGT and wind takes place. In the Full cost scenario these technologies have lower costs than existing coal capacity, bringing down price levels in 2020. In 2030, prices increase slightly compared to 2020 due to higher demand and increasing external costs of natural gas, while lower production costs of wind (through learning curve mechanisms) offset this increase somewhat.

h) CO2 emissions

One of the main purposes of CASES is to assess the relationship between external costs of electricity production and the environment. In this analysis, we have derived the CO2 emissions from electricity generation under the various scenarios. The results are summarised in Figure 3.24.

Figure 3.24: Total CO2 emissions in the EU area. Mton CO2.



The CO2 output corresponds to the generation output. In the Private cost scenario, capacity investments are dominated by coal and lignite, and CO2 emissions increase by about 50% from the base year to 2030. In the Full cost scenario coal and lignite are replaced by natural gas and wind, and as a result CO2 emissions in 2030 are almost 900 mtCO2 lower than in the Private cost scenario. Moreover, the CO2 mix is different, with CO2 emissions in the Full cost scenario mainly stemming from natural gas.

For the Full cost scenario, emissions fall in 2010 relative to 2007 by around 300 mtCO2. The main reason for this reduction is that natural gas replace existing coal and lignite generation, as well as a reduction in overall electricity demand. This relatively strong effect is due to Classic being a fundamental model assuming perfect competition and hence swift market adaptation as a result of changes to the merit order.

The increase in demand and restrictions on wind investment yield a lower reduction between 2020 and 2010. Between 2020 and 2030 there is no reduction in emissions. It is however clear that adding full costs to the marginal production costs curb emissions from power generation by over 50% compared to 1990 levels. This result is achieved with a CO2 price of 20€/tCO2.

Conclusions

Including external costs in the cost of electricity production has significant implications for the cost-efficient development of the electricity sector in Europe.

The first impact external costs have is on the merit order of generation technology marginal costs which thus leads to changes generation mix. External costs raise the costs of generating electricity from fossil fuels compared to renewable generation. This again alters investment costs, which in many cases shifts investment from coal to wind. Wind investment is however restricted due to limited natural endowments, land-use and system costs, so the thermal investments will still be carried out. Due to external costs, the thermal technology with the lowest marginal cost is CCGT, which is both a more efficient and "cleaner" technology than coal. With regards to the generation mix, there is also a second effect. Higher operating costs shorten the lives of existing (old) coal and lignite technologies, making new investment cheaper than coal and lignite refurbishment. The result is a distinct difference in the generation mix with and without external costs. Even nuclear plays a role in some countries, but is generally restricted due to political and public opinion objections. These objections are related to security issues surrounding waste transport and management and the risk of nuclear accidents, effects which are not included in the CASES external cost evaluations.

The second profound effect of including external costs is the increase in the price of electricity, due to higher costs of production. This curbs electricity demand, necessitating less investment and refurbishments compared to the situation with private costs.

The third and arguably most important effect is the mitigation of CO2. The shift in the generation mix displaces coal and lignite in favour of natural gas and wind, leading to huge gains in CO2 emission reductions. In fact, using external costs as provided by CASES will reduce CO2 emissions in the power generating sector by more 50% both in 2020 and 2030 compared to 1990 levels.

4. Electricity scenarios in Brazil, China, India and Turkey

Brazil[10]

The Brazil's power industry is divided into four main subsystems: South, Southeast/Midwest, North and Northeast, according to the geographical division of the country.

These four integrated subsystems make up the National Interconnected System (NIS) and are responsible for 98% of the electricity market in the five abovementioned regions, representing a consumption of 390 TWh. More than 85% of the generation capacity comes from hydropower plants situated in several river basins and interconnected by long transmission lines. Conventional and nuclear power plants complete the generation capacity.

The Southeast/Midwest subsystem has the most installed capacity, approximately 43 GW. The South region is next, with an installed capacity of 14.13 GW. The installed capacity of the Northeast subsystem is slightly smaller, 14.07 GW. Finally, the North subsystem has an installed capacity of 5.4 GW and only hydropower plants.

The Southeast/Midwest subsystem is also the largest consumer, representing 61.6% of the NIS load. The loads of the South, Northeast and North subsystems represent 16.2%, 15.6% and 6.6% respectively.

In addition to these four subsystems, the Brazilian electricity system also has a set of other subsystems made up of isolated generating units. These consist mostly of diesel thermal plants in the North of the country and they meet 3% of population demands, even though the region represents 45% of the country's territory.

With respect to CO_2 emissions, Brazil has a favorable scenario thanks to its energy structure, with a predominance of renewable sources. As a result, Brazil has one of the lowest rates of emissions from the energy sector, with respect to GDP, in the world. Nevertheless, in the last few years there has been a strong increase of fossil energy in the energy supply mix. This is mostly due to the recent restructuring of the power industry, which seeks to attract private capital for building new plants. Thus, technologies that don't require very high initial investments and that have a shorter payback period are preferred, as is the case of natural gas thermopower plants. Therefore, renewable energy sources, such as hydro, are losing ground, leading to an increase in energy based CO_2 emissions.

[10] *CASES PROJECT (WP1- WP7): Report of Brazilian Electricity Sector Greenhouse Gas Emissions Incorporating CO2 Cost.*

a) Brazilian economic profile

Table 4.1: Population and gross domestic product of Brazil in 2000

	Population		GDP		GDP per capita		GDP, PPP		GDP per capita, PPP
	Million	% World	Billion US$	% World	US$	Relative % to World	Billion Int'l $	% World	Int'l $
Brazil	170	3%	602	2%	3,538	68%	1,253	3%	7,366
WORLD	6,052	100%	31,573	100%	5,217	100%	45,007	100%	7,436

Source: World Development Indicator 2005 (World Bank, 2005)

Table 4.2: Brazil's merchandise trading by category in 2000

	Exports			Imports		
	Billion US$	% of GDP	% of World Trading	Billion US$	% of GDP	% of World Trading
Merchandise TOTAL	48.6	9.2%	0.9%	51.7	9.7%	0.9%
Agricultural Raw Material	2.3	0.4%	2.2%	1.0	0.2%	0.9%
Food	11.3	2.1%	2.9%	3.5	0.7%	0.9%
Fuel	0.8	0.2%	0.1%	7.8	1.5%	1.3%
Manufactures	28.4	5.4%	0.7%	37.7	7.1%	0.9%
Ores and Metals	4.8	0.9%	3.0%	1.6	0.3%	0.9%
Other	1.0	0.2%	0.7%	0.1	0.0%	0.0%

Source: World Development Indicator 2005 (World Bank, 2005)

Table 4.3: Key statistics of financial flow in and out of Brazil in 2000

	Foreign Direct Investment							
	Net	Net inflows		Net outflows				
	BoP*, Billion US$	BoP*, Billion US$	% of GDP	BoP*, Billion US$	% of GDP	% of GDP	Billion US$	% of GDP
Brazil	26.9	28.9	5.4%	2.0	0.4%	10.8%	0.3	0.1%
World	134.7	1,335.5	4.9%	1,200.8	4.3%	28.4%	51.4	0.2%

Table 4.4: Premises of real growth gates of the GDP and electrical demand (%/year)

Scenario Basis	2005/10	2010/15	2015/20	2020/25
GDP	4.26	4.11	4.05	4.05
Electrical Demand	2.00	4.00	4.00	3.60

Table 4.5: Demographic Indicators

	unit	2000	2005	2010	2015	2020	2025
Population	million	171.28	185.71	198.47	210.19	220.89	230.77
Capita/household		3.83	3.50	3.40	3.30	3.20	3.10
Households	million	44.78	53.06	58.37	63.70	69.03	74.44
Potential of labor force	[%]	47.35	48.14	48.56	48.94	49.36	49.53
Share of labor force	[%]	90.65	90.65	90.65	90.65	90.65	90.65
Active labor force	million	73.53	81.04	87.37	93.25	98.84	103.63
Rural population	million	33.35	33.84	35.64	37.31	38.74	39.86
Urban population	million	137.93	151.87	162.83	172.88	182.15	190.91

b) Energy sources

Oil

Since Law 2004, dated October 3, 1953, the history of the oil industry in Brazil is intrinsically related to the history of Petrobras. Brazil's energy resources are an important economic advantage for the country, and the more efficient development and utilization of domestic hydrocarbon supplies are key government policy goals. Brazil has the second largest oil reserves in South America – after Venezuela. In April 2006, after years of efforts, self-sufficiency in oil production was reached. Reserves are estimated at about 8 billion barrels (bbls) with a daily production of about 1.8 million bbls, the equivalent of the daily consumption.

Brazil is the 10th largest energy consumer in the world and the 3th largest in the Western Hemisphere, behind the United States and Canada. The national production goal set in the 2015 Petrobras Strategic Plan is 2.3 million barrels a day by 2010. To achieve this, 15 major oil production projects will be implemented by 2008. Year 2006 is a milestone in Brazil's sustainable self-sufficiency in oil production. With the start up of the P-50 FPSO (Floating Production Storage Offloading) operations in the giant field of Albacora Leste, in the northern part of Campos Basin, Rio de Janeiro State, Petrobras is expected to reach the mark of two million barrels a day[11].

In order to build the oil sector scenarios, it is assumed that Petrobras will increase its production, not only to end dependency but also to export crude and oil products.

Gas

[11] *Petrobras, 2006.*

Brazil currently ranks fourth in South America in volume of natural gas reserves; proven reserves have been estimated (as of January 2005) at about 11 trillion cubic feet (tcf). Brazil's potential reserves, however, are vast, with one estimate of the total undiscovered natural gas resources placed at more than 175 tcf[12].By far the greatest use for natural gas in Brazil is for electricity generation, and natural gas demand is climbing rapidly in Brazil due to greater reliance on gas-fired power generation in response to overdependence on hydroelectric sources. Until the late 1990s, Brazil's gas production and consumption had been in step, but Brazil is now a net gas importer, mostly from Bolivia's gas fields[13].
In fact, the domestic natural gas market in Brazil has grown significantly in recent years. Demand has expanded at annual rates of around 15 percent over the last five years, and now totals about 48 million cubic meters per day. Distribution networks have also expanded quite rapidly, at about 18 percent per year between 2000 and 2005 – from 5.6 to 13 000 kilometers covering various states. At the same time, there's been a boom in conversions of motor vehicles to run on natural gas (NGVs), from less than 150 000 vehicles nationwide in 2000 to over a million by the end of 2005. Industrial users of natural gas are also growing continuously, and an extensive network of gas-powered thermoelectric power plants has been installed, with a total capacity of 9.1 GW according to ANEEL, the National Electrical Energy Agency.

Further growth will demand heavy investments, especially to expand the pipeline network, which has been practically stagnated since the construction of the Brazil-Bolivia pipeline. In fact, there are already serious problems to meet current demand in certain regions of Brazil. Since Bolivia nationalized the hydrocarbon production, Petrobras decided to anticipate the currently projected offshore natural gas exploitation and pipeline. The demand beyond the level is reached with LNG imports.

Generally speaking, it's possible to say that Petrobras' main measures to mitigate GHG are concentrated on the increase of energy efficiency and on the use of natural gas. Natural gas is consumed in smaller amounts to produce the same number of kilowatt-hours, consequently emitting less GHG.
In fact, to reduce emissions in the oil and gas sector, it's necessary to:

- Improve energy efficiency;
- Encourage carbon dioxide capture and storage by working with partners to facilitate the development and deployment of technologies required to capture CO_2 and store it in depleted oil fields or deep saline aquifers.

Coal

Brazil has the largest coal reserves in Latin America. Total recoverable reserves have been estimated (as of January 2005) at about 11 billion short tons, most of which are located in the southern part of the country. Coal is responsible for about 5% of the country's energy supply. According to Brazil's National Department of Mineral Production, coal consumption in 2003 totaled 23.88 million tons, around 60% of which representing imported coal used in the steel industry, little more than 30% corresponding to coal used in thermoelectric power plants and the remainder used in other industries[14] The steel industry is the primary user of coal in Brazil. Brazil is currently the 32nd-largest coal producer, accounting for about 0.1% of the world's annual total coal production, and the 27th-largest coal consumer, accounting for about 0.4% of the world's total annual coal consumption.

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[12] GAS NATURAL, 2006.
[13] Half of the natural gas consumed in Brazil, 200,000 barrels of oil equivalent a day, comes from Bolivia (GAS NATURAL, 2006).
[14] GOMES et al., 2004.

Brazilian coal resources are low quality and concentrated in the South region. Ash and sulfur contents are very high, consequently, using coal in Brazil for electricity generation means increasing pollutant emissions in a small region. Moreover, exploiting Brazilian coal resources requires huge investments, thus coal is not competitive in the power sector. However, the cement and ceramics industry will continue to increase steam coal consumption.

c) The Brazilian refining industry

The capacity of the domestic refining industry has increased slightly over the past few years due to revamping in the Petrobras system refineries. In 2004, the domestic refining industry processed an average of 1.7 million bpd of oil (632.7 million barrels a year), an amount 7.2% greater than processed in the preceding year (588.7 million barrels a year). 73.4% of all the oil processed in 2004 was domestic.
Since early 2000, Petrobras has invested in the modernization of its refineries, noticeably in four major aspects:

- Increasing the capacity of atmospheric distillation and vacuum distillation units, to increase their processing capacity;
- Installing new conversion units (bottom-of-barrel units), to minimize residues and increase the production of derivatives with greater added value. Significantly, the largest investments have been in the delayed coking units and catalytic reform units;
- Installing new units for processing derivatives, in order to increase their quality (hydro-treatment, hydro-desulphurization units and gas-sweetening units to support the latter), to meet the increased strictness of environmental legislation and quality requirements. Improved product quality is a result of environmental legislation requirements of many countries. This will allow export of derivatives to them. Hydrogen generating units were also included in the hydro-treatment – HDT and hydro-desulphurization – HDS investments;
- Installing treatment units for effluents and refining residues (sludge treatment units), in order to meet environmental requirements.

Brazilian refineries are on average more than 30 years old (the last refinery to begin operations in Brazil was REPAR, in 1977), and were designed to process light crudes imported from the Middle East. Currently, the oil produced in the country is mostly heavy (~ 19^0 API) and with high naphthenic acidity. In the last few years and in its short-term planning, Petrobras has invested in conversion units (basically delayed coking units but also fluid catalytic cracking units for converting residues – RFCC, a domestic technology) in order to increase processing and increasing the value of domestic oils. It has also invested in units for processing derivatives, to remove sulfur.

As can be seen, the trend in Brazil is to increase the capacity of refineries. According to ANP – the National Petroleum Agency - and also according to recent sectoral studies, the sharp increase in demand for derivatives has led to increasing imports over the past few years, reaching levels that would suggest the construction of another refinery.

A clear trend of the projects that have already been approved by Petrobras and are in its Strategic Planning (for 2006 to 2010) is to invest in product treatment units to improve their quality. Among these are investments in gas sweetening units and hydrotreatments, which not only meet the demands of clients but, more importantly, meet the new and growing

environmental requirements that emerge in the country (particularly with respect to maximum sulfur content in derivatives such as diesel and gasoline).

Table 4.6: Nominal Capacity of Brazilian Refineries

Refinery	Location (State)	Owner	Capacity (m^3/ day)
REDUC	Rio de Janeiro	Petrobras	38,500
REPLAN	São Paulo	Petrobras	58,000
RECAP	São Paulo	Petrobras	8,500
REVAP	São Paulo	Petrobras	40,000
REGAP	Minas Gerais	Petrobras	24,000
REFAP	Rio Grande do Sul	Petrobras and Repsol-YPF	30,000
REMAN	Amazonas	Petrobras	7,300
RPBC	São Paulo	Petrobras	27,000
RLAM	Bahia	Petrobras	51,350
REPAR	Paraná	Petrobras	30,000
LUBNOR	Ceará	Petrobras	1,100
Ipiranga	Rio Grande do Sul	Grupo Ipiranga	2,700
Manguinhos	Rio de Janeiro	Grupo Peixoto de Castro and Repsol-YPF	2,200

Source: ANP, 2006.

d) Expansion of the power generation capacity: Baseline Scenario

To build the baseline scenario, the limits of energy resources shown in the previous item were used. In the case of hydropower, although the potential is 230 GW, the possibility of using all the availability was not considered. The limits considered per basin are shown in the table below.

Table 4.7: Potential for Hydropower Expansion (MW)

Basin	BASELINE SCENARIO
Amazonas	104,724
Tocantins	16,987
North/Northeast Atlant.	3,102
São Francisco	16,029
East Atlantic	11,447
Paraná	21,146
Uruguay	10,480
Southeast Atlantic	7,052
Total	190,967

Also taken into account was the commissioning of the Belo Monte Hydropower Plant with half of its capacity (5500 MW) in 2010 and the other half in 2015. In the case of the Angra III Nuclear Power Station, it was assumed that it will be commissioned in 2014, given the date of the approval for its construction by the National Energy Policy Council. Furthermore, the possibility for expansion of two additional nuclear power stations with a capacity of 1,000 MW each was also included.

All the HPPs included in the National System Operator's energy planning report (without any environmental constraints) were considered, as were all the plants with awarded licenses without significant environmental restrictions.
For the alternative renewable sources considered in PROINFA[15], the following methodology was used: a market growth of 5% p.a. was projected and the total market share of these sources in 2030 was estimated to be 12%. SPHs remained with a share of 45%, biomass (including self-generation) with 40% and wind with 15%.
The capacity in 2010 in the isolated system was taken to be 2010 MW, relating to the thermopower plants in Manaus and Macapá. In 2015, this capacity will be incorporated into the North/Northeast region because of it will be interconnected to the NIS (National Interconnected System).
The relevant data for each of the included technologies are shown in the table below.

[15] PROINFA – Programa de Incentivo às Fontes Alternativas de Energia Elétrica

Table 4.8: Power Plant Data (US$ 2005)

Technology	Efficiency (%)	Maximum Capacity Factor (%)	Fixed O&M Costs (US$/kW-year)	Variable O&M Costs (US$/MWh)	Fuel Cost (US$/MWh)	Investment Cost (US$/kW)	Construction Time (year)
Hydro-small	n/a	63	45.6	9.6	-	1570	2
Hydro-medium	n/a	60	18.4	3.4	-	1400	4
Hydro-large	n/a	53	15.8	2.8	-	1230	7
Coal	37	80	46.2	0.6	13.8	816	4
Gas CC	50	92	33.3	1.7	25.3	600	3
Gas open-cycle	35	92	31.4	1.3	25.3	495	2
Oil	30	85	40.0	1.6	22.0	1700	2
Biomass	25	80	43.0	2.0	-	720	3
Nuclear	37.5	90	60.0	7.4	7.1	2200	5
Wind	n/a	25	23.6	2.0	-	1157	2

With the use of these data, the baseline scenario for the Brazilian energy sector was simulated using the MESSAGE model. The result for the power industry is shown in the following tables.

Table 4.9: Annual Electricity Capacity (GW)

Year	Annual Electricity Capacity (GW)						
	Coal	Oil	Natural Gas	Hydro	Nuclear	Other	Total
2000	1.45	2.92	2.74	60.10	1.97	1.44	70.61
2005	1.74	1.80	9.00	76.70	1.96	3.48	94.69
2010	2.46	1.43	13.48	78.74	1.96	7.12	105.19
2015	2.46	1.47	17.45	95.13	1.96	11.74	130.21
2020	2.46	0.94	18.16	122.60	3.31	14.54	162.01
2025	2.46	1.15	18.16	160.06	3.31	14.54	199.68
2030	3.46	2.21	22.14	169.82	3.31	17.04	217.99

Table 4.10: Annual Electricity Generation (TWh

Year	Annual Electricity Generation (TWh)						
	Coal	Oil	Natural Gas	Hydro	Nuclear	Other	Total
2000	8.25	5.07	10.51	301.41	18.02	7.04	350.31
2005	10.99	2.02	38.21	350.27	12.82	13.59	427.89
2010	15.52	2.37	77.86	350.61	12.82	31.48	490.66
2015	15.52	3.18	118.84	428.21	12.88	58.17	636.80
2020	15.52	3.34	147.11	583.49	21.75	82.54	853.75
2025	15.52	4.82	147.11	702.76	21.75	82.54	974.50
2030	21.82	9.24	179.42	745.61	21.75	96.73	1,074.58

GHG emissions were calculated according to IPCC methodology. Given the average thermal efficiencies of the power plants for each type of fuel, an emission rate, expressed in tCO_2 /MWh released to the atmosphere, can be arrived at, as shown by the following table:

Fuel	Thermal Energy		Thermal Efficiency	Electricity		Emission Rate Used
	(t C/ TJ)	(tCO_2 / TJ)		(tCO_2 / TJ)	(tCO_2 / GWh)	(tCO_2 / MWh)
Natural Gas*	15.30	56.10	0.45	124.67	448.93	**0.449**
Domestic Coal**	26.20	96.07	0.31	309.89	1115.93	**1.116**
Diesel Oil	20.20	74.07	0.30	246.89	889.05	**0.889**
Fuel Oil	21.10	77.37	0,36	214.91	773.88	**0.774**

* Combined cycle plants
** Coal from the Jacuí and Candiota mines (RS)
Source: Adapted from IPCC, 2006.

CH_4 and N_2O emissions were also calculated and expressed in CO_2 equivalent. The table below summarizes the emission rates used in this paper.

Table 4.11: Emission Rates Used (t.CO2 equiv./MWh)

	CO_2	CH_4	N_2O
Domestic Coal	1.116	0.00015	0.00288
Fuel Oil	0.774	0.00019	0.00093
Diesel Oil	0.889	0.00023	0.00149
Natural Gas	0.449	0.00099	0.00

With this information it was possible to obtain the greenhouse gas emissions in terms of CO_2 equivalent, as shown by the table below.

Table 4.12: CO2 Emissions

Year	CO_2 Emissions (MM TCO_2e)			
	Coal	Oil	Natural Gas	Total CO2
2000	9.21	3.93	4.73	17.86
2005	12.26	1.56	17.19	31.02
2010	17.32	1.84	35.04	54.19
2015	17.32	2.46	53.48	73.26
2020	17.32	2.59	66.20	86.10
2025	17.32	3.73	66.20	87.25
2030	24.36	7.15	80.74	112.25

e) Alternative Scenario

The alternative scenario for the expansion of the generating capacity of the power industry was built taking into account penalties for greenhouse gas emissions, as shown by the table below.

Table 4.13: Marginal avoidance costs of GHG (Euro-2005/ton)

	2010	2015	2020	2025	2030	2040	2050
CO_2	21	21	21	23	30	46	61
CH_4	441	441	441	483	630	966	1281
N_2O	6510	6510	6510	7130	9300	14260	18910

These data change the variable O&M cost of plants that emit greenhouse gases. Since the emissions of hydropowers are not being considered, the penalty for emissions could be added to the price of fuel. The fuel cost column is changed as shown by the table below.

Table 4.14: Power Plant Data (US$ 2005)

Technology	Efficiency (%)	Maximum Capacity Factor (%)	Fixed O&M Costs (US$/kW-year)	Variable O&M Costs (US$/MWh)	Fuel Cost (US$/MWh)	Investment Cost (US$/kW)	Construction Time (year)
Hydro-small	n/a	63	45.6	9.6	-	1570	2
Hydro-medium	n/a	60	18.4	3.4	-	1400	4
Hydro-large	n/a	53	15.8	2.8	-	1230	7
Coal	37	80	46.2	0.6	46.0	816	4
Gas combined-cycle	50	92	33.3	1.7	30.9	600	3
Gas open-cycle	35	92	31.4	1.3	30.9	495	2
Oil	30	85	40.0	1.6	37.5	1700	2
Biomass	25	80	43.0	2.0	-	720	3
Nuclear	37.5	90	60.0	7.4	7.1	2200	5
Wind	n/a	25	23.6	2.0	-	1157	2

The increase in generation costs changes the expansion of the generating capacity. The new results are shown in the tables below.

Table 4.15: Annual Electricity Capacity (GW)

Year	Annual Electricity Capacity (GW)						
	Coal	Oil	Natural Gas	Hydro	Nuclear	Other	Total
2000	1.45	2.92	2.74	60.10	1.97	1.44	70.61
2005	1.74	1.80	9.00	76.70	1.96	3.48	94.69
2010	2.46	1.80	13.48	78.74	1.96	7.12	105.57
2015	2.46	1.81	15.45	98.13	1.96	11.74	131.54
2020	2.46	1.81	15.45	125.60	3.31	15.17	163.80
2025	2.46	1.81	15.45	163.06	3.31	15.41	201.51
2030	2.46	1.81	16.58	178.38	4.31	17.91	221.45

Table 4.16: Annual Electricity Generation (TWh)

Year	Annual Electricity Generation (TWh)						
	Coal	Oil	Natural Gas	Hydro	Nuclear	Other	Total
2000	8.25	5.07	10.51	301.41	18.02	7.04	350.31
2005	10.99	2.02	38.21	350.27	12.82	13.59	427.89
2010	15.52	3.00	77.86	350.61	12.82	31.48	491.30
2015	15.52	3.90	105.17	441.71	12.90	58.17	637.38
2020	15.53	6.45	125.17	597.76	21.77	86.11	852.79
2025	15.54	7.57	125.18	715.93	21.77	87.48	973.47
2030	15.54	7.57	134.34	783.16	28.35	101.67	1,070.62

Table 4.17: CO2 Emissions

Year	CO_2 Emissions ($MMTCO_2e$)			
	Coal	Oil	Natural Gas	Total CO2
2000	9.23	3.93	4.73	17.89
2005	12.29	1.57	17.19	31.05
2010	17.36	2.33	35.04	54.73
2015	17.37	3.02	47.33	67.72
2020	17.38	5.00	59.59	81.97
2025	17.38	5.87	56.33	79.58
2030	17.39	5.87	60.45	83.71

The new results show a reduction in emissions in 2030 from 112 $MMtCO_2$ to 84 $MMtCO_2$, that is, a reduction of 25%. An increase in the cost of expansion can also be seen in the alternative scenario, as shown by the table below that compares the results of both scenarios.

Table 4.18: Comparison of Results

		Cost (million US$)		Variation	Emissions (MMtCO2)		Variation	Abatement Curve
Year	Generation	Baseline	Alternative	Cost	Baseline	Alternative	Emissions	Thousand US$/tCO2
2010	490.66	7,622	7,948	326	54.19	54.73	0.54	0.61
2015	636.80	16,060	17,990	1,930	73.26	67.72	-5.53	-0.35
2020	853.75	22,515	26,260	3,745	86.10	78.70	-7.40	-0.51
2025	974.50	11,954	14,868	2,914	87.25	79.58	-7.67	-0.38
2030	1,074.58	11,364	12,449	1,086	112.25	83.71	-28.54	-0.04
Total	4,458.17	77,712	88,864	11,152	444.07	395.50	-48.57	-0.23

China[16]

Energy consumption plays an important role in economic growth and poverty alleviation. But on the other hand, rapid increases in energy consumption, also brings about many environmental, social, and economic problems. How can China maintain its rapid economic development and at the same time can have a secure energy supply, do a good job in global and domestic environment protection, and really getting onto the track of sustainable development ?

China is already the hugest coal consumer and producer in the world and second in terms of total energy consumption and energy imports. China's energy development will have global influence in many aspects, such as energy prices on the world market, energy resource exploration, environment, climate change, even geopolitics. Therefore, stick and implement the concept of all-around, harmonized, and sustainable development request the policy makers look beyond specific issues and the immediate future, but view China's energy development strategy in the long-term and under broader context. The close connections between economic development, energy problem, climate change, and environment protection mean these issues need to be tackled in an integrated approach.

The focus of this study is on the energy sector policies that mainstream climate interests within development choices. The country study results for future energy and environment projections that are included in this report are backed by intensive economy-energy-environment modeling by Energy Research Institute of China National Development and Reform Commission.

This paper uses the Sustainable Development Indicators developed by UNEP Risoe Centre and on the basis of modeling business as usual development and alternative policy scenario, the development indicators for 2000, 2010, 2020, and 2030 are calculated to show the sustainable development implications of different energy and climate policy scenarios. Also a cross country comparison about the results of Brazil, China, India (and other countries not analyzed here) case studies under the UNEP Risoe project is made before end of the report to show that sustainable development tendencies of different large developing countries.

The structure of the China country report goes at follows:

- An introduction about the framework of integrating climate change and energy into sustainable development
- China's profile
- Chinese existing development goals: including economic, social, environmental, energy, GHG emission aspects
- Modeling the reference scenario: the existing policies
- The Sustainable Development indicators
- Cross-country comparison

[16] *China Country Report of the Projecting future energy demand: Balancing development, energy and climate priorities in large developing economies Project that has been managed by the UNEP Risø Centre on behalf of UNEP's Division of Technology, Industry, and Economics (DTIE).*

a) Integrating climate change and energy into sustainable development

To assess the climate change effects of different sustainable development policies, UNEP Risø has outlined a framework for how sustainable development (SD) dimensions, energy and climate can be assessed jointly. The approach is here to use a number of key SD indicators[17] that reflect economic, social, and environmental dimensions of sustainable development, and to use these to examine specific clean energy policies.

Table 4.19: Measurement Standard for Covering SD Thematic Areas at Macro- Energy Sector- and Project Level

	Macro	**Energy Sector**	**Project**
Economic Impact	GDP change Investment Welfare change Total income	Sectoral costs: Financial, economic. Investment	Project costs: Financial, economic
Employment	Number of people	Number of people	Number of people
Energy	All sorts of energy indicators	All sorts of energy indicators	All sorts of energy indicators
Poverty alleviation	Total income distribution e.g. gini	Income generation related to change in value of energy supply (resource owners) and income impacts of energy access of low income groups	Income generation related to change in value of energy supply (resource owners) and income impacts of energy access of low income groups
Health Improvements	Productivity of labour force Welfare improvements in terms of better health	Welfare improvements in terms of better health	Welfare improvements in terms of better health
Air quality	Change in productivity of labour force Welfare improvements in terms of better health Value of improved local **Environment**	Welfare improvements in terms of better health Value of improved local environment	Welfare improvements in terms of better health Value of improved local environment
Climate change impacts	GDP impact Welfare implications	Sectoral costs: Financial, economic Loss of output	Project costs: Financial, economic Loss of output
GHG emissions	Total emissions	Sectoral emissions	Project emissions

The climate change effects are structured as "web-diagrams", where the development trends for the chosen SD indicators are shown for the period 2000-2030 (defined as index values with 2000=100). The SD indicators include variables where low index values are considered to be supporting SD, and other variables, where high index values support SD[18].

[17] A SD indicator in this context is used as a sort of measurement point for a quantitative assessment of the impacts of implementing specific policies with regard to areas that are considered to be key national focal points for addressing sustainable development.

[18] A low index value for the period 2000 to 2030 implies that the variable is decreasing or only slowly increasing, which for example is positive for CO2 emission. Contrary a high index value shows a large increase over time, which for example can be positive in terms of per capita electricity consumption.

The Sustainable Development Indicators are:

- CO_2 intensity of GDP (CO_2/GDP)
- CO_2 intensity of total final energy consumption (CO_2/TFEC).
- Energy intensity of GDP (TFEC/GDP).
- Fuel imports
- Average costs of electricity
- Household electricity access
- Per capita electricity consumption
- Renewable share in power production

Variables that are considered to have a positive impact on SD if the index value is low are:

- SO_2 intensity of energy consumptions (SO_2/TPES).
- Energy intensity of GDP (TPES/GDP).
- CO_2 intensity of GDP (CO_2/GDP).
- CO_2 intensity of energy (CO_2/TPES).

While variables that are considered to have a positive impact on SD if the index value is high are:

- Household electricity access.
- Per capita electricity consumption.
- Efficiency of electricity generation (fossil).
- Investments in new power plants.
- Renewable share in power production.

Under the UNEP Risoe project, the current status and future development paths of Brazil, China and India have been modeled. Then the SD indicators of each country in 2000, 2010, 2020 and 2030 are calculated. Based on the results, the sustainable development indicator web of each country is generated, to reflect that country's sustainable development changing tendency. The webs of different countries are then compared to understand how the policies integrated in the models will change their development sustainability in different aspects, which can be used as input for policy making in relevant countries.

Based on this approach, SD indicators have been applied to the country study results for Brazil, China, and India in order to reflect energy efficiency, supply structure, per capita electricity consumptions, and local and global pollution. The results of this assessment concern the period between 2000 and 2030.

b) Driving Forces to Future Energy and Emission Development

Because of the large population base and it takes decades to reverse the development trends of population, the Chinese population is still growing at the speed of around 7 million a year. It is generally expected that the growth trends will continue in the next 3 to 4 decades before the Chinese population growing from the current 1.3 billion to the peak of about 1.5 billion and starts slow declining. A population growth of around 200 million in the next few decades will be a major driving force to energy demand.

Secondly, China is in the stage of rapid urbanization. China's urbanization rate is 43%, far lower than the around 70% in developed countries. Since 1978, the share of urban residents in China's total population has increased from 18% to the current 44% (CNBC, 2007). The large redundant labours and the much higher income level in cities attract massive immigration from rural areas to cities, at a scale of 15 million people a year. Major differences in income level and life style means major difference in an urban resident consumes much more energy than a rural resident in daily life. In 2003, the per capita residential electricity consumption of urban residents is 259 kWh, yet that of rural residents is 115 kWh. Moreover, the majority of rural residents still rely on agricultural waste and firewood as the main source of energy for cooking and heating, however when they move into cities, the generally transit to commercial energy, mainly in the form of fossil fuel and electricity. This will also lead to significant increase in energy demand.

Concerning the economic growth, China's average annual economic growth is 8.5% during the 1975-2004 period, and even higher at 8.9% during the 1990-2004 period, much higher than any other country during the same period. Currently industry contributes over 50% of China's GDP, far higher than the world average of around 33%. The tertiary is under developed. Ongoing industrialization makes industry continues to be the pillar for the country's economic growth. Industrial sector contributes more than half of China's GDP and is still growing faster than the agricultural sector and the service sector. The rapid growth of industrial sector, especially such energy-intensive sectors as steel, cement, building materials, chemicals, leads to rapid increase in energy demand.

c) China's Existing Energy Policies

China energy policies focus on 3 key areas trying to develop 10 key programs:

Key areas

Industry:
Electricity generation, steel and iron making, non-ferrous metals, refining and petrochemicals, chemicals, building materials, coal, machinery.

Transportation:
Road, new vehicles, urban transport, railway transport, aviation, navigation, agricultural and fishery machinery

Building (residential, public, and commercial):

- Building and housing: 50% energy saving designing standard during the 2006-2010 period; energy conservation renovation.
- Household and office appliances: energy efficiency standard and labeling.
- Lighting: lower the share of incandescent light bulb, promote energy-saving florescent light.

Key programs

- The coal-fired industrial boiler renovation program.
- Regional heat and electricity co-generation program.

- Waste heat and waste pressure capture and using program.
- Oil saving and replacement program.
- Motor engine system energy saving program.
- Energy system optimization program.
- Building energy-saving program.
- Green lighting program.
- The program of energy-saving in governmental agencies.

d) Energy Demand and Emissions in 2030 in China: Scenarios and Policy Options

Recent rapid growth of energy use in China exerts great pressure on energy supply and environment. This study provides scenarios of future energy development and resulting pollutant and greenhouse gas emissions, taking into account the most up-to-date data and recent policy discussions that will affect future economic, industrial and energy supply trends. To address uncertainties, especially uncertainties surrounding the level of energy intensive production in the next several decades, three scenarios were defined, which reasonably represent the range of plausible futures for energy development. The results from quantitative analysis show that energy demand in China could be as high as 2.9 billion toe in 2030, which could exceed the available energy supply. Comparing with previous energy scenario studies, this result is much higher. By using various policy options, however, there is potential to reduce this high demand to 2.4 billion toe in 2030.

The IPAC-Emission model and IPAC-AIM/Technology model – components of the Integrated Policy Assessment Model for China (IPAC) – were used to perform the quantitative scenario and policy option analysis. The models project future energy and pollutant emissions. The IPAC-Emission model is a global model developed for the study of greenhouse gas emission scenarios[19] It divides the world into 9 regions covering United States (US), Pacific OECD (OECD-P), Europe OECD and Canada (OECD-W), Eastern Europe and Former Soviet Union (EFSU), Middle East (ME), China, other Asia (S.E.Asia), Africa, and Latin America (LA). Major emission sources including energy activities, industries, land use, agriculture, and forests, can be simulated in the model framework. The model consists of three modules: (i) macro-economic module, (ii) end-use module and (iii) land-use module. The macro-economic module was developed based on the Edmonds-Reilly-Barns (ERB) model (Edmonds and Reilly, 1983; Edmonds et al., 1996), a macroeconomic, partial-equilibrium model, which forecasts energy demand over the long term. It uses GDP and population as future development drivers, combined with other energy-related parameters, to forecast energy demand based on the supply and demand balance.

The IPAC-AIM/Technology model is a single region model for China, developed based on AIM/enduse model (AIM Project team, 1996; Hu et al., 1996; Hu et al., 2001; Jiang et al., 1998). This model includes three modules (i.e., energy service demand projection, energy efficiency estimation and technology selection). The demand is divided among the industrial, agricultural, service, residential, and transportation sectors; and these sectors are further divided into sub-sectors. For both demand and supply side, more than 400 technologies are considered, including existing as well as advanced technologies that may be used in the future. The model searches for the least-cost technology mix to meet the given energy service demand.

[19] Jiang et al., 2000a; IPCC, 2001b.

Linking these two models provides both detailed analyses of various sectors and a global analysis of China's energy future. The same scenarios and related model assumptions were used for both models. Energy demand for China was basically given by the IPAC-AIM/technology model by calculating demand from sectors with detailed technology information; whereas energy price and energy import data are derived from the IPAC-Emission model.

Table 4.20: Population assumption, million

	2000	2010	2020	2030
Population	1267	1380	1460	1530
Urban	459	656	847	995
Rural	809	725	613	536

Table 4.21: GDP growth in China

	2000-2010	2010-2020	2020-2030
Annual GDP Growth Rate	8.2%	7.0%	5.6%

In order to analyze energy trading, the IPCC SRES B2 scenario is used as a global scenario The IPCC SRES scenario is a scenario family developed by the Intergovernmental Panel on Climate Change in 2001, which includes seven scenario groups. The B2 scenario reflects a world with good intentions, which it is not always capable of implementing. All of China's emission scenarios were developed under the IPCC SRES B2 scenario. In IPAC-emission model, international energy trade was included in the study based on the resource cost effective availability[20].

Table 4.22: Key Scenario Drivers Assumed for the Developing Asia-Pacific and the World in IPAC-Emission model

Item	Assumptions
Asia-Pacific Population	4.7 billion in 2050 5.0 billion in 2100
Asia-Pacific Annual GDP Growth Rate	5.7% from 1990 to 2050, 3.8% from 2050 to 2100
World Population	11.7 billion in 2100
World GDP	$250 trillion in 2100
GDP/ capita trends	Disparity remains GDP/capita of OECD becomes 7 times of non-OECD (now 13 times).
AEEI	1.0%-1.2%
International Trade	Low trade across regions High trade cost
Urbanization	Increase in developing world before 2050, decrease in developed world

Table 4.23: Assumptions for B2 Scenario for the Developing Asia-Pacific and the world

Item	Assumptions
Resource availability	Oil/gas: medium; Biomass: high
Energy exploitation cost	Medium
Non-carbon renewable energy cost	High for nuclear, medium for solar and

[20] *Jiang et al., 2000b; Jiang et al., 1999*

	others
Biomass availability	Medium
End-use technology efficiency improvement	Medium
Social efficiency improvement	Medium
Transport conservation	High
Dematerialization trend	Medium
Land-use productivity improvement	Medium
Meat-oriented food habit	Low
Desulphurization degree	High

Scenarios

In order to analyze future energy demand and emissions in China, three scenarios are considered. The three scenarios are defined as follows:

- *Baseline scenario*: This scenario gives a basic trend to describe future economic activities. There will be better international trading and China's economy will be part of global economy. Therefore China could rely on international markets and energy resource imports to meet part of its energy supply needs.
- *High demand scenario*: This scenario presents a high demand for energy in the future. The major driving force is China's assumed role as a centre for manufacturing following WTO accession, which will bring more energy-intensive product production to China, such as steel, non-ferrous products and building materials. At the same time, more technology transfer and R&D on high efficiency energy use technologies is also assumed.
- *Policy scenario*: Various energy and emission control policies are assumed for this low demand scenario, which reflects energy supply and environmental constraints.

The basic assumptions for the three scenarios, such as population and GDP growth, are the same.

Table 4.24: Factors influenced by key driving forces

Driving forces	Sectors	Factors	Policies to promote the Change
Social Efficiency Change	Industry	Value added change by sub-sectors within the sector (as service demand of some sub-sectors including machinery, other chemical, other mining, other industry sector etc.) Products structure change within one sector(as service demand in most industrial sectors)	Various policies relative to value added such as price policy, national plan for key industry, promote well working market Market oriented policies, national development policies.
	Residential and Commercial	Energy activity change within the sector (such as change of use of heating, cooling; use of more efficient electric appliances etc.)	Public education, price policies
	Transport	Change of transport mode (more public transport, non-mobility etc.) Traffic volume conservation (use less private car)	Transport development policies, public education
Technology progress	For all sectors	Efficiency progress for technology(unit energy use improvement) Technology mix change(, more advanced technologies) Fuel mix change(more renewable energy and nuclear)	Technology R&D promotion, market oriented policies, international collaboration Market oriented policies, environmental regulation National energy industry policies, import & export policies, tax system

Table 4.25: Energy intensive products assumption in the model

	Unit	2002	Baseline scenario/ Policy scenario		High demand scenario	
			2020	2030	2020	2030
Steel	Mt	182.4	380	320	430	380
Copper	Mt	1.63	4.5	5.2	5.2	5.8
Aluminium	Mt	4.51	10	14	12	18
Ethylene	Mt	5.43	12	16	14	20
Ammonia	Mt	36.75	47	49	50	56
Chemical fertilizer	Mt	37.9	48	50	52	58
Cement	Mt	725	1000	900	1100	1100
Glass	Million cases	234.4	480	530	520	560
Vehicles	Million	3.25	11	12	15	17

Table 4.26: Policy options used in the modeling study

Policy options	Explanation
Technology promotion policy	End use technology efficiency increase by using new technologies
Energy efficiency standard for buildings	New buildings reach 75% increase standard in 2030
Renewable energy development policy	Promote use of renewable energy(subsidy for wind power, biomass power generation; government supporting village biogas supply system)
Energy tax	Introduce vehicle tax by 2005, and energy tax by 2015
Public transport policies	In cities public transport in 2030 will take 10 to 15% higher share than 2000.
Transport Efficiency Improvement	High fuel efficiency vehicles widely used, including hybrid vehicle, compact cars, advanced diesel car
Power Generation Efficiency	Efficiency of coal fired power plants increase to 40% by 2030
Nature Gas Incentive	Enhance natural gas supply, localization of technology to reduce cost
Nuclear power development	National promotion program by setting up target, enhanced government investment, technology development

Results

Energy demand scenarios

Primary energy demand in the *baseline scenario* could go to 2.1 billion toe in 2020 and 2.7 billion toe in 2030. The annual growth rate from 2000 to 2030 is 3.6%, while energy elasticity of GDP is 0.58. Coal will be the major component energy in China (1.5 billion toe in 2030), with a 58% share in total energy demand. There is a rapid increase for natural gas demand in China, with its share in total primary energy use increasing from 4% in 2000 to 17.3% in 2030 (average annual growth rate: 10%).

With respect to final energy use, electricity and oil increase rapidly. Electricity demand increases from 112 million toe in 2000 to 451 million toe in 2030. Coal use in the residential sector will generally decrease and be replaced by gas and electricity; coal will be mainly used in large equipment such as boilers, steel industry and cement industry. Demand for oil products used for transport will increase quickly, with the rapid growth of vehicles in China. Oil use in transport will increase from 74 million toe in 2000 to 410 million toe in 2030.

For the *high demand scenario*, primary energy demand in 2030 is 2.9 billion toe, which is 250 million tons higher than the baseline scenario. Of the total primary energy demand, coal provides 59.1%, oil 16.1%, natural gas 17.8%, and nuclear 1.2%. Because this scenario assumes better integration in international markets, there is greater reliance on imported energy such as natural gas and oil.

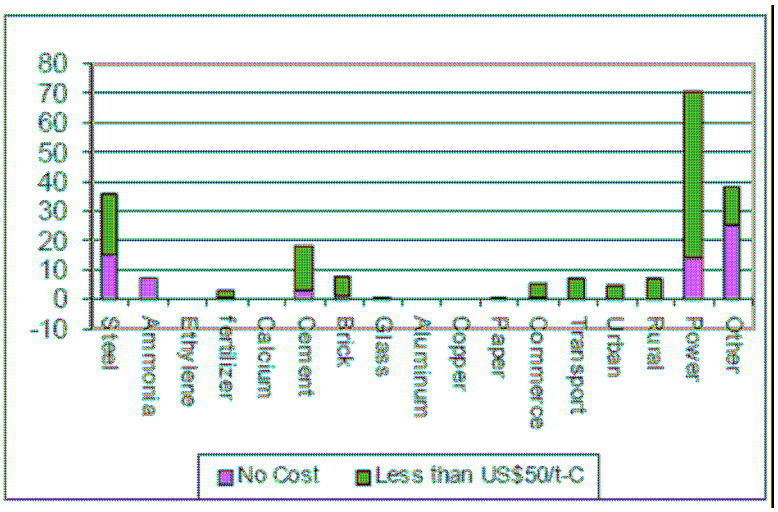
By assuming the adoption of energy and environmental policy measures, for the *policy scenario*, compared to the baseline scenario, there is nearly 245 million toe energy demand reduction in 2020, 280 Mtoe in 2030. By exploring the policy options, it has been found that there is big pressure to apply these policy options in order to reach the lower energy demand scenario, and also need to be introduced at early time because of long life span of energy technologies.

With the calculation of energy demand, several pollutant emissions were calculated. SO_2 emission will keep increasing before 2010 with the rapid increase of coal use in China. After 2010, more and more desulphurization technologies will be used and therefore SO_2 emission will be reduced from fossil fuel use. Compared with *high demand scenario*, SO_2 emission for *baseline scenario* in 2010 is 4.5million tons lower, but still increase 9.45million ton from 2000. This will be huge challenge for government target. Because of lack of policy to control NOx, its emission keeps going up. Same trend is seen for TSP emission.

Concerning the effects for policy options used in the *policy scenario*, by comparing with baseline scenario and high demand scenario, it has been noticed that there are a package of policy options could be adopted now to reduce the growth rate of energy demand. For example policy to promote penetration rate of high energy efficiency technologies, fiscal energy and environment policies including vehicle fuel taxes, subsidies for renewable energy, emission taxes, resource taxes etc., and policy to promote public involvement, are important for China to go to a low energy demand scenario.

The energy saving and CO_2 emission reduction potential by sector was simulated with a wider cost range of up to US$50/tC. Emission reduction potential by these sectors with cost less than US$50/tC is shown in Figure 6.14. From this figure we can much potential could comes from no-regret options.

Figure 4.1 : Emission reduction potentials by sectors



Energy supply scenarios

In the baseline and high demand scenarios coal production could reach 1.31 billion toe by 2020 and 1.48 billion toe by 2030. Chinese coal industry experts estimate an upper bound of coal production of 1.2 billion toe by 2020. Coal demand, therefore, could exceed domestic coal production in China. Oil production is projected to be 190 million tons in 2020 and 175 million tons in 2030. This is within the forecast of experts from the oil industry, which range from 180 to 200 million tons of oil in 2020. Natural gas production will be 133 billion m^3 in 2020 and 312 billion m^3 in 2030. The production of natural gas is within the range of natural gas production

forecast by energy experts, which ranges from 130 to 150 billion m^3 in 2020. Nuclear power generation will increase quickly in future, but still represents a small share, because of its high cost. The model results shows that nuclear power generation could reach 256 TWh in 2020 and 344 TWh in 2030, compared with 16.7 TWh in 2000. The installed capacity will be 39,400 MW in 2020 and 53,030 MW in 2030. Hydropower output will increase from 224 TWh in 2000 to 555 TWh in 2020 and 722 TWh in 2030, with capacity reaching 154 GW in 2020 and 201 GW in 2030.

In baseline scenario, future fossil energy imports could reach 375 million toe annually in 2020 and 562 million toe in 2030 (for comparison, in 2000, the USA imported 870 million tce). Oil will be the major energy source to be imported: oil imports will reach 230 million tons in 2020 and 300 million tons by 2030. Natural gas imports will amount to 154 billion and 183 billion m3 in 2020 and 2030, respectively. Even coal will be imported after 2020, with 129 million tons of coal needed annually by 2030.
In the high demand scenario, energy imports are much bigger. Total fossil energy import will be 445 million toe in 2020 and 680 million toe in 2030. There will be more coal import in this scenario, reaching 189 million toe in 2030.
This scenario study shows primary energy demand in 2020 could range from 1.9 billion toe to 2.4 billion toe. This depends on technology progress, energy intensive sector development, and polices applied etc. Such large amount of energy demand will bring serious pressure on energy supply in China.
Studies show that by 2020 the largest domestic oil supply could reach 200 million ton, natural gas 160 billion m^3, and coal 2.8 billion ton. This means for lowest energy demand scenario 200 million ton oil and 100 billion m^3 natural gas shall have to be imported; for high energy demand scenario, nearly 400 million ton oil, 260 billion m^3 natural gas and 300 million ton coal shall have to be imported.

Such large amount of energy demand and imports will put high pressure on energy supply industry in China, therefore a well-designed strategy for energy system and energy industry development in China should be prepared. Considering the possibility of policy options analyzed in this study, following suggestion are given:

- Technology progress is a key to reach future low energy demand and clean future, it should be put much more emphasis for new generation technologies. In the scenario study, technology progress will contribute much of the energy saving, while no disturbing on welfare.
- Using of energy tax, resource tax, export tax for energy intensive products etc., has good effect on energy saving and optimization of economic structure. These should be given much more attention.
- Similar to other developed countries which have large amount of energy import, China should establish energy security system. However the size of strategic storage should be decided based on global perspective of oil demand.
- Multi-energy system should be established to diversify energy supply. Renewable energy should be developed as alternative energy source. Bio-fuel for vehicle fuel could reduce energy import.
- Various national laws, regulations, and standards for energy industry should be prepared to reach the target of clean energy system. So far there is very weak legislation system to promote clean energy system.
- Clean coal technology should be emphasized to mitigate emission from coal combustion.

Only a few of countries in the world are using coal in large scale, therefore development of clean coal technologies depends on them. China is the biggest country to use coal, and in future the coal use will increase quickly, which could take more than 40% of world total coal use in 2020. Therefore, clean coal technology is crucial for China. China should have clear development plan to promote clean coal technology. It is better to work in close coordination with other countries to develop new generation of clean coal technologies.

Clean Coal Promotion

With rapid growth of economy in China, primary energy demand in the baseline scenario could go to 2.1 billion toe in 2020 and 2.7 billion toe in 2030. The annual growth rate from 2000 to 2030 is 3.6%, while energy elasticity of GDP is 0.58. Coal will keep major energy source in China in next several decades. In baseline scenario, coal use would be 1.4 billion toe in 2020 and 1.7 billion toe in 2030, taking share of 58%, when it is 720 million toe in 2000. There is a rapid increase for natural gas demand in China, with its share in total primary energy use increasing from 4% in 2000 to 17.3% in 2030 (annual growth rate: 10%).

With respect to final energy use, electricity and natural gas increase rapidly. Electricity demand increases from 112 million toe in 2000 to 478 million toe in 2030. Natural gas demand increases from 21 million toe in 2000 to 437 million toe in 2030. Coal and oil demand increase slowly. Coal use in the residential sector will generally decrease and be replaced by gas and electricity; coal will be mainly used in large equipment such as boilers and steel making, building material production. Demand for oil products used for transport will increase quickly, with the rapid growth of vehicles in China. Oil use in transport will increase from 105 million tce in 2000 to 457 million tce in 2030.

From the results we can see coal will play very important role in both primary energy supply and final energy supply. Coal production could reach 1.31 billion tce by 2020 and 1.48 billion tce by 2030. Chinese coal industry experts estimate an upper bound of coal production of 1.2 billion tce by 2020. Coal demand, therefore, could exceed domestic coal production in China.

In the baseline scenario, development of these technologies was set up in a preliminary diffusion way. Table 9 shows the technology involvement in the baseline scenario.

Table 4.27: Clean coal technologies in baseline scenario

Sector	Technology	Share in 2030
Power generation	Super Critical	25%
	IGCC	4%
Industry/Boiler	Advanced boiler	45%
Industry/Kiln	Advanced kiln	38%
Coal processing	Coal liquefaction	2% of total coal
Desulfurization in power plants		58% of total coal fired power plants

By assuming the adoption of energy and environmental policy measures, regarding the *policy scenario*, compared to the *baseline scenario*, there is nearly 245 Mtce energy demand lower in 2020, 280 Mtce in 2030. There is 160 Mtoe coal saved. There is an important pressure to apply these policy options in order to reach the lower energy demand scenario. These policy options need also to be introduced at early time because of long life span of energy technologies.

Among these policy options, clean coal technology development and diffusion is one of the key components.

Development of clean coal technologies can contribute to not only energy saving, emission reduction, but also local social economic activities. The next table presents a brief picture for clean coal future. Chinese clean coal industry could be expected to extend and continue to be one of important component of economic development.

Table 4.28: Factors for coal related activities

		2005	2010	2020	2030
Total Primary energy demand	Mtoe		2040	2450	2960
Coal use	Mt	2165	2791	2896	3102
Production	Mt	2204	2840	2880	3010
Output value	Bn Yuan	645	867	945	1073
Value added in coal mining and processing	Bn Yuan	314	422	460	523
Share of GDP	%	1.7%	1.5%	0.8%	0.5%
Employee in coal mining and processing	Million	7.8	7.7	6.3	5.2
Death of worker in coal mine	Person/Mt	2.8	2.6	2	1.1
Value added of Coal fired power manufacture	Bn Yuan	21.6	29.8	37	43
Coal fired power manufacture output	MW	5819	6320	6900	6900
Employees in coal fired power manufacture	Person	236400	250000	240000	210000

Development of clean coal technology could contribute to the local sustainable development in following ways:

- Reduce energy demand, which could release pressure on energy supply and energy import, increase energy security.
- Fundamental industry in China with large employment: 7.6 million employees in 2004, 7.8 million in 2030. Important thing is this is good for low income people to fine opportunity
- Extend economy activities. Taking lead for clean coal technology in the world will bring economy benefit. Three power equipment companies in China is becoming among top manufactures in the world in 2005 (largest power capacity suppliers for coal fired power plants), and started to export advanced coal fired power plants.
- Very good environment effects. SO_2, NOx, PM emission, water pollution will be significantly reduced by using clean coal technologies, also very important for GHG emission reduction. Clean coal technology development will be crucial for government environment target in 11th Five Year Plan.
- Contribution to global climate change collaboration. Asia-Pacific Partnership on Clean Development and Climate, China-EU Partnership on Climate Change have component of clean coal technology collaboration.

Clean coal technology should be emphasized to mitigate emission from coal combustion and various national laws, regulation, and standards for energy industry should be prepared to reach the target of clean energy system. Technology is the key issue for clean energy and lower energy demand future. Technology R&D must be emphasized and international collaboration for technology transfer and diffusion should be more encouraged. Clean coal technology development should be further worked by China and other few countries.

Fuel taxes

Use of energy tax has significant impact on energy use. By 2010 with tax rate 50 yuan/tce, energy demand will decrease 6.3%, around 123 million tce, compared with baseline scenario. By 2030 with tax rate 120yuan/tce, energy demand will decrease 16.2%, around 400 million tce. There will be some negative impact on GDP, but the impact is limited. In 2010, loss would be 0.4% and 0.36% in 2030. From long-term view point, use of carbon tax, or combined energy tax and carbon tax, could be a good choice. Use of carbon tax has good effect on carbon reduction and optimization of energy system in China, and has limited impact on GDP. Use of carbon tax could stimulate new technology manufacture sectors such as clean coal technology, new and renewable energy, energy services, and also upgrade technology in China. Therefore promote economy development.

Building sector

Final energy demand in building in the baseline scenario could go to 417 million toe in 2020 and 666 million toe in 2030. The annual growth rate from 2000 to 2030 is 6.2%. Electricity will be the major energy used in building, taking share of 42% in 2020, 48% in 2030. Coal use also increase due to cooking and space heating demand.

For the policy scenario, final energy demand in building could go to 347 million toe in 2020 and 479 million toe in 2030. Electricity will be the major energy used in building, taking share of 38% in 2020, 42% in 2030.

The energy demand in building in 2020 could range from 347 and 417 million toe, 479 to 666 million toe in 2030. This depends on technology progress and polices applied: policy and widely use of new technology could reduce largely energy demand in building in China.

e) Cross-country Comparative Results

The country summaries that are given in this report specifically focus on the timeframe until 2030.

Table 4.29: Economic growth assumptions as applied in the Development, Energy and Climate country studies (average annual GDP growth rates, %)

Country	1971-1990	1990-2004	2004-2015	2015-2030	2004-2030
Brazil	4.7	2.6	4.2	4.1	4.1
China	7.8	10.1	8	6.6	7.2
India	4.6	5.7	6.2	6	6.1

Sources: for data up to 2004 (IEA, 2005a); for future projections (Brazil, 2006; China, 2006; India, 2006)

Table 4.30: Population growth assumptions as applied in the Development, Energy and Climate country studies (average annual population growth rates, %)

Country	1971-1990	1990-2004	2004-2015	2015-2030	2004-2030
Brazil	2.2	1.5	1.2	1.0	1.1
China	1.6	1.0	0.7	0.5	0.6
India	2.2	1.7	1.4	0.9	1.1

Sources: Brazil, 2006; China, 2006; India, 2006.

Table 4.31: Resultant population projections (Millions)

Country	2000	2010	2020	2030
Brazil	171	198	221	241
China	1267	1380	1460	1530
India	997	1159	1290	1393

Sources: Brazil, 2006; China, 2006; India, 2006.

General scenario indicators: Intensities and elasticities

The trend in total primary energy supply (TPES) intensity of the GDP indexed from 1970 to 2030. As it can be seen the energy/GDP intensity is decreasing in the whole period for China, India, and Brazil. Some of the countries such as China and India are expected to have a very large decrease in energy/GDP intensity from 1970 to 2030 of as more than 80% in the case of China, and about 70% in the case of India.

The trend in CO_2 intensity of energy is very different from the energy/GDP intensity. An increase of almost 150% is expected for India and about 100% for Brazil from 1970 to 2030, and in China the expected increase is about 50%. The increases are predominantly a consequence of the increasing role of commercial fossil energy in the total primary energy supply of these countries. For one country namely China, the energy/GDP intensity decrease in the whole period from 1970 to 2030 is large enough to offset the increase in CO_2/energy intensity, so the CO_2/GDP intensity is therefore decreasing. Differently Brazil and India first experience an increasing CO2/GDP intensity, but expect a decrease over time in the scenario period from 2000 to 2030.

All together it can be concluded that in the period from 1970 to 2030, where a very large GDP growth is expected in most of the countries, a large decrease in energy/GDP intensity is expected. However, the CO_2/GDP intensity will tend to be kept constant or will only decrease after some period. In relation to a GHG emissions reduction perspective a specific focus on climate change policy issues is therefore needed if GHG emissions are to be managed, since

this goal is not automatically fulfilled by baseline energy policies as they are projected in the national scenarios. The relationship between the trend in GDP, energy, and CO_2 can also be illustrated by the corresponding elasticities, which are shown in the next tables.

Table 4.32: Energy (TPES) elasticity of GDP

Country	1971-1980	1981-1990	1991-2000	2001-2010	2011-2020	2021-2030
China	0.89	0.34	0.25	0.33	0.36	0.36
India	1.01	0.63	0.61	0.34	0.32	0.31
	1.33	2.90	1.67	0.35	0.66	0.21

Source: IEA, 2000a; IEA, 2000b; China, 2006; India, 2006.

Table 4.33: CO2 elasticity of Energy (TPES)

Country	1971-1980	1981-1990	1991-2000	2001-2010	2011-2020	2021-2030
China	1.44	1.31	1.00	1.43	1.12	0.85
India	1.68	1.80	2.04	2.02	1.95	1.17

Source: IEA, 2000a; IEA, 2000b; China, 2006; India, 2006.

Table 4.34: CO2 elasticity of GDP

Country	1971-1980	1981-1990	1991-2000	2001-2010	2011-2020	2021-2030
China	1.28	0.44	0.25	0.47	0.40	0.31
India	1.69	1.13	1.24	0.69	0.62	0.37

Source: IEA, 2000a; IEA, 2000b; China, 2006; India, 2006.

CO_2 and SO_2 emission projections

During 2005-2030, India emissions are projected to grow with 3.6% per year, 2.8% per year in China, 2.7% per year in Brazil. Coal consumption in China and India is the predominant driver of this emission growth, although the CO_2 intensity of coal use improves considerably in these countries due to efficiency improvements from 2005-2030.

Coal consumption for electricity generation is the major source of CO_2 and SO_2 emissions in China and India, coal also is expected to play a major role in the future. However, domestic pressures in the countries have implied increasing efforts over time to introduce various local air pollution control measures such as flue gas desulphurization (FGD), fluidized bed combustion (FBC) and integrated gasification combined cycle (IGCC) that can curb SO_2 and suspended particulate matter (SPM). CO_2 emissions, however, continue to rise but the growth tends to slow down over time. Road transport emissions are a major source of local air pollution and cleaner road transport technologies, although based on fossil-fuels, contribute to reduce SO_2, SPM, NO_X and CO emissions. CO_2 emissions again continue to rise since fossil-fuel based road transport continues to have a major share in all these countries. This also promotes local-GHG emission decoupling.

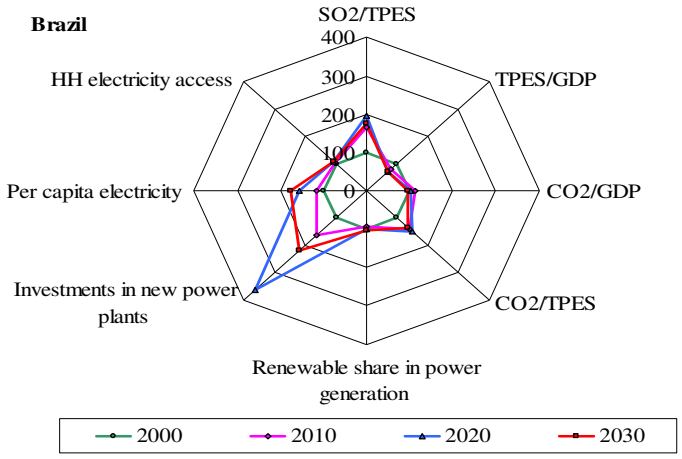
The air pollution control policies in China and India initiate a decoupling of global and local emissions from around 2010-2020. The Brazilian case is slightly different mainly due to a different energy mix. Hydro power, which is CO_2 and SO_2 emission free, dominates Brazil's

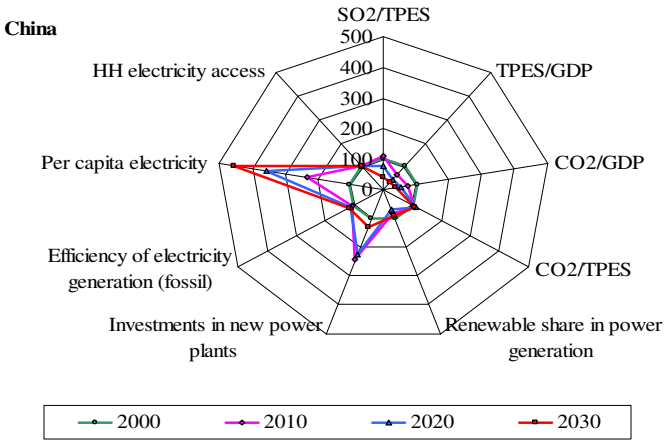
electricity production, so local and global emissions come from other sources as for example transportation. The high growth in SO_2 emissions from Brazil that are projected for the future is derived from a large increase in biofuel production, that has SO_2 emissions but is CO_2 neutral, and from coal consumption. Overall SO_2 emissions are projected to rise by 3.3 times over 2000-2030 while CO_2 emissions will rise by 2.5 times.

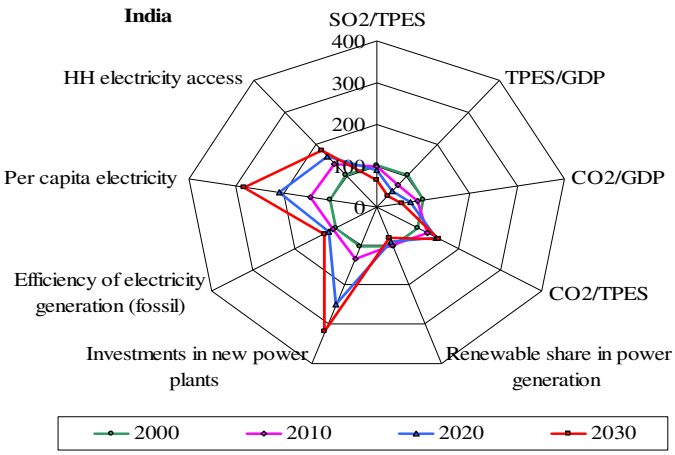
Sustainable Development Indicators

SD indicators have been applied to the country study results for Brazil, China and India in order to reflect energy efficiency, supply structure, per capita electricity consumptions, and local and global pollution.

4.2: Figure 2: Sustainable development indicator projections for Brazil, China and India (Indexed for year 2000 = 100, for all indicators)







The Brazilian baseline development trends from 2000 to 2030 that are shown are characterized by a large increase in power sector investments and increasing CO_2 and SO_2 intensity of energy consumption. The share of renewable energy increases slightly and there is a relatively small increase in per capita electricity consumption.

The baseline scenario for China for 2000 to 2030 implies an increasing share of renewable energy and a very large increase in per capita electricity, while the CO_2 and SO_2 emission intensities of energy are kept very close to the 2000 levels. There is also a high growth in power plant investments, and the efficiency of power production increases with about 20%.

In India, there is a growth in the CO_2 emission intensity of energy consumption, while the SO_2 intensity is decreasing from the 2000 level. The energy intensity of GDP is also decreasing in the period. The per capita electricity consumption is increasing about three times, and this is also the caste for power sector investments.

All together, the common conclusions that can be drawn are that there generally is a tendency for CO_2 and SO_2 emission intensities of energy and GDP to develop slowly in the countries in their 2000 to 2030 baseline cases. Investments in the power sector are expected to grow fast in the period, and in particularly in China and India this implies a large growth in per capita electricity consumption. It is here worth recognizing that none of the countries expect very large increases in the renewable share of electricity production in the period, however the absolute levels of renewable energy is projected to increase considerably in all the countries.

Conclusions on development, energy and climate synergies and tradeoffs

The 1970 to 2030 time frame studies for Brazil, China and India show that there is a tendency to decouple economic growth and energy consumption over time. Energy consumption, however seems to have a stable or increasing CO_2 intensity, so all together CO_2 emissions tend to grow with about the same or a lower rate than GDP in most countries.

The power systems of all the countries except Brazil are dominated by coal and this supply structure will continue to imply in the future high growth rates in CO_2 emissions. The application of SD indicators to the Brazilian, Chinese and Indian studies point to the conclusion that the countries all expect significant improvements in energy sector investment and per capita electricity consumption.

India[21]

The base-case scenario for India has been articulated by capturing the average GDP growth rate in the 10th Plan period (2002-07) and the future expectations. Though the achieved GDP growth rate of 7.2% during the period was below the target of 8%, it has been the highest growth rate achieved in any previous plan periods. The services sector has been the major driver of economic activity while the agricultural growth has become irrelevant to the economic growth – at 2.5% trend growth rate and a share of 16% in GDP it added 0.4 percentage points to the GDP. This factor has been well recognized and considered to be a major challenge by the policy makers while formulating 11th plan document. The 11th plan envisions a grandiose scenario with policies to achieve inclusive growth on a sustainable growth trajectory with a growth rate of approximately 10 per cent by the end of the Plan period.

Table 4.35: Macroeconomic Indicators for the Base Case Scenario

Growth rate of GDP (%) and share of	**8 per cent**
Agriculture	5.94 %
Industry	37.27 %
Commercial	50.42 %
Transport	6.37 %

Energy Supply and Prices

With a proven reserve of 92 Billion Tons, an equivalent of 10% of global coal reserves, coal has been the linchpin of India's energy sector contributing almost 50% in the primary commercial energy supply and 70% in the power generation. Coal production in India has risen from 73 Million Ton (MT) in 1972 to about 407 MT in 2006. According to Ministry of Coal, the demand for coal used by power plants is expected to touch about 750 MT by 2030 at an average growth rate of 2.4% per year with an associated power generation of 161 GW. The dominance of coal in India's energy mix is likely to continue till 2031-32 as per various modeling studies.

Coal Pricing

Since coal pricing is deregulated, Coal companies are fixing the price of coal with the approval of their Board of Directors. The total price of imported coal at Indian port varies from US $ 62.7 to US $ 87.2 per ton (Assumption of 1 US 6/10 $ = 40 Indian Rupees INR).
Compared to this, the ex-pithead price of Indian coal varies from US $ 13.7 per ton to US $ 54.5 per ton. It can be seen that in all cases Indian coal is a lot cheaper on per ton basis.

Gas Pricing

At present, there are broadly two pricing regimes for gas in the country, i.e. gas priced under Administered Price Mechanism (APM) and non-APM or free market gas as shown in the next table.
Table 4.36: Existing Gas pricing mechanism in India

[21] *From CASES D.7.1 for India*

SL.No	Network / Region	APM consumers		Non-APM Consumers
		(Power & Fertilizer sectors)	Price applicable to small consumers (allocation upto 50000 SCMD & City Gas Distribution companies)	Price applicable to Non-APM Consumers (incl. internal consumption by GAIL)
1	Mumbai, South Gujarat & along HVJ	US$ 80 / MSCM (w.e.f 01.07.2005)	US$ 96/MSCM (wef 06.06.2006)	US$ 4.75/MMBTU (w.e.f 01.04.2006)
2	KG Basin & Cauvery Basin	US$ 80 / MSCM (w.e.f 01.07.2005)	US$ 96/MSCM (w.e.f 06.06.2006)	US$ 3.50/MMBTU (w.e.f 01.08.2006)
3	NE region	US$ 48/ MSCM (w.e.f 01.07.2005)	US$ 57.6/MSCM (w.e.f 06.06.2006)	US$ 80 / MSCM (w.e.f 01.07.2005)

Source: Sixteenth Report Standing Committee on Petroleum & Natural Gas (2007-08)

The price of APM gas is set by the Government while the non-APM or free market gas is governed by the Sale and Purchase Agreement (SPA) between the LNG seller and the buyer for imported LNG and in terms of the Production Sharing Contracts (PSC) provisions for JV gas.

Energy Management in Energy Intensive Industries

Indian industrial sector accounts for half of the commercial energy used in the country. The six key industries, namely, aluminum, cement, fertilizers, pulp & paper, petrochemicals and steel consumes about 65 per cent of the total energy use in India. Compared to the developed countries Indian industries are highly energy intensive. Although the industries are going through transformations, there still remains huge scope for energy efficiency improvement.

Within the sector, energy efficiency improvements in the cement industry is mainly because of shifting away from inefficient wet kilns toward more efficient semi-dry and dry kilns, as well as adoption of less energy-intensive equipment and practices. However, the new generation plants installed in India have excellent energy efficiency norms comparable with the best and most energy efficient plants. In the Aluminum sector the technologies adopted both in India and abroad are same but they differ in energy efficiency as some of the units are still using self-baking anodes instead of multiple prebaked anodes. The iron and steel industry is the largest consumer of energy in the industrial sector consuming about 10 per cent of electricity and 27 per cent of coal consumed by the industry as a whole.

a) Base Case Scenario Results

The base case scenario results for India shows that the total primary energy supply has increased by almost 5.65 times during the period 2005 and 2050, mainly driven by increasing share of coal, oil, nuclear and biomass.

Nuclear and gas are making an impact in the energy supply not just because they are clean but also by the impending nuclear deal and recent gas discoveries respectively. As regards to coal,

it is going to be the mainstay in India's primary energy supply contribution almost 30 per cent of the primary energy supply.
Coming to the power generation, the results show that the total primary energy supply to power sector has increased by 7.5 times with 1835 Mtoe being supplied in the terminal year 2050. The installed capacity increased from 137 GW in year 2005 to 1448 GW in the terminal year 2050. Similarly, the generation output increased from 872 TWh in 2005 to 10076 TWh in year 2050.
Coal continues to be dominating in the final energy mix with a share of 63% in the installed capacity and 76% in the generation output. In the reference scenario, the GHG emission in terms of CO2 shows an increasing trend: from 1291 MT of CO2 in 2005 to 6636 MT in 2050.

b) Treatment of external costs

External costs are implemented in the model by multiplying the amount of electric power generated (i.e., kWh) from each power plant during each time period each region with corresponding external cost. This ensures that the matching external costs are directly charged to every unit of output from each power plant. With the aim of the model to minimize the total energy system cost, this extra cost thus invokes different response options in the energy system. The model thus solves various heuristics such as whether to pay or not an extra charge on power production from a technology; whether to install or not a system with NOx removal, SOx removal, or CO2-capture & sequestration; whether to reduce or not electricity consumption in different demand sectors and to substitute the electricity by other fuels etc.

Results
The power generation in the Baseline scenario is primarily coal driven with different types of coal power plants contributing by 61% to the total power generation at the end of 2050. Super critical technology slowly makes its way from year 2010 onwards and finally captures a share of 22% in the terminal year 2050. From the year 2030, the conventional coal plants are replaced by advanced coal like integrated coal gasification combined cycle (IGCC) taking a share of 12.4% in the year 2050. The other competitive system in 2050 is the CCGT, which contributes more than 24% of total power production. Approximately 15% of the electric power is supplied by the nuclear and renewable energy sources in the year 2050.

After the internalization of external costs into baseline cost, the structure of the power generation mix has altered considerably. In this scenario, the overall power generation gets reduced by 13% (in absolute terms 780 TWh) in the year 2050 as compared to the baseline scenario. In the externality scenario, although coal remains the major contributor to total power production, however, its share is reduced from 61 per cent in baseline scenario to 44 per cent in externality scenario in the year 2050.
Some of the advanced coal technologies like IGCC plus CCS also make its way along with only IGCC power plant technologies. Combined together these two contributes 15 per cent of generation in the externality scenario as compared to nil in the baseline scenario. Share of renewable energies including hydro and biomass also gets increased in the externality scenario.

Environmental Emissions

With the introduction of external cost into the total production cost of electricity, emission gets reduced quite considerably. Within the period, the emission reduction of CO2, SO2, and NOx happens because of the premature retirement of coal plants without SO2/NOx control. Although the dominance of technologies based on fossil fuels continues, however, different developments can be observed in CO2 emissions and local pollutants. With the penetration of CO2 removal technologies, total CO2 emissions are reduced by 12% in the externality scenario, 5/5 as compared to the Baseline. Substantial reduction in SO2 and NOx emissions relative to the Baseline scenario is also observed during the period. This suggests that ancillary benefits are also derived from policies that directly address other environmental issues than CO2 mitigation. Emissions of local air pollutants (SO2/ NOx) are substantial with replacement of conventional coal plants with the desulphurization systems together with advanced coal and IGCC plus CCS.

Turkey[22]

Turkey's strategic location makes it a natural "energy bridge" between the major oil producing areas in the Middle East and Caspian Sea regions on the one hand and consumer markets in Europe on the other.
Turkey's Bosporus Straits are a major shipping "choke point" between the Black and Aegean Seas. Finally, Turkey is a rapidly growing energy consumer. Turkey has experienced extremely sharp economic growth in recent years, which was largely achieved through a rapidly increasing population. Because of its demographic and economic growth, Turkey constitutes a major energy market.
Turkey's demand for energy, particularly for electricity, is also increasing rapidly. Since 1990, energy consumption has increased at an average annual rate of 3.7%.

With respect to global environmental issues, Turkey's carbon dioxide emissions have been growing along with its energy consumption. Emissions in 2004 reached 223 million metric tons.
Both, Turkey's economy and population are growing rapidly. From 1990–2004, population has increased at an average annual rate of 1.7% per year. In the same period, the gross domestic product has increased at an average rate of 3.6% per year. GDP in 2004 was US$362 billion and per capita GDP was about 4,172 US$/capita.
With GDP projected to grow at about 6% per year over the next 15 years, both the energy sector and the pollution associated with it are expected to increase substantially. This is expected to occur even when assuming stricter controls on lignite and hard coal-fired power generation. All energy consuming sectors, that is, power, industrial, residential, and transportation, will contribute to this increased emissions burden.

Because of social and economic development of the country, the demand for energy and particularly for electricity is growing rapidly. The main indigenous energy resources are hydro, mainly in the eastern part of the country, and lignite. Turkey has no big oil and gas reserves.
Almost all oil and natural gas is imported, as is high quality coal. Turkey also has a large potential for renewable energies. In Turkey, electricity is produced by thermal power plants (TPPs), consuming coal, lignite, natural gas, fuel oil and geothermal energy, and hydro power plants (HPPs). There is no nuclear power in Turkey as yet.

In the study, a Reference Case was developed to compare alternative scenarios. Greenhouse Gas Reduction scenarios analyze options in form of technologies and policies that are primarily oriented toward the reduction of CO2, CH4, and N2O. This analyze has a projection up to 2020. A projection up to 2030 is not available.

a) Energy trends

The Total Primary Energy Supply (TPES) and the Total Final Energy Consumption (TFC) for the period 1990-2004 have grown at an average annual rate of 3.7%. Both have grown more rapidly than either population or GDP (Population 1.7% and GDP3.6%). This reflects the changing

[22] *The Report :"Energy Scenarios in Turkey" has been prepared by TUBITAK Marmara Research Center Energy Institute.*

structure of the Turkish economy, including the energy sector, and increasing consumer energy use. The overall energy intensity of Turkey (based on TPES) increased from 0.377 toe/US$1,000 (2000 prices) of GDP in 1990 to 0.382 toe/US$1,000 (2000 prices) of GDP in 2004. The energy intensity is about equal to the world average of 0.32 toe/US$1,000 but is higher than the average for OECD countries of 0.20 toe/US$1,000. When the energy intensity is measured against GDP based on purchasing power parity (PPP), Turkey's is 0.12, the world average is 0.21, and the OECD average is 0.19 toe/US$1000 in 2003.
The distribution of final energy consumption (TFC) by sector in 1990 and 2004, shows that while the shares have shifted only by small amounts, residential and industrial consumption have shown significant changes over the period. The data shows significant increases in the share of electricity and natural gas with corresponding decreases in the shares of coal and renewable (mostly wood and wastes).

Supply Trends
Turkey is an energy-importing country; more than half of its energy requirements are met by imports (72% in 2004).

Coal
Lignite is one of the most important domestic energy resources of the country and is found in almost all regions. Total proven reserves are 7.3 billion tons of which 3.4 billion tons are in the Afsin-Elbistan region, which is in the southeastern part of the country. The main lignite consuming sectors are the residential, power, and industrial sectors. Lignite with the lowest calorific value is consumed in power plants. Higher quality lignite is used in the residential and industrial sectors.
There is a total of 1.3 billion tons of hard coal reserves in the Black Sea Region and 0.6 billion tons of total reserves are proven. Much of the domestic hard coal is first converted to coke and then used in the iron and steel sector. Hard coal is also used in the residential sector for heating purposes and in power plants. Hard coal production reached 1.9 million tons in 2004. In the same year, 16.4 million tons of hard coal was imported. In addition, 2.3 million tons of coke and petroleum coke were imported. More than 90% of the final hard coal consumption was consumed in the industrial sector. The iron and steel industry consumed about 26% of total hard coal imports, followed by the cement industry, which consumed 11%. The remaining hard coal was imported for household consumption in large towns to alleviate air pollution. Asphaltite (sub-bituminous coal) reserves of 79 million tons are found in the southwest Anatolia Region. Asphaltite, which is consumed mainly in the residential sectors in east and southeast Anatolia, is a valuable energy resource with a high calorific value and its production reached 722,000 tons in 2004.

Oil
It is estimated that there are 940 million tons of oil reserves in Turkey in already known areas. About 162 million tons of this reserve are economically recoverable. As of the end of 2004, a cumulative total of 119.6 million tons of this had been extracted. Crude oil production in 2004 was 2.3 million tons. With current production levels and no additional reserve discoveries, it is estimated that production capacity will be available for another 19 years.
In 2004, 23.8 million tons of crude oil were imported. When added to domestic oil production, a total of 25.9 million tons of crude oil was processed in the local refineries. Approximately 26 million tons of petroleum products were produced.

Natural Gas

Total natural gas reserves (in place) of Turkey are 20.1 billion m^3 (bcm) with recoverable reserves of 14.1 bcm. As of the end of 2004, cumulative production of natural gas was 6.2 bcm, leaving remaining recoverable reserves of 8 bcm. In 2004, domestic natural gas production was 0.7 bcm. The use of natural gas has grown rapidly, since gas imports started from the former Soviet Union in 1987. In 2004, 14.1 bcm were imported from Russia and 3.5 bcm from Iran. In order to diversify the gas supply, an LNG storage terminal was constructed in Marmara Ereglisi in 1994. In 2004 LNG imports were 3.2 bcm from Algeria and 1.0 bcm from Nigeria.

Renewable Energy

The economically recoverable hydropower potential of Turkey is about 127 TWh. Approximately 31% has already been developed. Biomass resources – wood, animal, and plant wastes – have traditionally been used as fuel for cooking and heating in rural areas of Turkey. The share of biomass in total primary energy production was 23% in 2004. Most of this was in the form of wood (18%). Turkey has considerable geothermal energy resources. The geothermal potential for electricity generation is approximately 98 MWe. Thermal capacity for agricultural greenhouse heating and district heating is 3,348 MWth. Many residential buildings, several tourist establishments, and many greenhouses in different locations in Turkey are heated by geothermal means.

According to studies on wind energy in Turkey, the average annual wind speed is 2.5 m/sec and the annual wind power density is 2.4 Watt/m^2. Marmara and the Aegean and southeast Anatolian regions were found to be the most favourable locations for wind potential.

Turkey is geographically well located with respect to solar energy potential. According to evaluations of meteorological data, the average annual solar irradiance intensity is 308 Cal/cm2 (3.6 kWh/m2) per day and the average annual sunshine duration is 2640 hours in Turkey.

Electricity

Electricity demand in Turkey has been growing rapidly. The average annual growth rate has been 7.2% in the period 1990–2004. In 2004, the peak demand was 23,485 MW. The total electricity generation for the year was 151 TWh. Total installed capacity at the end of 2004 was 36,824 MW. This total capacity is composed of approximately 24,145 MW thermal and 12,679 MW hydro, geothermal, and wind. Natural gas, hydro, and lignite, in that order, were the largest sources of electricity. In recent years there has been a considerable increase in the utilization of natural gas for electric power generation. This is the result of the implementation of the government policy to expand natural gas use in all sectors, including electric power.

b) Energy Sector Emissions and Environment

Turkey's total carbon dioxide emissions amounted to 193 million tonnes (Mt) in 2002. Emissions grew by 4% compared to 2001 levels and by just over 50% compared to 1990 levels.

Oil has historically been the most important source of emissions, followed by coal and gas. Oil represented 42% of total emissions in 2002, while coal represented 40% and gas 18%. The contribution of each fuel has however changed significantly owing to the increasingly important role of gas in the country's fuel mix starting from the mid-1980s.

In 2002, public electricity and heat production were the largest contributors of CO2 emissions, accounting for 28% of the country's total. The industry sector was the second largest, representing 26% of total emissions, followed by transport, which represented 19% and direct fossil fuel use in the residential sector with 10%. Other sectors, including other energy industries, account for 17% of total emissions. Since 1990, emissions from public electricity and

heat production have grown more rapidly than in other sectors, increasing by 6%. Simultaneously, the shares of emissions from the residential and transport sectors both dropped by 7% and 3% respectively while the share of emissions from the manufacturing industries and construction sector remained stable.

c) Energy Sector Scenarios

Reference Case Results:

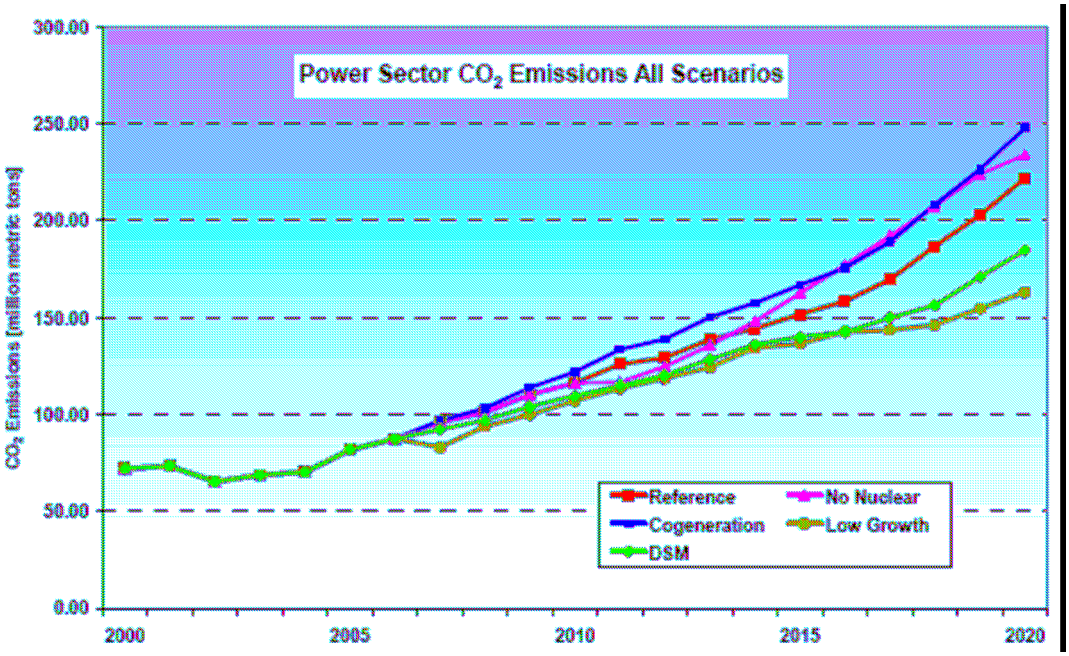
- The future price of coal index does not vary too much, after peaking in 2001 it gradually declines to 101. The future price of gas also declines continuously after peaking in 2005 (139). The oil price index has its peak in 2006 (150) and continually drops until 2015 (119) and after that steadily increases to 125 by 2020.
- A total capacity of 4500-5000 MW nuclear units would be added to the power system until the year 2015.
- Limitations on natural gas and import coal used to produce electricity would affect the system adversely; however, they would make import dependency increase.
- Final energy demand increases from 68 Mtoe to 177 Mtoe in the study period. Industry has the highest share, then residential and transportation. Oil products, electricity, and coal are the most important players. Demand of electricity and hard coal more than triple while that for oil products more than double.
- As for the final demand, primary energy supplies also about triple and reach 223 Mtoe (from 84 Mtoe in 2003) at the end of the study period.
- Overall energy imports are estimated to increase from 61 Mtoe to 157 Mtoe between 2003 and 2020.
- The total economic cost of the Reference Case is $350.4 billion of which $167.9 billion is going to meet import requirements.

GHG Scenarios Results:

Based on results from the GHG scenarios, the following conclusions can be drawn in relation to formulating a national policy on climate change.

As the next figure shows, Low Growth and DSM (Demand-Side Management Scenario) are clearly essential ingredients of future climate change policies. The DSM scenario is a “win-win” option compared to the Reference Case. Under the Low Growth and DSM scenarios, the economic cost of energy supply and the cost of energy imports will be lower, as well as the emissions of CO2/GHG. In addition, there are substantial ancillary benefits involved in terms of PM, SO2, NOX.

4.3: CO2 Projections to 2020 All Scenarios



However, it must be acknowledged that:

- The Low Growth Scenario results in a 10.5% decline in final energy demand and a 11.7 % decrease in total supply. Electricity and hard coal are the main contributors to these reductions. System costs and emissions are also estimated to drop in parallel with this. However, although the Low Growth Scenario has the greatest environmental impact in terms of projected emission reduction, it should be considered that the scenario, in essence, assumes a smaller future economy.
- The DSM scenario with a more conservative and efficient energy program would help both lowering demand and costs as well as decrease emissions considerably, making the scenario a "win-win" situation The reduction in CO2/GHG emissions from DSM is about 7.0% over the period 2003–2020 and the potential may be even higher as this analysis only concentrated on the residential and industrial sector but excluded the transportation sector for lack of country-specific information.
- The No Nuclear Scenario shows that, with the nuclear units, emissions would drop by 1%.
- The Cogeneration Scenario is also not a good option in decreasing GHGs. Although the cost for imports decreases substantially, the new cogeneration units are not seen to offset the total economic cost while at the same time would increase emissions substantially. However, the scenario has benefits in decreasing PM, SO2 and NOx emissions.

As a result, DSM is the best scenario in order to decrease CO2/GHG emissions. Just by implementing conservation in industrial and residential sectors, both CO2/GHG emissions could be decreased by 7% and cost effectiveness could be $-113/ton. Low Growth Scenario can't be accepted as effective because it downsizes the economy, although it decreases the emissions by 8.8.