INTEGRATING TURKEY'S RENEWABLE ENERGY WITH GLOBAL CARBON MARKET

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INTEGRATING TURKEY'S RENEWABLE ENERGY WITH GLOBAL CARBON MARKET

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Integrating Turkey's Renewable Energy with

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Thesis Abstract

Hasan Ali Göncü, “Integrating Turkey’s Renewable Energy with

Gobal Carbon Market”

Climate change is recognized as one of the major problems of the globe and unless appropriate measures are taken it is likely to result in irreparable damages on the planet in the near future. Electricity energy is at the heart of this problem and so must be an important player in the solution.

Turkey’s electricity energy market has recently entered into transition period and if properly managed, Turkey’s highly problematic electricity energy market may prosper. Turkey’s electricity energy sector is currently characterized by low supply security, high carbon intensivity and high costs. After examining global and Turkey’s electricity energy outlook in details, this sudy offers a solution to transform Turkey’s electricity energy sector into a low-cost, environment-friendly and reliable structure. Wind power is a candidate to play the key role when Turkey’s immense untapped wind power potential is considered.

Increasing global concern for climate change and the EU regulations are expected to force Turkey to recognize the importance of greenhouse gas (GHG) emissions in investment decisions in the near future. With extensive analysis on the regulated carbon markets and voluntary carbon markets, this study may serve as a roadmap for Turkey to take the right action in the global climate change negotiations. In addition, this study may serve as a guideline for wind power project developers in exploring the opportunities in the global carbon market.

Tez Özeti

Hasan Ali Göncü, "Türkiye'nin Yenilenebilir Enerjisini

Küresel Karbon Piyasası ile Bütünleştirme"

İklim değişikliği dünyanın başlıca sorunlarından biri olarak kabul edilmekte olup uygun önlemler alınmaz ise yakın gelecekte gezegende tamir edilemez hasarlara neden olacağa benzemektedir. Elektrik enerjisi bu sorunun kalbinde yer almaktadır ve bu yüzden çözümde önemli bir rol oynamalıdır.

Türkiye'nin elektrik enerjisi piyasası son zamanlarda bir geçiş dönemine girmiş olup eğer uygun şekilde yönetilirse, Türkiye'nin çok sorunlu elektrik enerjisi piyasası iyileşebilir. Türkiye'nin mevcut elektrik enerjisi sektörü düşük arz güvenliği, yüksek karbon yoğunluğu ve yüksek maliyeti ile karakterize edilmektedir. Bu çalışma, küresel ve Türkiye elektrik enerjisi görünümünü ayrıntılı olarak inceledikten sonra, Türkiye'nin elektrik enerjisi sektörünü düşük maliyetli, çevre dostu ve güvenilir bir yapıya dönüştürmek için bir çözüm önermektedir.

İklim değişikliği hakkında artan küresel kaygılar ve Avrupa Birliği düzenlemelerinin yakın gelecekte, Türkiye'yi, sera gazı emisyonlarının yatırım kararları üzerindeki etkisini tanımaya zorlayacağı beklenmektedir. Bu çalışma, zorunlu karbon piyasaları ile gönüllü karbon piyasaları üzerindeki yoğun analizleri ile, küresel iklim değişikliği müzakerelerinde Türkiye'nin doğru harekete geçmesi için bir yol haritası olarak hizmet edebilir. Ayrıca, bu çalışma rüzgar enerjisi proje geliştiricileri için, küresel karbon piyasalarındaki fırsatları keşfetmede, bir kılavuz olarak hizmet edebilir.

ACKNOWLEDGEMENTS

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CONTENTS

TABLES

FIGURES

CHAPTER I

INTRODUCTION

The EU regulations and increasing global concern for climate change are expected to force Turkey to recognize the importance of greenhouse gas (GHG) emissions in investment decisions in the near future. Turkey has the highest percentage increase, 119.1%, in GHG emissions (excluding LULUCF) among Annex I Parties from 1990 to 2007. 77.4% of GHG emissions and approximately 93% of total CO_2 emissions come from the energy sector in 2007. Power generation emitted 35% of total CO_2 emissions in 2007 whereas its share was 24% in 1990. The share of power sector in total CO_2 emissions has been increasing also since 1990. Therefore, power generation is the most important subsector in terms of CO_2 emissions. To combat climate change, renewable energy may become a promising alternative.

Among renewable energy sources, the penetration of wind energy in the EU and in the world is increasing more than the other renewable energy sources. Although Turkey has the largest wind energy capacity among the European OECD countries, her utilization of wind energy is far below the EU countries.

The European Heads of State agreed on 9 March 2007 to increase the share of renewable energy to 20% by 2020. By 2020 European Commission expects 34% of electricity to come from renewables and wind power to provide 12% of EU electricity, making wind energy the largest contributor to achieve this target (EWEA, 2009). The EU energy mix is on the way of a transition from conventional energy sources like coal, nuclear and large hydro, to more environmentally friendly sources like renewables and natural gas. 2009 has been the second year in which renewable energies formed more than half of the new installations and wind power installed was more than any other energy generating technology in the EU, comprising 39% of newly installations. In 2009, 74,767 MW of installed wind power capacity forms 9.1% of EU's installed power capacity and meets 4.8% of EU's electricity demand by producing 163 TWh electricity.

In the EU, net capacities of fuel oil, coal and nuclear have decreased in nominal terms during 2000-2009, meaning that the removed capacities of these power sources are more than newly installed capacities. Europe is escaping from carbon intensive sources like coal, fuel oil. EU is also cautious about nuclear power due to safety and cost concerns. EU almost stopped adding nuclear capacity in the 1980s, and some Member States plan huge decommissioning programmes over the next ten years. EWEA (2009) expects EU installed wind power capacity to be 80,000 MW in 2010, 180,000 MW in 2020 and 300,000 MW in 2030 in the reference scenario and wind power's share of EU electricity consumption to reach 5% in 2010, 11.7% in 2020 and 21.2% in 2030.

Among the European OECD countries, Turkey has the highest technical potential with 83,000 MW, nearly doubling the existing installed capacity and with 166 TWh/year that almost meets the present electricity consumption of Turkey (Erdoğdu, 2009). According to PricewaterhouseCoopers (2009), Turkey's wind power economic potential (wind speed more than 7.5 m/s) is 88,000 MW, but given the grid infrastructure constraints, the highest feasible wind-power generation capacity is estimated at 20,000 MW, which has also been set as the target capacity to be attained by 2023 in the new Electricity Energy Market and Supply Security Strategy Paper (2009). However, the share of wind power in total electricity generation has been 0.3%, 0.5% and 1.0% in 2007, 2008 and 2009 respectively in

Turkey. The installed wind power capacity is 363.7 MW in 2008 and 801 MW in 2009.

European Union gives importance to developments in Turkey about renewable energy and climate change. Turkey Progress Reports prepared by Commission of the European Communities between 2005-2009 involve important issues, guidelines and criticisms about renewable energy and climate change. In 2005 - 2009 Progress Reports Turkey is criticised for not establishing a greenhouse gas emission allowance trade scheme, not transposing the Emissions Trading Directive and related decisions. A national environmental approximation strategy (UCES) was adopted by the High Planning Council in 2006, that includes a plan for the transposition, implementation and enforcement of the EU environmental acquis. According to the timetable for legislative approximation about air sector to transpose Directive of Emissions Trading 2003/87/EC, infrastructural investment and technical study are needed in order to strengthen technical capacity. Enforcement date will be designated by the legislation prepared according to the result of these technical studies. Therefore the European Union Greenhouse Gas Emission Trading System (The EU ETS), global carbon markets become crucial issues for Turkey since they may have huge impact on economic development of Turkey and electricity generation.

Renewable energies and carbon markets are strongly related. The share of renewable energy projects in the global voluntary carbon market increased from 27% (in 2007) to 51% in 2008. Turkey is ineligible to supply CDM or JI credits at least until the end of the first commitment period 2012, because of its position in the Kyoto Protocol as an Annex I but a non-Annex B country. So, voluntary market is the only available market for Turkey at least until the end of 2012. When Turkey's incredible renewable energy potential is considered, Turkey has the opportunity to actively participate in voluntary carbon markets and use GHG emission reductions as a commercial commodity by transforming the emission reduction investment costs into revenues for the enterprises.

Gold Standard is the most credible standard and Gold Standard Verified Emission Reductions (GS VERs) have price premiums over other standard utilized VERs. In the Gold Standard, wind power projects dominate in both the amount of VER credits (59.3%) and number of projects (40.7%). This study estimates how much revenue would be generated from the sale of GS VERs, in case Turkey's 20,000 MW wind power target is achieved, and how many tonnes of CO_2 would be avoided in the light of Gold Standard regulations. This can be compared to the potential revenue if Turkey becomes eligible to host Clean Development Mechanism projects and so issue CERs. Although these revenues are only related to the wind power projects and the real revenues from the global carbon market may be much more, this still gives an idea about what Turkey would lose if she enters into the EU ETS.

The aim of Chapter II is to show the wind power's increasing positon in the global energy market. Chapter II will analyze the global primary energy outlook to show the unsustainability of the current picture for many developed countries and the developing countries. Then the general outlook of renewable energy and electricity with recent trends in these energy sources will be analyzed showing the critical importance of wind power in this unsustainable outlook. The future prospects for the development of wind power is studied with a focus on the European Union and the economic and environmental issues related to wind power.

Chapter III will provide an insight regarding climate change outlook of Turkey, the impact of electricity generation on climate change, electricity outlook of Turkey, and her renewable electricity potentials and current utilizations. The aim of Chapter III is to provide a comprehensive review to detect problems of Turkey in energy balances, electricity supply security issues, climate change issues and to asssess whether Turkey has enough renewable energy potential and the necessary incentives and legislations to utilize these potentials. The focusing will be on Turkish electricity generation capacity projections, targets determined in the Electricity Energy Market and Supply Security Strategy Paper and recent trends.

Turkey is likely to confront electricity energy deficiency around 2014-2015. To prevent such a deficiency Turkey should start to install new power plants as soon as possible considering the long construction periods of power plants. Turkey should select the best electricity generation technology for the society by taking into account the externalities. Therefore, Turkey has a problem to rank and select the best electricity generation technology among natural gas combined cycle power plants, coal power combined heat plants, wind onshore power plants, small hydro power plants, nuclear power plants and solar PV power plants by taking into account cost efficiency, cost volatility risk, supply security, climate change & other pollution and supply-demand mismatch. Chapter IV will use grey relational analysis procedure to analyze this problem and propose solutions. Sensitivity analysis has been carried out for different scenarios and different priorities as well. According to the outcomes of GRA, it has been concluded that Turkey should focus on installing small hydro power plants, nuclear power plants and wind onshore power plants. Since hydro power and wind power are related to the natural resources of a country, Turkey's potential for these sources has been investigated and concluded that Turkey has an immense untapped potential for these renewable energy resources.

Since renewable energy has a strong relationship with climate change and carbon markets, Chapter V, VI and VII focus on regulated carbon market, voluntary carbon market and Gold Standard respectively to show the project developers the opportunity to actively participate in carbon markets and use GHG emission reductions as a commercial commodity by transforming the emission reduction investment costs into revenues.

Chapter V helps to understand the basis of the regulated carbon market in the world by explaining the Kyoto Protocol, the The European Union Greenhouse Gas Emission Trading System (EU ETS), the regulations about Clean Development Mechanism (CDM), emissions trading, carbon taxes, the European Climate Exchange and synthesis approaches such as revenue-neutral carbon taxes and hybrid schemes.

Chapter VI helps to comprehend a general outlook of the voluntary carbon market and enables to estimate the future of this market by focusing on the size, growth and recent trends in the voluntary carbon market with an analysis of the sources, prices of voluntary carbon offset credits according to their project types, project locations, utilised standards, seller categories as well as buyer-supplier profiles and contract structures.

Chapter VII helps investors to understand the basis of the Gold Standard with an analysis of Gold Standard VER projects in the light of the most recent statistical data, detailed explanations about the project eligibility criterias, project cycles, Gold Standard documentation and fee structure. Chapter VII will show how to calculate emission reductions in the light of Gold Standard regulations and

UNFCCC approved CDM methodologies. As a case study, the combined margin CO_2 emission factor will be calculated with the most recent data available, that may be used by wind power project developers in 2010. Additionally, this chapter will calculate the amount of revenue Turkey's target of 20,000 MW wind power projects would generate by selling the carbon offset credits as GS VERs in the voluntary carbon market or as CERs in the EU ETS, its impact on Turkey's international trade balances, and the quantity of CO_2 that would be avoided in case 20,000 MW wind power capacity installation target is achieved.

Chapter VIII suggests policy recommendations and conclusions.

This study contributes to the literature in the following ways. Firstly, it can help Turkey to rank and select the socially best electricity generation technologies in different scenarios and from different viewpoints. Secondly it can show the attributes a country may consider when ranking and selecting the best alternative electricity generation technologies. Thirdly, this study can help to compare the unit electricity generation costs of different technologies by using the REcalculator with the assumptions of International Energy Agency's (IEA) Renewable Energy Costs and Benefits for Society (RECABS) project (2007) and fuel price and CO_2 price assumptions of World Energy Outlook 2009. Fourthly, the outcomes of this study can provide guidelines for ranking alternative electricity generation technologies and may serve as a baseline in designing market structure and necessary incentives by the government to encourage private sector investment in the socially best technologies. Fifthly, this study shows that the impact of the distinguishing coefficient on the result of Grey Relational Analysis is negligible.

In addition, to our knowledge, this is the first academic study calculating potential revenues from sale of carbon offset credits in the carbon market in case

Turkey's 20,000 MW wind power target is achieved, the quantity of CO_2 that would be avoided in the light of Gold Standard regulations, and impact of 20,000 MW wind power installation on Turkey's international trade balances. This study shows that investors should take into account revenues from carbon offset credits in electricity generation project analysis. This study can help the project developers in renewable electricity generation technologies to estimate how much revenue they can get from the sale of carbon offset credits and also serves as a guideline about how they can participate in the carbon market. This study indicates that installing wind power plants can decrease Turkey's trade deficit significantly. This study may also serve as a roadmap for the government in determining the characteristics of an emissions trading system and carbon emissions exchange.

CHAPTER II

WIND POWER IN THE GLOBAL ENERGY OUTLOOK

The aim of this chapter is to show the wind power’s increasing positon in the global energy market. The first section will analyse the global primary energy outlook to show the unsustainability of the current picture for many developed countries and developing countires. The second section will analyse the general outlook of renewable energy and electricity with recent trends in these energy sources. The third section will mention how the wind power emerged in this unsustainable outlook and future prospects for the development of wind power by focusing on the European Union. This section will also analyse economic and environmental issues related to wind power.

Energy sources can be classified into two main groups: Primary energy sources and secondary energy sources. Figure 1 shows the classification of energy sources as follows:

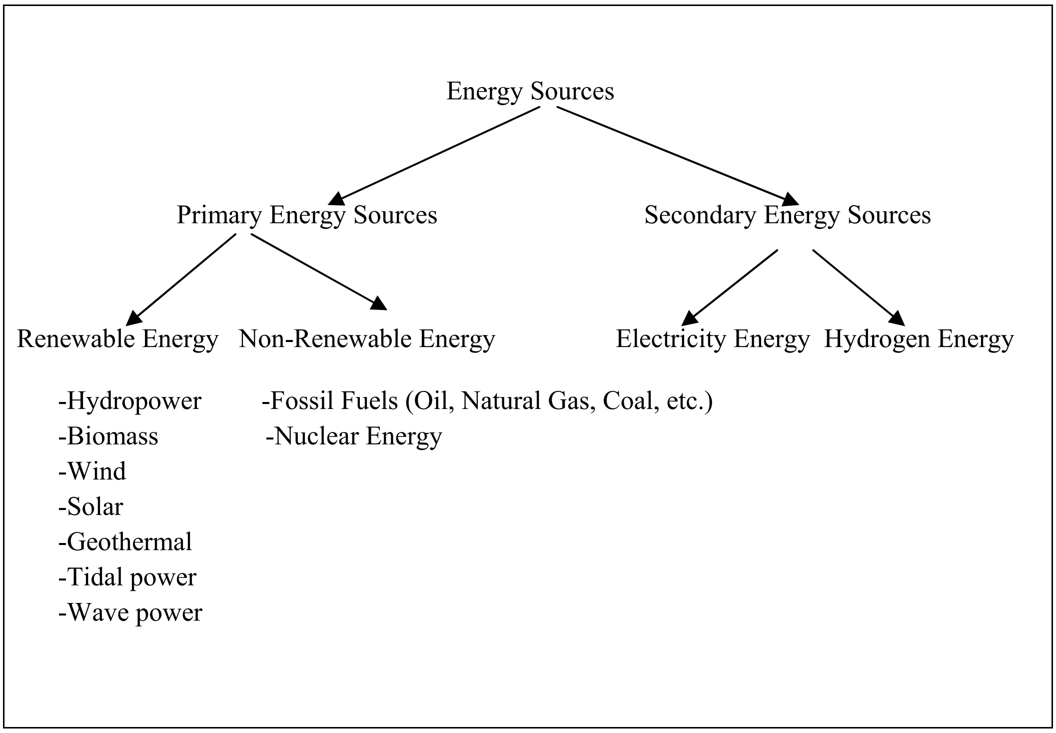

Figure 1. Classification of energy sources

Primary energy sources are energy sources that have not been been transformed from another energy source and this energy is already found in nature. Secondary energy sources are energy sources that have been transformed from another energy source after an energy conversion process. Electricity energy and hydrogen energy are important secondary energy sources. For example, electricity energy is transformed from wind energy, nuclear energy or natural gas, etc.

Primary energy sources are composed of renewable energies and non-renewable energies. Renewabe energy sources are hydropower, biomass, wind, solar, geothermal, tidal power and wave power. Non-renewable energy sources are mainly composed of fossil fuels (oil, natural gas, coal, etc) and nuclear energy.

Renewable energy is defined as energy derived from natural processes that do not involve the consumption of exhaustible resources such as fossil fuels and uranium, including hydropower, wind power, wave power, solar energy, geothermal energy, combustible renewables and renewable waste (landfill gas, waste incineration, solid biomass and liquid biofuels) (BP, 2009). Large-scale hydro power generation and non-commercial combustible renewables and renewable waste are sometimes excluded from the definition of renewables, and remaining small-scale hydro, wind power, wave power, solar energy, geothermal energy and modern biomass energy, including ethanol, comprises narrowly defined renewable energy (BP, 2009).

Global Primary Energy Outlook

This section presents the trends in global energy consumption, production, reserves and prices for oil, coal, natural gas, nuclear energy and hydroelectricity. The aim of this section is to provide a general idea about the future of global energy outlook. After stating global primary energy consumption patterns by each fuel type in different periods, each oil, natural gas, coal, nuclear energy and hydroelectricity's production and consumption patterns, reserve positions, price dynamics will be analysed globally and regionally.

The data of this section is provided from British Petroleum's (2009) Statistical Review of World Energy 2009. In this Review, primary energy comprises commercially traded fuels only. So, fuels such as wood, peat and animal waste which, though important in many countries, are excluded since they are unreliably documented in terms of consumption statistics. Also wind, geothermal and solar power generation are excluded in this Review.

Global primary energy consumption patterns by each fuel type will be mentioned as follows:

World primary energy (oil, natural gas, coal, nuclear, hydro power) consumption grew by 1.4% in 2008, that is the slowest growth rate since 2001, due to the global economic crisis. 87% of this growth came from Asia Pacific region and majority of primary energy consumption growth has been provided by coal for the third consecutive year.

Chinese consumption increased by 7.2% whereas US consumption decreased by 2.8% that is the largest decline since 1982. And for the first time, non-OECD primary energy consumption exceeded OECD primary energy consumption.

Figure 2 shows world primary energy consumption between 1965-2008 as follows:

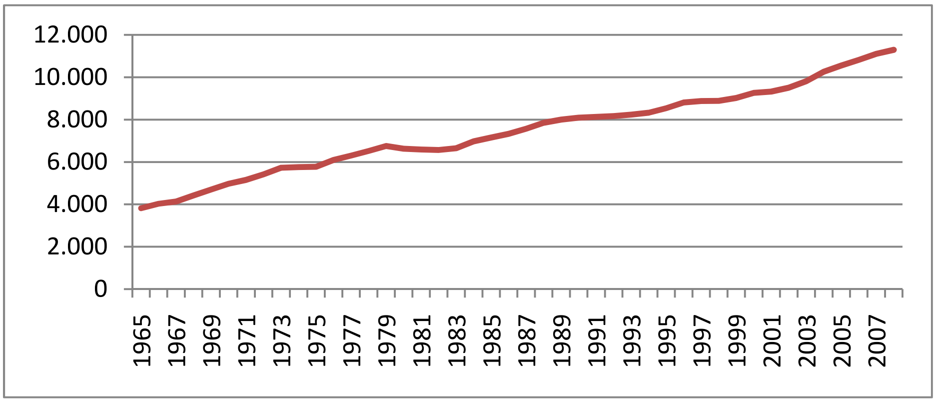

Figure 2. World primary energy consumption between 1965-2008 in mtoe (BP, 2009)

World primary energy consumption has been increasing steadily since 1965 other than 1980-1982 period. And world primary energy consumption increased from 3,820 mtoe in 1965 to 11,295 mtoe in 2008 indicating 4.6% annual growth rate. And 11,295 mtoe of primary energy consumption in 2008 shows 1.9%, 1.9.% and 2.5% increases according to the years 1980, 1990 and 2000 respectively. So, energy consumption growth rates have been increasing after 2000. The low growth rates during 1980-2008 periods and 1990-2008 periods largely come from the economic crisis. The slowdown in consumption growth rates in 1974-1975, 1980-1983, 1991-1994, 1997-1999 and 2001 coincides with global economic crisis or slowdown.

Figure 3 shows consuptions of oil, coal, natural gas, nuclear energy and hydroelectricity in mtoe between 1965-2008.

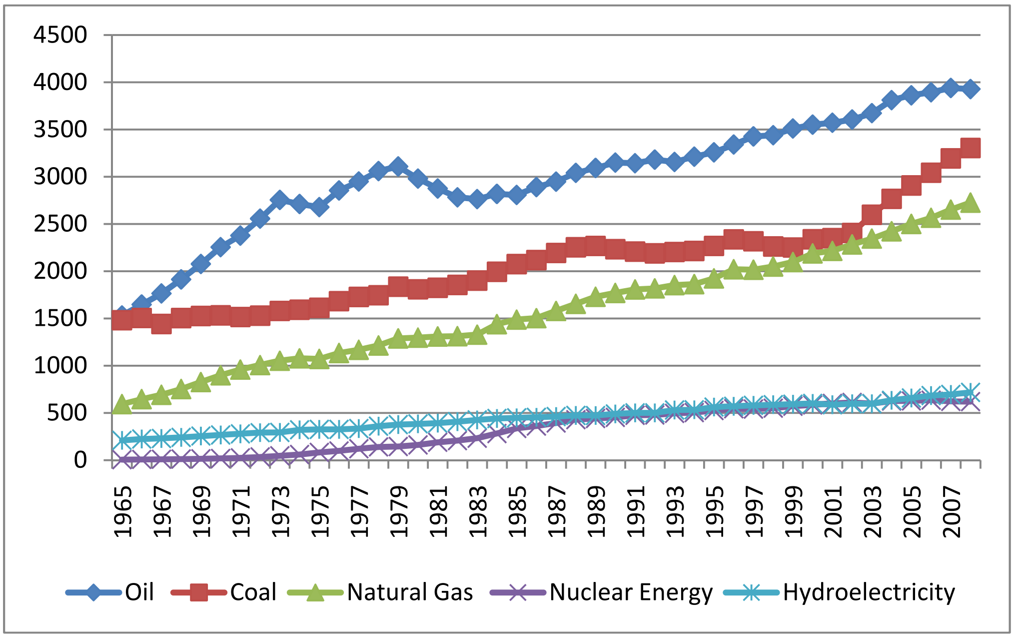

Figure 3. The consumptions of oil, coal, natural gas, nuclear energy and hydroelectricity in mtoe between 1965-2008 (BP, 2009)

Oil is the most consumed fuel type. Oil consumption was 1,530 mtoe in 1965 and nearly doubled to 3,108 mtoe in 1979. Then it started to decrease until the year 1983 to 2763 mtoe and after 1983 it entered into a long term upward trend and reached to 3,929 mtoe in 2008. Share of oil consumption in total energy consumption was 40.1% in 1965 and it increased upto 48.1% in 1973. After 1973, the share of oil consumption has entered a long term decrease and decreased to 34.8% in 2008. But it is still the most consumed type of energy.

The second most consumed fuel is coal. In 1965, coal consumption was near to oil consumption with 1,481 mtoe comprising 38.8% of total consumption. Its growth until 2002 was below total energy consumption growth and was 2,405 mtoe in 2002 comprising 25.3% of total energy consumption. After 2002, it coal consumption started to increase significantly and 3,304 mtoe in 2008 comprising

29.2% of world energy consumption. This largely comes from the increasing use of coal by China.

The most stably increasing energy fuel has been natural gas from 594 mtoe in 1965 to 2,726 mtoe in 2008. And natural gas consumption has never decreased according to the preceding year. The share of natural gas in world energy consumption increased from 15.5% to 24.1% between this period.

Figure 4 shows the shares of of oil, coal, natural gas, nuclear energy and hydroelectricity consumption in total energy consumption between 1965-2008 as follows:

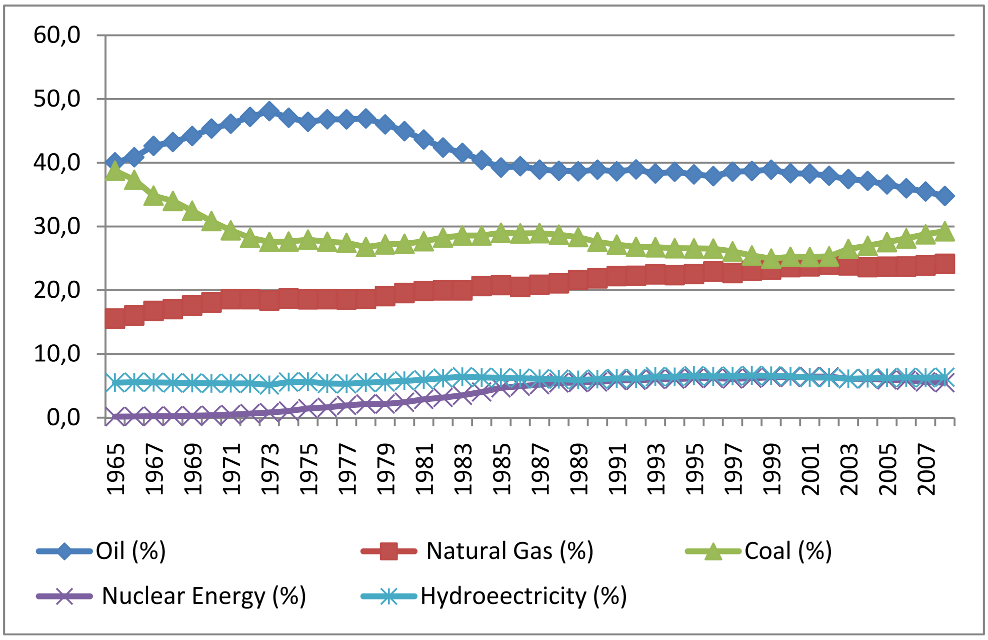

Figure 4. The shares of of oil, coal, natural gas, nuclear energy and hydroelectricity consumption in global energy consumption between 1965-2008 (BP, 2009)

In 1965, nuclear energy has already entered the world energy market and was only 5.8 mtoe comprising 0.2% of word energy consumption. It reached to 611 mtoe in 2002 forming 6.4% of world energy consumption. In 2008 its consumption was 620 mtoe and the share decreased to 5.5%.

Hydroelectricity consumption growth was 210 mtoe in 1965 with 5.5% share and increased stably during 1965-2008. Its consumption reached to 717 mtoe in 2008 comprising 6.4% of world energy consumption. Its share fluctuated between 5.1% and 6.4% during 1965-2008 period.

Table 1 shows primary energy consumption in mtoe by regions and their consumption shares in 2008.

Table 1. Primary Energy Consumption in mtoe by Regions and Their Shares in 2008 (BP, 2009)

Region	Consumption (mtoe)	Percentage Share
Asia Pacific	3,981.9	35.3%
Europe & Eurasia	2,964.6	26.2%
North America	2,799,1	24.8%
Middle East	613.5	5.4%
South and Central America	579.6	5.1%
Africa	356.0	3.2%
Total World	11,294.9	100.0%
European Union	1,728.2	15.3%
OECD	5,508.4	48.8%

Asia Pacific Region is the most energy consuming region with 3,981.9 mtoe comprising 35.3% of world consumption in 2008. Europe & Eurasia is is the second most consuming region with 26.2 % of world consumption and North America follows this region with a share of 24.8%. So, these three regions consume together more than four fifth of primary energy consumption. Other regions such as Middle East, South & Ceantral America and Africa consume 5.4%, 5.1% and 3.2% of total primary energy. In 2008, the primary energy consumption of OECD decreased to less than half of the world for the first time, indicating non-OECD countries’ primary energy consumption exceeded OECD countries.

Table 2 shows primary energy consumption of ten most consuming countries and Turkey and their consumption shares in 2008 as follows:

Table 2. Primary Energy Consumption of Ten Most Consuming Countries and Turkey with Their Shares in 2008 (BP, 2009)

Country	Consumption (mtoe)	Percentage Share
US	2,299.0	20.4%
China	2,002.5	17.7%
Russian Federation	684.6	6.1%
Japan	507.5	4.5%
India	433.3	3.8%
Canada	329.8	2.9%
Germany	311.1	2.8%
France	257.9	2.3%
South Korea	240.1	2.1%
Brazil	228.1	2.0%
Turkey	102.6	0.9%

Within the Asia Pacific region, China comes the first with 2,002.5 mtoe primary energy consumption comprising 17.7% of world consumption. China also is the second most energy consuming country after US. Japan, India and South Korea are other leading countries in primary energy consumption in the region with 4.5%, 3.8% and 2.1% of world consumption respectively. Within the Europe & Eurasia region, European Union consumes 1,728 mtoe primary energy forming 15.3% of world consumption and Russian Federation consumes 6.1% of the world primary energy.

US is the most consuming country with 2,299.0 mtoe forming 20.4% of world primary energy consumption. And so US comprises most of North America consumption. Canada is the second in the region and sixth in the world with 2.9% of world consumption.

Turkey consumes 102.6 mtoe primary energy comprising 0.9% of world consumption and is the twenty second most energy consuming country in 2008.

Five of the ten most energy consuming countries, namely China, Russian Federation, India, South Korea and Brazil are emerging market economies and the remaining five countries are industrialized countries. Also, the shares of these two groups are almost the same, showing the presence of emerging markets in the world energy market is evident.

Oil is the most consumed primary energy source. Production, consumption, reserves, R/P ratios and prices of oil will be analysed globally and regionally as follows:

Table 3 shows proved reserves, annual production and consumption of oil by regions and some important countries with their percentage shares and R/P Ratios in 2008.

Table 3. Proved Reserves, Annual Production and Consumption of Oil in Thousand Million Barrels, Their Percentage Shares and R/P Ratios by Regions in 2008 (BP, 2009)

	Reserves		Annual Production		Annual Consumption		
Regions	Thousand million barrels	Share of Total	Thousand million barrels	Share of Total	Thousand million barrels	Share of Total	R/P Ratio
North America	70.9	5.6%	4.79	16.0%	8.67	28.1%	14.8
South & Central America	123.2	9.8%	2.44	8.2%	2.15	7.0%	50.3
Europe & Eurasia	142.2	11.3%	6.42	21.5%	7.36	23.9%	22.1
Middle East	754.1	59.9%	9.56	32.0%	2.34	7.6%	78.6
Africa	125.6	10.0%	3.75	12.6%	1.05	3.4%	33.4
Asia Pacific	42.0	3.3%	2.89	9.7%	9.25	30.0%	14.5
Total World	1,258.0	100.0%	29.86	100.0%	30.83	100.0%	42.0
European Union	6.3	0.5%	0.82	2.7%	5.39	17.5%	7.7
OECD	88.9	7.1%	6.72	22.5%	17.27	56.0%	13.2
US	30.5	2.4%	2.46	8.2%	6.99	22.7%	12.4
Russian Federation	79.0	6.3%	3.61	12.1%	1.02	3.3%	21.8
China	15.5	1.2%	1.39	4.6%	2.92	9.5%	11.1
India	5.8	0.5%	0.28	0.9%	1.05	3.4%	20.7

Middle East is the leader in oil proved reserves and production with nearly 60% of world reserves and 32% of world oil production. Russian Federation has 6.3% of world reserves and forms 12.1% of world oil production. So, it is obvious that there is a serious mismatch regionally between oil reserves, productions and consumption.

For example OECD countries hold 7.1% of reserves, carries out 22.5% of world production and forms 56% of world consumption.

R/P ratios are important in evaluating the sustainability of any energy sources. Reserves-to-production (R/P) ratio is calculated by dividing the reserves remaining at the end of the year by the production in that year, and so shows the length of time that those remaining reserves would last if production were to continue at that rate. Oil R/P ratio for the world is 42 years. Although R/P ratio is 42 years in 2008 for the world, this does not necessarily mean that the oil resources will deplete in 2050. If the proved reserves growth rate exceeds production growth rate this this period extends. When historical R/P ratios are analysed, R/P ratio increased from 29.0 to 42.0 years between 1980 and 1990. Because, oil proved reserves increased significantly during 1980-1990 period from 667 to 1003 thousand million barrels whereas oil production increased from 23.0 to 23.9 thousand million barrels. And since 1990, R/P ratios have not changed much, fluctuating between 39.8 and 43.4 years. It is hard to predict when the oil resources will deplete precisely but it is precise that they will deplete one day in the future. And athough new oil reserves are explored, extraction of oil from these new reserves usually become more expensive.

In fact, the situation is very critical for OECD countries and the most energy consuming countries. R/P ratio is only 13.2 years for OECD. The sustainability of European Union oil condition is worse with R/P ratio of 7.7 years. US and China’s position are not well with 12.4 years and 11.1 years respectively. And these numbers show the length of time to maintain current production levels with proved reserves. But on a country basis, the ratio of proved reserves to consumption may be more important in terms of energy security. And reserve to consumption ratios for OECD, EU, US, Asia Pacific region, China and India are alarming with 5.1, 1.2, 4.3, 5.3 and

5.5 years. And these countries are not only the industrialized countries, but they involve the largest two emerging economies China and India. So, this is the problem of all world, except a few regions like Middle East, Russian Federation and some small economies. But, in case of a trouble in oil flow between countries these countries can't escape from the detrimental effects of global turmoil. So, all of the leading countries both industrialized or emerging are highly in need of finding alternative energy resources.

Figure 5 shows proved oil reserves in thousand million barrels between 1980-2008 as follows:

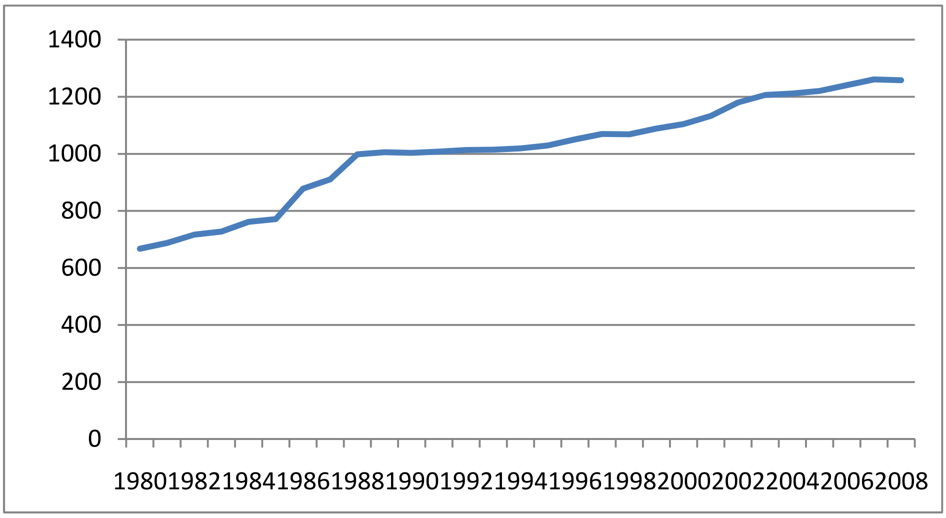

Figure 5. Oil proved reserves in thousand million barrels between 1980-2008 (BP, 2009)

Oil reserves increase sharply between 1980-1988 period from 667 to 998 thousand million barrels meaning 49.6% growth. And the growth slows down during the 1988-2000 period increasing from 998 to 1104 thousand million barrels showing a 10.6% growth rate. And reserves grow upto 1206 thousand million barrels in 2003 showing a 9.2% growth between 2000-2003 period. And then it slows down again and reaches 1258 thousand million barrels showing an only 4.2% growth between 2003-2008.

Figure 6 shows annual oil production in thousand million barrels between 1980-2008 as follows:

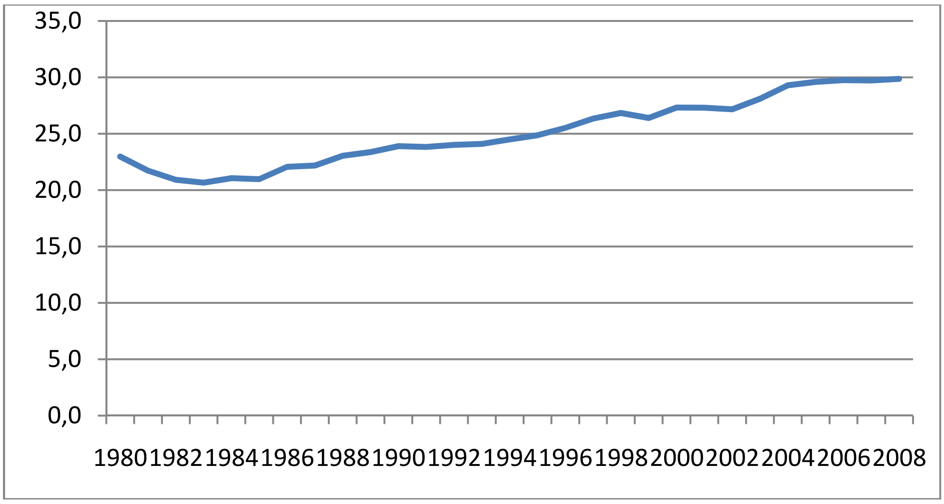

Figure 6. Oil production annually in thousand million barrels between 1965-2008 (BP, 2009)

Oil production decreases between 1980-1985 period from 23 to 21 thousand million barrels. And it increases upto 29.9 thousand million barrels in 2008. During this period the sharpest growth occurs between 1985-2000 increasing from 21 to 27.3 thousand million barrels. Then prouction stays the same during 2000-2002 period and then jumps to 29.3 in 2004 and increses slightly thereafter to 29.9 thousand million barrels in 2008.

Figure 7 shows Brent crude oil prices per barrel between 1960-2008 in USD of the day and in 2008 USD as follows:

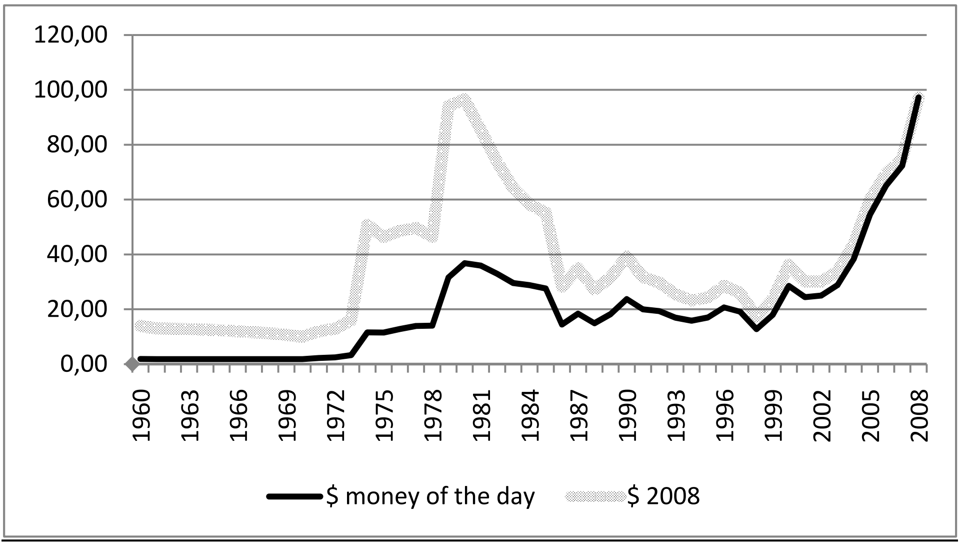

Figure 7. Brent crude oil prices per barrel between 1960-2008 in USD of the day and in 2008 USD (BP, 2009)

Crude oil prices remain stable until 1970 and it starts to increase from 1.80 USD in 1970 to 3.29 in 1973 and jumps to 11.58 USD in 1974, meaning more than 300% increase in one year. 11.58 USD in 1974 corresponds to 50.78 USD in terms of 2008 USD. And after a relatively stable period of 1975-1978, prices jump to 31.61 USD in 1979 from 14.02 USD in 1978. 31.61 USD corresponds to 94.13 USD in terms of 2008 USD. And then prices go into a downward trend covering a period between 1980-1998. Although prices increase according to the preceding year in some years, during this period the general trend is downward. And prices decrease to as low as 12.72 USD in 1998 corresponding to 17.32 USD in terms of 2008 USD. And prices start to increase after 1998 and go into an acceerating upward trend during 1998-2008. In 2008 prices reach upto 97,26 USD. Also, it should be taken into account that the prices in Figure 7 shows annual average prices. A figıre showing monthly or daily averages would show the fluctuations more precisely. For example, a daily crude oil price graph would show that oil prices reach upto 147 USD in 2008.

Natural gas has the most growing consumption among primary energy sources. roduction, consumption, reserves, R/P ratios and prices of natural gas will be analysed globally and regionally as follows:

Table 4 shows proved reserves, annual production and consumption of natural gas, by regions and their percentage shares and R/P ratios in 2008.

Table 4. Proved Reserves, Annual Production and Consumption of Natural Gas, Their Percentage Shares and R/P Ratios by Regions in 2008 (BP, 2009)

	Reserves		Annual Production		Annual Consumption		
Regions	Trillion cubic metres	Share of Total	mtoe	Share of Total	mtoe	Share of Total	R/P Ratio
North America	8.87	4.8%	740.0	26.7%	751.2	27.6%	10.9
South & Central America	7.31	4.0%	143.0	5.2%	128.7	4.7%	46.0
Europe & Eurasia	62.89	34.0%	978.6	35.4%	1,029.6	37.8%	57.8
Middle East	75.91	41.0%	343.0	12.4%	294.4	10.8%	-
Africa	14.65	7.9%	193.3	7.0%	85.4	3.1%	68.2
Asia Pacific	15.39	8.3%	370.1	13.4%	436.8	16.0%	37.4
Total World	185.0	1.0	2,768.0	100.0%	2,726.1	100.0%	60.4
European Union	2.87	1.6%	171.3	6.2%	441.1	16.2%	15.1
OECD	16.63	9.0%	1031.9	37.3%	1,354.1	49.7%	14.6
US	6.73	3.6%	533.0	19.3%	600.7	22.0%	11.6
Russian Federation	43.30	23.4%	541.5	19.6%	378.2	13.9%	72.0
China	2.46	1.3%	68.5	2.5%	72.6	2.7%	32.3
India	1.09	0.6%	27.5	1.0%	37.2	1.4%	35.6

Middle East and Russian Federation hold 41% and 23.4% of natural gas reserves respectively. They own an important part of natural gas reserves as was the case for oil reserves. The world R/P ratio is 60.4 years in 2008. R/P ratios of OECD, EU, US, China and India are very low according to world average with 14.6, 15.1, 11.6, 32.3 and 35.6 years respectively. But the picture for these countries is better than the case for oil. The reserves to consumption ratios are worse for these countries. R/C ratio for OECD, EU, US, China and India are 11.2, 5.8, 10.3, 30.4 and 26.3 respectively.

Figure 8 shows proved reserves of natural gas in trillion cubic metres between 1980-2008 as follows:

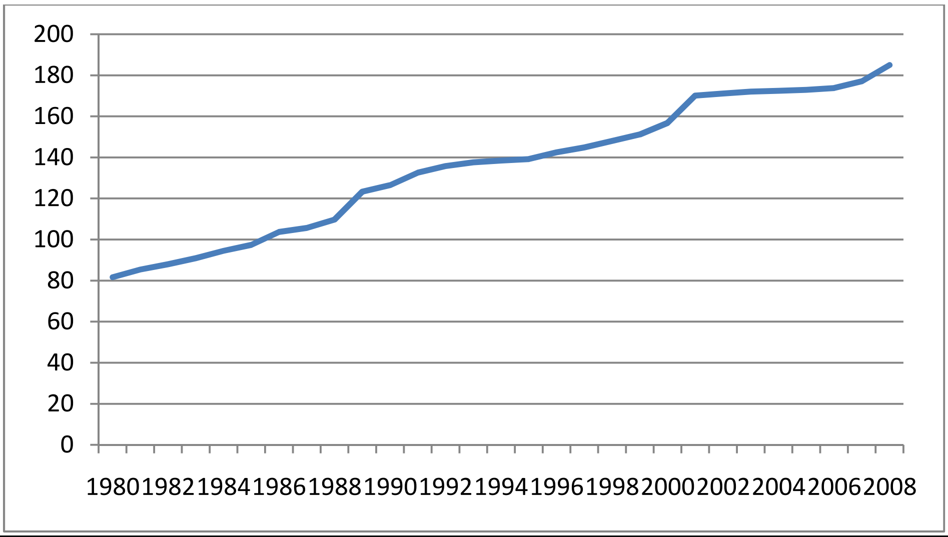

Figure 8. Proved reserves of natural gas in trillion cubic metres between 1980-2008 (BP, 2009)

Proved reserves increase steeply between 1965 and 2001 from 82 to 170 trillion cubic metres. But after 2001 the increase slows down and reaches 185 trillion cubic metres in 2008.

Figure 9 shows production of natural gas in mtoe between 1980-2008 as follows:

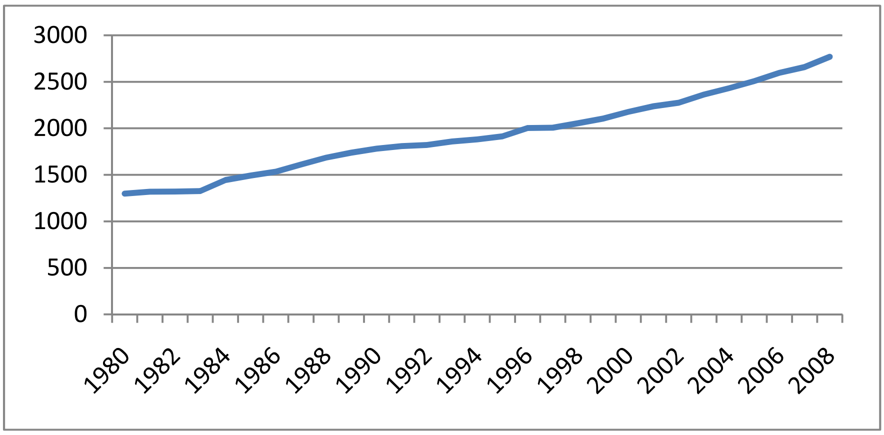

Figure 9. Production of natural gas in mtoe between 1980-2008 (BP, 2009)

Natural gas production is 1,298 mtoe in 1980 and at the end of a long term growth period, production increases to 2,768 mtoe in 2008. The Figure 9 shows that there is a clear upward trend in natural gas production unlike oil production. So, natural gas production is less sensitive to economic crisis than oil production.

Fgure 10 shows European Union CIF natural gas prices in USD per million British Thermal Unit (Btu) between 1984-2008.

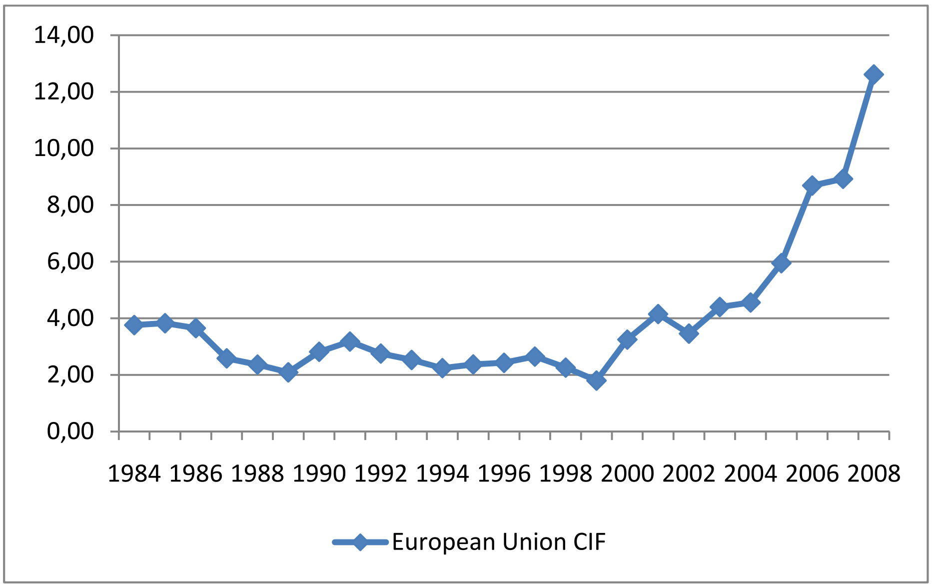

Figure 10. European Union CIF natural gas prices in USD between 1984-2008 (BP, 2009)

Natural gas prices decline from 3.76 USD to 2.09 USD between 1984 and 1989, and fluctuates between 3.18 and 1.80 USD between 1989-1999 period. And natural gas prices jumps from value of 1.80 USD in 1999 to 3.25 USD in 2000. Then, natural gas prices continue to increase reaching 12.61 USD in 2008.

In 2008, majority of primary energy consumption growth has been provided by coal for the third consecutive year. There are two types of coal: Anthracite and bituminous; sub-bituminous and lignite. The reserve shares of these two coal types are nearly the same in the world. But all of Turkey's resources are sub-bituminous and lignite. Coal production, consumption, reserves, R/P ratios and prices of coal globally and regionally will be analysed as follows:

Table 5 shows proved reserves, annual production and consumption of coal by regions and some important countries:

Table 5. Proved Reserves, Annual Production and Consumption of Coal, Their Percentage Shares and R/P Ratios by Regions in 2008 (BP, 2009)

	Reserves		Annual Production		Annual Consumption		
Regions	Million tonnes	Share of Total	mtoe	Share of Total	mtoe	Share of Total	R/P Ratio*
North America	246,097	29.8%	638.4	19.2%	606.9	18.4%	216
South & Central America	15,006	1.8%	55.5	1.7%	23.3	0.7%	172
Europe & Eurasia	272,246	33.0%	456.4	13.7%	522.7	15.8%	218
Middle East	1,386	0.2%	0.5	<0.05%	9.4	0.3%	>500
Africa	32,013	3.8%	143.4	4.3%	110.3	3.3%	131
Asia Pacific	259,253	31.4%	2,030.7	61.1%	2,031.2	61.5%	64
Total World	826,001	100.0%	3,324.9	100.0%	3,303.7	100.0%	122
European Union	29,570	3.6%	171.5	5.2%	301.2	9.1%	51
OECD	352,095	42.6%	1,042.5	31.4%	1,170.6	35.4%	164
US	238,308	28.9%	596.9	18.0%	565.0	17.1%	224
Russian Federation	157,010	19.0%	152.8	4.6%	101.3	3.1%	481
China	114,500	13.9%	1,414.5	42.5%	1,406.3	42.6%	41
India	58,600	7.1%	194.3	5.8%	231.4	7.0%	114
Turkey	1,814	0.2%	17.8	0.5%	30.4	0.9%	21

*R/P ratios have been calculated by dividing reserves in tonnes to production in tonnes, not in mtoes.

Coal reserves are less concentrated in the world when compared with oil or natural gas reserves. Europe & Eurasia holds 33% of coal reserves, but it carries out 13.7% of world production and forms 15.8% of world consumption. So, the region's production and consumption share is less than its reserve shares. This largely comes from the Russian Federation's position. Russian Federation holds 19% of world coal reserves alone, but its production and consumption shares are only 4.6% and 3.1% respectively. The situation is reverse for the EU, that EU's production and consumption shares are 5.2% and 9.1% respectively whereas it holds only 3.6% of world reserves. Asia Pacific region holds 31.4% of coal reserves, its production and consumption shares are 61.1% and 61.5% respectively, showing a balanced structure.

China and US are the most important players in the coal market. US holds 28.9% of coal reserves alone and its share in world production and consumption are 18% and 17.1% respectively and. China is the most producing and consuming country with 42.5% and 42.6% shares respectively, although it holds only 13.9% of world reserves. So, R/P ratio of China is 41 years that is quite below world R/P ratio of 122 years. R/P ratio of US is quite well that is 224 years. EU is again below world average with 51 years. Turkey's R/P ratio is lower than even EU, that is only 21 years. Because, Turkey holds only 0.2% of reserves and all of these reserves are lignite reserves, and calorific equivalent of one mtoe is 1,5 tonnes of hard coal or 3 tonnes of lignite. Reserves to consumption ratio is around 12 years for Turkey.

Figure 11 shows coal prices of Northwest Europe marker price and US Central Appalachian coal spot price index as folows:

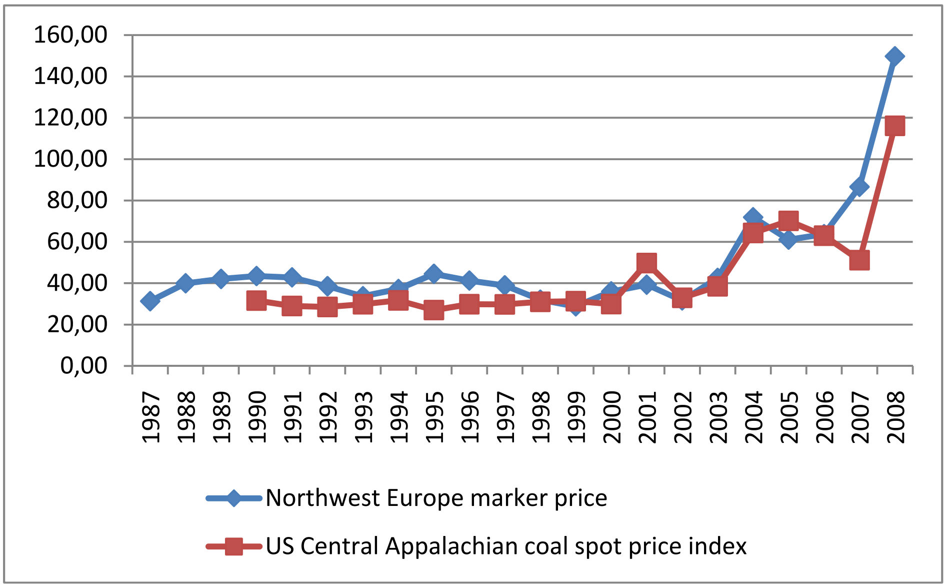

Figure 11. Coal prices in USD per tonne between 1984-2008 (BP, 2009)

Coal prices fluctuate between 29 USD and 49 USD during 1987-2003 period. And it enters into a bullish market after 2003. Northwest Europe marker prices increase from 31.65 USD in 2002 to 149.78 USD in 2008. US Central Appalachian coal spot price index increases from 32.95 USD in 2002 to 116.14 USD in 2008.

The most debatable primary energy source is the nuclear energy. Global nuclear energy consumption trends and consumption shares on regional and country basis will be analysed as follows:

Table 6 shows nuclear energy consumption in by regions and their percentage shares in 2008 as follows:

Table 6. Nuclear Energy Consumption in TWh and mtoe by Regions and Their Percentage Shares in 2008 (BP, 2009)

Regions	Consumption (TWh)	Consumption (mtoe)	Share of Total
North America	952.1	215.4	34.8%
South & Central America	21.1	4.8	0.8%
Europe & Eurasia	1222.8	276.7	44.7%
Middle East	-	-	-
Africa	13.3	3.0	0.5%
Asia Pacific	529.4	119.8	19.3%
Total World	2738.6	619.7	100.0%
European Union	940.0	212.7	34.3%
OECD	2279.1	515.7	83.2%
US	848.6	192.0	31.0%
Russian Federation	163.0	36.9	6.0%
China	68.4	15.5	2.5%
India	15.5	3.5	0.6%
France	440.3	99.6	16.1%
Japan	251.7	57.0	9.2%
Germany	148.8	33.7	5.4%

83.2% of nuclear energy is consumed by OECD countries. US is dominant in consumption with 31.0% of world nuclear energy. France, Japan, Russian Federation and Germany are other important countries in nuclear energy consumption with shares of 16.1%, 9.2%, 6.0% and 5.4% respectively. So, these five countries make up around 65% of world nuclear energy consumption.

Figure 12 shows nuclear energy consumption between 1965-2008 period:

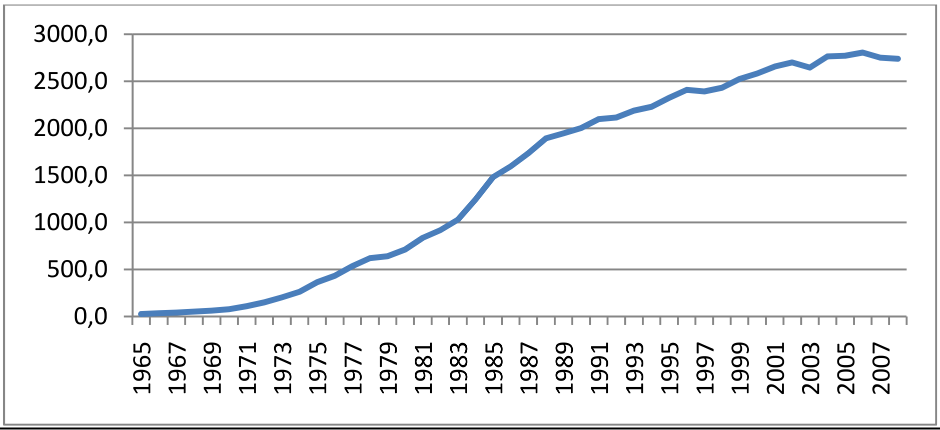

Figure 12. Nuclear energy consumption in TWh between 1965-2008 (BP, 2009)

Nuclear energy consumption increases with an upward slope between 1965-1988 and reaches from 25.7 TWh in 1965 to 1893.2 TWh in 1988, meaning an increase of around 73 times. During 1988-2008 period, its growth slows down and reaches to 2838.6 TWh in 2008 meaning 45% increase according to 1988. And during 1998-2008 period, it increases from 2431.6 TWh to 2838.6 TWh, that is 12.6% increase in the last ten years. And the increase from 2699.7 TWh in 2002 to 2838.6 TWh in 2008 is only 1.4%. The peak value for nuclear energy occurs in 2006 with 2805.9 TWh and decreases 2.4% in 2008 acrording to 2006. So, nuclear energy consumption seems to be saturated.

Global hydroelectricity outlook will be mentioned as follows:

Table 7 shows hydroelectricity consumption in 2008:

Table 7. Hydroelectricity Consumption in TWh and mtoe by Regions and Their Percentage Shares in 2008 (BP, 2009)

Regions	Hydroelecricity Consumption (TWh)	Hydroelecricity Consumption (mtoe)	Share of Total
North America	658.2	148.9	20.8%
South & Central America	674.2	152.5	21.3%
Europe & Eurasia	796.3	180.2	25.1%
Middle East	12.6	2.8	0.4%
Africa	98.1	22.2	3.1%
Asia Pacific	931.6	210.8	29.4%
Total World	3,170.9	717.5	100.0%
European Union	311.9	70.6	9.8%
OECD	1,274.0	283.3	40.2%
US	250.6	56.7	7.9%
Russian Federation	167.0	37.8	5.3%
China	585.2	132.4	18.5%
Canada	369.5	83.6	11.7%
Brazil	363.8	82.3	11.5%
India	115.6	26.2	3.6%
Turkey	33.1	7.5	1.0%

Hydroelectricity consumption is related mostly to geographic conditions. So, it is not as concentrated as other energy sources like oil, natural gas etc. North America, South & Central America, Europe & Eurasia and Asia Pacific have 20.8%, 21.3%, 25.1% and 29.4% shares respectively. Middle East has only 0.2% share due to water scarcity in the region and abundance of other energy sources in the region. Africa’s share is also only 3.1%, because of water scarcity and high investment costs. On country basis; China, Canada, Brazil, US, Russian Federation have important shares with 18.5%, 11.7%, 11.5%, 7.9% and 5.3% respectively, comprising together 55% of world consumption. The common attributes of these countries are large areas and abundance of water sources. Turkey consumes 33.1 TWh and so has a share of 1% in world hydroelectricity consumption.

Global Renewable Energy and Electricity Outlook

This section will present the general outlook of renewable energy production, their share in TPES and trends by each renewable energy sources together with the general electricity outlook, shares of energy sources in electricity production, their trends and prices for the world, OECD and specific countries. The aim of this section is to provide a general idea about the trends of global and OECD renewable energy and electricity outlook and trends. After analyzing in details the renewables and electricity outlook and trends globally, renewables and electricity outlook in the OECD and some specific countries will be stated in details. The first subtitle will focus on the global renewable energy outlook while the second subtitle will focus on the global electricity outlook. The data of this section is obtained from International Energy Agency's IEA Statistics-Renewable Information and IEA Statistics-Electricity Information published in 2009.

Global Renewables Outlook

This subtitle will present the general outlook of renewable energy production, their share in TPES, their share in electricity generation and their trends by each renewable energy sources for the world, OECD and specific countries. The data of this subtitle is obtained from International Energy Agency's IEA Statistics-Renewable Information published in 2009.

Table 8 shows renewable energy indicators by regions in 2007 as follows:

Table 8. Renewable Energy Indicators by Regions in 2007 (IEA, 2009b)

				Share of Fuel Categories in Total Renewables (%)		
	TPES (Mtoe)	Of Which Renewables (Mtoe)	Share of Renewables in TPES (%)	Hydro	Geothermal, Solar, Wind, Tide	Combustibl e Renewables and Waste
Africa	630.9	304.6	48.3%	2.7%	0.3%	97.0%
Latin America	551.1	168.3	30.5%	34.2%	1.6%	64.2%
Asia	1377	375.2	27.2%	5.9%	4.3%	89.8%
China	1,969.5	241.3	12.3%	17.3%	2.1%	80.6%
Non-OECD Europe	105.8	10.1	9.5%	37.6%	1.3%	61.1%
Former Soviet Union	1,015.6	30.7	3.0%	69.3%	1.5%	29.2%
Middle East	548.3	4	0.7%	48.2%	21.7%	30.1%
OECD	5,497.1	357.9	6.5%	30.2%	13.2%	56.6%
World Marine & Aviation Bunkers	330.5	-	-	-	-	-
World	1,2026	1492.2	12.4%	17.7%	4.9%	77.3%

In 2007, world total primary energy supply (TPES) is 12,026 Mtoe in 2007 of which 12.4% is from renewables. The shares of other energy sources in 2007 are as follows: 34% oil, 26.4% coal, 20.9% natural gas and 5.9% nuclear energy. By IEA (2009b) definition, renewable energy sources include combustible renewables and waste (solid biomass, charcoal, renewable municipal waste, gas from biomass and liquid biomass), hydro, solar, wind and tide energy. Renewables do not involve non-renewable waste sources (nonrenewable industrial waste or non-renewable municipal waste).

In global renewable energy supply, combustible renewables and waste (CRW) comprises the majority with 77.3% market share because of its widespread non-commercial use, whereas hydro forms 17.7%, geothermal comprises 3.3% and “new renewables” (solar, wind and tide) forms 1.6% of renewables.

85.9% of solid biomass is produced and consumed in non-OECD countries. Africa accounts for only 5.2% of the world’s total TPES in 2007 while it supplies 26.2% of the global solid biomass. Africa has the largest share of renewables in

TPES with 48.3% and 97% of renewables in Africa comes from CRW. Developing countries in South Asia and sub-Saharan Africa use non-commercial biomass for residential cooking and heating. Because of non-OECD countries' heavy use of non-commercial biomass they account for 76% of world total renewables supply. OECD countries supply only 24% of world renewables, while they constitute 45.7% of the world TPES. So, in OECD countries the share of renewables in total energy supply is only 6.5% while it is 18.3% for non-OECD countries. However the OECD countries have the majority in "new" renewables, with supply of 68.8% of global wind, solar and tide energy in 2007. The share of non-OECD countries in hydro is 59.1% in 2007 and may increase further due to their great untapped potentials.

In Latin America and Asia, the share of renewables in TPES is more than the world avereage with 30.5% and 27.2% shares respectively. CRW forms 64.2% and 89.8% of renewables in Latin America and Asia respectively. Hydro is an important source of renewables in Latin America with 34.2% share of renewables. In the OECD, the share of renewables in TPES is 6.5% that is less than the world average and share of CRW in renewables is 56.6%, hydro forms 30.2% and geothermal, solar, wind, tide comprises 13.2% of renewables.

Table 9 shows renewable energy indicators by some specific countries in 2007 as follows:

Table 9. Renewable Energy Indicators by Countries in 2007 (IEA, 2009b)

				Share of Fuel Categories in Total Renewables (%)		
	TPES (Mtoe)	Of Which Renewables (Mtoe)	Share of Renewables in TPES (%)	Hydro	Geothermal, Solar, Wind, Tide	CRW
The United States of America	2,339.9	110.9	4.7%	19.4%	11.9%	68.7%
People's Republic of China	1,955.8	241.3	12.3%	17.3%	2.1%	80.6%
Russia	672.1	19.4	2.9%	78.5%	2.2%	19.4%
India	595.3	173.5	29.1%	6.1%	0.7%	93.2%
Japan	513.5	16.3	3.2%	39.0%	21.9%	39.1%
Germany	331.3	26.1	7.9%	6.9%	16.1%	77.0%
Canada	269.4	43.5	16.2%	72.8%	0.6%	26.6%
France	263.7	17.8	6.7%	28.1%	3.1%	68.7%
Brazil	235.6	104.7	44.4%	30.7%	0.2%	69.1%
Turkey	100	9.6	9.6%	32.1%	15.6%	52.3%

The United States of America (USA) and People's Republic of China are the two greatest energy suppliers in the world forming 35% of the world TPES together in 2007 with 2,339.9 Mtoe and 1,955.8 Mtoe respectively. Share of renewables in TPES in the USA is 4.7% that is much less than the world average. CRW forms 68.7% of renewables, hydro forms 17.3% and geothermal, solar, wind, tide comprises 11.9% of renewables in the USA. In People's Republic of China, the share of geothermal, solar, wind, tide in renewables is only 2.1% that is less than the world average whereas the share of CRW of 80.6% is more than the world average. Russia, India, Japan and Germany are other important primary energy suppliers in the world with 672.1 Mtoe, 595.3 Mtoe, 513.5 Mtoe and 331.3 Mtoe respectively. The share of renewables is quite low in Russia and Japan with 2.9% and 3.2% respectively. In Germany although the renewable's share of 7.9% is less than the world average, it is more than many industrialized countries like the USA, Japan. In India, CRW is the major source of renewables forming 93.2% of renewables. In Russia hydro froms the majority of renewables with 78.5% share. In Japan, the sources of renewable energy are distributed quite balanced with 39%, 21.9% and 39.1% shares of hydro; geothermal, solar, wind, tide; and renewable combustibles waste respectively. In Canada, hydro is an important energy source. The share of renewables in TPES in Canada is 16.2% that is more than the world average and hydro forms 72.8% of renewables. In Turkey, TPES in 2007 is 100 Mtoe of which 9.6 Mtoe comes from renewables meaning that the share of renewables in Turkey is less than the world average but more than the world average. CRW forms 52.3% of renewables in Turkey, hydro forms 32.1% and geothermal, solar, wind, tide comprises 15.6% of renewables. So, in Turkey the share of CRW in renewables is less than the world and OECD averages whereas the shares of hydro and geothermal, solar, wind, tide are more than the world and OECD averages.

Table 10 shows primary energy supply by renewable energy sources in 2007 as follows:

Table 10. Primary Energy Supply By Renewable Energy Sources in 2007 in ktoe (IEA, 2009b)

	Hydro	Wind	Solar/Tide	Geothermal	CRW	Total
World	264,746.70	14,906.00	9,643.50	49,028.00	1,153,858.00	1,492,182.10
OECD Total	108,227.20	12,871.40	4,017.10	30,375.30	202,391.20	357,882.10
Non-OECD Total	156,519.50	2,034.70	5,626.40	18,652.70	951,466.80	1,134,300.00
IEA Europe	42,071.90	9,049.80	1,703.50	6,927.20	92,678.70	152,431.00
Germany	1,797.70	3,415.30	579.6	211.7	20,140.90	26,145.30
France	5,004.10	348.5	81.5	130	12,235.90	17,799.90
Iceland	721.9	-	-	3,223.80	3.3	3,949.00
Denmark	2.4	616.9	11.2	13.7	2,707.70	3,351.90
United States	21,467.20	2,975.90	1,474.60	8,786.20	76,191.40	110,895.20
Japan	6,364.80	225.7	539.8	2,820.60	6,388.60	16,339.40
Turkey	3,083.20	30.5	419.8	1,047.60	5,020.70	9,601.90

In the world renewable energy supply is 1,492 Mtoe in 2007 of which 1,154 Mtoe comes from CRW and 265 Mtoe from hydro. Geothermal sources supply 49 Mtoe, wind 15 Mtoe and solar/tide 9 Mtoe. In the OECD, renewable energy supply is 357

Mtoe forming 24% of the world renewable supply. OECD's CRW supply forms 18% of the world CRW supply, whereas the share of the OECD in hydro, wind, solar/tide and geothermal supplies are 41%, 86%, 42% and 62% respectively. In the USA, renewable energy supply is 111 Mtoe of which 21 Mtoe comes from hydro, 3 Mtoe from wind, 1.4 Mtoe from solar/tide, 9 Mtoe from geothermal and 76 Mtoe from CRW. In Turkey, renewable energy supply is 9.6 Mtoe of which 3 Mtoe comes from hydro, 0.03 Mtoe from wind, 0.4 Mtoe from solar/tide, 1 Mtoe from geothermal and 5 Mtoe from CRW. For primary renewable energy supplies, Turkey's share in the world is 1.2% for hydro, 0.2% for wind, 0,4% for solar/tide, 0.2% for geothermal and 0.4% for CRW in 2007 and 0.6% for renewable energies altogether.

Table 11 shows the contribution of renewable energy sources to TPES in 1990, 2000 and 2007 as follows:

Table 11. Contribution of Renewable Energy Sources to TPES (IEA, 2009b)

	1990	2000	2007
World	12.7%	12.9%	12.4%
OECD Total	5.8	5.9%	6.5%
Non-OECD Total	20.9%	21.8%	18.7%
IEA Europe	5.7%	6.8%	8.4%
Germany	1.5%	2.7%	5.8%
France	7.0%	6.8%	6.7%
Iceland	67.0%	74.4%	80.7%
United States	5.0%	4.5%	4.7%
Turkey	18.3%	13.2%	9.6%

The share of renewables in TPES has not changed much between 1990 and 2007 in the world decreasing slightly from 12.7% to 12.4%. This decrease comes from the decrease of renewables' share in non-OECD from 20.9% in 1990 to 18.7% in 2007. The share of renewables in TPES in the OECD increases slightly from 5.8% to 6.5% between 1990 and 2007. The increase in the OECD largely took place during the 2000-2007 period from 5.9% to 6.5%. In the USA, the renewables' share in TPES decreased from 5.0% in 1990 to 4.5% in 2000 and then has incrased slightly to 4.7% in 2007. Although the share of renewables in Germany is less than the share in the world and IEA Europe in 1990, 2000 and 2007, the increase of renewables' share in TPES is encouraging from 1.5% in 1990 to 5.8% in 2007. In Turkey, the share of renewables in TPES has decreased dramatically from 18.3% in 1990 to 13.2 in 2000 and then to 9.6% in 2007.

OECD Europe has the highest share of primary energy supply from renewable sources with 8.6% among the different OECD regions. It is also the only OECD region whose renewable share increased since 1990. This increase largely comes from the implementation of strong supporting policies for renewable energy in Europe.

Since 1990, renewables have grown at an average annual rate of 1.7%, while the growth rate of world TPES has been 1.9% per annum. Growth has been especially high for wind power, which grew at an average annual rate of 25%, that is due to its very low base in 1990 and has much way to grow. Most of the production and growth of solar and wind energy comes from the OECD countries. The second highest growth has been in renewable municipal waste, biogas and liquid biomass with a 10.4% annual growth rate since 1990. Solar photovoltaics and solar thermal has grown with 9.8% per annum. Primary solid biomass, that is the largest contributor to renewable energy in the world, has experienced the slowest growth among the renewables with 1.2% annual growth rate.

The development of renewables in TPES in the OECD during 1990-2007 period will be mentioned as follows:

Renewables supply in the OECD increased from 262 Mtoe in 1990 to 358 in 2007 with an average annual growth of 1.9%. In 2007, renewables contributed 6.5%

of TPES in the OECD, that is higher than its 1990 share of 5.8%. 56.6% of renewables in the OECD comes from CRW, hydro power accounts for 30.2% of renewables and geothermal energy has 8.5% share. Of the CRW, solid biomass, including wood, wood wastes and other solid wastes, has the largest share forming 42.9% of renewables. Annual growth rate of solid biomass, hydro and geothermal combined have been 0.8% between 1990-2007 period, that is lower than the average annual growth rate of 1.2% for TPES in the OECD. Annual growth rate of hydro power has been only 0.4% since hydro capacity is mature in most OECD countries. Annual growth rate of geothermal energy has been 0.7% that is well below the TPES growth rate. Within the CRW category, the growth rate of renewable municipal waste, gas from biomass and liquid biomass combined has been 12.9% that is much more than the growth in solid biomass. Solar energy (solar thermal and solar photovoltaic) has grown at an average annual rate of 5.9% during 1990-2007. Solar photovoltaic has grown at an average annual rate of 36.8% and wind at an average annual rate of 24%. Despite these high growth rates, wind, solar, tide, gas from biomass, renewable municipal waste and liquid biomass comprises only 1.2% of TPES and 18.4% of renewable primary energy supply in 2007 in the OECD. However their share in renewables was only 3% in 1990.

The USA is the largest producer of solid biomass, providing 37.6% of the total solid biomass supply in the OECD in 2007. Canada is the largest hydro power producer in the OECD. The USA is the largest producer of geothermal energy, providing 28.9% of the total geothermal energy in the OECD in 2007. The USA is also the largest producer of renewable municipal waste with 30.9%, liquid biomass with 59.1% and gas from biomass with 39.7% shares in the OECD in 2007. Solar thermal energy is mainly produced in the United States, Japan, Turkey, Germany and

Greece, while reported solar photovoltaic production is concentrated in Germany, Spain, and Korea. Wind power production is predominant in Germany, the USA, Spain and Denmark. The USA produces 31% of renewable energy in the OECD followed by Canada, with 12.2% of renewables production in the OECD.

Globally a big part of renewables is consumed in residential, commercial and public services sectors, while more than half of the renewables in the OECD countries is used in the transformation sector to generate electricity. Globally only 24.4% of renewables are used for electricity generation, 52.3% are used in residential, commercial and public sectors. Table 12 shows the share of electricity generation from renewable sources in 1990, 2000 and 2007 as follows:

Table 12. Share of Electricity Generation From Renewable Sources[1] (%) (IEA, 2009b)

	1990	2000	2007
World	19.5%	18.5%	17.9%
OECD Total	17.3%	15.6%	15.4%
Non-OECD Total	23.3%	23.3%	20.9%
IEA Europe	17.5%	18.7%	19.5%
Germany	3.5%	6.2%	14.2%
France	13.4%	13.1%	11.8%
United Kingdom	1.8%	2.7%	5.0%
Iceland	99.9%	99.9%	100.0%
Norway	99.8%	99.7%	99.3%
United States	11.5%	8.2%	8.3%
Turkey	40.4%	24.9%	19.0%

[1]Renewable sources include hydro, geothermal, solar thermal, solar PV, tide, wind, renewable municipal waste, solid biomass, liquid biomass and biogas.

Renewables account for 17.9% of world electricity generation in 2007, behind coal with 41.6% and gas with 20.9% but ahead of nuclear with 13.8% and oil with 5.7%. In electricity generation, hydro accounts for 15.6% of world electricity generation and 87% of total renewable electricity. CRW accounts for only 1.1% of world electricity generation. Geothermal, solar and wind energies account for only 1.2% of world electricity generation in 2007 but they grow rapidly.

Global electricity generation from renewables have grown by 2.6% per annum since 1990, while total electricity generation has grown by 3.1% per annum. In the world, the share of renewables in electricity generation has decreased from 19.5% in 1990 to 17.9% in 2007. This decrease largely came from the slow growth of hydro power in the OECD countries. Between 1990-2007 electricity generation from renewables has grown at an average annual rate of 1.3% in the OECD countries, while it has grown at 3.9% in non-OECD countries.

Renewable electricity in non-OECD regions has grown at 3.9% per annum that is slightly lower than the growth rate in total electricity generation of 4.6%. In OECD countries renewable electricity growth rate has been 1.3% while total electricity generation growth rate has been 2%. Since population growth is much higher in developing countries than in OECD countries and income increases, people switch from fuel wood and charcoal to kerosene and liquefied petroleum gases for cooking, and have better access to electricity. As a consequence, IEA (2009) expects future electricity growth, including renewable electricity growth to remain higher in non-OECD countries than in OECD countries.

The share of electricity generation from renewable sources has decreased in both the OECD and non-OECD from 17.3% and 23.3% in 1990 to 15.4% and 20.9% in 2007 respectively. The share of renewables in electricity generation in IEA Europe has increased slightly from 17.5% in 1990 to 18.7% in 2000 and then to 19.5% in 2007. The increase in Germany has been encouraging from 3.5% in 1990 to 6.2% in 2000 and then to 14.2% in 2007. However, the renewables' share in Germany is still less than the world, OECD and IEA Europe averages. France's utilization of renewables in electricity generation has decreased from 13.4% in 1990 to 11.8% in 2007. In Iceland, all of electricity is generated from renewable sources and in

Norway 99.3% of electricity is generated from renewables. In the USA, the share of electricity generation from renewable sources decreased from 11.5% in 1990 to 8.2% in 2000 and then increased slightly to 8.3% in 2007. In Turkey, the decrease in the share of electricity generation from renewables has been drastic, from 40.4% in 1990 to 24.9% in 2000 and then to 19% in 2007. Turkey's total electricity generation increased from 57.5 TWh to 191.6 TWh between 1990 and 2007, whereas renewable electricity generation increased from 23.2 TWh to only 36.5 TWh over the same period, causing the share of renewables to fall from 40.4% to 19.0%.

Most of the renewables utilized in electricity generation is hydro. Table 13 shows the share of electricity generation from renewables excluding hydro as follows:

Table 13. Share of Electricity Production From Renewable Sources[1] Excluding Hydro (%) (IEA, 2009b)

	1990	2000	2007
World	1.3%	1.4%	2.3%
OECD Total	1.8%	1.8%	3.6%
Non-OECD Total	0.4%	0.7%	0.9%
IEA Europe	0.7%	2.0%	5.8%
Germany	0.3%	2.4%	10.9%
France	0.5%	0.6%	1.5%
Iceland	6.7%	17.2%	29.9%
Denmark	3.1%	16.1%	27.2%
United States	3.0%	1.9%	2.6%
Turkey	0.1%	0.2%	0.3%

[1]Renewable sources include hydro, geothermal, solar thermal, solar PV, tide, wind, renewable municipal waste, solid biomass, liquid biomass and biogas.

Renewable sources excluding hydro involves geothermal, solar thermal, solar PV, tide, wind, renewable municipal waste, solid biomass, liquid biomass and biogas. In the world, renewables excluding hydro generates 2.3% of electricity in 2007 whereas this share was 1.3% in 1990 and 1.4% in 2000. So, the utilization of these renewables in electricity generation has accelerated since 2000 in the world. The OECD's use of renewables excluding hydro in electricity generation is 3.6% in 2007 whereas it is only 0.9% in non-OECD. The share of new renewables in electricity generation has doubled in OECD between 2000 and 2007. The utilization of these renewables has been much more encouraging in IEA Europe increasing from 0.7% in 1990 to 2.0% in 2000 and then to 5.8% in 2007. In Germany this increase has been incredible from only 0.3% in 1990 to 2.4% in 2000 and then to 10.9% in 2007. So, Germany has been one of the leading countries in generating electricity from renewables excluding hydro. In the USA, the share of electricity generation from these renewables decreased from 3.0% in 1990 to 1.9% in 2000 and then increased to 2.6% in 2007. Iceland and Denmark use renewables excluding hydro heavily that are 29.9% and 27.2% respectively in 2007 whereas they were only 6.7% and 3.1% in 1990. In Turkey, nearly all of electricity generation from renewables comes from hydro. In 1990 the share of renewables excluding hydro in electricity generation was only 0.1%, and it increased slightly to 0.2% in 2000 and then to 0.3% in 2007. So, Turkey is far away from the world or OECD's utilization of renewables excluding hydro in electricity generation.

Global Electricity Outlook

This subtitle will present the general outlook of electricity production by sources, electricity consumption by sectors, and general trends for the world, OECD and specific countries. The aim of this section is to provide a general idea about the trends of global and OECD electricity outlook. The data of this section is obtained from International Energy Agency's IEA Statistics-Electricity Information published in 2009.

Table 14 shows electricity gross production, final consumption, imports, exports and transimission & distribution losses for the world, OECD and specific countries in 2007 as follows:

Table 14. Electricity Indicators in 2007 in TWh (IEA, 2009c)

	Gross Production	Imports	Exports	Transmission & Distribution Losses	Final Consumption
OECD Total	10,718.50	408.60	399.90	679.50	9,239.50
Non-OECD Total	9,126.40	215.50	220.60	990.40	7,194.30
World	19,844.90	624.00	624.00	1,669.90	16,433.80
OECD Europe	3,612.50	337.50	333.60	229.00	3,060.40
The USA	4,348.90	51.40	20.10	267.00	3,824.80
China	3,318.20	15.20	18.60	201.30	2,716.90
Japan	1,133.70	-	-	51.00	1,009.10
Turkey	191.60	0.90	2.40	26.60	152.80

World electricity production is 19,844.9 TWh and final consumption is 16,433.80 TWh in 2007. The difference between the world electricity production and consumption comes from transmission & distribution losses, own use of energy by power plants and energy sector use. The USA is the largest producer and consumer of electricity producing 4,348.9 TWh in 2007 22% of world production and 41% of OECD production. Electricity import and export comprise around 3% of world production. Transmission & distribution losses are 1,670 TWh in 2007 forming 8.4% of world production. While transmission & distribution losses are 6.3% of production in OECD they form 10.9% of production in non-OECD. The ratio of transmission & distribution losses to production is 6.3% for OECD Europe while it is 6.1% for the USA and China and 4.5% for Japan, 13.9% for Turkey. In 2007, OECD electricity production in 10,719 TWh comprising 54% of global production while the remaining 46% of global electricity is produced in non-OECD countries. China produces 36% of non-OECD electricity alone in 2007.

Table 15 shows gross electricity production by sources in 2007 for the world, OECD and specific countries as follows:

Table 15. Gross Electricity Production By Sources in 2007 in TWh (IEA, 2009c)

	Nuclear	Hydro	Geothermal	Solar / Wind	Fossil Fuels	CRW	Total
OECD Total	2,272.64	1,331.96	40.21	158.48	6,697.95	217.26	10,718.49
Non-OECD Total	446.42	1,830.23	21.61	25.54	6,761.39	41.24	9,126.43
World	2,719.06	3,162.19	61.82	184.02	13,459.33	258.50	19,844.82
OECD Europe	925.32	533.11	9.51	111.93	1,924.54	108.09	3,612.50
United States	836.63	275.55	16.80	36.44	3,111.79	71.65	4,348.86
China	62.13	485.26	-	8.91	2,720.62	2.31	3,318.19
Japan	263.83	84.23	3.04	2.63	756.95	23.02	1,133.71
Turkey	-	35.85	0.16	0.36	154.98	0.21	191.56

In 2007, fossil fuels is the major source of global electricity production with 13,459 TWh forming 67.8% of global production. The second largest source of production is hydro power with 3,162 TWh forming 15.9% of global production followed by nuclear energy with 2,719 TWh forming 13.7% of global production. The remaining sources of geothermal, solar, wind and CRW comprises 2.6% of global electricity production in 2007.

Hydro power produces 12.4% of OECD electricity whereas it produces 20.1% of non-OECD electricity in 2007. The hydro power capacities are maturated in OECD so the newly installed hydro power plants have low load factors compared to non-OECD and the difference between OECD and non-OECD for hydro power are likely to expand in the future.

Nuclear power produces 21.2% of OECD electricity whereas it produces 4.9% of non-OECD electricity in 2007. In nominal terms, 2,273 TWh electricity is produced from nuclear power in the OECD and 446 TWh electricity is produced from nuclear power in non-OECD. Nuclear energy production in the OECD increased at an average annual growth rate of 7.6% between 1973 and 2007, reflecting new capacity additions in the 1970s and 1980s. However, new capacity additions declined sharply since 1985 and then installed capacities started to decrease marginally in 1998. The share of nuclear power in electricity production is very high in some countries. In 2007, France produces 76.5% of her electricity from nuclear power, Slovak Republic 56.5%, Belgium 53.9%, Sweden 42.6% and Switzerland 40.1%. In 2007, 318.6 GW OECD nuclear power capacity forms 12.6% of OECD total installed capacity. Non-OECD nuclear power production has slowed down as well. Non-OECD electricity produced from nuclear power grew at an average annual rate of 26% during 1973-1985 period while it has been 3% during 1985-2007 period.

Geothermal energy produces 0.4% of OECD electricity whereas it produces 0.2% of non-OECD electricity in 2007. In nominal terms, 40 TWh electricity is produced from geothermal energy in the OECD and 22 TWh electricity is produced from geothermal energy in non-OECD. Electricity produced from geothermal energy in the OECD has grown at an average annual rate of 5.5% during 1973-2007 period, while it decreased by 0.5% in 2008 compared to 2007 level.

Solar / wind power produces 1.5% of OECD electricity whereas it produces 0.3% of non-OECD electricity in 2007. In nominal terms, 158 TWh electricity is produced from solar / wind power in the OECD and 26 TWh electricity is produced from solar / wind power in non-OECD. The dominance of the OECD over non-OECD is obvious in new renewables like solar / wind power and CRWs. Electricity produced from wind power in the OECD increased from 0.1 TWh in 1985 to 183.4 TWh in 2008. OECD wind power increased by 22.5% in 2008 compared to 2007. In 2008, OECD electricity produced from solar power has increased by 78% compared to 2007 and has reached 8.2 TWh. OECD electricity produced from tide and wave power has been 0.5 TWh in 2008.

Geothermal and other non-combustible renewable energy (solar, wind, wave, tide) capacity in the OECD is about 94 GW in 2007 by increasing 23.4% compared to 2006. This increase largely came from the 14.6 GW wind power capacity addition. In non-OECD, geothermal and other non-combustible renewable energy produced 47 TWh electricity in 2007 forming 0.5% of non-OECD total electricity generation. In 2007 non-OECD wind power production increased by 67.4% while geothermal power production increased by only 1.6% compared to 2006. As technology improved and costs declined for wind power, wind power is likely to increase in the future. The fact that up to 10%-15% of electricity production from intermittent power such as wind power can be managed easily and the current low shares of intermittent power in many regions increase the prospects for wind power.

Table 16 shows electricity production from combustible fuels by sources in 2007 as follows:

Table 16. Gross Electricity Production From Combustible Fuels By Sources in 2007 in TWh (IEA, 2009c)

	Coal				Oil	Gas	Wood	Industrial Waste	Municipal Waste	Biogas/liquid biofuels
	Hard	Brown	Peat	Gases						
OECD Total	3,269.09	583.85	9.93	94.46	433.77	2,306.85	122.22	9.41	53.55	32.09
Non-OECD Total	3,939.01	276.32	0.79	42.28	683.91	1,819.08	36.02	2.07	3.02	0.14
World	7,208.10	860.17	10.72	136.74	1,117.68	4,125.93	158.24	11.48	56.57	32.23
OECD Europe	600.43	366.37	9.93	35.97	109.89	801.95	52.63	3.96	29.25	22.25
The USA	2,024.23	90.23	-	3.99	78.14	915.20	41.99	5.01	17.1	7.55
China	2,662.85	-	-	22.12	33.75	40.86	2.31	-	-	-
Japan	272.27	-	-	38.53	156.28	289.88	15.76	0.43	6.84	-
Turkey	14.04	38.29	-	1.10	6.53	95.03	0.03	0.12	-	0.07

Combustible fuels are divided int two main categories: Fossil fuels and combustible renewables and waste (CRW). Fossil fuels involve coal (hard, brown, peat, gases), oil and natural gas. CRW are non-fossil fuels that can be combusted to produce heat that can be used for electricity generation directly or by converting to steam. CRW comprises five sub-categories: wood / wood waste / other solid waste, industrial waste, municipal waste (renewable and non-renewable), biogas (landfill gas, sewage sludge gas and other biogas) and liquid biofuels and waste.

In the world, coal is the major electricty producer with 8,216 TWh forming 41.4% of global electricity production in 2007. OECD electricity production from coal is 3,957 TWh that is 48% of global production from coal, while the remaining 52% of global production from coal takes place in non-OECD in 2007. China is the largest producer from coal with 2,685 TWf forming 32.7 of global electricity production from coal. China is followed by the USA with 2,118 TWh forming 25.8% of global electricity production from coal. In 2007, the share of electricity produced from coal in electricity production is 80.9%, 48.7% and 28% in China, the USA and OECD Europe respectively.

In the world, natural gas is the second largest source for electricity prduction with 4,126 TWh forming 20.8% of global electricity production in 2007. OECD electricity production from coal is 2,307 TWh that is 56% of global production from coal, while the remaining 44% of global production from coal takes place in non-OECD in 2007. OECD Europe produces 802 Twh electricity from coal comprising 19.4% of global electricity prduction from natural gas.

In the world, oil produces 1,118 TWh electricity forming 5.6% of global electricity production in 2007. OECD electricity production from coal is 434 TWh that is 39% of global production from coal, while the remaining 61% of global production from coal takes place in non-OECD in 2007.

CRW produces 2.0% of OECD electricity whereas it produces 0.5% of non-OECD electricity in 2007. In nominal terms, 258 TWh electricity is produced from CRW in the OECD and 41 TWh electricity is produced from CRW in non-OECD.

Table 17 shows gross electricity production in the OECD by sources and their average annual growth rates as follows:

Table 17. Gross Electricity Production in the OECD by Sources in TWh in 1973, 1990, 2007 and Average Annual Percentage Changes (IEA, 2009c)

	1973	1990	2007	Average Annual Perc. Change 1973-1990	Average Annual Perc. Change 1990-2007
Gross Production	4,467.3	7,611.6	10,718.5	3.2%	2.0%
Nuclear	188.5	1,724.8	2,272.6	13.9%	1.6%
Hydro	925.6	1,213.0	1,332.0	1.6%	0.6%
Geothermal	6.6	28.7	40.2	9.0%	2.0%
Solar	-	0.7	4.6	-	11.9%
Tide, wave, ocean	0.6	0.6	0.6	0.4%	-0.5%
Wind	-	3.8	149.7	-	24,0%
Combustible Fuels	3,346.0	4,639.9	6,915.2	1.9%	2.4%
Coal	1,694.0	3,054.6	3,957.3	3.5%	1.5%
Oil	1,125.2	691.7	433.8	-2.8%	-2.7%
Gas	520.2	771.1	2,306.9	2.3%	6.7%
Comb. Renew. and Waste	6.6	122.5	217.3	18.7%	3.4%

In the OECD, electricity production increased at an average annual growth rate of 3.2% during 1973-1990 period, and slowed down to 2.0% during 1990-2007 period. Nuclear power production growth rate per annum has slowed down incredibly from 13.9% for 1973-1990 period to 1.6% for 1990-2007 period. The annual growth rates of combustible fuels increased from 1.9% for 1973-1990 period to 2.4% for 1990-2007 period. So, 2.4% growth rate of combustible fuels electricity production exceeded 2.0% total electricity production growth rate during 1990-2007 period, while it was below 3.2% total electricity production growth rate during 1973-1990 period. This comes from the drastic slow down in nuclear power growth rates that was compensated by combustible fuels. Within combustible fuels, natural gas as a source of electricity production has increased significantly, from 520 TWh in 1973 to 771 in 1990 and then to 2,307 TWh in 2007 with an average annual growth rate of 2.3% for 1973-1990 period and 6.7% for 1990-2007 period. The installed capacities of combustible fuels growth rate increased as well from 2.2% to 2.6% when 1973-1990 and 1990-2007 periods are compared. Electricity generated from oil in the OECD decreased significantly from 1,125 TWh in 1990 to 434 TWh in 2007 by an average of 2.8% per annum. Electricity generated from CRW in the OECD increased from 7 TWh in 1973 to 122 TWh in 1990 and then to 217 TWh in 2007. The average annual growth rate of CRW in the OECD electricity production has slowed down from 18.7% for 1973-1990 period to 3.4% for 1990-2007 period.

The electricity generation from renewables in the OECD increased from 1,310 TWh to 1,636 TWh between 1990 and 2007 but the share of renewables in electricity generation decreased from 17.3% in 1990 to 15.4% in 2007. Renewable electricity generation has grown at an average annual rate of 1.3%, while total electricity generation has grown at 2.0% since 1990. This low growth rate of renewable electricity largely comes from the slow growth rates in hydro power. While hydro electricity generated 15.4% of total OECD electricity in 1990, it generated only 11.8% of total OECD electricity in 2007 since hydro power has reached its capacity limit in most OECD countries.

The share of renewable electricity in electricity generation decreased significantly, in the emerging economies of the OECD, such as Korea, Mexico and Turkey. Electricity consumption of these countries and so generation has increased very rapidly in these countries since 1990. This electricity demand was mostly met by electricity generation from traditional fossil fuels rather than renewables because of high installation costs and long construction periods of renewables.

Although very small, the share of renewable electricity excluding hydro power has grown from 1.8% in 1990 to 3.6% in 2007. The increase is mainly due to OECD Europe, where implementation of strong renewables stimulation policies by European Union member countries encouraged the growth of new renewables production. Policy initiatives such as feed-in tariffs and tax incentives have made electricity generation from renewable sources marketable in many countries. However, the OECD total went down in their overall renewables share of electricity production between 1990 and 2007 as OECD North America and OECD Pacific experienced decreases.

Renewables sources in the electricity generation of the OECD will be mentioned individually further as follows:

In the OECD, annual growth rates of hydro and geothermal power slowed down from 1.6% and 9.0% to 0.6% and 2.0% respectively when 1973-1990 and 1990-2007 periods are compared. The slow down in hydro power comes from the fact that hydro power has reached its potential capacity limit in most OECD countries. In 2007, the largest hydro power generating countries were Canada with 368 TWh, the USA with 250 TWh and Norway with 134 TWh. The USA with 16.8 TWh is the largest producer of electricity from geothermal energy accounting for 41.8% of electricity generated from geothermal energy in the OECD in 2007. The USA is followed by Mexico with 7.4 TWh, Italy with 5.6 TWh.

New renewables increased at high growth rates due to the developments in these technologies and cost reductions, increasing concern for climate change and their low values in base years. Wind and solar power increased at average annual growth rates of 24% and 11.9% respectively during 1990-2007 period.

In 2007, 9.1% of renewable electricity was generated from wind power in the OECD. Electricity generated from wind exceeded electricity generated from solid biomass for the first time in 2006. Most of the growth occurred in OECD Europe with an average growth rate of 33.5% per annum, where wind energy is heavily subsidised. In 2007, Germany, the USA and Spain are the largest producers of electricity from wind with 39.7 TWh, 34.6 TWh and 27.5 TWh respectively.

Electricity generated from solar photovoltaic increased from 19 GWh to 3,920 GWh in the OECD between 1990 and 2007 with an average growth rate of 36.8% per annum. European Union showed the highest growth rates, especially Germany has the fastest growth rate with 60.4% per annum increasing from 1 GWh in 1990 to 3,075 GWh in 2007 because of its high feed in tariffs for solar photovoltaic electricity generation.

Solar thermal power production reached 887 GWh in 1998, but then decreased from their peak in 1999. Prior to 2007, production took place exclusively in the USA and was 673 GWh in 2007. Spain opened a new solar thermal power plant in 2007 and became the second OECD country generating electricity from solar thermal and electriciy generated from solar thermal became 681 GWh in the OECD in 2007.

550 GWh of electricity were generated from tide, wave and ocean motion in 2007 in the OECD. The largest producer was France generating 519 GWh from tidal movements in 2007. The second electricity producer from tide, wave was Canada, producing 31 GWh.

Electricity generated from solid biomass increased from 93.1 TWh to 122.2 TWh in the OECD between 1990 and 2007 with an average growth rate of 1.6% per annum. The share of electricity generated from solid biomass forms 7.5% of total electricity in the OECD in 2007 that is the third largest renewable electricity source after hydro power and wind power. The USA with 42 TWh is the largest producer of electricity from solid biomass accounting for 34.4% of electricity generated from solid biomass. The USA is followed by Japan with 15.8 TWh, and Germany with 10.4 TWh.

Electricity generated from renewable municipal waste is 28.6 TWh forming 1.7% of renewable electricity generation in 2007 in the OECD. The USA with 9.6 TWh is the largest producer of electricity from renewable municipal waste accounting for 33.5% of electricity generated from renewable municipal waste in the OECD in 2007.

Electricity generated from biogas increased from 3.6 TWh in 1990 to 28.5 TWh in 2007. Germany with 8.5 TWh is the largest producer of electricity from biogas accounting for 29.9% of electricity generated from biogas in the OECD in 2007. Germany is followed by the USA with 7.4 TWh, and the United Kingdom with 5.1 TWh.

Electricity generated from liquid biomass was 3.6 TWh in 2007. The largest electricity producer from liquid biomass was Germany with 2.9 TWh.

In the OECD installed capacity fuelled by renewable sources (excluding hydro pumped storage and industrial waste, but including non-renewable municipal waste capacity) is 480.2 GW in 2007 that accounts for around 19% of the OECD capacity. 348.5 GW are hydro power plants (excluding pumped storage) followed by 78.3 GW of wind power, 23.6 GW of solid biomass, 9.6 GW of municipal waste, 7.8

GW of solar photovoltaic, 5.7 GW of gas from biomass, 5.4 GW of geothermal, 0.8 GW of industrial waste, 0.6 GW of liquid biomass, 0.5 GW of solar thermal, and 0.3 GW of tide, wave, and ocean power capacity. Pumped storage capacity was 92.7 GW. Capacity growth has been strongest in the wind and solar power and they are very concentrated.

Table 18 shows non-OECD electricity production by sources in 2007 as follows:

Table 18. Non-OECD Gross Electricity Production By Sources in 2007 in TWh (IEA, 2009c)

Energy Source	Gross Production	Percentage Share
Coal	4,258	46.7%
Oil	684	7.5%
Gas	1,819	19.9%
CRW	41	0.4%
Hydro	1,830	20.0%
Nuclear	446	4.9%
Geothermal, wind, solar, tide, wave	47	0.5%
Total Non-OECD Production	9,126	100.0%

Non-OECD electricity production is 9,126 TWh in 2007 increasing by 7.7% compared to 2006. Electricity production in non-OECD has increased at an average annual growth rate of 5% during 1973-2007 period. As a result of high growth rates compared to the OECD, the share of non-OECD in electricity production has increased from 27% in 1973 to 46% in 2007. Combustible fuels is the largest source in non-OECD electricity production with 74.5% in 2007, more specifically 74.1% for fossil fuels and 0.4% for CRW. Within fossil fuels coal produces 46.7% of total electricity, oil 7.5% and natural gas 19.9%. In 2007, hydro power supplies 20% of non-OECD electricity, while the share of nuclear power is 4.9% and the share of geothermal, solar, wind and others is 0.5%.

Hydro power in non-OECD increased at an average annual growth rate of 4.8% during 1973-2007 period and increased by 4.3% in 2007 compared to 2006. Nuclear power increased at an average annual growth rate of 26% during 1973-1985 period while it became 3% for 1985-2007 period. Nuclear power increased by 2.5% in 2007 compared to 2006. In 2007, geothermal power and wind power increased by 1.6% and 67.4% respectively compared to 2006.

Combustible fuels in non-OECD increased at an average annual growth rate of 7.3% during 1973-2007 period and exceeded total electricity annual growth rate of 5% thereby increasing their share in non-OECD total electricity. Hard coal is the largest source of non-OECD electricity production with 3,939 TWh and increased at an average annual growth rate of 5.7% since 1978 and increased by 11.8% in 2007 compared to 2006. Electricity produced from oil has remained between 560 TWh and 685 TWh since 1984 but its share in non-OECD total electricity declined from 23% in 1973 to 7.5% in 2007. The share of electricity from natural gas increased until the mid 1980s and stayed around 20% thereafter. Production from natural gas increased by 6.4% in 2007 compared to 2006. Non-OECD electricity produced from CRW increased by 14% in 2007 compared to 2006.

In the OECD, electricity consumption increased at an average annual growth rate of 2.7% during 1973-2007 period whereas Korea, Turkey, Mexico, Portugal and Iceland experienced 10.6%, 8.2%, 5.6%, 5.4% and 5.1% growth rates per annum respectively. The USA annual growth rate has been 2.5% and OECD Europe 2.4% during the same period. Table 19 shows the OECD electricity consumption by sectors and their average annual growth rates as follows:

Table 19. Electricity Consumption[1] in OECD By Sectors in TWh in 1973, 1990, 2007 and Average Annual Percentage Changes (IEA, 2009c)

Sectors	1973	1990	2007	Average Annual Perc. Change 1973-2007
Industry	1,836.12	2,558.98	3,144.57	1.6%
Transport	61.47	89.76	113.83	1.8%
Agriculture and Fishing	43.99	68.67	113.83	2.1%
Commercial and Public Services	726.76	1,678.25	2,853.26	4.1%
Residential	1,081.93	1,960.73	2,879.05	2.9%
Energy	128.67	211.48	266.67	2.2%
Sector non specified	7.23	10.66	164.91	9.6%
Statistical Difference	0.00	-3.06	4.23	-
Total Consumption	3,886.18	6,581.59	9,506.14	2.7%

[1]Electricity consumption refers to electricity production plus imports less exports less electricity used at power stations (own use) less electricity used for pumped storage, heat pumps and electric boilers, less transmission & distribution losses. Electricity final consumption refers to electricity consumption less energy sector consumption.

Industry, residential and commercial / public services are the major sectors with 33%, 30% and 30% of total OECD consumption. When the trends of these sectors during 1973-2007 period are analysed, residential and commercial / public serivices has grown by 2.9% and 4.1% per annum respectively exceeding the total consumption growth rate of 2.7%, thereby increasing their shares in total consumption from 27.8% to 30% and from 17.8% to 30% respectively. During the same period industrial electricity consumption experienced an average annual growth rate of 1.6% thereby decreasing their share from 47.2% in 1973 to 30.1% in 2007.

Non-OECD electricity consumption is 7,194 TWh in 2007 increasing by 8.7% compared to 2006 level. During 1973-2007 period non-OECD electricity consumption increased at an average annual growth rate of 5% thereby increasing their share in global consumption from 26.3% in 1973 to 43.7% in 2007. People’s Republic of China, Russia, India and Brazil have 60% of non-OECD consumption. People’s Republic of China experienced 9.1% annual growth rate during 1973-2007 period.

Although electricity has not alternatives in some uses, it competes with other energy sources in many sectors. Table 20 shows the shares of energy sources in the OECD final energy consumption by sectors in 2007 as follows:

Table 20. Percentage Shares of Energy Sources in Final Energy Consumption in OECD By Sectors in 2007 (IEA, 2009c)

Sectors	Coal	Oil	Natural Gas	CRW	Geoth ermal	Solar	Electricity	Heat
Industry	13.21%	14.78%	29.69%	8.19%	0.03%	0.01%	31.02%	3.05%
Transport	0.01%	95.42%	1.88%	1.90%			0.79%	
Agriculture and Fishing	1.76%	75.27%	7.71%	2.93%	0.27%	0.02%	11.52%	0.52%
Commercial and Public Services	0.79%	13.29%	30.42%	0.99%	0.16%	0.07%	52.63%	1.64%
Residential	1.74%	14.20%	38.09%	7.50%	0.32%	0.43%	35.64%	2.08%
Sector non specified	0.19%	4.22%	20.74%	0.05%	0.47%	0.10%	31.32%	42.90%
Non-energy Use	0.63%	90.37%	9.00%					
Total Final Consumption (%)	3.57%	49.70%	19.57%	4.07%	0.10%	0.09%	21.08%	1.82%
Total Final Consumpt.(Mtoe)	134.77	1,874.40	738.20	153.53	3.68	3.48	794.96	68.48

In 2007, electricity meets 21.1% of total final consumption (TFC) of energy in the OECD with 795 Mtoe. Oil is the dominant energy source in TFC with 49.7 share. Natural gas comes just after electricity as the third major source with 19.6% share in TFC. Coal, CRW and heat have 3.6%, 4.1% and 1.8% shares in TFC respectively. Each of geothermal and solar have only 0.1% shares in TFC in the OECD in 2007. In the OECD industry sector, electricity is the largest source supplying 31% of TFC, followed by natural gas with 29.7%, oil 14.8%, coal 13.2%, CRW 8.2% and heat 3.1%. In the OECD residential sector, natural gas is the largest source supplying 38.1% of TFC, followed by electricity with 35.1%, oil 14.2%, CRW 7.5%, heat 2.1% and coal 1.7%. In the OECD commercial / public sector, electricity is the major source supplying 52.6% of TFC, followed by natural gas with 30.4%, oil 14.2%, heat

2.1%, coal 1.7%. In the OECD transportation sector, oil is the dominant source supplying 95.4% of TFC, followed by natural gas and CRW with 1.9% each.

Table 21 shows electricity prices for industrial consumers as follows:

Table 21. Electricity Prices For Industry in OECD in US Dollars / kWh (IEA, 2009c)

	1990	2000	2007	2008
OECD	0.066	0.059	0.094	
OECD Europe	0.072	0.051	0.116	
The USA	0.048	0.046	0.064	0.070
Turkey	0.082	0.080	0.109	0.139

Average electricity prices in the OECD was 6.6 US cent / kWh in 1990 and declined to 5.9 US cent / kWh in 2000 and increased to 9.4 US cent / kWh in 2007. In 2007 average electricity prices in OECD Europe is 11.6 US cent / kWh that is above OECD average. In the USA, average electricity prices have been below the OECD averages and in 2007 it is 6.4 US cent / kWh that is nearly half of the OECD Europe average prices. In Turkey average electricity prices have been above the OECD averages, reaching 10.9 US cent / kWh in 2007 and then increasing sharply to 13.9 US cent / kWh in 2008.

In 2007 the lowest average electricity prices have been 4.8 US cent / kWh in Norway, 5.6 US cent / kWh in France, 6.4 US cent / kWh in the USA, 6.8 US cent / kWh in New Zealand, 6.9 US cent / kWh in Korea. In 2007 the highest average electricity prices have been 23.7 US cent / kWh in Italy, 14.9 US cent / kWh in Ireland, 13.7 US cent / kWh in Slovak Republic, 13.7 US cent / kWh in Spain, 13.4 US cent / kWh in Hungary, 13.4 US cent / kWh in Austria, 130 US cent / kWh in United Kingdom, 12.4 US cent / kWh in Portugal, 11.6 US cent / kWh in Japan, 11.5 US cent / kWh in Czech Republic, 10.9 US cent / kWh in Germany and 10.9 US cent / kWh in Turkey. In 2008, within reported countries' data, the most expensive electricity are in Italy with 29 US cent / kWh, Ireland 18.6 US cent / kWh, Slovak

Republic 17.4 US cent / kWh, Hungary 17.0 US cent / kWh, Austria with 15.4 US cent / kWh, 15.1 US cent / kWh in Czech Republic, United Kingdom 14.6 US cent / kWh and Turkey 13.9 US cent / kWh. The cheapest electricity in 2008 is France and Korea with 6.0 US cent / kWh, Norway with 6.4 US cent / kWh, the USA with 7.0 US cent / kWh and New Zealand with 7.1 US cent / kWh.

Table 22 shows electricity prices for household consumers as follows:

Table 22. Electricity Prices For Households in OECD in US Dollars / kWh (IEA, 2009c)

	1990	2000	2007	2008
OECD	0.103	0.101	0.144	-
OECD Europe	0.131	0.107	0.204	-
United States	0.079	0.082	0.107	0.114
Turkey	0.051	0.084	0.122	0.165

Average electricity prices in the OECD for household consumers is 14.4 US cent / kWh in 2007 whereas it is as high as 20.4 US cent / kWh in the OECD Europe. In the USA it was 10.7 US cent / kWh in 2007 and increased to 11.4 US cent / kWh in 2008. In Turkey, average electricity prices for household consumers was 5.1 US cent / kWh in 1990, increased to 8.4 US cent / kWh in 2000, to 12.2 US cent / kWh in 2007 and then to 16.5 US cent / kWh in 2008. So, average electricity prices for household consumers in Turkey have been well below the average prices in the OECD and OECD Europe. This shows that in the OECD, generally average electricity prices for industrial consumers are determined quite below the prices for household consumers whereas the price difference between industrial consumers and household consumers are not significant in Turkey, thereby decreasing Turkey's competitiveness in international markets.

GHG Emissions and Electricity Sector

After a general look at sources of GHG emissions by sectors, this subtitle will focus on the relationship between the electricity generation sector and GHG emissions, by comparing the effects of different electricity generation technologies over GHG emissions.

Table 23 shows GHG emissions from Annex I Parties by sectors and their change from 1990 to 2007 as follows:

Table 23. GHG Emissions / Removals from Annex I Parties by Sector in 1,000 Mt CO_2e in 1990 and 2007 and Percentage Change from 1990 to 2007 (UNFCCC, 2009a)

	1990	2007	Change (%)
Energy	15.19	15.00	-1.3%
Industrial Processes	1.46	1.30	-10.6%
Agriculture	1.64	1.30	-20.6%
Waste	0.53	0.48	-9.4%
LULUCF	-1.39	-1.56	12.7%

Emissions from each sector decreased between 1990 and 2007 when Annex I Parties were taken together. GHG emission removals by LULUCF increased by 12.7%. Most of the GHG emissions come from energy sector whose GHG emissions comprise 87.1% of total GHG emissions including LULUCF in1990 and 90.8% in 2007. And the least percentage decrease has been in the energy sector by 1.3%, whereas agriculture sector experienced the largest percentage decrease by 20.6% from 1990 to 2007.

Since energy sector comprises most of GHG emissions, it is worth to analyse the sources at the sector level. Energy sector is divided into five subsectors: energy industry, manufacturing industries and construction, transport, fugitive emissions and other energy sectors. The trends in aggregate GHG emissions from Annex I Parties in the energy sector are as follows:

Table 24. GHG Emissions from Annex I Parties in the Energy Sector in 1,000 Mt CO_2e, in1990 and 2007 and Percentage Change from 1990 to 2007 (UNFCCC, 2009a)

	1990	2007	Change (%)
Energy Industries	5.75	6.07	5.6%
Manufacturing Industries and Construction	2.57	2.27	-11.7%
Transport	3.19	3.76	17.9%
Other Sectors	2.12	1.75	-17.3%
Fugitive Emissions	1.05	0.88	-15.7%

GHG emissions from transport increased by 17.9% from 1990 to 2007 and energy industries' GHG emissions increased by 5.6%. However, GHG emissions from manufacturing industries and construction, fugitive emissions and other energy sectors decreased by 11.7%, 15.7% and 17.3% respectively, during the same period.

It is clear that, energy sector is the most important sector for climate change. Within the energy sector, the most GHG emitting subsector is the power sector, that accounts for 41% of global CO_2 emissions in 2005 (EWEA, 2009). And improvements in energy efficiency in the power sector are offset by the strong growth in global power demand. Electricity production accounts for over about 10,500 Mt CO_2 in 2004 globally.

Electricity generation has had an average growth rate of 2.6% since 1995 and IEA expects it to continue growing by 2.1–3.3% annually until 2030, that would result in a doubling of global electricity demand (EWEA, 2009). Much of this growth is expected to come from developing Asia, with India and China taking the lead. So, global CO_2 emissions from power production are projected to increase by about 66% between 2004 and 2030, China and India accounting for 60% of this increase.

When the role of power sector in GHG emissions is assesseed, power sector should be the main area of concern to deal with climate change.

The carbon intensity of electricity generation depends on the utilized energy mix of the country in electricity generation (EWEA, 2009). Emissions change significantly according to the fuels used. Emissions from inefficient coal steam turbines are over 900 tCO2/GWh and from oil steam turbines are around 800 tCO2/GWh while modern combined cycle gas turbines produce around 400 tCO2/GWh. Although the global carbon intensity of electricity generation is quite high, that is around 600 tCO2/GWh, it varies significantly on country basis, due to the electricity generation mix of the countries. For example, carbon intensity of electricity generation in China and India are over 900 tCO2/GWh, since share of coal is very high in these countries' power mix; while Brazil produces power with only 85 tCO2/GWh due to the high share of renewable energies in her power mix (EWEA, 2009). OECD carbon intensity is also near to global carbon intensity of 600 tCO2/GWh (EWEA, 2009).

Life cycle assessment process is an important and comprehensive device in evaluating and comparing the emissions of various electricity generation technologies. Life-cycle assessment (LCA) process evaluates the environmental burdens related to a product, process or activity by identifying energy and materials used and wastes released to the environment during the entire life cycle of the product, process or activity involving extracting and processing raw materials; manufacturing, transportation, use, and maintenance; recycling; and final disposal, etc (EWEA, 2009).

Environmental benefits of alternative energy sources can be assessed more accurately by making comparisons between different electricity generation technologies. Table 25 shows emissions of pollutants produced by wind power, coal and natural gas in the whole life cycle by LCAs as follows:

Table 25. Emissions of Pollutants Produced by Wind Power, Coal and Natural Gas in the Whole Life Cycle (EWEA, 2009)

	Onshore wind	Offshore wind	Average wind	Hard coal	Lignite	NGCC
Carbon dioxide, fossil (g)	8	8	8	836	1060	400
Methane, fossil (mg)	8	8	8	2554	244	993
Nitrogen oxides (mg)	31	31	31	1309	1041	353
NMVOC (mg)	6	5	6	71	8	129
Particulates (mg)	13	18	15	147	711	12
Sulphur dioxide (mg)	32	31	32	1548	3808	149

All of these quantities except particulates, are far below the emissions of conventional technologies such as coal and natural gas. For example, 828 g of CO_2 can be avoided per kWh produced by wind instead of coal, and 391 g of CO_2 per kWh in the case of natural gas. Wind power provides significant emission reductions in other pollutants such as methane, nitrogen oxide, NMVOC and sulphur dioxide when compared to coal or natural gas.

Table 26 shows emissions of pollutants produced by wind power and other clean technologies like nuclear, solar PV, solar thermal and biomass CHP in the whole life cycle as follows:

Table 26. Emissions of Pollutants Produced by Wind Power and Other Clean Technologies (EWEA, 2009)

	Average wind	Nuclear	Solar PV	Solar Thermal	Biomass CHP
Carbon dioxide, fossil (g)	8	8	53	9	83
Methane, fossil (mg)	8	20	100	18	119
Nitrogen oxides (mg)	31	32	112	37	814
NMVOC (mg)	6	6	20	6	66
Particulates (mg)	15	17	107	27	144
Sulphur dioxide (mg)	32	46	0	31	250

Wind energy results in lower emissions of CO_2, methane, nitrogen oxide, sulphur dioxides, NMVOCs and particulates than other clean technologies like nuclear, solar PV, solar thermal and biomass CHP.

When it comes to energy balance, modern wind energy technology also has an extremely good energy balance. The CO_2 emissions related to the manufacture, installation and servicing over the 20-year life cycle of a wind turbine are offset after only three to six months of operation, and so results in net CO_2 savings thereafter.

The 97 GW of wind energy capacity installed at the end of 2007 saves 122 million tonnes of CO2 every year (EWEA, 2009). According to GWEC's wind energy senarios, global wind energy capacity can stand at more than 1,000 GW by the end of 2020, producing 2,500,000 TWh annual, that can result in as much as 1,500 $MtCO_2$ savings every year (EWEA, 2009). So, wind power will be analysed in details in succeeding section.

Wind Power Outlook

This section provides an insight about wind energy and the growth of wind energy in the world and European Union. Major areas of focus are installed capacities of wind power, wind energy potentials, economics of wind power and the relationship between wind power and environmental issues. In the first subtitle, after having a look at the place of wind energy in the general classification of energy; global installed wind power capacities, major countries or regions in the wind power market will be mentioned. The second subtitle will focus on wind power in European Union, by analysing recent developments in installed capacities, penetration levels, economics of wind power, relationship between wind power and environmental isues and the EU targets on different scenarios.

Global Wind Power Outlook

This subtitle provides an insight about the place of wind energy in the general classification of energy, growth of global installed wind power capacities, major countries or regions in the wind power market and recent deveopments in this market. The data of this section is obtained from British Petroleum's (2009) Statistical Review of World Energy 2009. The accuracy and validity of this data have been cross checked with the data of Global Wind Energy Council.

Despite high growth rates, renewable energy still represents only a small part of today's global energy picture. Electricity generation from geothermal, wind and solar combined, is estimated to be approximately 1.5% of global electricity generation. However, these sources may make significant contributions to electricity generation at the country level. For example, wind power has a significant share in total electricity generation in Denmark (around 20%), Spain (around 11%) and Germany (around 7%) (BP, 2009).

Figure 13 shows cumulative installed capacities of wind turbines in the world as follows:

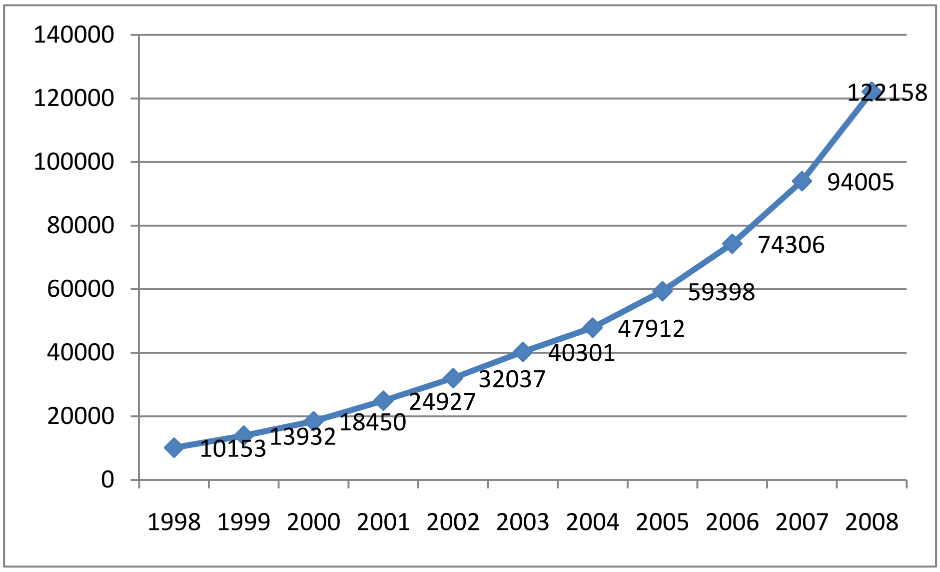

Figure 13. Cumulative installed capacities of wind turbines in the world in megawatts (BP, 2009)

The installed capacity of wind turbines has been growing significantly since 1998 with an annual average growth rate of 28.2% between 1998-2008 period. And the installed capacities inceased nearly eleven times during this ten-year period. Installed capacities increased by 30% in 2008 to 122,158 MW from 94,005 MW in 2007. The capacity in place at the end of 2008 is estimated to produce more than 250 TWh of electricity per annum (BP, 2009).

Table 27 shows cumulative installed wind turbine capacities at the end of 1998, 2007 and 2008 by countries and regions as follows:

Table 27. Cumulative Installed Wind Turbines at the End of Years by Countries and Regions in MW (BP, 2009)

Countries / Regions	1998	2007	2008	Change 2008 Over 2007	Change 2008 Over 1998	2008 Share of Total
US	2,141	16,879	25,237	49.5%	1,078.7%	20.7%
Canada	83	1,845	2,371	28.5%	2,756.6%	1.9%
Mexico	2	86	332	286.0%	16,500.0%	0.3%
Total North America	2,226	18,810	27,940	48.5%	1,155.2%	22.9%
Argentina	14	31	33	6.5%	135.7%	*
Brazil	19	392	687	75.3	3,515.8%	0.6%
Costa Rica	27	79	104	31.6%	285.2%	0.1%
Other S. & Central America	6	79	153	93.7%	2,450.0%	0.1%

Countries / Regions	1998	2007	2008	Change 2008 Over 2007	Change 2008 Over 1998	2008 Share of Total
Total S. & Central America	66	581	977	68.2%	1,380.3%	0.8%
Belgium	10	297	385	29.6%	3,750.0%	0.3%
Denmark	1,420	3,088	3,159	2.3%	122.5%	2.6%
Finland	18	113	113	0.0%	527.8%	0.1%
France	21	2,471	3,671	48.6%	17,381.0%	3.0%
Germany	2,874	22,272	23,933	7.4%	732.7%	19.6%
Greece	55	987	1,102	11.7%	1,903.6%	0.9%
Ireland	64	807	1,015	25.8%	1,485.9%	0.8%
Italy	197	2,721	3,731	37.1%	1,793.9%	3.1%
Netherlands	379	1,745	2,222	27.3%	486.3%	1.8%
Poland	2	313	472	50.8%	23,500.0%	0.4%
Portugal	51	2,150	2,829	31.6%	5,447.1%	2.3%
Spain	880	14,714	16,543	12.4%	1,779.9%	13.5%
Sweden	176	789	1,024	29.8%	481.8%	0.8%
United Kingdom	338	2,394	3,263	36.3%	865.4%	2.7%
Other Europe & Eurasia	87	1,985	2,536	27.8%	2,814.9%	2.1%
Total Europe & Eurasia	6,572	56,851	65,998	16.1%	904.2%	54.0%
Iran	9	91	91	0.0%	911.1%	0.1%
Other Middle East	9	9	9	0.0%	0.0%	*
Total Middle East	18	100	100	0.0%	455.5%	0.1%
Egypt	6	310	384	23.9%	6,300.0%	0.3%
Morocco	0	124	206	66.1%	n.a	0.2%
Other Africa	4	34	106	211.8%	2,550.0%	0.1%
Total Africa	10	469	696	48.4%	6,860.0%	0.6%
Australia	10	972	1,587	63.3%	15,770.0%	1.3%
China	200	5,875	12,121	106.3%	5,960.5%	9.9%
India	992	7,845	9,655	23.1%	873.3%	7.9%
Japan	30	1,681	2,033	20.9%	6,676.7%	1.7%
New Zealand	25	321	325	1.2%	1,200.0%	0.3%
Other Asia & Pacific	5	498	725	45.6%	14,400.0%	0.6%
Total Asia & Pacific	1,261	17,193	26,446	%53.8	1,997.2%	%21.6
Total World	10,153	94,005	122,158	29.9%	1,103.2%	100.0%

*less than 0.05%
Note: Because of rounding some totals may not agree exactly with the sum of their component parts.

Euorope & Eurasia is the leader with 54% share of total installed capacities in the world. On a country basis, Germany and Spain together comprises nearly two-thirds of Euorope & Eurasia capacity. Other dominant regions are North America and Asia & Pacific, with 22.9% and 21.6% shares of world capacity respectively. US has nearly 90% of North American installed capacity and China, India has nearly 83% of Asia & Pacific installed capacity. Other regions such as South & Central America, Africa and the Middle East have less than 1% shares each. So, the global distribution of installed capacities is very concentrated on region and country basis. For example US, Germany and Spain have more than half of the global capacity, and when Chinese and Indian capacities are added these five countries make up 71% of global capacity.

In 2008, the US added the most new capacity by 8.4 GW (growth rate of 49.5%) in nominal terms, so overtaking Germany and becoming the leader in installed capacity of just over 25 GW. Mexico and China recorded the fastest growth rates with 286.0% and 106.3% respectively. Although Mexico increased its capacity nearly 0.2 GW, its growth rate was too high since the installed capacity of base year 2007 was quite low in Mexico. But Chinese capacity increase was significant in nominal terms, too with 6.2 GW increase. So, the US and Chinese capacity increase in 2008 comprised more than half of the global capacity increase. The Chinese wind capacity has been doubling since 2004 every year.

The contribution of wind energy to European electricity generation is increasing significantly. In 2007, wind power provides 21.3% of power generation in Denmark, and 11.8% of power generation in Spain. The contibution of wind power is important in Germany, too by providing about 7.0% of power generation that is nearly two times of the share of hydro. Although US became the leader in installed capacity with nearly 25 GW in 2008, this wind capacity forms only about 2% of total power capacity and provides nearly 1% of power generation. But wind power became the only significant source of power generation growth in the US in 2008 (BP, 2009). EU provides 3.7% of its electricity from wind power in 2008 and wind power forms 7% of total installed capacities in EU. These numbers increased more in 2009 to nearly 4.8% of electricity generation from wind power and to 9.1% for the share of wind power in total installed capacities. Wind power in the EU wil be analysed in more details in the succeeding subtitle.

European Union Wind Power Outlook

This subtitle investigates the recent developments in wind power in the EU. The first subtitle will analyse wind power capacity developments, penetration levels in the EU countries and also compare the share of wind power to other electricity generating technologies in different time periods. The second subtitle will focus on economics of wind power, by analysing cost structure of wind power, effect on spot prices, employment in wind power. The third subtitle will mention a study carried out by European Wind Energy Association (EWEA), estimating wind power capacities in the EU in three different scenarios and comparing investment costs with avoided fuel and CO_2 costs. The fourth subtitle will present environmental issues related to wind power.

Data in this section are obtained from European Wind Energy Association's (EWEA) (2009) Wind Energy – The Facts Report. Data for 2009 values are obtained from EWEA's Press Release of Wind in Power 2009 European Statistics released on 3 February 2010.

Recent Developments in the EU Wind Power

The EU passed 2001 Renewable Energy Directive (EC Directive 2001/77/EC) in 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market with an indicative target of 21% of electricity demand to be covered by renewable energy by 2010. In March 2007 The European Council decided to cover 20% of its energy from renewable energy sources by 2020. A new directive was adopted in December 2008, with a target of raising the share of renewable energy to 20% by 2020 meaning that around 35% of the EU's electricity will come from renewables in 2020. This target is highly ambitious when compared to 8.5% renewable energy share in total energy in 2005 and the 15% share of renewables in electricity. Wind energy seems to be the largest contributor to achieve this target by comprising nearly 35% of the power coming from renewables by 2020. According to this Directive, the overall 20% renewables target in EU is broken down into differentiated national targets for 2020 and each Member State will have drawn up a detailed National Action Plan (NAP) by June 2010 explaining how they will meet their 2020 targets. This NAP may include sectoral targets for shares of renewable energy, the meausures to deal with administrative barriers, grid barriers and other barriers, etc. Also the Member States take an indicative trajectory to follow until 2020. Each member state should reach 20% of the trajectory towards the target by 2011-2012; 30% by 2013-2014, 45% by 2015-2016 and 65% by 2017-2018. These indicative trajectories will be compared according to 2005. If the Member State falls short of their trajectory over any two-year period significantly, she should submit an amended NAP showing how they will compensate the shortfall.

After having a general review on EU regulations and targets, developments in EU wind power capacities will be mentioned as follows. Table 28 shows global and EU cumulative wind power capacities and the share of EU between 1990–2008.

Table 28. Global and EU Cumulative Wind Power Capacity in MW and The Share of the EU Between 1990–2008, (EWEA, 2009)

Year	EU	Rest of The World	Total	Share of EU
1990	439	1,304	1,743	25.2%
1991	629	1,354	1,983	31.7%
1992	844	1,477	2,321	36.4%
1993	1,211	1,590	2,801	43.2%
1994	1,683	1,848	3,531	47.7%
1995	2,497	2,324	4,821	51.8%
1996	3,476	2,628	6,104	56.9%
1997	4,753	2,883	7,636	62.2%
1998	6,453	3,700	10,153	63.6%
1999	9,678	3,916	13,594	71.2%
2000	12,887	4,470	17,357	74.2%
2001	17,315	7,133	24,448	70.8%
2002	23,098	8,150	31,248	73.9%
2003	28,491	10,490	38,981	73.1%
2004	34,272	13,248	47,520	72.1%
2005	40,500	18,591	59,091	68.5%
2006	48,031	26,102	74,133	64.8%
2007	56,535	37,587	94,122	60.1%
2008	64,948	55,843	120,791	53.8%

EU has more than half of total wind power capacities since 1995 and EU's share reached upto 74.2% of total wind power capacities in 2000 but then decreased to 53.8% in 2008. Decline in EU's share did not result from decreases in nominal terms, it comes from the higher capacity growth rates for the rest of the world. In 2008, EU wind power capacity reached upto ten times of the 1998's wind power capacity, showing 26% annual growth rate between 1998-2008. The EU wind power capacity growth rate for 2003-2008 period is 17.9% annually. In 2008 it increased by 14.8%

according to 2007. And it increased by 15.6% in 2009 to 74,767 MW according to 2008. So, the growth rates in EU seem to be stabilising around 15% - 18%. When the installed wind power capacities in rest of the world is analysed, the growth rates accelerate instead of stabilizing, contrary to EU. Annual growth rates of installed wind power capacities in rest of the world for the periods 1998-2008, 2003-2008 and 2007-2008 are 31.2%, 39.7% and 48.6% respectively. And these growth rates are likely to accelerate in the near future when the increasing interests of China, US, etc and the huge potentials of many countries are taken into account.

Table 29 shows global and EU annual increases in newly installed wind power capacities between 1991-2008.

Table 29. Global Annual Newly Installed Wind Power Capacity in MW Between 1991–2008 (EWEA, 2009)

Year	EU	Rest of The World	Total
1991	190	50	240
1992	215	123	338
1993	367	113	480
1994	472	258	730
1995	814	476	1,290
1996	979	304	1,283
1997	1,277	255	1,532
1998	1,700	817	2,517
1999	3,225	216	3,441
2000	3,209	554	3,763
2001	4,428	2,663	7,091
2002	5,913	1,357	7,270
2003	5,462	2,671	8,133
2004	5,838	2,369	8,207
2005	6,204	5,327	11,531
2006	7,592	7,715	15,307
2007	8,554	11,519	20,073
2008	8,484	18,572	27,056

Annual newly installed wind power capacities have been increasing both in the EU and in the rest of the world. Annual installations of wind power have increased steadily from 472 MW in 1994 to 10,163 MW in 2009, with an annual average growth of 23%. In 2009, 10,163 MW of newly installed wind power capacity has been up 23% from the newly installations in 2008. Of the 10,163 MW installed in the EU in 2009, 9,581 MW was onshore, and 582 MW offshore, and growth rates for onshore wind power has been 21%, and for offshore wind power growth has been 56% from 2008 to 2009. On country basis, Spain was the largest market in 2009, installing 2,459 MW, while Germany's newly installations was 1,917 MW. Italy, France and the United Kingdom were in third, fourth and fifth place respectively, with installation of Italy 1,114 MW, France 1,088 MW and the UK 1,077 MW. So, Europe's 2009 installations continue to be characterised by the mature markets of Spain and Germany. But, Italy, France, and the United Kingdom starts to show presence in this market and other EU countries will join this trend in the near future. So, it seems realistic for the EU overall to maintain its current growth by these countries.

In terms of newly installed capacities, although EU was always in front of the rest of the world during 1991-2005 with a significant difference, rest of the world caught up and slighty outpassed EU in 2006 and outpassed significantly in 2007 and 2008. In 2008, rest of the world installed 18,572 MW new wind power capacities whereas EU installed only 8,484 MW new wind power capacities. 8,358 MW newly installed capacity came from US and 6,246 MW came from China, so these two countires' new installations made up 78.6% of new installations in the rest of the world.

Table 30 shows total installed capacities by EU countries in 2009 and their percentage shares as follows:

Table 30. Total Installed Capacities in MW by Countries in EU in 2009 and Their Percentage Shares (EWEA, 2010)

	Total Installed Capacity (MW)	Share of Total (%)
Germany	25,777	34%
Spain	19,149	26%
Italy	4,850	6%
France	4,492	6%
UK	4,051	5%
Portugal	3,535	5%
Denmark	3,465	5%
Netherlands	2,229	3%
Sweden	1,560	2%
Ireland	1,260	2%
Greece	1,087	1%
Austria	995	1%
Poland	725	1%
Other	1,592	2%
EU Total	74,767	100%

Germany is the leader in EU with 25,777 MW capacity forming 34% of EU wind power capacity and Spain comes the second with 19,149 MW and 26% share. On country basis, all other EU countries' wind power capacity is less than 5,000 MW. When Germany and Spain's wind power capacity is compared with other EU countries, there is still much more room for these countries and so for overall EU to increase wind power capacities.

Table 31 shows total installed wind power capacities of Europen countries other than EU-27 Member States in 2009.

Table 31. Total Installed Wind Power Capacities of Europen Countries Other than EU-27 Member States in MW in 2009 (EWEA, 2010)

	Country	Total Installed Capacity (MW)
Candidate Countries	Turkey	801
	Croatia	28
	Macedonia	0
EFTA	Iceland	0
	Liechtenstein	0
	Norway	431
	Switzerland	18
Other European Countries	Russia	9
	Ukraine	94
	Faroe Islands	4

Other European countries not member of EU-27 do not have much installed wind power capacity other than Turkey. Most of this wind power capacity at the end of 2009 in Turkey has been installed in 2008 and 2009. While wind power capacity was only 147 MW in 2007, it reached upto 458 MW in 2008 and 801 MW in 2009. Wind power in Turkey will be analysed in details in the succeeding chapters.

Wind energy penetration is as important as wind power capacity in determining the countries' utilization of wind power. Wind energy penetration measures the percentage of demand covered by wind energy in a certain region, normally on an annual basis. Wind energy penetration is calculated by dividing total amount of wind energy produced to gross annual electricity demand.

Table 32 shows wind energy penetration levels in Europe at the end of 2007 as follows:

Table 32. Wind Energy Penetration Levels in Europe at the End of 2007 (EWEA, 2009)

Country	Wind Energy Penetration (%)
Denmark	21.3%
Spain	11.8%
Portugal	9.3%
Ireland	8.4%
Germany	7.0%
EU-27	3.8%
Greece	3.7%
Netherlands	3.4%
Austria	3.3%
UK	1.8%
Estonia	1.8%
Italy	1.7%
Sweden	1.3%
France	1.2%
Lithuania	1.1%
Luxembourg	1.1%
Latvia	0.9%
Belgium	0.7%
Bulgaria	0.5%
Poland	0.4%
Czech Republic	0.4%
Hungary	0.4%
Finland	0.3%
Slovakia	0.0%
Romania	0.0%
Slovenia	0.0%
Malta	0.0%
Cyprus	0.0%

Wind power meets 3.7% of total EU electricity demand in 2007 by producing 119 TWh electricity from wind power, including 4 TWh offshore. Wind power in EU also has 7.3% of total installed electricity generating capacity in 2007. Denmark takes the lead in wind penetration levels by producing 21.3% of its annual electricity from wind power. Spain, Portugal, Ireland and Germany are also above EU-27 average with 11.8%, 9.3%, 8.4% and 7.0% wind power penetration levels in 2007. UK's penetration level is only 1.8% and France, Italy and Poland has 1.2%, 1.7% and 0.4% penetration levels respectively. So, there is much room for many EU countries given their reatively low penetration levels. In 2009, 74,767 MW of installed wind power capacity forms 9.1% of EU's installed power capacity and meets 4.8% of EU's electricity demand by producing 163 TWh electricity. Only a small portion of this comes from offshore wind installations. Offshore wind comprises only 1.9% of wind capacity with 1,080 MW and 3.5% of the electricity production from wind power.

Table 33 shows installed wind power capacities in MW per 1000 km^2 land area in EU countries as follows:

Table 33. Wind Installation, MW/1000 km^2 (EWEA, 2009)

Country	MW/1000 km^2
Denmark	72.5
Germany	62.3
Netherlands	42.0
Spain	30.0
Portugal	23.3
Luxembourg	13.7
EU-27	12.2
Austria	11.7
Ireland	11.4
Belgium	9.4
Italy	9.0
Greece	6.6
France	4.5
UK	4.4
Sweden	1.8
Czech Republic	1.5
Estonia	1.3
Poland	0.9
Lithuania	0.8
Hungary	0.7
Bulgaria	0.6
Latvia	0.4
Finland	0.3
Slovakia	0.1
Romania	0.0
Slovenia	0.0
Malta	0.0
Cyprus	0.0

Average installed capacity per 1000 km^2 of land area in the EU at the end of 2007 was 12.2 MW. Denmark was again the leader with 72.5 MW per 1000 km^2 land area largely due to its small area compared with Spain and Germany. And Germany, Netherlands, Spain, Portugal and Luxembourg were above EU average, with 62.3, 42, 30, 23.3 and 13.7 MW per 1000 km^2, respectively. France and UK seem to have quite below their potentials with 4.5 and 4.4 MW per 1000 km^2 land area, when their favorable locations and potentials are taken into account.

After anaysing recent developments in EU wind power by comparing with rest of the world and EU country basis, the share of wind power will be compared to other electricity generating technologies as follows. Table 34 shows the shares of energy sources capacities in the EU electricity production capacity in 1995, 2000, 2007 and 2009, thereby enabling to see the changes from 1995 to 2007.

Table 34. Evolution of the EU Energy Mix, 1995 versus 2007 (EWEA, 2009) (EWEA, 2010)

Energy Source	1995	2000	2007	2009
Coal	31%	27.7%	30%	27.9%
Nuclear	24%	22.3%	17%	15.6%
Large hydro	20%	18.3%	15%	14.7%
Fuel oil	13%	11.6%	7%	6.7%
Natural Gas	10%	14.5%	21%	21.6%
Wind	0%	2.2%	7%	9.1%
PV	0%	0%	0%	1.6%
Biomass	0%	0.5%	1%	0.4%
Other	2%	2.9%	2%	2.5%

EU energy mix is on the way of a transition from conventional energy sources like coal, nuclear and large hydro, to more environmentally friendly sources like renewables and natural gas. Coal decreases to 27.9% in 2009 from 30% in 2007. The main sources losing shares during 1995-2009 period are nuclear falling from 24% to 15.6%, fuel oil falling from 13% to 6.7% and large hydro falling from 20% to 14.7%. This decrease is compensated by the increasing share of natural gas from 10% to 21.6%, wind from 0% to 9.1%. Recent increase in share of PV is also encouraging reaching 1.6% despite its high costs. EU energy mix has changed in favour of natural gas and wind from 1995 to 2007 and electricity production capacities from nuclear energy, large hydro and fuel oil have lost significant shares from 1995 to 2009. Between 2007 and 2009, EU energy mix changed in favour of renewable energies more apparently rather than natural gas. Between 2007-2009, while natural gas increased its share from 21% to only 21.6%, wind increased from 7% to 9.1%, PV reached to 1.6%.

Total EU power capacity increased by 200 GW between 2000 and 2007, reaching to 775 GW. During this period, wind energy increased more than four times, from 13 GW to 57 GW; and natural gas nearly doubled to 164 GW. Table 35 shows the newly installed power capacities by energy sources between 2000-2007 as follows:

Table 35. New Power Capacity in EU During 2000-2007 Period (EWEA, 2009)

Energy Source	New Power Capacity (GW)	Percentage Share (%)
Natural gas	81	55%
Wind	47	30%
Coal	10	6%
Fuel oil	4	3%
Large hydro	3	2%
Biomass	2	1%
Nuclear	1	1%
Other	3	2%

Natural gas and wind formed 85% of newly installed capacities. 30% of newly installed power capacity in the EU between 2000 and 2007 was wind power; that comes after natural gas share of 55%. The share of wind was 40% in 2007 in newly installed power capacities with 8.6 GW of 21.2 GW new capacity.

When newly installed capacities in 2009 is analysed, the picture in favour of renewable energies and specifically wind power appears more clearly. 2009 was the second year in which renewable energies formed more than half of the new installations and wind power installed was more than any other generating technology. Newly installed and decommissioned power capacities in 2009 by energy sources and the percentage shares of new installations are as shown in Table 36:

Table 36. Newly Installed and Decommissioned Power Capacities in MW by Energy Sources and Share of New Capacity Installations in 2009 (EWEA, 2010)

Energy Source	New Capacity Installation (MW)	Share of Total (%)	Decommissioned Capacity (MW)
Wind	10,163	39%	115
Natural Gas	6,630	26%	404
Solar PV	4,200	16%	0
Coal	2,406	9%	3,200
Biomass	581	2.2%	39
Fuel Oil	573	2.2%	472
Waste	442	1.7%	24
Nuclear	439	1.7%	1,393
Large Hydro	338	1.3%	166
Concentrated Solar Power	120	0.46%	0
Small Hydro	55	0.2%	0
Other Gas	12	0.04%	0
Geothermal	3,9	0.01%	0
Ocean Power	0,4		0
Total	25,963	100.0%	5813

Of 25,963 MW new capacity installations in 2009; 10,163 MW (39%) was wind, 6,630 MW was natural gas (26%) and 4,200 MW was solar PV (16%). When 581 MW (2.2%) of biomass, 442 MW (1.7%) of waste, 338 MW (1.3%) of large hydro, 120 MW2 (0.46%) of concentrated solar power, 55 MW (0.2%) of small hydro, 3.9 MW (0.01%) of geothermal, and 405 kW of ocean power were taken into account in addition to wind power and solar PV; 15,094 MW renewable energies comprise 61% of new capacity installations in 2009. While share of renewable energies in new capacity installations was 14% in 1995, its share has been increasing since 1994 and reached to 61% in 2009. Renewable energies' share has been more than half of new capacity installations in 2008 and 2009. The nuclear and coal power sectors continued trend of decommissioning more MW than new installations in 2009:

nuclear power sector decommissioned 1,393 MW, and the coal power sector decommissioned 3,200 MW while their new installations were 439 MW and 2,406 MW respectively. So, net capacities of conventional power sources have decreased significantly in nominal terms.

When decommisioning of old capacity is taken into account, net increases or decreases in power capacities during periods of 2000-2007 and 2000-2009 are as shown in Table 37:

Table 37. Net Increase/Decrease in Power Capacity in MW in EU During 2000–2007 and 2000-2009 (EWEA, 2009) (EWEA, 2010)

Energy Source	Net Change in 2000-2007	Net Change in 2000-2009
Natural Gas	76,641	81,067
Wind	46,856	65,102
PV	0	13,027
Large hydro	2,299	2,897
Biomass	1,655	2,450
Fuel oil	–14,385	–12,920
Coal	–11,027	–12,010
Nuclear	–5,871	–7,204
Other	1,795	1,951

Net capacities of fuel oil, coal and nuclear have decreased in nominal terms during 2000-2009, meaning that the removed capacities of these power sources are more than newly installed capacities. Europe is escaping from carbon intensive sources like coal, fuel oil. EU is also cautious about nuclear power due to safety and cost concerns. EU almost stopped adding nuclear capacity in the 1980s, and some Member States plan huge decommissioning programmes over the next ten years. For example, Germany plans to decommission 20 GW of nuclear capacity by 2020. There is only one nuclear reactor under construction in the EU now, that is in Finland, and will add less than 5 GW capacity in the medium term. Although the natural gas capacities increased significantly between 2000-2007, concerns about supply security, energy dependency to Russia and Middle East, and increasing gas prices are likely to decrease the charm of this power source. Therefore only one source remains in hand: namely renewable energy. Wind alone comprises nearly 36% of net increase in power capacity between 2000 and 2007. And new installations of other renewable energy sources like PV combined with wind power especially offshore wind power are likely to be the main actors in EU's energy mix transition period. When net changes during 2000-2007 period and 2000-2009 period are compared, this trend appears more obviously since 2007. Whereas net capacity change in natural gas has been 4,426 MW, net change in wind power and PV capacity has been 18,246 MW and 13,027MW, respectively between 2007-2009 period.

Economics of Wind Power

This subtitle will focus on economic issues related to wind power, such as cost structure of wind power, effect of wind power on spot prices and employment in wind power.

Ongoing improvements in turbine efficiency, high fossil fuel prices and increasing cost of carbon emissions makes wind power more and more feasible in economic terms, and lead to the increasing use of wind power. As mentioned in the preceeding subtitle, while the total wind power capacity was only 1,743 MWs in 1990, it reached up to 120,791 MWs in 2008 in the world.

Wind power project costs is composed of wind turbine installation cost and operational-maintenance (O&M) cost. The main cost component of wind power projects is the cost of the wind turbine. O&M costs are secondary costs in a wind power project since these projects do not use fuels. Firstly, wind turbine installation cost and then O&M cost will be mentioned below:

The total cost per MW of installed wind power capacity differs between countries, from around 1,000,000 €/MW to 1,350,000 €/MW. The total investment cost of an average turbine installed in Europe is about 1.23 million €/MW in 2006, including all additional costs like foundation cost, grid connection cost, electrical installation cost and consultancy cost, etc. In 2009, investment in EU farms have been 13 billion €, while onshore wind power sector attracting 11.5 bilion €, offshore wind power sector attracting 1.5 billion €. When the installed capacities of 9,581 MW of onshore and 582 MW of offshore are taken into account, these unit investment costs for 2006 seem to be current for 2009, too.

Table 38 shows cost structure of a typical 2 MW wind turbine installed in Europe in 2006 per MW.

Table 38. Cost Structure of a Typical 2 MW Wind Turbine Installed in Europe in 2006 per MW (EWEA, 2009)

	Investment Cost (€)	Percentage Share
Turbine (ex-works)	928,000	75.6%
Foundations	80,000	6.5%
Electric installation	18,000	1.5%
Grid connection	109,000	8.9%
Control systems	4,000	0.3%
Consultancy	15,000	1.2%
Land	48,000	3.9%
Financial Costs	15,000	1.2%
Road	11,000	0.9%
Total	1,227,000	100.0%

Main costs come from wind turbine (75.6%), grid connection (8.9%) and foundation costs (6.5%), comprising 91% of total investment costs together.

The swept rotor area (The number of square metres covered by the turbine's rotor) is a good indicator of the turbine's power production, making this measure a suitable index for the development in costs per kWh. From the late 1980s until 2004, total investments per unit of swept rotor area decreased by more than 2% annually due to technological developments, corresponding to a total reduction in cost of almost 30% over these 15 years. But, total investment costs rose by approximately 20% between 2004 and 2006, due to a marked increase in global demand for wind turbines, rising commodity prices and supply constraints.

The experience curve approach relates the cumulative quantitative development of a product to the development of the specific costs by converting the effect of mass production into an effect upon production cost, without taking into account other changes, like technological breakthroughs and commodity price fluctuations. The experience curve simply shows, how much the production costs would decrease if the cumulative production doubles. On costs per kWh produced, learning rates range from 0.17 to 0.09; meaning that, when the total installed capacity of wind power doubles, the costs per kWh produced for new turbines decrease between 9% and 17%. Since wind power capacity has developed on average by 25% - 30% per year for the last ten years; it is reasonable to expect the total wind power capacity to double every three to four years, and so wind power production costs to decrease by approximately 9% - 17% due to learning effect every three to four years. The European Commission, in its Renewable Energy Roadmap, assumes onshore wind energy cost as 948€/kW in 2007 (in €2005) and the costs to drop to 826€/kW in 2020 and €788/kW in 2030 (EWEA, 2009).

Other than investment costs, the second significant portion of wind power project is O&M costs. The components of O&M costs are related to insurance, regular maintenance, repair, spare parts and administration. O&M costs change according to the age of the wind turbine. As the turbine gets older, O&M costs increase due to more repair, spare part, etc. costs. For a new wind turbine, it may comprise 20% – 25% of the total levelised cost per kWh produced over the lifetime of the turbine. For a fairly new one, it may only be 10% – 15%, but this may increase to at least 20% – 35% by the end of the turbine's lifetime. Based on experiences in Germany, Spain, the UK and Denmark, EWEA estimates O&M costs to be around 1.2 to 1.5 c€ per kWh of wind power produced over the total lifetime of a turbine.

The average total cost per kWh produced is calculated by discounting and levelising investment and O&M costs over the lifetime of the turbine and then dividing them by the annual average electricity production. Since this is the average cost over the lifetime of the turbine, actual costs will probably be lower than this average cost at the beginning of the turbine's life because of low O&M costs, and will get higher over the period of turbine use.

The most important factor for the cost per KWh produced is the turbine's power production. Assumptions of EWEA (2009) to estimate unit electricity cost produced from wind power are as follows: Calculations relate to new land-based, medium sized turbines (1.5–2 MW). Investment costs are between 1,100–1400 €/kW, with an average of 1225 €/kW. O&M costs are 1.45 c€/kWh as an average over the lifetime of the turbine. The lifetime of the turbine is 20 years. The discount rate ranges from 5% to 10% annually and an annual discount rate of 7.5% is used in calculations. Taxes, depreciation and risk premiums are not taken into account and all calculations are based on fixed 2006 prices.

According to the EWEA (2009)'s calculations based on these assumptions, the costs range from approximately 7 – 10 c€/kWh at sites with low average wind speeds to approximately 5 – 6.5 c€/kWh at windy coastal sites, with an average of approximately 7 c€/kWh at a wind site with average wind speeds.

A sensitivity analysis for the interest rate (discount rate) would give better ideas since this may change significantly between countries and around 75% – 80% of wind power production costs are related to capital costs, like the costs of turbine, foundations, grid connection and electrical equipment whereas in the conventional fossil fuel-fired technologies, such as natural gas power plants, around 40% – 60% of total costs are related to fuel and O&M costs (EWEA, 2009). The sensitivity analysis shows that, when the interest rates increase from 5% to 10%, the costs range between approximately 6 – 8 c€/kWh in medium wind speed areas, between 8 – 11 c€/kWh in low wind areas, between 5 – 7 c€/kWh in coastal areas (EWEA, 2009).

As mentioned in the preceeding subtitles, the share of wind power in total power production is increasing in EU, especially in Denmark, Spain and Germany where the contribution of wind power to total electricity production is 21%, 12% and 7% respectively. So, wind power becomes an important factor in spot power prices. Since wind power has very low marginal cost because of zero fuel costs, it enters near the bottom of the power production supply curve, shifting the curve to the right. The shift in supply curve results in lower power prices. The extent of the price reduction changes according to the price elasticity of the power demand. The impact of wind power on spot prices depends on the time of day . For example, at midday when power demand is very high, most of the available wind generation can be used, resulting in strong impact on reducing the spot power price since the price is on the steep part of the supply curve. But during the night, when power demand is low, the impact of wind power on the spot price is low since the price is on the flat part of the supply curve. Also, the months of the year and the hours of the day is highly correlated with spot prices. In some hours of the day, wind power penetration ranges from 0 to more than 100%, depending on the speed of the wind.

A study carried out in Denmark that is the leading country with 21% wind power penetration, shows that the price of power to consumers (excluding transmission and distribution tariffs, and VAT and other taxes) in 2004 to 2007 would have been approximately 4% – 12% higher if wind power had not contributed to power production, meaning that in 2007, power consumers saved approximately 0.5 c€/kWh (EWEA, 2009). Although this is lower than consumer payments to wind power of approximately 0.7 c€/kWh as feed-in tariffs, meaning the cost of wind power to consumers is still greater than the benefits, lower power prices lead to a noticeable reduction in net expenses (EWEA, 2009).

Wind power may also have significant effects on energy employment. There is an obvious trend of energy employment decline in Europe, especially in the coal sector. In EU countries, more than 150,000 utility and gas industry jobs disappeared in the second half of the 1990s and it is estimated that another 200,000 jobs will be lost during the first half of the 21st century (EWEA, 2009). Renewable energy sector may mitigate these negative trend in the power sector. The energy sector in EU employs 2.69 million people, that is 1.4% of total EU employment. Around half of this is employed in the production of electricity, gas, steam and hot water. Employment from the wind energy sector, that is nearly 150,000 people makes up around 7.3% of employment. When 3.7% share of wind energy in EU electricity is taken into account, wind energy seems to be more labour intensive than the other electricity generating technologies. Wind energy companies in the EU create empoyment for 108,600 people directly, and around 150,000 people both directly and indirectly in 2007. Direct jobs refer to employment in wind turbine manufacturing companies and sub-contractors supplying mainly wind turbin components, wind energy promoters, utilities selling electricity from wind energy, and specialised wind energy services. Indirect jobs refer to employment in wind-related activities in companies that do not mainly operate in the wind industry. According to a survey carried out by EWEA (2009), direct employment by type of company is as shown in Table 39:

Table 39. Direct Employment by Type of Company (EWEA, 2009)

Type of Company	Percentage Share
Manufacturers	37%
Component manufacturers	22%
Developers	16%
IPP/Utility	9%
Installation/Repair/O&M	11%
Consutancy/Engineering	3%
R&D/University	1%
Financial/Insurance	0.3%
Others	1%

Manufacturers of wind turbine and its components account for 59% of the jobs. There is a strong relationship between wind energy direct empoyment in a country and the country's installed capacity. Germany, Spain and Denmark that have nearly 70% of installed capacity in the EU, have 75% of wind energy direct employment in the EU in 2007. According to analysis of EWEA (2009), for each new MW installed, 15,1 jobs are created; and additionally 0,4 jobs are created per MW of installed capacity for operations, maintenance and other activities in the EU.

Scenarios and Targets

This subtitle will mention a study carried out by EWEA (2009), estimating wind power capacities in EU in three different scenarios and comparing investment costs with avoided fuel and CO_2 costs.

The European Commission's 1997 White Paper target on renewable sources of energy was to increase the share of renewable energy in the EU's energy mix from 6% to 12% by 2010. The target for wind energy was to reach 40,000 MW of wind power in the EU by 2010, producing 80 TWh of electricity and saving 72 Mt CO_2 emissions per year (EWEA, 2009). This 40,000 MW target was already reached in 2005. The European Commission has changed its baseline scenario five times since 1996. Targets for wind energy in 2010 has been increased from 8,000 MW to 71,000 MW and target for wind energy in 2020 has been increased from 12,000 MW to 120,000 MW between European Commission's baseline scenarios made in 1996 and 2008.

The European Heads of State agreed on 9 March 2007 to increase the renewable energy share to 20% by 2020. European Commission expects 34% of electricity to come from renewables to reach this target by 2020 and wind power to provide 12% of EU electricity (EWEA, 2009). The share of renewable energy was about 7% of primary energy and 8.5% of final energy consumption in 2005. So, % 20 target is a quite ambitious target.

EWEA has three different scenarios for the years 2010, 2020 and 2030 and so estimates of total wind power capacities in the EU. Table 40 shows wind power installed capacities for EWEA's three wind power scenarios.

Table 40. Wind Power Installed Capacities in EU for EWEA's Three Wind Power Scenarios in GW (EWEA, 2009)

	2010			2020			2030		
	Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
Low Sc.	76.5	3	79.5	120	20	140	160	40	200
Refer. Sc.	76.5	3.5	80.0	145	35	180	180	120	300
High Sc.	76.5	4	80.5	170	40	210	200	150	350

EWEA's (2009) predictions for wind power are 80,000 MW for 2010, 180,000 MW for 2020 and 300,000 MW for 2030 in the reference scenario. EWEA is confident that its 2010 predictions will be met, but uncertain about 2020 and 2030 predictions that largely will depend on the developments in the offshore market.

Table 41 shows electricity production from wind power for EWEA's three scenarios as follows:

Table 41. Electricity Production from Wind Power in EU for EWEA's Three Scenarios in TWh (EWEA, 2009)

	2010			2020			2030		
	Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
Low Sc.	165	11	176	285	76	361	415	156	571
Refer. Sc.	165	13	177	344	133	477	467	469	935
High Sc.	165	15	179	403	152	556	519	586	1104

According to the reference scenario, wind power production will increase to 177 TWh in 2010, 477 TWh in 2020 and 935 TWh in 2030. Assuming European Commission's baseline scenario of an increase in electricity demand of 33% between 2005 and 2030 (4,408 TWh) is realized, wind power's share of EU electricity consumption will reach 5% (177 TWh) in 2010, 11.7% (477 TWh) in 2020 and 21.2% (935 TWh) in 2030. If the new scenarios released by the European Commission in 2006 on high energy efficiency and renewables case is realized, wind energy's share of electricity demand will reach 5.2% in 2010, 14.3% in 2020 and 28.2% in 2030.

Table 42 shows the share of wind power in the reference scenario:

Table 42. Share of Wind Power in the Reference Scenario (EWEA, 2009)

	2000	2007	2010	2020	2030
Wind Power Production (TWh)	23	119	177	477	935
Reference Electricity Demand (TWh)	2577	3243	3568	4078	4408
Wind Energy Share (%)	0.9%	3.7%	5.0%	11.7%	21.2%

The advantage of wind power of being fuel free, enables to predict the cost of producing wind energy throughout the 20 to 25 year lifetime of a wind turbine with great accuracy since it is not affected by highly volatile fuel prices. Although fuel price assumptions are not necessary to estimate electricity cost produced from wind power, fuel prices are necessary to estimate costs avoided by wind power. The costs avoided by wind power are mainly fuel costs and CO_2 costs. The fuel and CO_2 costs that are avoided by installing wind power capacity depend on the assumptions of fuel and CO_2 prices significantly.

According to a study carried out by EWEA, necessary investments to reach installed wind power capacities of EWEA (2009)'s predictions in three different scenarios and avoided CO_2 costs and avoided fuel costs as a result of newly installed wind power capacities during the lifetime of the wind turbine are as shown in Table 43:

Table 43. Savings (million €) Made Depending on the Prices of Fuel and CO_2 per Tonne (EWEA, 2009)

		2008-2010	2011-2020	2021-2030	2008-2020	2008-2030
Oil price 90$, CO_2 25€	Investment	31,062	120,529	187,308	151,591	338,899
	Avoided CO2 Cost	21,014	113,890	186,882	134,904	321,786
	Avoided Fuel Cost	51,165	277,296	455,017	328,462	783,479
Oil price 50$, CO_2 10€	Investment	31,062	120,529	187,308	151,591	338,899
	Avoided CO2 Cost	8,406	45,556	74,753	53,962	128,714
	Avoided Fuel Cost	30,456	165,057	270,843	195,513	466,356
Oil price 120$, CO_2 40€	Investment	31,062	120,529	187,308	151,591	338,899
	Avoided CO2 Cost	33,623	182,223	299,011	215,846	514,857
	Avoided Fuel Cost	67,002	363,126	595,856	430,128	1,025,984

EWEA (2009) calculates CO_2 costs and fuel costs avoided during the lifetime of the wind energy capacity installed for each year from 2008 to 2030, assuming a technical lifetime for onshore wind turbines of 20 years and for offshore wind turbines of 25 years. For example, for installed onshore capacities in 2030, costs avoided during 2030-2050 are taken into account. Another important issue about the calculations is that only the capital cost of wind energy is taken into account, the operation, maintenance costs and replacement costs of some components is not taken into account. The study of EWEA (2009) in Table 43 mainly compares the investment value in an individual year with the avoided fuel and CO_2 cost over the lifetime of the wind turbines. Other important assumptions in the calculations are that wind energy avoids 690 g of CO_2 per kWh produced, and that 42 million € worth of fuel is avoided for each TWh of wind power produced, equivalent to an oil price throughout the period of 90 $ per barrel.

Based on the reference scenario, the annual investments are expected to stabilise at around 10 billion € until 2015, with a gradually increasing share of investments for offshore. By 2020, the annual investments are expected to increase to 17 billion €, with nearly half of investments going to offshore. By 2030, annual investments are expected to reach to about 20 billion €, with 60% of investments for offshore. According to EWEA's reference scenario, approximately 340 billion € will be invested in wind energy in the EU-27 between 2008 and 2030.

In low CO_2 prices (10 €/t) and fuel prices (equivalent of 50 $/barrel of oil) scenario throughout 2008-2030, the wind power investments totaling 339 bilion € over the next 23 years avoid 466 billion € fuel costs and 129 bilion € CO_2 costs whereas in high CO_2 prices (40€/t) and fuel prices (equivalent of 120$/barrel of oil) scenario the savings of fuel costs reach to 1,026 billion € and CO_2 cost saving reaches to 515 billion €. In medium CO_2 prices (25€/t) and fuel prices (equivalent of 90$/barrel of oil) scenario, the cost avoidance will be 783 billion € for fuel costs and 322 bilion € for CO_2 costs.

CHAPTER III

CLIMATE CHANGE AND RENEWABLES ELECTRICITY OUTLOOK OF TURKEY

This chapter provides an insight regarding climate change outlook of Turkey, the impact of electricity generation on climate change, electricity outlook of Turkey and renewable electricity potentials. The aim of this chapter is to provide a comprehensive review to detect problems of Turkey in energy balances, electricity supply security issues, climate change issues and to asssess whether Turkey has enough renewable energy potential and necessary incentives and legislations to utilize these potentials. The first section will present climate change outlook of Turkey and the role of electricity generation on climate change. The second section will analyse the electricity generation from renewables by focusing on Turkish electricity generation capacity projections, current utilizations and potentials of renewables in electricity generation and recent trends.

Climate Change Outlook of Turkey

This section will firstly analyse GHG emissions of Turkey by sectors and gases in details and the importance of power generation in GHG emissions will be stressed. Then Turkey's position in the Kyoto Protocol will be stated with the priority activities to be carried out in the energy sector to combat climate change determined in the National Climate Change Strategy Document (2009) of Turkey.

Greenhouse gas emissions inventory of Turkey has been calculated in accordance with IPCC Guidelines for National Greenhouse Gas Inventories. The emission from land use and land use change are not included in the inventory. The global warming potentials of greenhouse gases were taken into account according to IPCC guidelines as CH_4 21, N_2O 310, HFCs 140-11700, SF_6 23900 times CO_2 global warming potential.

Figure 14 shows GHG emissions of Turkey from 1990 to 2007 in million tonnes (Mt) of CO_2e as folows:

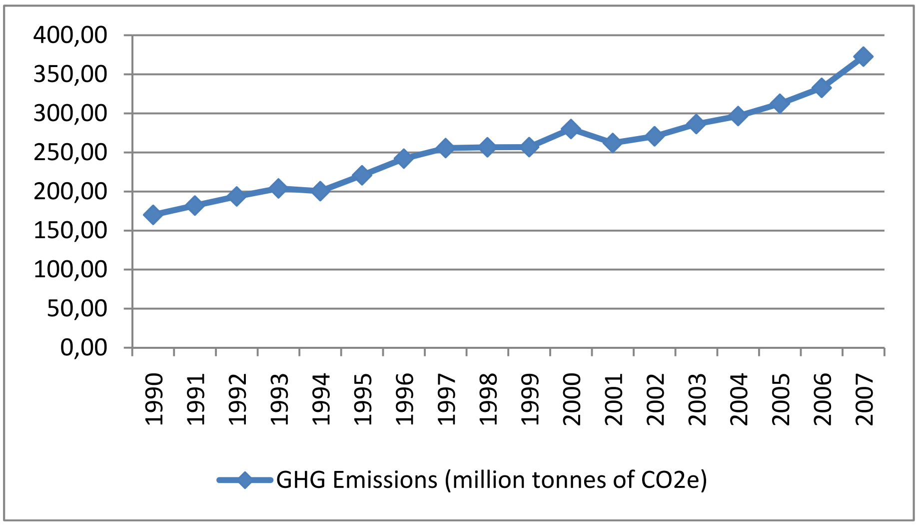

Figure 14. GHG emissions of Turkey from 1990 to 2007 in million tonnes of CO_2e (TSI, 2009)

GHG emissions has been increasing in Turkey since 1990 except the years 1994 and 2001 in which GHG emissions fell according to the preceding year. Turkey had economic crises in these years, showing that economic growth and GHG emissions are highly correlated.

The overall GHG emissions for the year 2007 is 372,6 Mt CO_2e, whereas it was 170,1 Mt CO_2e in 1990, indicating a 119% increase according to 1990. As was mentioned in the preceding sections, Turkey's GHG emissions increased the most in percentage terms in 2007 according to the base year 1990 among Annex I Parties.

When GHG emissions time series data of Turkey is analysed, especially the increase since 2004 has been incredible. GHG emissions increased from 296,6 Mt CO_2e in 2004 to 372,6 Mt CO_2e in 2007, indicating 76 Mt CO_2e increase in nominal terms. Specifically, the increase from 2006 to 2007 has been nearly 30 Mt CO_2e in nominal terms and 12% in percentage terms.

Analysing GHG emissions by sectors may gives more meaningful results in combating with climate change. Table 44 shows GHG emissions by sectors in MtCO_2e as follows:

Table 44. GHG Emissions by Sectors in Turkey in MtCO_2e (TSI, 2009)

	1990	1995	2000	2005	2007
Energy	132.13	160.79	212.55	241.45	288.33
Industrial Processes	13.07	21.64	22.23	25.39	26.18
Agricultural Activities	18.47	17.97	16.13	15.82	26.28
Waste	6.39	20.31	29.04	29.75	31.85
Total	170.06	220.72	279.96	312.42	372.64

288,3 Mt CO_2e of GHG emissions come from energy sector comprising 77,4% of GHG emissions in 2007. The increase in GHG emissions in energy sector has been 118% between 1990-2007. The least increase has been in the agriculture that is only 42%. GHG emissions in industrial process increased 100% and waste increased 398%. Between 1990-2007, the increase in total GHG emissions and increase in energy sector are nearly the same, largely comming from the large share of energy sector in total GHG emissions.

Table 45 shows the percentage shares of GHG emissions by sectors between 1990 – 2007 as follows:

Table 45. The Percentage Shares of GHG Emissions by Sectors Between 1990 – 2007 (%) (TSI, 2009)

Years	Energy	Industrial Processes	Agriculture	Waste	Total
1990	77.70	7.69	10.86	4.83	100.00
1991	75.82	8.37	10.47	7.06	100.00
1992	74.51	8.90	9.73	9.21	100.00
1993	73.92	9.11	9.13	10.61	100.00
1994	74.14	8.45	9.14	11.17	100.00
1995	72.85	9.81	8.14	12.63	100.00
1996	73.92	9.27	7.43	12.68	100.00
1997	74.90	8.68	6.59	13.12	100.00
1998	74.28	8.81	6.51	14.00	100.00
1999	74.23	8.35	6.52	14.67	100.00
2000	75.92	7.94	5.76	13.66	100.00
2001	74.79	8.09	6.02	14.85	100.00
2002	75.39	8.65	5.46	13.92	100.00
2003	76.15	8.43	5.17	13.47	100.00
2004	76.68	8.92	5.12	12.11	100.00
2005	77.28	8.13	5.06	12.32	100.00
2006	77.62	8.43	4.92	11.64	100.00
2007	77.37	7.03	7.05	11.05	100.00

The share of energy sector in total GHG emissions has never fallen below 72% and usually has been nearly between 75-78%. Waste increased its share from 3.8% to 8.5% between 1990-2007, whereas agricultural activities' share decreased from 10.9% to 7.1%. Industrial processes' share decreased slightly from 7.7% to 7.0%. In 2007 GHG emissions, the energy sector has the largest portion with 77%, the waste comes the second with 9%, and the agricultural activities and industrial sectors follow with 7% shares.

Table 46 shows GHG emissions by gases in Turkey as follows:

Table 46. GHG Emissions by Gases in Turkey in $MtCO_2e$ (TSI, 2009)

	1990	1995	2000	2005	2007
CO_2	139.59	171.85	223.81	256.43	304.47
CH_4	29.21	42.54	49.27	49.32	54.38
N_20	1.26	6.33	5.74	3.43	9.65
F Gases	0	0	1.14	3.24	4.13
Total	170.06	220.72	279.96	312.42	372.64

Of 372,64 Mt CO_2e emissions in 2007, 304,47 Mt is CO_2 forming 81.7% of total GHG emissions. And CH_4 forms 14.6%. So, CO_2 comprises most of GHG emissions.

In terms of CO_2 emissions, the highest increase has been observed in energy sector in Turkey with 123% between 1990-2007. It is followed by industrial processes with 71%. Approximately 93% of total CO_2 emission was emitted from energy sector and the rest portion, which is %7, was emitted from industrial proceses in 2007. However, 59% of CH_4 emission is originated from waste, disposal and 33% from agricultural activities while 84% of N_2O emission is from agricultural activities.

Table 47 shows CO_2 emissions of subsectors of the energy sector and industrial processses as follows:

Table 47. CO_2 Emissions by Subsectors in Turkey in Percentage Shares (TSI, 2009)

	1990	1995	2000	2005	2007
Energy	90.76	90.4	92.52	92.05	92.77
1. Power generation	24.37	27.53	34.31	34.53	35.01
2. Manufacturing	26.89	24.43	26.75	26.17	26.28
3. Transport	18.59	19.1	15.62	15.8	16.75
4. Other Energy Sectors	20.92	19.33	15.83	15.55	14.73
Industrial Processes	9.24	9.6	7.48	7.95	7.23
1. Mineral Production	7.96	8.61	7.08	7.54	7.23
2. Chemical Industry	0.59	0.56	0.07	0.23	0
3. Mining Industry	0.69	0.44	0.34	0.18	0

Approximately 93% of total CO_2 emission was emitted from energy sector and %7 was emitted from industrial proceses in 2007. The share of the energy sector has been above 90% during 1990-2007 period. In terms of subsectors of the energy sector, in 2007, 35% of total CO_2 emissions was originated from power generation while 26% from manufacturing industries, 17% from transport and 15% from energy generation of other sectors. So, power generation emitted 35% of total CO_2 emissions in 2007 whereas its share was 24% in 1990. And the share of power sector in total CO_2 emissions has been increasing since 1990. The largest increase has been during 1990-2000 period reaching 34% in 2000 and then the increase slowed reaching 35% in 2007. The slowdown of the increase after 2000 may come from the increased share of natural gas in electricity generation that generates less CO_2 emissions than lignite or other thermal sources.

In order to meet one of her obligations to the United Nations Framework on Climate Change (UNFCCC), Turkey prepared First National Communication of Turkey on Climate Change and submitted to UNFCCC in January 2007. The aim of this Report is to: prepare an inventory of greenhouse gases in Turkey for the period 1990-2004; make an analysis of potential measures to abate the increase in GHG emissions and an assessment of potential impacts of climate change in Turkey and propose adaptation measures; assess cost and benefits of various energy policy alternatives on climate change and to enable the development of sustainable information supply in Turkey on a continuous basis (T.R. Ministry of Environment and Forestry, 2007). According to this Report, general energy demand is projected to reach to 223 mtoe in 2020 with an annual growth rate of 6.1% and final energy consumption is projected to reach to 177 in 2020 mtoe with an annual growth rate of 6.1%. In 2020, the share of electricity energy is projected to increase to 24%, coal to 24%, natural gas to 14% while share of oil is projected to decline to 31% and renewables to 5%. Electricity demand is projected to increase to 499 TWh in 2020 with an annual growth rate of 7.7%. In the Reference Scenario (business as usual scenario without taking any new measures) CO_2 emissions are projected to reach to 605 Mt CO_2 with an annual growth rate of 6.3% of which 222 Mt CO_2 are projected to come from electricity generation. These projections are compatible with the projections of Report on GHG Emissions Reductions in the Energy Sector prepared by the Ministry of Energy and Natural Resources in 2006. According to the First

National Communication of Turkey on Climate Change (2007), electricity generation capacity is projected to reach to 544 TWh in the same year. Of 544 TWh electricity generation capacity, coal is projected to generate 136 Twh (25%), natural gas 199 TWh (36.5%), hydro and other renewables to 118 TWh (22.5%), nuclear 32 (5.8%)TWh and oil 19 TWh (3.6%). Of the 22.5% share of hydro and other renewables projected in 2020, wind power projection is only 1.5% of total generation capacity in 2020.

Consequently, power generation is the most important subsector in terms of CO_2 emissions. To combat with climate change, significant measures should be taken in power generation sector in Turkey.

Energy indicators of Turkey, OECD and world in 2005 are as shown in Table 48:

Table 48. Energy Indicators of Turkey, OECD and World in 2005 (World Energy Council Turkish National Committee, 2008) (IEA Key World Energy Statistics, 2007)

	World	OECD	Turkey
Primary Energy Supply (mtoe)	11,434	5,548	85
Primary Energy Supply (mtoe) per Capita	1.78	4.74	1.18
Primary Energy Supply (mtoe) per GDP	0.32	0.2	0.35
Electricity Consumption (TWh)	16,695	9,800	137
Electricity Consumption (TWh) per Capita	2,596	8,365	1,898
CO2 from Energy Sector (Mt)	27,136	12,910	219
CO2 from Energy Sector (t) per Capita	4.22	11.02	3.04

Turkey’s per capita primary energy supply and electricity generation are below world averages and far below OECD averages. So, electricity consumption and primary energy supply will probably increase in Turkey in higher growth rates in the future. As mentioned, Turkey’s GHG emissions mainly originated from the energy sector and power generation is the most GHG emitting subsector. When the high potential in Turkey’s electricity consumption is taken into account with the long lives of electricity generation plants, source determination from which electricity will be generated carries more importance in future GHG emissions.

Although Turkey's energy intensity seems much more than OECD average in 2005, when energy intensity is measured against GDP based on purchasing power parity, Turkey's is 0.12, the world average is 0.21, and the OECD average is 0.19 toe/$1,000 in 2003 (T.R. Ministry of Environment and Forestry, 2007).

After having analysed Turkey's GHG emissions in details, Turkey's position in the Kyoto Protocol and National Climate Change Strategy Document of Turkey determining the priority activities to be carried out and the urgent measures to combat climate change will be mentioned as follows:

Turkey became a party to the UNFCCC on 24 May 2004 after the Decision 26 that was adopted in the 7th Conference of Parties (COP7) of the UNFCCC in 2001, on deleting the name of Turkey from Annex II and recognizing the special circumstances of Turkey (within Annex-1 countries) accepting that Turkey is in a situation different from that of other Parties included in Annex I. The Coordination Board on Climate Change (CBCC) was reestablished pursuant to the Prime Ministry Circular no 2004/13 to determine the policies and measures of Turkey to combat climate change.

"The Bill on the Endorsement of Turkey's Ratification of the Kyoto Protocol to the UNFCCC" was adopted in the General Assembly of the Turkish Grand National Assembly on 5 February 2009 by Law No 5836 that was published in the Official Gazette No 27144, dated 17 February 2009. The UN Secretary General, was notified on 28 May 2009, after the publication of Cabinet Decree on the "Ratification Instrument" declaring Turkey's accession to Kyoto Protocol in the Official Gazette dated 13 May 2009. According to the Article 25 of the Kyoto

Protocol, Turkey officially became party to the Kyoto Protocol on 26 August 2009, that is the ninetieth day following the date of deposit of the Ratification Instrument to the UN Secretary General.

Turkey developed National Climate Change Strategy Document under the coordination of the Ministry of Environment and Forestry, by the participation of public and private sector institutions, nongovernmental organizations and universities, within the framework of "Developing Turkey's National Climate Change Action Plan Project" in 2009. This project is co-implemented by the Ministry of Environment and Forestry and United Nations Development Programme (UNDP), and National Climate Change Strategy Document was published by the Ministry of Environment and Forestry in December 2009. This Document determines the priority activities to be carried out and the urgent measures to combat climate change. Turkey aims to combat climate change within her own capacity within the framework of "common but differentiated responsibilities", which is one of the basic principles established in the UNFCCC. The data of this section is obtained from National Climate Change Strategy Document.

Welfare of Turkey is relatively low compared to all Annex I Parties which have GHG emissions reduction targets according to the Kyoto Protocol. Even, welfare of most of the Non-Annex I Parties which have rapidly developed recently are better than Turkey. It is obvious that, Turkey's industrialization is not comparable with other Annex I Parties or OECD countries. Some energy indicators of Turkey compared with the world or OECD indicators are stated as follows:

In 2008, Turkey's primary energy consumption per capita is equivalent to 1.29 tons of oil while the world average and OCED average are equivalent to 1.80 and 4.70 tons of oil respectively. Turkey has the lowest values in cumulative GHG emissions, per capita GHG emissions, and per capita primary energy consumption when compared to all Annex I Parties and OECD countries. In 2007, Turkey's per capita GHG emissions value is equivalent to 5.3 tons of CO_2, whereas it is equivalent to 15.0 tons of CO_2 in OECD countries, and 10.2 tons of CO_2 in the European Union.

According to National Climate Change Strategy Document, within the framework of post-2012 international climate change negotiations Turkey will strive to be defined in the category of developing country and to benefit from the flexibilities for the developing countries and the new mechanisms like sectoral approach and crediting Nationally Appropriate Mitigation Actions (NAMAs) still negotiated under the Kyoto Protocol. Turkey seems decisive to make all necessary attempts to sustain its non-Annex-B position for the post-2012 period since commitment on quantified GHG emissions reductions will bring additional burdens on Turkish economy.

In the Strategy Document, Turkey determines measures and policies on sector basis to combat climate change to the extent of accessibility of national and international funding and grants. These sectors are energy; transportation; industry; waste and land use, agriculture and forestry. Since energy sector is the most important sector within the scope of climate change, short term, medium term and long term policies and measures for only the energy sector determined in the Strategy Document will be mentioned as follows:

In the short term (1 year), use of clean and highly efficient resources will be ensured in all new facilities and energy efficiency will be increased by promoting the use of combined heat and power systems, and preventing electricity transmission losses.

In the medium term (1-3 years), use of low and zero emission technologies, primarily the renewable and nuclear energy, will be encouraged; energy efficiency potentials in the buildings will be realized at the maximum level, the R&D activities on clean technologies will be carried out; the domestic industry will be supported in these fields and rehabilitation of existing thermal power plants will be finalized.

In the long term (3-10 years), best technical practices, especially in Turkey's domestic resources such as coal, hydroelectric, wind, geothermal and solar energy, will be used at maximum level, and the share of renewable energy in total electric power generation will be increased up to 25% by 2020, the focus on the transition process to global hydrogen economy will continue, strategies on the use of renewable energy resources by nearby settlements will be developed.

And in the medium term (1-3 years) for the industry sector, the voluntary carbon markets in the industry, allowing the use of GHG emissions as a commercial meta and transforming the emission reduction investment costs into revenues for the enterprises, will be expanded.

So, utilizattion of renewable energy sources in electricity generation will be one of the major policies of Turkey to combat with climate change. Renewables electricity outlook of Turkey will be mentioned in the succeeding section.

Renewables Electricity Outlook of Turkey

The aim of this section is to provide a general idea about the electricity generation from renewables in Turkey. The first subtitle will analyse the energy balance of Turkey in a static approach and the trends in Turkey's primary energy production and consumption patterns by sources in a dynamic approach. The second subtitle will analyse electricity energy in Turkey by sources comprehensively. The third subtitle will mention the Turkish Electricity Energy Generation Capacity Projection (2009-2018) prepared by TEIAS (Turkish Electricity Transmission Company) to show that Turkey should start to install new capacities in 2010 to prevent an energy deficiency in 2014. Then the Electricity Energy Market and Supply Security Strategy Paper will be stated determining ambitious targets for utilizing renewable energy sources in electricity generation. The fourth subtitle will explain regulations and incentives about renewable energy sources by focusing on exisiting laws, amendment proposals and Turkey's progess reports. The fifth subtitle will investigate the potentials and utilization of renewable energy sources in Turkey.

Energy Outlook of Turkey

Having a general idea about Turkey's energy outlook requires analysing energy balances of Turkey. Table 49 shows energy balance of Turkey in 2006 as follows:

Table 49. 2006 Energy Balance For Turkey in ktoe (IEA Statistics, 2006)

Supply and Consumption	Coal and Peat	Crude Oil	Petroleum Products	Gas	Nuclear	Hydro	Geothermal, Solar, etc.	Combustible Renewables and Waste	Electricity	Heat	Total*
Production	13,085	2,134	0	745	0	3,805	1,392	5,170	0	0	26,330
Imports	13,580	23,892	13,071	25,171	0	0	0		49	0	75,764
Exports	0	0	-6,557	0	0	0	0	0	-192	0	-6,750
International Marine Bunkers**	0	0	-971	0	0	0	0	0	0	0	-971
Stock Changes	-217	303	-508	49	0	0	0	0	0	0	-374
TPES	26,448	26,329	5,034	25,965	0	3,805	1,392	5,170	-143	0	93,999
Transfers	0	0	0	0	0	0	0	0	0	0	0
Statistical Differences	21	-85	-16	0	0	0	0	0	0	0	-80
Electricity Plants	-11,132	0	-836	-11,609	0	-3,805	-92	-36	14,498	0	-13,011
CHP Plants	-185	0	-208	-1,680	0	0	0	-7	663	958	-459
Heat Plants	0	0	0	0	0	0	0	0	0	0	0
Gas Works	0	0	0	0	0	0	0	0	0	0	0
Petroleum Refineries	0	-26,314	26,349	0	0	0	0	0	0	0	35
Coal Transformation	-2,144	0	0	0	0	0	0	0	0	0	-2,144
Liquefaction Plants	0	0	0	0	0	0	0	0	0	0	0
Other Transformation	0	71	-73	0	0	0	0	0	0	0	-2
Own Use	-296	0	-1,573	-105	0	0	0	0	-725	0	-2,698
Distribution Losses	-32	0	0	-21	0	0	0	0	-2,134	0	-2,187
TFC	12,680	0	28,676	12,551	0	0	1,300	5,127	12,160	958	73,453
Industry sector	10,192	0	3,115	3,338	0	0	121	0	5,707	958	23,432

Supply and Consumption	Coal and Peat	Crude Oil	Petroleum Products	Gas	Nuclear	Hydro	Geothermal, Solar, etc.	Combustible Renewables and Waste	Electricity	Heat	Total*
Transport sector	0	0	14,805	116	0	0	0	2	68	0	14,990
Other sectors	2,488	0	5,113	8,966	0	0	1,179	5,125	6,386	0	29,255
Residential	2,488	0	1,956	6,181	0	0	1,179	5,125	2,964	0	19,892
Commercial and Public Services	0	0	0	2,784	0	0	0	0	3,040	0	5,824
Agriculture / Forestry	0	0	3,157	0	0	0	0	0	368	0	3,526
Fishing	0	0	0	0	0	0	0	0	13	0	13
Non-Specified	0	0	0	0	0	0	0	0	0	0	0
Non-Energy Use	0	0	5,644	132	0	0	0	0	0	0	5,775
Of which petrochemical feedstocks	0	0	1,692	132	0	0	0	0	0	0	1,824

* Totals may not add up due to rounding.

** International marine bunkers are not subtracted out of the total primary energy supply for world totals.

Turkey's total primary energy supply (TPES) is 93,999 ktoe of which only 26,330 ktoe comes from domestic production. Turkey provides 75,764 ktoe of its TPES from imports and she exports only 6,750 ktoe. Turkey's domestic production only provides 28% of its TPES, and the remaining is provided by imports that stands as one of the major challenges of Turkish energy balance. 27,510 ktoe that forms 29.2% of TPES are used in electricity plants, and 2,080 ktoe (2.2%) of TPES are used in CHP plants. 13,470 ktoe are lost during electricity and heat generation process in these plants and so, 15,161 ktoe electricity and 958 ktoe heat are generated. 2,134 ktoe electricity are lost during electricity distribution process and 725 ktoe are consumed for own use; leaving 12,160 ktoe electricity for final consumption. Other than 725 ktoe electricity consumed for own use, 1,573 ktoe petroleum products, 296 ktoe coal and 105 ktoe gas are consumed for own use, as well. 2,144 ktoe coal are lost during coal transformation process. When these energy losses during electricity generation, coal transformation; energy distribution losses; and energy consumed for own use are subtracted from TPES; it remains only 73,453 ktoe energy for final consumption. So, total final energy consumption (TFEC) comprises only 78% of TPES, meaning 22% energy loss in Turkey's energy balance. Other than huge import dependency of Turkish energy market, energy efficiency appears another major problem of Turkish energy balance. 16,329 ktoe of 20,466 ktoe energy loss occurs within the electricity sector.

When the components of Turkey's TPES is analysed; coal forms 28.1%, crude oil 28.0%, petroleum products 5.4%, natural gas 27.6%, hydro 4.0%, combustible renewables and waste 5.5%, geothermal, solar, wind, etc. 1.5% of TPES. So, the share of renewables in TPES is only 11% of which nearly half is combustible renewables and waste that is consumed by residential usually for heat generation. 89% of TPES of Turkey comes from fossil fuel energies. This appears another main problem of Turkish energy outlook, in today's world of increasing concerns about climate change and high carbon costs that Turkey may confront with, in the near future.

Although the share of domestic production in Turkey's TPES is only 28%, the components of it should be analysed, too. Since Turkey is lack of rich oil or gas reserves, 49.6% of its domestic production is coal and peat, 8.1% crude oil, 2.8% natural gas, 14.5% hydro, 19.6% combustible renewables and waste, 5.3% geothermal, solar, wind, etc. Turkey's reserve to production ratio is 21 years and reserve to consumption ratio is 12 years for coal. In addtion to the low share of domestic production in TPES, the low amount of proved reserves of Turkey's coal, oil and natural gas, when low reserve to production and reserve to consumption ratios are taken into account; the future seems much more gloom for Turkish energy balance. There appears to be only one solution for Turkish energy market: renewables.

When import dependency of Turkish TPES is analysed on type of energy source basis; 49.6% of coal, 8.1% of crude oil, 2.9% of natural gas and none of petroleum products are produced domestically; and the remaining shares of these energy sources are imported.

When Turkey's 73,453 ktoe of total final energy consumption is analysed on sectoral basis; industry sector is the leader with 31.9% of consumption, followed by residential, transport sector, commercial and public services, agriculture-forestry with 27.1%, 20.4%, 7.9% and 4.8% respectively. The mix of final energy consumption is composed of petroleum products with 39.0%, coal and peat with

17.3%, gas 17.1%, electricity 16.6%, combustible renewables and waste 7.0%, geothermal, solar etc. 1.8% and heat 1.3%.

29,590 ktoe energy that forms 31.5% of TPES is consumed in electricity plants and CHP plants for electricity generation. So, electricity generation has a significant share in TPES allocation. Renewable energies used to generate electricity is only 3,933 ktoe that forms 13.3% of 29,590 ktoe energy used for electricity generation. The share of renewable energies in 15,161 mtoe electricity generated before distribution losses and own use, is 25.9%.

As mentioned, 10,367 ktoe renewables forms 11% of TPES. When the components of these renewables are analysed; 5,170 ktoe is combustible renewables and waste forming 49.9% of renewable energy supply, 3,805 ktoe is hydro forming 36.7%, and 1,392 ktoe are geothermal, solar, wind, etc forming 13.4%.

Only 3,933 ktoe renewables comprising 37.8% of total renewable energy supply is used for electricity generation. 6,304 ktoe renewables comprising 60.8% of renewable supply is used by residential. Of 3,933 ktoe renewables used in electricity generation, 3,805 ktoe is hydro, 92 ktoe is geothermal, solar,wind, etc, and 36 ktoe is combustible renewables and waste. So, new generation renewables like wind, solar are nearly absent in Turkish electricity generation in 2006.

After having analysed energy balance of Turkey in 2006 in a static manner, Turkey's primary energy production and consumption will be stated in a dynamic manner to show the trends by energy sources as follows: Table 50 shows primary energy production of Turkey between 1992-2008:

Table 50. Primary Energy Production of Turkey in toe Between 1992-2007 (Nenem, 2009) (TSI, 2008)

	Oil	Natural Gas	Mineral Coal	Lignite	Biomass	Hydro	Solar	Geo. Heat	Others	Total
1992	4,495	180	1,727	10,299	7,209	2,345	60	388	91	26,794
1993	4,087	182	1,722	9,790	7,148	2,988	88	400	36	26,441
1994	3,871	182	1,636	10,471	7,109	2,698	129	415	0	26,511
1995	3,692	166	1,319	10,735	7,068	3,131	143	437	28	26,719
1996	3,675	187	1,382	10,899	7,045	3,553	159	471	15	27,386
1997	3,630	230	1,347	11,759	7,024	3,431	179	531	78	28,209
1998	3,385	514	1,143	12,792	6,983	3,639	210	582	76	29,324
1999	3,063	644	1,023	12,221	6,883	2,971	236	618	0	27,659
2000	2,887	582	1,060	11,418	6,457	2,662	262	648	71	26,047
2001	2,679	284	1,145	11,124	6,211	2,073	287	687	86	24,576
2002	2,564	344	1,047	10,311	5,974	2,906	318	730	88	24,282
2003	2,494	510	1,132	9,501	5,748	3,046	350	784	218	23,783
2004	2,389	644	1,081	9,141	5,532	3,971	375	811	388	24,332
2005	2,395	816	1,184	9,648	5,325	3,410	385	926	460	24,549
2006	2,284	839	1,348	11,545	5,159	3,813	403	898	291	26,580
2007	2,223	819	1,588	12,742	5,027	3,097	420	914	623	27,453

Turkey's primary energy production values in 1992 and in 2007 are similar. Although it increased from 26,794 toe to 29,324 toe between 1992 and 1998, it decreased to 23,783 toe until the year 2003. It started to increase again in 2004 and increased upto 27,453 toe in 2007. During 1992-2007 period, oil production has decreased steadily to 2,223 toe in 2007, that corresponds to nearly half of oil production in 1992. Another energy source that has declined significantly is biomass, decreasing from 7,209 toe to 5,027 toe during 1992-2007 period. Mineral coal has declined slightly to 1,588 toe in 2007. Lignite production has increased significantly from 9,141 toe to 12,742 toe between 2004-2007, but when compared with production of 10,299 toe in 1992, the increase is not significant on annual basis. Contrary to the steady decrease in oil production, natural has increased steadily during 1992-2007 period from 180 toe to 819 toe. When it comes to hydro, although its increase during 1992-1996 period was encouraging, it did not increase much thereafter. On the contrary, it decreased to 2,073 toe in 2001 and then after a fluctuating period its production has been 3,097 toe in 2007. The increase in solar, geothermal heat and other renewables has been steady. Solar increased upto 420 toe in 2007 from 60 toe in 1992. Geothermal heat has increased as well from 388 toe to 914 toe during the same period. Other primary energy production has increased too, from 91 toe to 623 toe between 1992-2007. Despite high growth rates of these renewables from 1992 to 2007, total renewables has not changed from 1992 to 2007, because of the significant decrease in biomass.

Table 51 shows primary energy consumption of Turkey between 1992-2008 as follows:

Table 51. Primary Energy Consumption of Turkey in toe Between 1992-2007 (Nenem, 2009) (TSI, 2008)

	Oil	Natural Gas	Mineral Coal	Lignite	Biom ass	Hydro	Solar	Geo. Heat	Others	Total
1992	24,865	4,197	6,105	10,423	7,209	2,345	60	388	543	56,135
1993	28,114	4,532	5,712	9,918	7,148	2,988	88	400	562	59,462
1994	27,142	4,921	5,124	10,331	7,109	2,698	129	415	388	58,257
1995	29,324	6,313	5,905	10,605	7,068	3,131	143	437	28	62,954
1996	30,712	7,213	7,401	11,187	7,045	3,553	159	471	413	68,154
1997	30,615	9,265	8,291	12,423	7,024	3,431	179	531	2,020	73,779
1998	30,449	9,690	8,592	12,631	6,983	3,639	210	582	1,933	74,709
1999	30,239	11,741	7,426	12,314	6,883	2,971	236	618	2,297	74,725
2000	32,297	13,728	10,147	12,519	6,457	2,662	262	648	1,780	80,500
2001	30,936	14,868	7,305	11,429	6,211	2,073	287	687	1,607	75,402
2002	30,932	16,102	9,039	10,435	5,974	2,906	318	730	1,895	78,331
2003	31,806	19,450	11,461	9,471	5,748	3,046	350	784	1,710	83,826
2004	32,922	20,426	12,356	9,450	5,532	3,971	375	811	1,975	87,818
2005	32,192	24,726	12,693	9,326	5,325	3,410	385	926	2,090	91,074
2006	32,551	28,867	14,901	11,188	5,159	3,813	403	898	1,862	99,642
2007	33,482	32,683	16,593	14,015	5,027	3,097	420	914	1,394	107,625

Primary energy consumption of Turkey has increased significantly during 1992-2007 period, reaching 107,625 mtoe in 2007; although its primary energy production has almost has not changed. Primary energy consumption is highly correlated to economic growth. As Table 51 shows; Turkey's primary energy consumption decreased only in 1994 and 2001, and did not change in 1999, that are the years Turkey was in economic crisis. When the increase in Turkey's primary energy consumption is analysed, annual growth rates in primary energy consumption during periods of 1992-2007, 1997-2007 and 2002-2007 have been 4.4%, 3.8% and 6.6% respectively. When 1997-2007 period is ignored due to the fact that Turkey experienced two huge economic crisis, primary energy production growth rates has accelerated.

When the sources to meet this huge primary energy consumption is anaysed, oil, natural gas and mineral coal play the leading roles. When the fact that, these are all fossil fuels and Turkey is dependent on imports in all of these sources, is taken into account; it is clear that Turkey's energy outlook has gone into worse and worse.

When the fossil fuels are analysed during 1992-2007 period; Turkey's oil consumption has increased from 24,865 to 33,482 toe showing annual growth rate of 2%, natural gas consumption increased from 4,197 to 32,683 toe catching up oil consumption as a result of annual 14.6% growth rates; mineral coal increased from 6,105 to 16,593 toe with 6.9% annual growth rates; lignite increased from 10,423 to 14,014 toe with 2% annual growth rates. The annual growth rates of natural gas and mineral coal have been above the annual growth rate of total primary energy consumption that is 4.4%, resulting in the increases in percentage shares of them. During 1992-2007 period, the changes in percentage shares of these fossil fuels in total primary energy consumption has been, increase from 7.5% to 30.4% for natural gas, from 10.9% to 15.4% for mineral coal; decrease from 44.3% to 31.1% for oil and from 18.6% to 13.0% for lignite.

Turkey’s renewable energy sources are mainly composed of biomass, hydro, solar and geothermal heat. Although these renewables have changed significantly alone during 1992-2007 period, the sum of these renewables did not change much. Since total primary energy consumption has increased incredibly, the share of renewables in total primary energy consumption has decreaesed significantly.

Turkey’s Electricity Energy Outlook

This subtitle will analyse the structure of and the recent trends in electricity generation, capacity installation. After determinig the trends in gross electricity generation, net electricity consumption, total installed capacities in short, medium and long terms, these indicators will be analysed by each primary energy sources and utility types in details and the relationship between them will be displayed.

The most important macro indicators of electricity energy outlook of a country are total installed capacities, gross electricity generation and net electricity consumption of the country. Turkey’s total installed capacities, gross electricity generation and net electricity consumption between 1975-2008 are as shown in Table 52:

Table 52. Installed Capacities of Power Plants, Gross Electricity Generation and Net Electricity Consumption in Turkey Between 1975-2008 (TEIAS, TSI, 2010)

Year	Total Installed Capacity (MW)	Gross Generation (GWh)	Net Consumption (GWh)	Imports (GWh)	Exports (GWh)
1975	4,186.60	15,622.80	13,491.70	96.2	-
1976	4,364.20	18,282.80	16,078.90	332.2	-
1977	4,727.20	20,564.60	17,968.80	492.2	-
1978	4,868.70	21,726.10	18,933.80	621.0	-
1979	5,118.70	22,521.90	19,663.10	1044.3	-
1980	5,118.70	23,275.40	20,398.20	1341.2	-
1981	5,537.60	24,672.80	22,030.00	1616.1	-
1982	6,638.60	26,551.50	23,586.80	1773.4	-
1983	6,935.10	27,346.80	24,465.10	2220.8	-
1984	8,461.60	30,613.50	27,635.20	2653.0	-
1985	9,121.60	34,218.90	29,708.60	2142.4	-
1986	10,115.20	39,694.80	32,209.70	776.6	-
1987	12,495.10	44,352.90	36,697.30	572.1	-
1988	14,520.60	48,048.80	39,721.50	381.2	-
1989	15,808.20	52,043.20	43,120.00	558.5	-
1990	16,317.60	57,543.00	46,820.00	175.5	906.8
1991	17,209.10	60,219.10	49,282.90	759.4	506.4
1992	18,716.10	67,342.20	53,984.70	188.8	314.2
1993	20,337.60	73,807.50	59,237.00	212.9	588.7
1994	20,859.80	78,321.70	61,400.90	31.4	570.1
1995	20,954.30	86,247.40	67,393.90	0.0	695.9
1996	21,249.40	94,861.70	74,156.60	270.1	343.1
1997	21,891.90	103,295.80	81,885.00	2492.3	271.0
1998	23,354.00	111,022.40	87,704.60	3298.5	298.2
1999	26,119.30	116,439.90	91,201.90	2330.3	285.3
2000	27,264.10	124,921.60	98,295.70	3791.3	437.3
2001	28,332.40	122,724.70	97,070.00	4579.4	432.8
2002	31,845.80	129,399.50	102,948.00	3588.2	435.1
2003	35,587.00	140,580.50	111,766.00	1158.0	587.6
2004	36,824.00	150,698.30	121,141.90	463.5	1144.3
2005	38,843.50	161,956.20	130,262.90	635.9	1,798.1
2006	40,564.80	176,299.80	143,070.50	573.2	2,235.7
2007	40,835.70	191,558.10	155,135.20	864.3	2,422.2
2008	41,817.20	198,418.00	161,947.60	789.4	1,122.2

When growth rates and patterns of total installed capacities, gross elecrticity generation and net electricity consumption for the last 30, 20, 10 and 5 years are analysed, the patterns get more obvious. They will be analysed seperately as follows:

Figure 15 shows installed capacities of Turkey between 1975-2008:

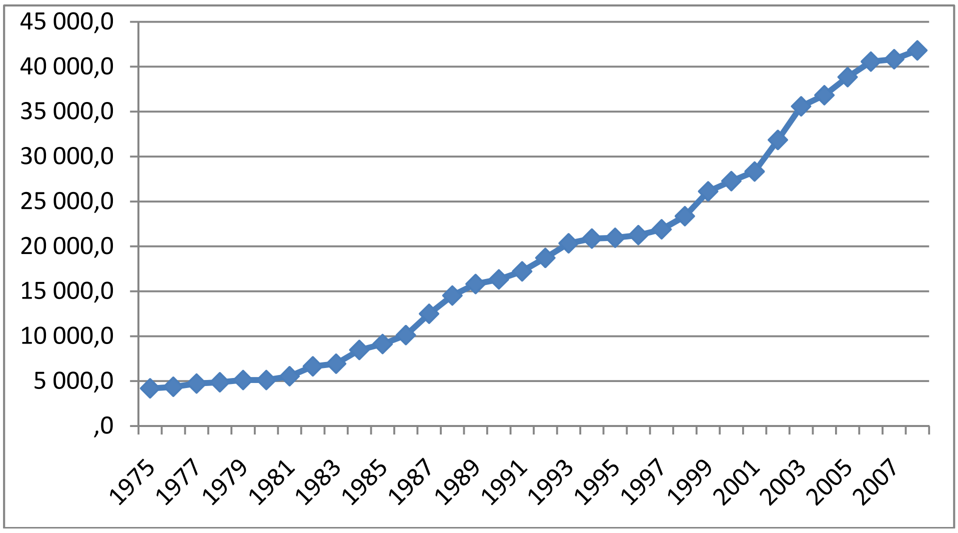

Figure 15. Installed capacities of power plants in Turkey, 1975-2008 (TSI, 2010)

During periods of 1978-2008, 1988-2008, 1998-2008 and 2003-2008; annual growth rates of total installed capacities have been 7.4%, 5.4%, 6.0% and 3.3% respectively. So, the growth in total installed capacities has slowed down recently as seen in Figure 15.

Figure 16 shows gross electricity generation and net electricity consumption of Turkey between 1975-2008 as follows:

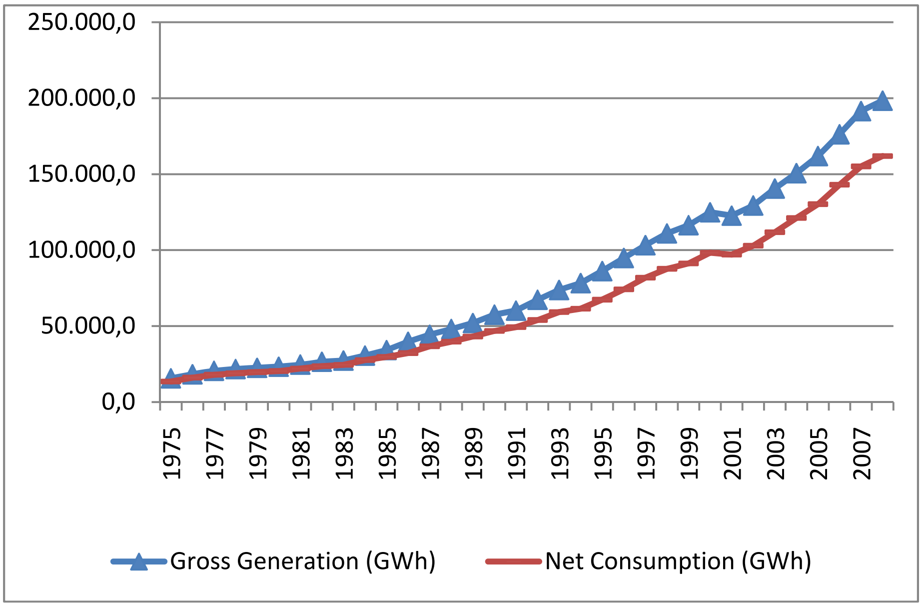

Figure 16. Gross electricity generation and net electricity consumption in Turkey between 1975-2008 (TSI, 2010)

During the periods of 1978-2008, 1988-2008, 1998-2008 and 2003-2008; annual growth rates of gross electricity generation have been 7.7%, 7.3%, 6.0 and 7.1% respectively. During the periods of 1978-2008, 1988-2008, 1998-2008 and 2003-2008; annual growth rates of net electricity consumption have been 7.4%, 7.3%, 6.3 and 7.7% respectively. The annual growth rates of gross electricity generation and consumption are similar, largely due to the low shares of of electricity exports and imports and non-storable nature of electricity.

The annual growth rates of gross electricity generation and net electricity consumption have not changed much for 30 years showing around 7.5% growth rates except 1998-2008 period declining to around 6.0%. This decline for 1998-2008 period looks like the growth patterns of Turkey's total primary energy consumption and largely comes from the 2001 economic crisis experienced during this period. And despite the 2001 economic crisis, electricity generation and consumption declined only around 1%. In 1994 and 1999 crisis, electricity generation and consumption have continued to increase but at a slower rate. In 2009, gross electricity generation declined to 194,112.1 GWh because of the economic crisis.

Table 53 shows Turkey's electricity generation by type of utilities in 2009 as follows:

Table 53. Electricity Generation in Turkey by the Electricity Utilities for 2009 in GWh (TEIAS, 2010)

EUAS	Thermal	42,453.2
	Hydro+Geothermal+Wind	28,322.0
	Total	70,775.2
Affiliated Partnership of EUAS	Thermal	18,668.8
Mobile Power Plants	Thermal	0.0
Production Companies	Thermal	78,435.8
	Hydro+Geothermal+Wind	7,909.7
	Total	86,345.5
Autoproducers + Toor	Thermal	16,686.4
	Hydro+Geothermal+Wind	1,636.2
	Total	18,322.6
Turkey's Total Generation	Thermal	156,244.2
	Hydro+Geothermal+Wind	37,867.9
	Total	194,112.1

State is a major player with its company Electricity Production Inc. (EUAS) and affiliated partnerships of EUAS generating 36.5% and 9.6% of Turkey's total electricity respectively. And the rest of total generation is provided by private companies. Production companies generate 44.5% of total electricity, autoproducers and companies having transfer of operating rights (toor) generate 9.4% of total electricity. 74.8% of electricity generated from hydro, geothermal and wind are provided by EUAS, 20.9% by production companies and the small remaining part of 4.3% is provided by autoproducers and companies having toor.

Table 54 shows electricity generation in Turkey by the electricity utilities between 1975-2008 as follows:

Table 54. Electricity Generation in Turkey by the Electricity Utilities Between 1975-2008 in GWh (TEIAS, 2010)

	EUAS	Affiliated Partnerships of EUAS	Concessionary Companies	Production Companies	Municipal.	Autoproducers	Mobile Power Plants	Toor	Total	Share of EUAS and Its Aff. Partner.
1975	12,844.8		1,730.1		134.7	913.2			15,622.8	82.2%
1976	15,454.3		1,639.0		141.3	1,048.2			18,282.8	84.5%
1977	17,229.9		1,716.3		112.5	1,505.9			20,564.6	83.8%
1978	17,968.0		1,874.9		90.3	1,792.9			21,726.1	82.7%
1979	18,933.9		1,554.3		64.3	1,969.4			22,521.9	84.1%
1980	19,414.5		1,609.7		62.4	2,188.8			23,275.4	83.4%
1981	20,587.5		1,937.5		62.4	2,085.4			24,672.8	83.4%
1982	23,243.1		1,589.7		59.7	1,659.0			26,551.5	87.5%
1983	23,688.9		1,617.6		41.4	1,998.9			27,346.8	86.6%
1984	26,685.7		1,691.1		3.3	2,233.4			30,613.5	87.2%
1985	30,248.9		1,592.2			2,377.8			34,218.9	88.4%
1986	35,470.1		1,454.0			2,770.7			39,694.8	89.4%
1987	39,679.3		1,591.7			3,081.9			44,352.9	89.5%
1988	43,013.6		1,857.9			3,177.3			48,048.8	89.5%
1989	47,454.1		1,316.9	4.8		3,267.4			52,043.2	91.2%
1990	52,854.2		1,304.5	23.0		3,361.3			57,543.0	91.9%
1991	55,460.7		1,369.5	47.0		3,369.1			60,246.3	92.1%
1992	61,533.3		2,014.8	67.0		3,727.1			67,342.2	91.4%
1993	67,099.8		2,466.6	69.2		4,171.9			73,807.5	90.9%
1994	71,942.5		1,686.2	73.7		4,619.3			78,321.7	91.9%
1995	71,544.1	6,650.8	2,301.4	126.2		5,624.9			86,247.4	90.7%

	EUAS	Affiliated Partnerships of EUAS	Concessionary Companies	Production Companies	Municipal.	Autoproducers	Mobile Power Plants	Toor	Total	Share of EUAS and Its Aff. Partner.
1996	69,123.6	16,291.1	2,907.6	468.8		6,070.6			94,861.7	90.0%
1997	72,486.8	18,432.3	2,213.8	2,409.0		7,753.9			103,295.8	88.0%
1998	78,580.9	17,493.9	2,299.2	2,517.1		10,131.3			111,022.4	86.5%
1999	74,401.6	17,910.9	2,169.2	9,224.0		12,529.0	205.2		116,439.9	79.3%
2000	73,941.8	19,292.2	1,902.9	12,038.6		15,962.0	643.5	1,140.6	124,921.6	74.6%
2001	67,468.5	18,893.9	1,345.6	13,279.1		17,914.0	1,117.1	2,706.5	122,724.7	70.4%
2002	60,075.2	17,256.9	4,507.2	19,700.0		20,446.6	3,208.8	4,204.8	129,399.5	59.8%
2003	52,169.5	13,518.1	2,021.1	45,461.0		23,126.9	2,557.9	4,316.7	143,171.2	45.9%
2004	58,514.3	14,881.5	0.0	53,699.7		23,758.2	1,288.0	3,935.2	156,076.9	47.0%
2005	61,629.5	18,363.4	0.0	66,408.8		17,087.2	877.7	4,120.6	168,487.2	47.5%
2006	71,082.4	13,633.7	0.0	72,668.5		14,436.7	418.0	4,060.5	176,299.8	48.1%
2007	73,839.2	18,488.2	0.0	78,840.5		15,325.4	797.3	4,267.5	191,558.1	48.2%
2008	74,919.1	22,797.8	0.0	80,332.8		15,722.6	330.5	4,315.2	198,418.0	49.2%

During 1975-1994 period, EUAS is the main electricity generator providing 82%-92% of total electricity generation, and concessionary companies, autproducers are other players in the electricity market. Affiliated partnerships of EUAS come into the market in 1995, and in 1997 autoproducers, production companies' electricity generation starts to increase significantly in 1999 and thereafter reaches 80,332.8 GWh in 2008. 1999 is also the year EUAS and its affiliated partnerships start to lose significant market share in total generation declining from 86.5% to 45.9% between 1998 and 2003. After 2003, share of EUAS and its affiliated partnerships in total generation increase slightly reaching to 49.2% in 2008.

Table 55 shows electricity generation in Turkey by primary energy sources in 2009 as follows:

Table 55. Electricity Generation in Turkey by Primary Energy Sources in 2009 in GWh (TEIAS, 2010)

Primary Energy Source	Gross Generation	Share of Total
Hard Coal + Imported Coal	15.809,2	8,1%
Lignite	38.832,4	20,0%
Liquid Fuels	6.518,2	3,4%
Natural Gas	94.173,8	48,5%
Hydro	35.904,8	18,5%
Geothermal+Wind	1.963,0	1,0%
Renew and Wastes	910,6	0,5%
Total Generation	194.112,1	100,0%

Nearly half (48.5%) of Turkey's electricity in 2009 is genarated from natural gas, 20.0% from lignite, 8.1% from hard coal and imported coal, 3.4% from liquid fuels, totaling 80.0% from thermal sources. Hydro provides 18.5% of total electricity generation; geothermal and wind provides only 1.0%, and renew and waste provide only 0.5%.

Table 56 shows electricity generation in Turkey by primary energy sources between 1975-2008 as follows:

Table 56. Electricity Generation in Turkey by Primary Energy Sources, 1985-2008 in GWh (TEIAS, 2010)

	Hard Coal + Imported Coal	Lignite	Coal Total	Fuel Oil**	Diesel Oil, LPG, Naphta	Natural Gas	Renew and wastes	Thermal Total	Hydro Total	Geothermal + wind*	Turkey's Total
1985	710.3	14,317.5	15,027.8	7,028.6	53.4	58.2	0.0	22,168.0	12,044.9	6.0	34,218.9
1986	772.8	18,664.5	19,437.3	6,941.3	59.3	1,340.7	0.0	27,778.6	11,872.6	43.6	39,694.8
1987	627.8	17,025.7	17,653.5	5,418.1	77.5	2,528.1	0.0	25,677.2	18,617.8	57.9	44,352.9
1988	345.3	12,141.3	12,486.6	3,248.7	56.0	3,239.5	0.0	19,030.8	28,949.6	68.4	48,048.8
1989	317.0	19,952.5	20,269.5	4,209.2	38.3	9,524.0	0.0	34,041.0	17,939.6	62.6	52,043.2
1990	620.8	19,560.5	20,181.3	3,920.9	20.8	10,192.3	0.0	34,315.3	23,147.6	80.1	57,543.0
1991	998.4	20,563.1	21,561.5	3,291.0	2.2	12,588.6	38.4	37,481.7	22,683.3	81.3	60,246.3
1992	1,814.6	22,756.2	24,570.8	5,271.3	1.7	10,813.7	47.1	40,704.6	26,568.0	69.6	67,342.2
1993	1,796.1	21,963.8	23,759.9	5,171.4	3.1	10,788.2	56.4	39,779.0	33,950.9	77.6	73,807.5
1994	1,977.6	26,257.1	28,234.7	5,546.8	2.0	13,822.3	50.9	47,656.7	30,585.9	79.1	78,321.7
1995	2,232.1	25,814.8	28,046.9	5,498.2	273.8	16,579.3	222.3	50,620.5	35,540.9	86.0	86,247.4
1996	2,574.1	27,839.5	30,413.6	6,174.4	365.2	17,174.2	175.4	54,302.8	40,475.2	83.7	94,861.7
1997	3,272.8	30,587.2	33,860.0	6,520.7	636.6	22,085.6	294.0	63,396.9	39,816.1	82.8	103,295.8
1998	2,980.9	32,706.6	35,687.5	7,275.6	647.7	24,837.5	254.6	68,702.9	42,229.0	90.5	111,022.4
1999	3,122.8	33,908.1	37,030.9	6,472.4	1,607.1	36,345.9	204.7	81,661.0	34,677.5	101.4	116,439.9
2000	3,819.0	34,367.3	38,186.3	7,459.1	1,851.7	46,216.9	220.2	93,934.2	30,878.5	108.9	124,921.6
2001	4,046.0	34,371.5	38,417.5	8,816.6	1,549.6	49,549.2	229.9	98,562.8	24,009.9	152.0	122,724.7
2002	4,093.1	28,056.0	32,149.1	9,505.0	1,238.8	52,496.5	173.7	95,563.1	33,683.8	152.6	129,399.5
2003	8,663.0	23,589.9	32,252.9	8,152.7	1,043.5	63,536.0	115.9	105,101.0	35,329.5	150.0	140,580.5
2004	11,998.1	22,449.5	34,447.6	6,689.9	980.4	62,241.8	104.0	104,463.7	46,083.7	150.9	150,698.3
2005	13,246.2	29,946.3	43,192.5	5,120.7	361.8	73,444.9	122.4	122,242.3	39,560.5	153.4	161,956.2
2006	14,216.6	32,432.9	46,649.5	4,232.4	108.0	80,691.2	154.0	131,835.1	44,112.1	352.6	176,299.8
2007	15,136.2	38,294.7	53,430.9	6,469.6	57.2	95,024.8	213.7	155,196.2	35,787.2	574.7	191,558.1
2008	15,857.5	41,858.1	57,715.6	7,208.6	309.9	98,685.3	219.9	164,139.3	33,286.6	992.1	198,418.0
2009	15,809.2	38,832.4	54,641.6	6,518.2		94,173.8	910.6	156,244.2	35,904.8	1,963.0	194,112.1

*Geothermal and wind valus for 2006-2008 are calculated by multiplying percentage share of this source by total generation.
**Fuel oil value in 2009 comprises fuel oil, diesel oil, naphta and LPG.

As mentioned, during the periods of 1988-2008, 1998-2008 and 2003-2008; annual growth rates of gross electricity generation have been 7.3%, 6.0 and 7.1% respectively. Since electricity generation in 2009 decreased in Turkey in the largest amount observed upto now, because of the economic crisis, the annual growth rates change significantly for the last 20, 10 and 5 years. In numbers, during the periods of 1989-2009, 1999-2009 and 2004-2009; annual growth rates of gross electricity generation have been 6.8%, 5.2 and 5.2% respectively. Since 2009 was an extreme year for both Turkey and the world, annual growth rates taking electricity generation in 2008 as reference points are more realistic. Although this is more realistic for the overall generation in the economy, taking electricity generation values in 2009 by primary energy sources may give the recent trends in composition of sources and do not distort data and comments.

During the periods of 1989-2009, 1999-2009 and 2004-2009; annual growth rates for hard coal and imported coal have been 21.6%, 17.6% and 5.7% respectively, showing a slowing down pattern of growth rates. High growth rates for the last 20 years should not be confusing, this largely comes from the fact that base value was quite small in 1989, since coal import had recently started in those years. For lignite, annual growth rates have been 3.4%, 1.4% and 15.8% for the last 20, 10 and 5 years respectively. But electricity generation from lignite decreased sharply in 2009 according to 2008, from 41,858 GWh to 38,832 GWh, meaning 7.3% decrease in percentage terms, and in nominal values this nearly equals the decline in overall electricity generation. And these growth rates for total coal have been 5.1%, 4.0% and 9.7%, that are all above growth rates for total electricity generation. Fuel oil use in electricity generation have not changed significantly during these periods.

The most drastic increase has been in natural gas use increasing from 58 GWh in 1985 to 94,174 GWh in 2009. Annual growth rates have been 21.4%, 10.0% and 8.6% during the last 20, 10 and 5 years respectively, outpassing annual growth rates of total generation significantly, and so making natural gas to generate nearly half of total electricity. But electricity generated from natural gas decreased from 98,865 GWh to 94,174 GWh between 2008 and 2009. Although renew and wastes generate only a small portion of total elecricity, its increase seems encouraging with 16.1% and 54.3% annual growth rates during 1999-2009 period and 2004-2009 period respectively. Especially its increase in 2009 according to 2008 has been tremendous from 220 GWh to 911 GWh. Geothermal and wind power's increase has also been encouraging in percentage terms, with annual growth rates of 18.8%, 34.4% and 67.0% for the last 20, 10 and 5 years respectively. And in 2009 electricity generated from geothermal and wind power has doubled reaching to 1,963 GWh. Although its increase is drastic in percentage terms, its share in total electricity generation has reached only to 1.0% in 2009.

Hydroelectricity fluctuated between 30,000 GWh and 46,000 GWh during 1993-2009 period, when decrease to around 24,000 GWh in 2001 is ignored. Annual growth rates change significantly according to the base year chosen and hydro electricity does not show a clear growth pattern. The only clear pattern is that hydroelectricity is far away from catching the increase in total electricity generation and it is losing market share significantly. Hydro electricity annual growth rates have been 3.5% during 1989-2009 period, there has not been any growth between 1999-2009 and even it has decreased annually 4.9% during the 2004-2009 period. Although it increased in 2009 according to 2008 by 7.8% and reached to 35,905 GWh, it is still far away from 44,112 GWh it reached in 2006.

Hydroelectricity grew 9.4% annually between 1985-1998 period and reached to 42,229 GWh in 1998. And instead of continuing to increase, it started to decline thereafter and it was only 35,095 GWh in 2009. So the last ten years have been lost years for hydro electricity and so for Turkey.

Table 57 shows percentage shares of electricity generation in Turkey by primary energy sources between 1970 and 2009. A long term of 40 years were chosen to see clearly how the energy mix of a country could change drastically.

Table 57. Percentage Shares of Electricity Generation in Turkey by Primary Energy Sources Between 1970-2009 (TEIAS, 2010)

	Hard Coal + Imported Coal	Lignite	Fuel Oil	Diesel Oil, LPG, Naphta	Ren. and wastes	Natural Gas	Thermal Total	Hydro Total	Geot.+ wind	Turkey's Total
1970	16.0%	16.7%	27.1%	3.1%	1.9%	0.0%	64.8%	35.2%	0.0%	100.0%
1971	14.8%	15.6%	39.8%	1.4%	1.7%	0.0%	73.3%	26.7%	0.0%	100.0%
1972	12.7%	13.3%	43.1%	0.8%	1.6%	0.0%	71.5%	28.5%	0.0%	100.0%
1973	12.1%	14.0%	47.0%	4.3%	1.6%	0.0%	79.0%	21.0%	0.0%	100.0%
1974	11.3%	17.5%	39.9%	4.9%	1.5%	0.0%	75.1%	24.9%	0.0%	100.0%
1975	9.1%	17.2%	30.1%	4.4%	1.4%	0.0%	62.2%	37.8%	0.0%	100.0%
1976	7.4%	16.3%	25.5%	4.1%	0.9%	0.0%	54.2%	45.8%	0.0%	100.0%
1977	6.2%	17.6%	26.9%	6.5%	1.1%	0.0%	58.3%	41.7%	0.0%	100.0%
1978	5.6%	20.1%	26.1%	4.6%	0.6%	0.0%	57.0%	43.0%	0.0%	100.0%
1979	4.7%	23.9%	22.7%	2.4%	0.6%	0.0%	54.3%	45.7%	0.0%	100.0%
1980	3.9%	21.7%	22.4%	2.6%	0.6%	0.0%	51.2%	48.8%	0.0%	100.0%
1981	3.6%	21.3%	21.1%	2.5%	0.4%	0.0%	48.9%	51.1%	0.0%	100.0%
1982	3.4%	20.8%	20.0%	2.4%	0.0%	0.0%	46.6%	53.4%	0.0%	100.0%
1983	2.9%	28.5%	23.2%	3.9%	0.0%	0.0%	58.5%	41.5%	0.0%	100.0%
1984	2.3%	30.7%	21.9%	1.1%	0.0%	0.0%	56.0%	43.9%	0.1%	100.0%
1985	2.1%	41.8%	20.5%	0.2%	0.0%	0.2%	64.8%	35.2%	0.0%	100.0%
1986	2.0%	47.0%	17.5%	0.1%	0.0%	3.4%	70.0%	29.9%	0.1%	100.0%
1987	1.4%	38.4%	12.2%	0.2%	0.0%	5.7%	57.9%	42.0%	0.1%	100.0%
1988	0.7%	25.3%	6.8%	0.1%	0.0%	6.7%	39.6%	60.3%	0.1%	100.0%
1989	0.6%	38.3%	8.1%	0.1%	0.0%	18.3%	65.4%	34.5%	0.1%	100.0%
1990	1.1%	34.0%	6.8%	0.0%	0.0%	17.7%	59.6%	40.2%	0.2%	100.0%
1991	1.7%	34.1%	5.6%	0.0%	0.1%	20.8%	62.3%	37.6%	0.1%	100.0%
1992	2.7%	33.8%	7.8%	0.0%	0.1%	16.0%	60.4%	39.5%	0.1%	100.0%
1993	2.4%	29.7%	7.0%	0.0%	0.1%	14.6%	53.8%	46.1%	0.1%	100.0%
1994	2.5%	33.5%	7.1%	0.0%	0.1%	17.6%	60.8%	39.1%	0.1%	100.0%
1995	2.6%	29.9%	6.4%	0.3%	0.3%	19.2%	58.7%	41.2%	0.1%	100.0%
1996	2.7%	29.3%	6.5%	0.4%	0.2%	18.1%	57.2%	42.7%	0.1%	100.0%
1997	3.2%	29.6%	6.3%	0.6%	0.3%	21.4%	61.4%	38.5%	0.1%	100.0%
1998	2.7%	29.5%	6.6%	0.6%	0.2%	22.4%	61.9%	38.0%	0.1%	100.0%
1999	2.7%	29.1%	5.6%	1.4%	0.2%	31.2%	70.1%	29.8%	0.1%	100.0%
2000	3.1%	27.5%	6.0%	1.5%	0.2%	37.0%	75.2%	24.7%	0.1%	100.0%
2001	3.3%	28.0%	7.2%	1.2%	0.2%	40.4%	80.3%	19.6%	0.1%	100.0%
2002	3.1%	21.7%	7.4%	0.9%	0.1%	40.6%	73.8%	26.0%	0.2%	100.0%
2003	6.1%	16.8%	5.8%	0.8%	0.1%	45.2%	74.8%	25.1%	0.1%	100.0%
2004	7.9%	14.9%	4.4%	0.6%	0.1%	41.3%	69.2%	30.6%	0.2%	100.0%
2005	8.1%	18.5%	3.2%	0.2%	0.1%	45.3%	75.4%	24.4%	0.2%	100.0%
2006	8.0%	18.4%	2.4%	0.0%	0.1%	45.8%	74.8%	25.1%	0.2%	100.0%
2007	7.9%	20.0%	3.4%	0.0%	0.1%	49.6%	81.0%	18.7%	0.3%	100.0%
2008	8.0%	21.1%	3.6%	0.1%	0.1%	49.7%	82.7%	16.8%	0.5%	100.0%
2009	8.1%	20.0%	3.4%	0.0%	0.5%	48.5%	80.5%	18.5%	1.0%	100.0%

Major players have been fuel oil, hard coal and lignite, natural gas and hydro during 1970-2009 period although their shares have changed drastically. Fuel oil reaches its top value of 47% in 1973, and starts to lose market share significantly therafter; declining to as low as 6.8% in 1988, Then after a slightly fluctuating period, it keeps its downward trend and in 2009 fuel oil generates only 3.4% of total electricity.

During the period of 1970-1988 that fuel oil lost market share tremendously, lignite and hydro took its market share. When fuel oil reached its top generation share of 47.0% in 1973, share of lignite and hydro were 14.0% and 21.0% respectively. Lignite's share in total electricity generation increased from 14.0% to 47.0% in 1986. An important part of the increase in lignite's share came from the decrease in hard coal's share, that they are substitutes. In 2009 lignite generates 20.0% and hard coal generates 8.1% of total electricity. And, when the long term energy mix of Turkey is analysed, hard coal and lignite have always been an important energy source, and its total share has never declined below 22.0% and never passed 49.0%.

Natural gas is the only source that has increased its share so significantly and steadily. Natural gas started to be used in electricity generation in 1985 with 0.2% share and after an incredible fast growth period it reached 20.8% in 1991. Its share did not increase during 1992-1998 period and it was 22.4% in 1998, but its growth accelarated again in 1999 jumping to 31.2%, and in 2001 its share was 40.4%. Although growth slowed down thereafter, natural gas was generating 49.6% of Turkey's electricity in 2007. In 2009 its share declined slightly to 48.5%.

As mentioned, when fuel oil started to lose its share in 1973, hydro took an important part of this share. Hydro's share was 21.0% in 1973 and after a significant growth period, it reached 51.1% in 1981, meaning that hydro was generating more than all other sources combined. Then it increased its share slightly to 53.2% in 1982 and started to decline thereafter, fluctuating between 30.0% and 60.0%. until 1999.

The average percentage of shares during this fluctuating period of 1983-1996 was 41.0%, meaning that hydro was again the most important source. The declining trend started in 1997 by decreasing to 38.5% and in 2008, hydro was generating only 16.8% of total electricity. In 2009 it increased its share slightly to 18.5%. But when these recent shares are compared with past shares, they are far away from being enough for Turkey's urgent need of domestic, clean electricity. The share of geothermal and wind power in total electricity generatiion have been 0.3%, 0.5% and 1.0% in 2007, 2008 and 2009 respectively.

Table 58 shows annual development of Turkey's installed capacities by primary energy sources between 1984 and 2008 as follows:

Table 58. Turkey's Installed Capacity by Primary Energy Sources in MW Between 1984-2008, (TEIAS, 2010)

	Hard Coal + Imp. Coal	Lignite	Fuel Oil	Diesel Oil, LPG, Naphta	Natural Gas*	Renew and Waste	Multi Fuel Fired	Thermal	Hydro	Geothermal **	Wind	General Total
1984	219.9	2,359.3	1,100.5	627.3			262.3	4,569.3	3,874.8	17.5		8,461.6
1985	219.9	2,864.3	1,100.5	627.3	100.0		317.3	5,229.3	3,874.8	17.5		9,121.6
1986	197.7	3,579.3	1,100.5	625.4	400.0		317.3	6,220.2	3,877.5	17.5		10,115.2
1987	181.6	4,434.3	1,197.4	543.7	800.0		317.3	7,474.3	5,003.3	17.5		12,495.1
1988	181.6	4,434.3	1,197.4	544.0	1,555.2		372.3	8,284.8	6,218.3	17.5		14,520.6
1989	331.6	4,713.7	1,194.4	545.6	2,035.8		372.3	9,193.4	6,597.3	17.5		15,808.2
1990	331.6	4,874.1	1,202.2	545.6	2,210.0		372.3	9,535.8	6,764.3	17.5		16,317.6
1991	352.6	5,040.9	1,191.4	545.6	2,555.4	10.0	381.9	10,077.8	7,113.8	17.5		17,209.1
1992	352.6	5,405.1	1,157.0	372.8	2,591.7	13.8	426.9	10,319.9	8,378.7	17.5		18,716.1
1993	352.6	5,608.8	1,163.3	372.5	2,700.5	13.8	426.9	10,638.4	9,681.7	17.5		20,337.6
1994	352.6	5,818.8	1,169.2	372.5	2,823.9	13.8	426.9	10,977.7	9,864.6	17.5		20,859.8
1995	326.4	6,047.9	1,148.9	204.2	2,883.9	13.8	448.9	11,074.0	9,862.8	17.5		20,954.3
1996	341.4	6,047.9	1,168.4	219.2	3,051.2	13.8	455.2	11,297.1	9,934.8	17.5		21,249.4
1997	335.0	6,047.9	1,171.9	237.5	3,490.4	13.8	475.3	11,771.8	10,102.6	17.5		21,891.9
1998	335.0	6,213.9	1,225.4	306.6	4,047.1	22.4	870.9	13,021.3	10,306.5	17.5	8.7	23,354.0
1999	335.0	6,351.9	1,207.3	334.8	4,958.8	23.8	2,344.3	15,555.9	10,537.2	17.5	8.7	26,119.3
2000	480.0	6,508.9	1,260.8	324.8	4,904.5	23.8	2,549.7	16,052.5	11,175.2	17.5	18.9	27,264.1
2001	480.0	6,510.7	1,608.4	391.2	4,850.7	23.6	2,758.5	16,623.1	11,672.9	17.5	18.9	28,332.4
2002	480.0	6,502.9	2,009.0	391.2	7,247.1	27.6	2,910.7	19,568.5	12,240.9	17.5	18.9	31,845.8
2003	1,800.0	6,438.9	2,331.1	402.1	8,861.8	27.6	3,112.9	22,974.4	12,578.7	15.0	18.9	35,587.0
2004	1,845.0	6,450.8	2,307.6	261.6	10,131.2	27.6	3,120.9	24,144.7	12,645.4	15.0	18.9	36,824.0
2005	1,986.0	7,130.8	2,253.3	252.4	10,976.2	35.3	3,268.3	25,902.3	12,906.1	15.0	20.1	38,843.5
2006	1,986.0	8,210.8	2,123.2	273.3	11,462.2	41.3	3,323.4	27,420.2	13,062.7	81.9	-	40,564.8
2007	1,986.0	8,211.4	1,772.4	227.8	11,647.4	42.7	3,384.0	27,271.6	13,394.9	169.2	-	40,835.7
2008	1,986.0	8,205.0	1,770.8	47.8	10,656.8	59.7	4,869.0	27,595.0	13,828.7	29.8	363.7	41,817.2

*The reason for the decrease of natural gas share at installed capacity is that some autoproducers plants have passed into multi fueled generation due to shortage of natural gas in 2000,
**Included wind p.p.in the years 2006 and 2007.

Turkey's total installed capacities is 41,817 MW in 2008. Hydro has the most installed capacity with 13,829 MW comprising 33.1% of total capacity, and natural gas comes the second with 10,657 MW forming 25.5% of total capacity. Lignite installed capacity is 8,205 MW and hard coal, imported coal installed capacity is 1,986 MW, and these together comprise 24.4% of total capacity. Multi fuel fired plants are composed of solid with liquid, solid with natural gas, liquid with natural gas. They are 4,869 MW comprising 11.6% of total capacity and most of multi fuel fired capacity is of liquid with natural gas plants that is 4,398 MW. The installed wind power capacity is 363.7 MW in 2009.

As mentioned, during periods of 1978-2008, 1988-2008, 1998-2008 and 2003-2008; annual growth rates of total installed capacities have been 7.4%, 5.4%, 6.0% and 3.3% respectively. So, the growth in total installed capacities has slowed down recently.

Table 59 shows incremental increase in installed capacities by primary energy sources and their percentage shares in 2008, during 2004-2008 period and 1999-2008 period to determine the recent trends in new capacity installations:

Table 59. Incremental Increase in Installed Capacities by Primary Energy Sources in MW and Their Percentage Shares, (TEIAS, 2010)

	2008	Share in 2008	2004-2008	Share in 2004-2008	1999-2008	Share in 1999-2008
Hard Coal	0.0	0.0%	186.0	3.0%	1651.0	8.9%
Lignite	-6.4	-	1,766.1	28.3%	1991.1	10.8%
Fuel Oil	-1.6	-	-560.3	-	545.4	3.0%
Diesel Oil, LPG, Naphta	-180.0	-	-354.3	-	-258.8	-
Natural Gas	-990.6	-	1,795.0	28.8%	6,609.7	35.8%
Renew and Waste	17.0	1.7%	32.1	0.5%	37.3	0.2%
Multi Fuel Fired	1,485.0	151.3%	1,756.1	28.2%	3,998.1	21.7%
Thermal Total	323.4	33.0%	4,620.6	74.2%	14,573.7	78.9%
Hydro	433.8	44.2%	1,250.0	20.1%	3,522.2	19.1%
Geothermal + Wind	224.3	22.8%	359.6	5.7%	367.3	2.0.%
General Total	981.5		6,230.2		18,463.2	

Hydro installed capacity made up 19.1% of incremental increase in installed capacity during 1999-2008 period. Share of natural gas was 35.8%, share of multi fuel fired was 21.7%, share of hard coal and lignite was 19.7% during the same period. When the fact that, most of multi fuel fired plants' are natural gas with liquid, is taken into account; nearly half of the incremantal increase in installed capacities were natural gas during 1999-2008, and nearly one fifth was coal, and one fifth was hydro.

During 2004-2008 period, 28.8% of incremantal increase in installed capacities were natural gas, 28.2% was multi fuel fired, 31.3% was coal and 20.1% was hydro. Since most of multi fuel fired was natural gas with liquid, it would not be misleading to say that natural gas made up nearly half of the incremental increase. 359.6 MW capacities of geothermal and wind power installed during 2004-2008 made up 5.7% of incremental increase during the same period. So, geothermal and wind power come into the market during 2004-2008 with 5.7% share, whereas it was only 2.0% during 1999-2008.

Although the incremental increases in installed capacities are similar for the periods of 2004-2008 and 1999-2008, the picture is quite different for 2008. But it is too early to define this as a changing trend, it would be misleading to look at only one year when talking about installed capacities. Because, they have long construction periods, and they are commissioned in bulk. So, a new commissioned plant may change the picture significantly when one year is analysed. The share of multi fuel fired plants seen in Table 59 as 151% in 2008 should not be misleading. This largely comes from the natural gas plants turning into multi fuel fired plants. In 2008, total installed capacity increased by 981 MW of which 33.0% was thermal mainly natural gas, 44.2% was hydro and 22.8% was geothermal and wind power plants. Although 224,3 MW wind and geothermal capacity installed in 2008 is small, its share in increase in total capacity is quite significant. But the important question is whether this newly installed capacities in wind power will continue by accelerating.

As an emerging economy, Turkey's electricity consumption has increased significantly and is expected to continue this trend. When the low shares of electricity imports and exports are taken into account with non-storable nature of electricity, supply of electricity energy security comes out as an important isssue. So, TEIAS (Turkish Electricity Transmission Company) prepares Turkish electricity energy generation capacity projections for the future 10 years to take necessary measures, provide important recommendations and guidelines. TEIAS prepared Turkish Electrical Energy 10-Year Generation Capacity Projection (2009-2018) in June 2009. This Paper shows invaluable data to make estimations about the future of electricity. The succeeding subsection will mention these projections briefly as follows:

Turkey's Electricity Capacity Projections and Supply Security Strategy Paper

The preceeding subtitle has analysed the electricity energy indicators of Turkey comprehensively with the most recent data. But the future of electricity energy indicators are more important when Turkey's increasing electricity consumption; low shares of electricity imports and exports; and non-storable nature of electricity are taken into account. TEIAS prepared Turkish Electrical Energy 10-Year Generation Capacity Projection (2009-2018) in June 2009 to take necessary measures, provide important recommendations and guidelines.

According to this paper, peak load and electricity consumption of Turkish electricity system between 1999–2008 is as follows:

Table 60. Peak Load and Electricity Consumption of Turkish Electricity System Between 1999–2008 (TEIAS, 2009)

	Peak Load	Increase Rate (%)	Electricity Consumption	Increase Rate (%)
1999	18,938	6.4%	118,485	3.9%
2000	19,390	2.4%	128,276	8.3%
2001	19,612	1.1%	126,871	-1.1%
2002	21,006	7.1%	132,553	4.5%
2003	21,729	3.4%	141,151	6.5%
2004	23,485	8.1%	150,018	6.3%
2005	25,174	7.2%	160,794	7.2%
2006	27,594	9.6%	174,637	8.6%
2007	29,249	6.0%	190,000	8.8%
2008	30,517	4.3%	198,085	4.2%

TEIAS (2009) made two demand forecasts for the projection: high demand and low demand. Demand series are for total Turkish Electricity System and they are gross values. Transmission and distribution losses and internal consumptions of plants are included in this gross demand. Further, embedded generation (connected to the distribution system) and the generation of plants which are not subject to load dispatching instructions are included, too.

Table 61 shows energy demand projections on high demand scenario as follows:

Table 61. Demand Forecast (High Demand) (TEIAS, 2009)

	Peak Load		Energy Demand	
	MW	Increase Rate (%)	GWh	Increase Rate (%)
2009	29,900		194,000	
2010	31,246	4.5%	202,730	4.5%
2011	33,276	6.5%	215,907	6.5%
2012	35,772	7.5%	232,101	7.5%
2013	38,455	7.5%	249,508	7.5%
2014	41,339	7.5%	268,221	7.5%
2015	44,440	7.5%	288,338	7.5%
2016	47,728	7.4%	309,675	7.4%
2017	51,260	7.4%	332,591	7.4%
2018	55,053	7.4%	357,202	7.4%

In high demand scenario, energy demand increases by 4.5% in 2010 due to the economic crisis, and then growth rate increases to 6.5% in 2011. From 2012 on energy demand increases nearly 7.5% annually.

Table 62 shows energy demand projections on low demand scenario as follows:

Table 62. Demand Forecast (Low Demand) (TEIAS, 2009)

	Peak Load		Energy Demand	
	MW	Increase Rate (%)	GWh	Increase Rate (%)
2009	29,900		194,000	
2010	31,246	4.5%	202,730	4.5%
2011	32,964	5.5%	213,880	5.5%
2012	35,173	6.7%	228,210	6.7%
2013	37,529	6.7%	243,500	6.7%
2014	40,044	6.7%	259,815	6.7%
2015	42,727	6.7%	277,222	6.7%
2016	45,546	6.6%	295,519	6.6%
2017	48,553	6.6%	315,023	6.6%
2018	51,757	6.6%	335,815	6.6%

In low demand scenario, energy demand increases by 4.5% in 2009 due to the economic crisis, and then growth rate increases to 5.5% in 2011. From 2012 on energy demand increases nearly 6.7% annually.

This study of TEIAS has some assumptions in making generation capacity projections. These assumptions are mainly about demand and installed capacities. Assumptions about demand are as follows:

In the study for Generation Capacity Projection 2009-2018, taking into account the impact of economic crisis on electrical energy demand, revised demand series have been used. In the demand series, it is assumed that electrical energy demand will decrease 2% in 2009, the increase in electrical energy demand will be low in 2010-2011 due to the impacts of economic crisisis, and in the following years. High Demand and Low Demand series which are occurred from the study results on May 2008 of MAED Model used by Ministry of Energy and Natural Resources is used in this study for the period of 2009-2018 (TEIAS, 2009).

Assumptions of TEIAS (2009) about installed capacities are as follows:

Two scenarios have been assumed about capacities under construction, capacities granted by licence by the end of 2008 and expected to be in service on planned dates.

In the first scenario, the plants of which 70% have been constructed are assumed to be in service in 2009. The year the plants of which 35-70% have been constructed will be in service, changes according to their installed capacity projects as follows:

For installed capacities less than 100 MW, in 2010;

For installed capacities between 100 MW-1000 MW , in 2011;

For installed capacities more than 1000 MW, in 2012.

For the plants of which 10%-35% have been constructed, one year is added to the years above according to their installed capacity projects. The plants of which less than 10% have been constructed, the years they will be in service are assumed undetermined.

In the scenario 2, the same methodology was used by taking into account 15% instead of 10%, 40% instead of 35% and 80% instead of 70%.

According to Scenario 1, capacity of 14,864.5 MW and according to Scenario 2, capacity of 12,722.8 MW are assumed to be in service during the projection period (TEIAS, 2009). Using High Demand and Low Demand series for these two alternative scenarios, demand-supply balances have been formed according to Project Generation Capacity and Firm Generation Capacity.

Energy reserve ratios are very important for system reliability. In case of the realization of the expected demand increases, taking into account the power plants which are existing, under construction and granted by licence and expected to be in service on the projection period; reserve ratios according to project generation capacities in scenarios 1 and 2 are as shown in Table 63:

Table 63. Reserve Ratios According to Project Generation Capacities in Scenarios 1 and 2 (TEIAS, 2009)

Scenario 1	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High Demand	27.3	25.1	22.1	23.8	24.9	17.1	9.2	3.3	-4.1	-11.8
Low Demand	27.3	25.1	23.3	25.9	28.0	20.8	13.5	8.3	1.2	-6.2

Scenario 2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High Demand	27.1	24.5	21.4	18.7	17.8	12.0	4.5	-1.0	-8.2	-15.6
Low Demand	27.1	24.5	22.5	20.8	20.7	15.6	8.7	3.7	-3.1	-10.2

According to project generation capacity;

In Scenario 1, for high demand series in 2017, for low demand series in 2018;

In Scenario 2, for high demand series in 2016, for low demand series in 2017;

Demand is expected not to be covered.

Reserve ratios according to firm generation capacities in scenarios 1 and 2 are as shown in Table 64:

Table 64. Reserve Ratios According to Firm Generation Capacities in Scenarios 1 and 2 (TEIAS, 2009)

Scenario 1	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High Demand	8.0	5.9	3.5	5.5	10.2	2.9	-3.5	-9.1	-15.6	-22.4
Low Demand	8.0	5.9	4.4	7.3	12.9	6.2	0.3	-4.7	-10.9	-17.5

Scenario 2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
High Demand	7.9	5.5	3.0	0.9	3.6	-1.7	-7.9	-13.1	-19.3	-25.9
Low Demand	7.9	5.5	4.0	2.6	6.1	1.4	-4.2	-9.0	-14.8	-21.2

According to firm generation capacity;

In Scenario 1, for high demand series in 2015, for low demand series in 2016;

In Scenario 2 , for high demand series in 2014, for low demand series in 2015;

Demand is expected not to be covered.

Since energy deficiency is expected in 2014 according to Scenario 2 and high demand series, TEIAS (2009) proposes from 2010 on to take measures for granting licences, monitoring investment starting dates and taking them into the system, by taking into account construction periods for new capacities. Energy deficiency will grow in an increasing manner as seen in the tables above, if taking the additional capacity into the system delays.

Reserve ratios and years of demand not covered have been calculated according to the following assumptions (TEIAS, 2009):

All of the power plants which are existing connected to the system, under construction and granted by licence will generate electricity as much as the amount of their project and firm generation capacities,

There will not be any constraint with supply of fuel,

Related to hydro conditions, generations of hydro power plants will realise as expected before and

Power plants which are granted by licence and under construction will be in service on proposed date.

In case of different realization of any assumptions stated above, reserve ratios and the years that energy demand will not be covered will change. Therefore it is essentially necessary that capacity and energy reserves by primary energy resources should be kept on certain amounts for reliable operation of the electricity system. So, in order to operate generation system with reserves before the overlap of demand with supply, TEIAS (2009) proposes to adopt necessary measures from 2010 on, to grant licences and start investments by taking into consideration of construction duration of investment facilities.

So, Turkey should decide as soon as possible, from which primary energy sources she will generate electricity. The state's intention about this issue, targets have been declared on Electricity Energy Market and Supply Security Strategy Paper on 18 May 2009 that will be stated as follows:

According to supplementary article 3 of The Electricity Market Law No 4628, The Ministry of Energy and Natural Resources is responsible for monitoring electrical energy supply security and taking necessary measures about supply security. The Ministry also prepares Electrical Energy Supply Security Report until the end of each year and submits this Report to the Council of Ministers. This report includes the evaluations about the development and processing of electricity market and problems, solution proposals about supply security. The Higher Board of Planning has decided to approve Electricity Energy Market and Supply Security Strategy Paper on 18 May 2009, prepared under coordination of the Ministry of Energy and Natural Resources with participation and contributions of relevant stakeholders.

Electricity Energy Market and Supply Security Strategy Paper defines the primary objective as, to ensure delivery of electricity in an adequate, high-quality, uninterrupted, low-cost, and environment-friendly manner. The principles in structuring of the electricity energy sector and functioning of the market were determined in this Strategy Paper as follows (Higher Board of Planning, 2009):

- Creation and maintenance of market structure in a way to ensure supply security;
- Taking into consideration climate change and environmental impacts in activities in all areas of the industry; toward the target of creating a sustainable electricity energy market
- Increasing efficiency, minimizing losses during production, transmission, distribution and utilization of electricity energy; reducing electricity energy costs by building a competitive environment based on

resource priorities of energy policy; and using such gains to offer more reasonably priced electricity service to consumers;

- Encouraging new technologies to diversity resources, to ensure maximum use of
  domestic and renewable resources in order to reduce external dependency in energy supply;
- Increasing the share of domestic contribution in investments to be made in the sector.

These principles seem quite encouraging. But the important thing is whether these principles will be followed in real life. The success of this Strategy Paper, will largely depend on which measures for directing the market will be taken in order to encourage the use of domestic resources. Based on these principles and priority target of increasing share of domestic resources in production of electricity energy, The Strategy Paper determines challenging resource utilization targets for each primary energy source in electricity generation by 2023, but targets will be subject to revision in consideration of developments in technology, markets, resource potential and demand projections. These resource utilization targets declared on the Strategy Paper are as follows (Higher Board of Planning, 2009):

For domestic lignite and hard coal; proven lignite deposits and hard coal resources will be put to use by 2023 in electricity energy generation. To that end, efforts will continue for making good use of exploitable domestic lignite and hard coal fields in electricity generation projects.

For nuclear energy; activities initiated for use of nuclear power plants in electricity generation will continue. Target is to increase the share of these power plants in electricity energy up to at least 5% by the year 2020, and to increase it even further in the longer run.

For natural gas; share of natural gas in electricity generation will be reduced down to below 30%, through measures for utilization of domestic and renewable resources.

For imported coal; although domestic and renewable resources are given precedence in electricity generation, power plants based on high-quality imported coal will also be made use of, taking into consideration supply security.

When it comes to renewable energy resources, primary target is to increase the share of renewable resources in electricity generation up to at least 30% by 2023. This target will be subject to revision based on potential developments in technology, market, and resource potential. In this context, long term works will take into account the following targets by each renewable energy source:

For hydroelectric; technically and economically available hydroelectric potential of Turkey will entirely be put to use in electricity generation, by 2023.

For wind energy; target is to increase installed wind energy power to 20,000 MW by 2023.

For geothermal; potential of 600 MW geohermal energy, that is presently established as suitable for electricity energy generation, will entirely be commissioned by 2023.

For solar energy; target is to generalize its use for generating electricity, ensuring maximum utilization of country potential. In this context, technological advances will be closely followed and implemented. The Strategy Paper also commits that within 2009, Law No 5346 will be accordingly amended in order to encourage generation of electricity using solar energy. Although there is a bill on amendment of Law No 5346 to increase incentives for renewables, it has not been adopted yet. This will be explained in details in the succeeding subtitle.

For other renewable resources, preparation of production plans will take into account potential changes in utilization potentials of these renewable energy resources based on technological and legislative developments.

To reach these targets necessiate legislative developments increasing incentives in favour of renewables. Although Turkey has some regulations to increase the utilization of renewable sources in electricity generation, these ambitious targets determined in Electricity Energy Market and Supply Security Strategy Paper may require more incentives. Turkish legislation on renewables will be mentioned in the succeeding subtitle as follows:

Turkish Legislation on Renewable Energy and Turkey's Progress Reports

There is only one main law about renewables, that is Law No 5346 Law on Utilization of Renewable Energy Resources for the Purpose of Generating Electrical Energy adopted on 10 May 2005 and enacted on 18 May 2005. Law No 5346 Law on Utilization of Renewable Energy Resources for the Purpose of Generating Electrical Energy (from here on it will be referred as Renewable Energy Law No 5346) encompasses the procedures and principles for conservation of the renewable energy resource areas, certification of the energy generated from these resources and utilization of these resources

The purpose of the Law No 5346 is to expand the utilization of renewable energy resources in generating electrical energy, to benefit from these resources in secure, economic and high-quality manner, to increase the diversification of energy resources, to reduce greenhouse gas emissions, to promote the reuse of waste products, to protect the environment and to develop the related manufacturing sector with a view to achieve these objectives.

According to Article 3/11 of Renewable Energy Law No 5346, renewable energy resources in the scope of this Law include the electrical energy generation resources suitable for wind, solar, geothermal, biomass, biogas, wave, current and tidal energy resources together with hydraulic generation plants either canal or run of river type or with a reservoir area of less than fifteen square kilometers. Although large HPPs are considered as a renewable resource, they are not included in the support mechanism defined in this Law.

Article 3 of the Environment Law No 2872, stating the general principles about protection, treatment of the environment and prevention of environmental pollution, has been amended by Law No 5491 dated 26.4.2006. The amendment was made to allow the use of market-based and financial tools including carbon trading, together with the provision of incentives such as obligatory standards, tax credits and fee exemptions to promote renewable and clean energy technologies, imposition of emission fees, to protect environment and prevent environmental pollution.

In 2007, Energy Efficiency Law No 5627 was enacted, including the provision of a 20% discount on the electricity costs of industrial enterprises signing a contract to reduce their energy intensity by 10% over a three-year period, and renewable energy generation is not included in the energy intensity calculations.

Electricity Market Law No 4628 and Renewables Law No 5346 provide some incentives to promote investment in renewable energy.

The purpose of Electricity Market Law No 4628, is to ensure the development of a financially sound and transparent electricity market operating in a competitive environment under provisions of civil law and the delivery of sufficient, good quality, low cost and environment-friendly electricity to consumers. The scope of this law covers generation, transmission, distribution, wholesale, retailing and retailing services, import, export of electricity. Incentives provided by Electricity Market Law No 4628 are about licensing fee, connection to the grid, purchase obligation and, exemption from licensing and company establishment obligations.

For renewable power plants, initial licensing fee are limited to 1% of the regular licensing fee applicable to non-renewable power plants. Renewable power plants are exempt from the annual licence fee during the first eight years following their commissioning. Renewable power plants have priority to be granted by TEIAS and the distribution companies in connection to their grid. In their supply to ineligible customers, the distribution companies have to procure the renewable power plants' output if the latter's offer is less than or equal to the TETAŞ tariff and there is no other supply source.

A third paragragh to the Article No 3 of Electricity Market Law was supplemented by Law No 5627 dated 18.04.2007 and amended by Law No. 5783 dated 09.07.2008. According to the amended paragraph, real or legal persons installing renewable energy resource based generation plants of maximum installed capacities 500 KW, and micro cogeneration plants are exempt from taking licences and company establishment obligations. Technical and financial procedures and principles about giving to the system the electrical energy generated above their own needs of these legal persons is determined by a regulation made by Energy Market Regulatory Authority. Micro cogeneration plants are defined in Article 1 as cogeneration plants based on electrical energy with installed capacities of 50 KW and less.

Incentives provided by Renewables Law No 5346 are about purchase guarentee, feed in tariff and fees on land use.

According to Article 6/b of Renewables Law No 5346, each of the legal entities holding a retail sale license should purchase the amount of Renewable Energy Resource (RES)-certified electrical energy in accordance with the proportion of the energy amount they sold within the previous calendar year to the total electrical energy amount they sold in the country. Legal entities holding a retail sale license, should buy electrical energy from power plants generating electrical energy from renewable energy resources within the scope of this Law, which are holding a RES certificate and which have not completed 10 years of operation. Violation of this obligation by the legal entities holding a retail sale license is linked to strict sanctions in Article 10. According to Article 10, the legal entities who breach the provisions of Article 6 of this Law will be charged with a fine of 250 billion TL by EMRA and they will be warned to remedy the breach within sixty days. In the case that such actions requiring a fine are not remedied in spite of warning or that they are repeated, such fines will be doubled for each case. However, in the case that the same act is committed within two years, the amount of the fine to be increased will not exceed ten percent of the gross profit of the relevant legal person in its balance sheet for the previous accounting year. EMRA may cancel the license, if a fine reaches such a level.

Renewable Energy Resource (RES) Certificate is regulated under Article 5. According to this article, the legal entity holding generation license will be granted by EMRA with a RES Certificate for the purpose of identification and monitoring of the resource type in purchasing and sale of the electrical energy generated from renewable energy resources in the domestic and international markets. The procedures and principles of the RES Certificate is specified in the Regulation About Procedures and Principles of Granting Renewable Energy Resource Certificate.

Validity of them will be one year and regarding the hybrid plants they will be granted for only the electrical energy generated from the renewable energy resources.

According to Article 6/c; the price to be applicable to the electrical energy to be purchased within the scope of this Law, for each year will be the electricity average wholesale price in Turkey for the previous year as determined by EMRA. However, such applicable price will not be less than the Turkish Lira equivalent of 5 Euro Cent per kWh and may not exceed the Turkish Lira equivalent of 5.5 Euro Cent per kWh. However, legal entities that hold licenses based on renewable energy resources and which have the opportunity to sell above the limit of 5.5 Euro Cent kWh in the market will benefit from this opportunity. The implementations within the scope of this Article will cover the plants that are put into operation before 31 December 2011. However, the Council of Ministers could extend the expiration date to 2 years at the most, provided that such extension is published in the Official Gazette until 31 December 2009. On 17 December 2009 with Decision No 2009/15713, the Council of Ministers has decided to extend the expiration date two years and this Decision was published in the Official Gazette No 27447 on 29 December 2009.

Article 8 involves the applications related to acquisition of land. According to this Article, in case any real estate under the private ownership of the Forest Administration or Treasury, or under the discretion and disposal of the state is used for the purposes of generating electrical energy from renewable energy resources within the scope of this Law, the Ministry of Environment and Forestry or the Ministry of Finance provides permission, leases, institutes an easement right or permits the use of the land for the plant, access roads and the energy transmission line up to grid connection point. With respect to power plants which will be commissioned by the end of the year 2011, 85% discount will be applied to the fees regarding permit, lease, easement right and the right to use with respect to the plant, access roads and the energy transmission line up to the grid connection point during the first ten years of operation. With respect to forestlands, ORKOY and Special Allowance for Tree Planting Revenues will not be collected.

According to Article 7, real persons and legal entities establishing an isolated or grid connected power plant with a maximum installed capacity of 1,000 kW for meeting solely their own needs, will not pay service fees for these projects whose final project planning, master-plan, pre-reviews or first studies have been prepared by DSI or EIE.

In line with the ambitious targets of Turkey in renewable energy, the recent amendment proposal to the Renewable Energy Law No 5346 involves significant changes in feed-in tariff mechanism. The proposed incentive scheme is based on higher and differentiated tariffs for RES Certificate holders with power plants to become operational before 31 December 2015. This proposed feed-in tariff structure is shown in Table 65 as follows:

Table 65. Proposed Feed-in Tariff structure

Power Plant Technologies	First 10 Years in Operation (€cent/kWh)	Second 10 Years in Operation (€cent/kWh)
HPP	7	
Onshore WPP	8	
Off-shore WPP	12	
Geothermal	9	
Photovoltaic	25	20
Concentrating Solar	20	18
Biomass (inc. Landfill)	14	8
Tidal	16	

The duration of the participation to the scheme will start from the commissioning date for operating power plants or for those yet to commence operating. The situation about power plants becoming operational after 31 December 2015 will be renegotiated after 2011.

Licensees generating power for their own need with power plants of a maximum installed capacity of 500 kW will be eligible for the feed-in tariffs in Table 65, except photovoltaic power plants. PVs with a maximum capacity of 500 kW will in turn be provided as follows: For generation upto 2,999 kWh/month: 35 €cent/kWh and for generation between 3,000 – 6,000 kWh/month: 30 €cent/kWh.

The feed-in tariff levels displayed in Table 65 will be further upgraded with the rates displayed in Table 66, if the mechanical and / or electromechanical equipment is procured from domestic suppliers. This incentive will be applicable over the first five years of operation. According to the Commission Report of the amendment proposal (2009), this application aims to reduce energy dependency of Turkey, pioner technology transfer, supplement employment.

Table 66. Proposed Upgrades to Feed-in Tariff Structure for Domestic Procurement

Power Plant Type	Manufactruing Good	Domestic Procurement Premium (€cent/kWh)
HPP	Turbine	1
	Generator and power electronics	0,8
WPP	Blade	0,6
	Generator and power electronics	0,8
	Turbine tower	0,5
Solar PV	Entire mechanical equipment in rotor and blade groups	1
	PV panel integration and solar structure mechanics	0,6
	PV modules	1
	PV module cells	3
	Inverter	0,5
	Focusing tool to collect solar rays onto PV modules	0,4
Concentrating Solar	Radiation collection tube	2
	Surface plate reflector	0,5
	Solar tracking system	0,5
	Mechanical equipment in the thermal energy storage system	1
	Mechanical equipment in steam production system via collection of solar rays on roof	2
	Stirling engine	1
	PV panel integration and solar structure mechanics	0,5
Biomass	Steam boiler with fluid bed	0,6
	Liquid-fired and gas-fired steam boiler	0,3
	Gasification and gas removal group	0,5
	Steam or gas turbines	1,5
	Internal combustion engine or stirling engine	0,7
	Generator and power electronics	0,4
	Cogeneration system	0,3
Geothermal	Steam or gas turbines	1
	Generator and power electronics	0,5
	Steam injector or vacuum compressor	0,5

Although these feed-in tariffs and other incentives are likely to promote renewable energy, the amendment proposal has not been approved yet. This decreases the competitiveness of Turkish renewable market against European countries.

European Union gives importance to the developments in renewable energy resources of Turkey. Turkey Progress Reports prepared by Commission of the

European Communities between 2005-2009 involves important issues, guidelines and criticisms about renewable energy and some environmental issues that may have important consequences on renewable energy. Since these Progress Reports provide guidelines for Turkish legislation, firstly energy section of these Progress Reports and then environment section of these Progress Reports that are related to renewable energy will be mentioned briefly as follows:

According to 2005 Progress Report of Turkey; as regards renewable energy sources, some progress is reported. The adoption of The Law on the Use of Renewable Energy Sources in Electricity Generation, establishing the necessary legal framework for the promotion of renewable energy, is assessed as a first step towards implementation of the renewables acquis. However, this Law is criticised for not setting a target for electricity generated from renewable sources by 2010, as foreseen by the relevant directive. Turkey is recommended to set itself an ambitious target for further development of renewable energy, given Turkey's significant untapped potential for renewable energy; and to develop an overall strategy for renewable energy sources.

2006, 2007 and 2008 Progress Reports criticise Turkey for not setting itself an ambitious target for their increase.

2009 Progress Report admires that good progress can be reported on renewable energy. 2009 Progress Report admires the revised strategy paper for the electricity sector set a target of producing 25% of the country's electricity from renewable sources by the end of 2020 and installing 20,000 MW of wind power capacity by the same year. (This strategy paper has been revised again setting a target of producing 30% of the country's electricity from renewable sources by the end of 2020.) When the fact that, Turkey was producing 17% of its electricity from renewable energy sources by the end of 2008 is taken into account, with the expectation of electricity consumption to double by the same date, EU thinks that this objective will require significant efforts. EU also sees as a progress, the adoption of implementing regulations on wind energy about clarifying technical evaluation of applications for licences for wind-based power and on use of geothermal resources. As a conclusion of 2009 Progress Report, EU sees some, but uneven, progress in the overall energy sector. But EU finds developments on renewable energy, energy efficiency and the electricity market encouraging.

Although it is not directly related to renewable energy, in 2009 Progress Report's energy section, EU thinks that the accession of Turkey to Energy Community will be of particular relevance, both for the internal market in electricity and gas, renewable energy sources and energy efficiency, but also as regards energy related environmental issues. The Energy Community will be introduced briefly as follows:

The Energy Community is established by The Treaty Establishing Energy Community that entered into force on 1 July 2006, to extend the EU internal energy market to South East Europe and beyond. The general objective of the Energy Community is to create a stable regulatory and market framework to attract investment in power generation and networks, create an integrated energy market allowing for cross-border energy trade, enhance the security of supply, improve the environmental situation in relation with energy supply, enhance competition and exploit economies of scale. The Parties to the Treaty are the European Community, and seven Contracting Parties, namely, Albania, Bosnia & Herzegovina, Croatia, former Yugoslav Republic of Macedonia, Montenegro, Serbia and the United Nations Interim Administration Mission in Kosovo. 14 European Union Member

States have the status of Participants and Georgia, Moldova, Norway, Turkey and Ukraine are Observers. The Contracting Parties have committed to implement the relevant acquis communautaire, to develop an adequate regulatory framework and to liberalise their energy markets.

EU environment policy aims to promote sustainable development and protect the environment, based on preventive action, the polluter pays principle, shared responsibility, and the integration of environmental protection into other EU policies. Although environmental issues are not directly related to renewable energy, it may have important consequences on renewable energy use. These environmental issues reported in Turkey's Progress Reports will be mentioned briefly as follows:

In 2005, 2006, 2007 and 2008 Progress Reports, Turkey is criticised as there has been no substantial progress in the field of horizontal legislation, not having ratified the Kyoto Protocol, not establishing a greenhouse gas emission allowance trade scheme, and not transposing the Emissions Trading Directive and related decisions. Turkey is also criticised not having become a party to the Espoo or the Aarhus Conventions and not having a timetable for future membership status of these conventions.

In 2009 Progress Report the fact that Turkey has ratified the Kyoto Protocol is regarded as a good progress. But Turkey is still criticised for not establishing a greenhouse gas emission allowance trade scheme, not transposing the Emissions Trading Directive and related decisions, not starting negotiations on the EN 77 EN memorandum of understanding with on its participation in the Community civil protection financial instrument.

A national environmental approximation strategy (UCES) was adopted by the High Planning Council in 2006, that includes a plan for the transposition, implementation and enforcement of the EU environmental acquis. According to the timetable for legislative approximation about air sector, to transpose Directive of Emissions Trading 2003/87/EC, infrastructural investment and technical study, in order to strengthen technical capacity are needed. Enforcement date will be designated by the legislation prepared according to the result of these technical studies.

As important as incentives and legislations about renewable energy are the potentials of these renewable energy sources for electricity generation. Without significant potential, incentives and legislations may remain meaningless. The potentials of renewable energy sources will be mentioned in the succeeding subtitle.

Potentials of Renewable Energy Sources in Turkey

This subtitle will investigate the potentials of renewable energy sources (hydro, wind, solar power and geothermal power) for electricity generation and then will look at the licences granted in 2008 and stages of applications for renewable energies in 2008 to evaulate whether these potentials are utilized or not.

Turkey's hydroelectricity potential will be mentioned as follows:

According to PricewaterhouseCoopers (2009), Turkey has a technical hydroelecricity potential of 37.1 GW. Figure 17 shows the breakdown of technical hydroelectric capacity of Turkey as follows:

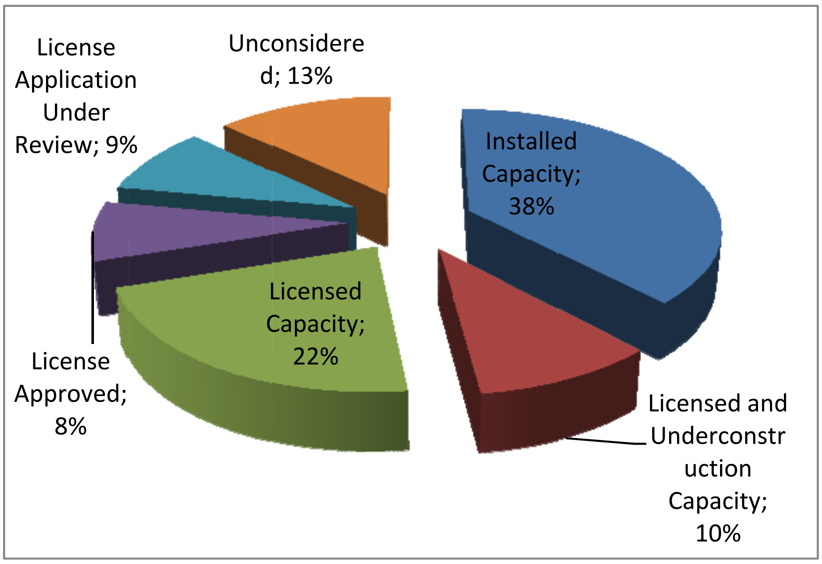

Figure 17. Breakdown of 37,1 GW technical hydroelectric capacity of Turkey (%) (PricewaterhouseCoopers, 2009a) (MENR)

As seen in Figure 17, 38% of Turkey's technical hydroelectricity capacity that is 13,8 GW is installed, 40% have been licensed and 9% have been applied for licence. So, there remains only 13%, as unconsidered showing that the hydroelectricity market can be saturated soon, but the low level of completion performance of the hydro power plants under construction, long construction periods and the upcoming privatisation of the EUAS hydro portfolio is likely to keep the deal ground busy enough (PricewaterhouseCoopers, 2009).

Turkey's wind power potential will be mentioned as follows:

Turkey has a huge wind power potential due to its climatic and geographic conditions. Table 67 shows annual average wind speeds and wind densities of various regions of Turkey as follows:

Table 67. Wind Potentials of Various Regions in Turkey (Erdoğdu, 2009)

Region	Annual Average Wind Speed (m/s)	Annual Average Wind Density (W/m2)
Marmara	3.3	51.9
Southeast Anatolia	2.7	29.3
Aegean	2.6	23.5
Mediterranean	2.5	21.4
Central Anatolia	2.5	20.1
Turkey average	2.5	24.0
Black Sea	2.4	21.3
East Anatolia	2.1	13.2

Average wind speeds range from 2.1 of East Anatolia to 3.3 m/sn of Marmara on regional basis. Marmara, Sotheast Anatolia and Aegean are the most attractive regions for wind power.

Table 68 compares European OECD countries according to their technical potential in MW and in TWh/year as follows:

Table 68. Wind Potential of European OECD Countries (Erdoğdu, 2009)

Country	Territory (thousand km2)	Specific Wind Potential (Class>3) (thousand km2)	Side Potential (km2)	Technical Potential (MW)	Technical Potential (TWh/year)
Turkey	781	418	9,960	83,000	166
UK	244	171	6,840	57,000	114
Spain	505	200	5,120	43,000	86
France	547	216	5,080	42,000	85
Norway	324	217	4,560	38,000	76
Italy	301	194	4,160	35,000	69
Greece	132	73	2,640	22,000	44
Ireland	70	67	2,680	22,000	44
Sweden	450	119	2,440	20,000	41
Iceand	103	103	2,080	17,000	34
Denmark	43	43	1,720	14,000	29
Germany	357	39	1,400	12,000	24
Portugal	92	31	880	7,000	15
Finland	337	17	440	4,000	7
The Netherlands	41	10	400	3,000	7
Austria	84	40	200	2,000	3
Belgium	31	7	280	2,000	5
Switzerland	41	21	80	1,000	1
Luxemburg	3	0	0	0	0

Among European OECD countries, Turkey has the highest technical potential with 83,000 MW nearly doubling the existing installed capacity and with 166 TWh/year that almost meets the present electricity consumption of Turkey.

According to PricewaterhouseCoopers (2009), Turkey’s wind power economic potential (wind speed more than 7.5 m/s) is 88,000 MW, but given the grid infrastructure constraints, the highest feasible wind-power generation capacity is estimated at 20,000 MW, which has been also set as the target capacity to attain by 2023 in the new EMSP.

The licensing for wind power started in 2002, and since then 1,118 applications, totalling 86 GW, all for onshore projects have been filed. During this period, 01 November 2007 was a milestone, in that a total of 725 licence applications making a total 71.4 GW were filed, most of which targeting overlapping locations, and exceeding the available grid capacity although a grid capacity of 7 GW is to be supported according to TEIAS, meaning that only 10% of the total application figure can be licensed (PricewaterhouseCoopers, 2009).

As a next step, these applications will get a technical review by EIE, assessing the feasibility of the non-overlapping applications and determining the overlapping ones. For the overlapping applications, TEIAS will launch a tender and the highest bidder among the applications for the same grid location will be granted the licence.

Licenses granted for wind power are 3,300 MW and licences approved are 910 MW. But total istalled capacity at the end of 2008 is only 469 MW, forming only around 15% of licensed capacity, largely due to barriers such as shortage in the global turbine supply, high upfront investment cost and ineffective feed-in tariff mechanism in financing (PricewaterhouseCoopers, 2009). Although 801 MW installed wind capacity at the end of 2009 represents more than 100% increase when compared to its 2008 level of 364 MW, it is far away from being a promising alternative energy for Turkey with its current installed capacity of around 2% of total installed capacity.

In Turkey, although wind farms are capable of a high average capacity factor of 30-35% (globally 20-25%), higher feed-in tariff levels and longer support periods in European countries decreases Turkey's competitiveness (PricewaterhouseCoopers, 2009). The bill amends the feed-in tariffs as 8 €cent /kWh for onshore wind power plants and 12 €cent/kWh for offshore wind power plants over the first 10 years of operation. If this bill is approved, Turkey may attract the investments she deserves.

Turkey's solar power potential will be mentioned as follows:

According to the solar energy potential atlas of Turkey, 4,600 km2 area is feasible for solar investment, and with a total insolation of 2,640 hours per annum Turkey has a technical solar power generation capacity of 380,000 GWh per annum, making Turkey second in Europe (PricewaterhouseCoopers, 2009). The highest solar potential is in the southern and western parts of Turkey.

Solar power generation applications is very limited in Turkey because of high installation costs. In Turkey, the total photovoltaic generation capacity is only 1 MW, basically used by fire-watch towers of the Ministry of Environment and Forestry communication towers, meteorological stations, emergency phones and lighting of highways (PricewaterhouseCoopers, 2009). Big estate projects have started to use solar power. Aydınlı solar city is under construction now.

The bill aims to amend the feed-in tariffs as 25 €cent /kWh for photovoltatic power plants and 20 €cent /kWh for concentrating solar power plants over the first 10 years of operation; and as 20 €cent /kWh and 18 €cent /kWh respectively over the next 10 years. Also, PVs with a maximum capacity of 500 kW will be incentivised according to this bill, as follows: For generation upto 2,999 kWh/month feed-in tariffs will be 35 €cent/kWh and for generation between 3,000 – 6,000 kWh/month they will be 30 €cent/kWh. This may incerase the solar power in housing by giving the residents opportunity to sell the excess electricity in these high prices. If this bill is not approved, solar power is not likely to attract necessary investments.

Turkey's geothermal power potential will be mentioned as follows:

Turkey has the most geothermal resources in Europe and she is seventh in the world (PricewaterhouseCoopers, 2009). Out of 2,000 MW of economic power generation potential, only 30 MWe has been materialised so far and licensed underconstruction power plants have a capacity of 64 MW (PricewaterhouseCoopers, 2009). The Aegean region hosts most of the country's geothermal resources.

Geothermal power is regulated by two laws. Geothermal Resources and Mineral Waters Law No 5686, enacted in 2007 regulates the exploration, development, production, protection, ownership and economic use of geothermal resources; Electricity Market Law No 4628 and Renewables Law No 5346 regulates licensing, feed-in tariffs and other incentives.

The Strategy Paper sets the target of 600 MW by 2023 however the latest EIE studies envision a faster growth in this capacity, forecasting its reaching 455 MWe by 2010 and 550 MWe by 2013 MW (PricewaterhouseCoopers, 2009).

Utilization of renewable energy potentials of Turkey will be analysed as follows:

Despite Turkey's high untapped renewable energy sources potential, capacity breakdown of the granted licences of 12 GW in 2008 as shown in Figure 18, displays that Turkey's renewable sources do not have the place it deserves.

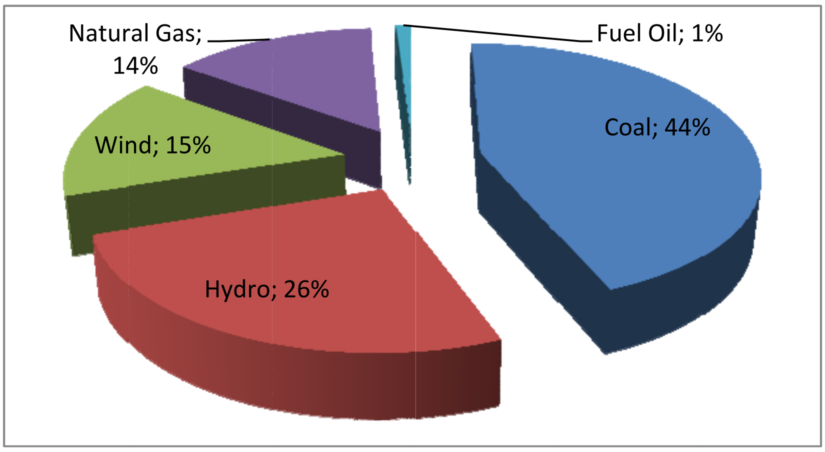

Figure 18. Capacity breakdown of 12 GW granted licenses in 2008 (PricewaterhouseCoopers, 2009a)

Coal forms 44% and natural gas 14% of granted licences in 2008. This picture shows that thermal sources still dominate the energy market. Although, the presence of wind with 15% share seems encouraging, when Turkey's high untapped potential of wind energy is taken into account, it needs to be promoted more. Figure 19 shows these 12 GW granted licences breakdown of 221 generation and 18 autoproduction licenses.

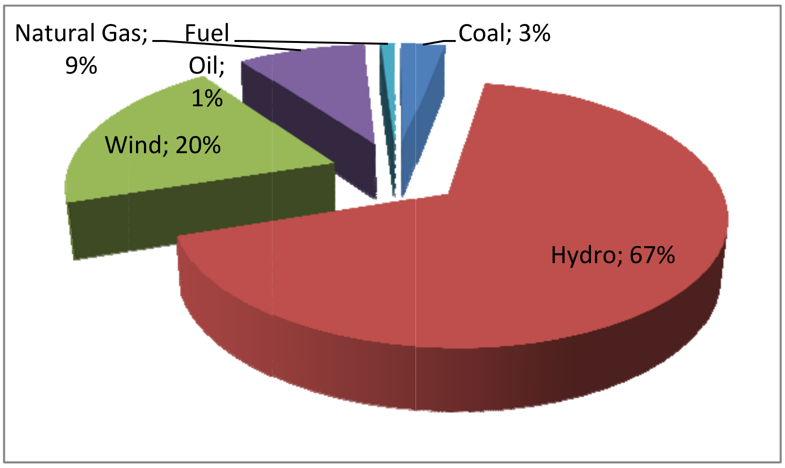

Figure 19. Number breakdown of 239 licenses granted in 2008 (PricewaterhouseCoopers, 2009a)

Share of coal is only 3% implying that coal power plant licences are very big when its share in capacity breakdown of 44% is taken into account. 67% of licenses are for hydro power plants, and the fact that its share in capacity breakdown is only 26%, shows that they are mostly small hydro power projects.

Table 69 shows at what stage are the applications of renewable energy sources as of 15 September 2009:

Table 69. The Stage Position of Applications by Renewable Energy Sources as of 15.09.2008 (Amendment Proposal, 2008)

	Application Stage		Investigation, Evaluation		Approval		Licenses Granted		Operating Capacity	
Renewable Energy Source	Number of Appl.	Installed Capacity (MW)	Number of Appl.	Installed Capacity (MW)	Number of Appl.	Installed Capacity (MW)	Number of Appl.	Installed Capacity (MW)	Number of Appl.	Installed Capacity (MW)
Hydro	74,0	3.368,6	138,0	3.057,2	184,0	3.292,3	379,0	11.522,5	50,0	1.253,0
Wind	6,0	75,2	754,0	77.062,6	17,0	1.153,4	91,0	3.311,0	16,0	334,0
Geothermal	1,0	5,0					6,0	92,0	4,0	24,5
LFG	1,0	4,0					6,0	40,0	4,0	12,1
Biogas	1,0	0,7	2,0	9,7			7,0	13,7	2,0	4,1
Biomass	2,0	2,8			1,0	4,0				
General Total	85,0	3.456,3	894,0	80.129,4	202,0	4.497,7	469,0	14.999,3	76,0	1.627,7

Hydroelectricity is dominant in licences granted and approved applications with 11,522 MW and 3,292 MW respectively. Applications for 3,057 MW are under investigation, evaluation. Wind power comes after hydroelectricity in licences granted and approved applications with 3,311 MW and 1,153 MW respectively. Wind power outpasses hydroelectricity in applications under investigation, evaluation with applications for 77,062 MW. But most of these applications are targetting overlapping locations. These applications should be concluded soon. Geothermal, LFG, biogas, biomass have very small shares in all application stages that their utilization may be neglected.

CHAPTER IV

DETERMINING THE BEST ELECTRICITY GENERATION TECHNOLOGIES FOR TURKEY BY USING GREY RELATIONAL ANALYSIS

According to TEIAS's (2009) Turkish Electrical Energy 10-Year Generation Capacity Projection (2009-2018) Report, electricity energy deficiency is expected in 2014 for high demand series and in 2015 for low demand series in case of Scenario 2 and firm generation capacities. Therefore, TEIAS (2009) proposes from 2010 on to take measures for granting licenses, monitoring investment starting dates and taking them into the system, by taking into account construction periods for new capacities. It is essential to keep capacity and energy reserves on certain levels for reliable operation of the electricity system due to factors that may create uncertainty, such as deficiency in demand side, constraints in the supply and quality of fuel, long term outages at power plants, and delays in plants under construction.

Turkey should decide as soon as possible, from which primary energy resources it will generate electricity, in other words the optimum electricity generation technology. Electricity can be generated from non-renewable resources such as natural gas and coal, nuclear power or renewable resources such as hydro, wind and solar power. Regarding the recent developments and feasibility of alternative electricity generation technologies, this study will assess the performances of natural gas combined cycle power plants, coal power combined heat plants, wind onshore power plants, small hydro (run of river) power plants, nuclear power plants and solar PV power plants.

When designing the market framework for the electricity sector, taking the costs and benefits of different energy resources into account with externalities is important in choosing the best alternative for the whole economy and stimulating sustainable investments in the best technologies. Externalities are impacts from the electricity generation that have no financial impacts on the owner of the power plant, but which result in economic costs or benefits to society. The difficulty is to quantify the costs and benefits in terms of money so that the externalities can be included in socio-economic evaluations. RECABS monetizes some of these externalities for different electricity generation technologies and so enables comparing of them.

Turkey performs relatively worse than the European Union on average in energy vulnerability indicators since it is more dependent on imports, has a more concentrated nature of energy suppliers, is less efficient in energy consumption, spends more carbon rich fuels and imports from less politically stable countries (Nenem, 2009). Supply security is the major issue in energy vulnerability of the electricity sector. Supply security is mostly related to how much the primary energy source is dependent on imports and on how concentrated are the foreign suppliers' of this primary energy source. The importance of electricity energy supply security increases when the non-storable nature of electricity and the limited interconnection rates with other countries are considered. Contrary to this negative standing, Turkey has more renewable energy opportunities compared to the European Union and thus exhibits a higher potential to reduce its energy vulnerability for the future.

In addition, increasing global concern for climate change and the EU regulations are expected to force Turkey to recognize the importance of greenhouse gas (GHG) emissions in investment decisions in the near future. Turkey has the highest percentage increase of 119.1% in GHG emissions (excluding LULUCF) among Annex I Parties from 1990 to 2007. Most of the GHG emissions are generated from energy sector and specifically, electricity generation. When all these factors are taken into account, renewable energy and nuclear energy may become a promising alternative. Among renewable energy sources, the penetration of wind energy in the EU and in the world is increasing more than other renewable energy sources. Turkey has the most wind energy capacity among the EU countries.

The state has declared its intention about this issue on Electricity Energy Market and Supply Security Strategy Paper approved by The Higher Board of Planning on 18 May 2009. Electricity Energy Market and Supply Security Strategy Paper defines the primary objective as, to ensure delivery of electricity in an adequate, high-quality, uninterrupted, low-cost, and environment-friendly manner. The principles in structuring of the electricity energy sector and functioning of the market were determined as ensuring supply security; taking into consideration climate change and environmental impacts, increasing efficiency, reducing electricity energy costs, encouraging new technologies to diversify resources, ensuring maximum use of domestic and renewable resources in order to reduce external dependency in energy supply and increasing the share of domestic contribution in investments to be made in the sector. Since some of these attributes are highly correlated and some attributes such as cost volatility risk are not mentioned explicitly, this study will take into account the following performance attributes: Cost efficiency, cost volatility risk, supply security, climate change & other pollution and supply-demand mismatch.

In this study, the Grey Relational Analysis (GRA) will be utilized to solve this multiple attribute decision making (MADM) problem by combining these entire range of performance attribute values. Sensitivity analyses will be carried out to determine the best solution in electricity generation for the Reference Scenario and the 450 Scenario of IEA's World Energy Outlook 2009. Also, the weights of performance attributes will be changed to explore the optimum solutions if the priorities change in favor of an attribute. The empirical results reveal that Turkey should focus on installing small hydro power plants, nuclear power plants and wind onshore power plants. Since hydro power and wind power are related to the natural potentials of a country, Turkey's potential for these resources has been assessed and it is concluded that Turkey has an immense untapped potential for these renewable energy resources. The empirical results of the GRA will be compared with the results of the Data Envelopment Analysis to see whether the results of these two methods are similar.

The objective of this study is to explore potential energy sources in electricity generation under different scenarios for Turkey by utilizing Grey Relational Analysis (GRA). The decision making process depends on ranking and selecting the best electricity generation technology by taking into account cost efficiency, cost volatility risk, supply security, climate change & other pollution and supply-demand mismatch. So, it is difficult to determine the best alternative by taking into account all possible trade-offs between these conflicting attributes. This is a problem of multiple attribute decision making (MADM) in nature. MADM ranks and selects the best from existing alternatives, by taking into account multiple attributes that are usually in conflict. There are several common methodologies for MADM, such as simple additive weighting (SAW), the technique for order preference by similarity to ideal solution (TOPSIS), analytical hierarchy process (AHP), data envelopment analysis (DEA) and so on (Kuo, Yang & Huang, 2008). In this study, the grey system, proposed by Deng (1982), is preferred because it has been widely applied to various fields and has been proven to be more competent for dealing with poor, incomplete, and uncertain information (Kuo, Yang & Huang, 2008). The weights of these attributes will change according to different viewpoints on whether it gives more or less priority to cost efficiency or supply security. GRA will propose the best technology for society, not for the private investor. So, government and the policy makers may use the outcomes of this study to incentivize the best technology for society while making this technology the best for the private investor as well.

This study contributes to the literature in the following ways. Firstly, it will help to rank and select the socially best electricity generation technologies in different scenarios and from different viewpoints giving different priorities for the attributes. Secondly it will show which attributes a country should consider when ranking and selecting the best alternative electricity generation technologies. Thirdly, this study will help to compare the unit electricity generation costs of different technologies by using the REcalculator with the assumptions of International Energy Agency's (IEA) Renewable Energy Costs and Benefits for Society (RECABS) project (2007) and fuel price and CO_2 price assumptions of World Energy Outlook 2009. Fourthly, the outcomes of this study will provide guidelines for ranking alternative electricity generation technologies and may serve as a baseline in designing market structure and necessary incentives by the government to encourage private sector investment in the socially best technologies. Lastly, this study will show that the impact of the distinguishing coefficient on the result of Grey Relational Analysis is small.

The first section will summarize the methodology. The second section will discuss the potential energy sources and their attributes in electricity generation for

Turkey. The third section will present empirical findings, will test the impact of the distinguishing coefficient on the results of GRA and will cover the sensitivity analysis. The fourth section will discuss the policy implications of the study. Concluding remarks will be given in the last section.

Methodology and the Major Attributes of the Analysis

Grey Relational Analysis (GRA) procedure is used for ranking these alternative technologies and providing a basis for selecting the best technology. Therefore, the MADM problem takes into account economic costs, externalities and supply security issues and GRA proposes the best technology for society, not for the private investor.

In the literature, GRA is part of grey system theory and GRA has been applied successfully in solving a variety of MADM problems, such as the hiring decision (Olson & Wu, 2006), the restoration planning for power distribution systems (Chen, 2005), the inspection of the integrated-circuit marking process (Jiang, Tasi, & Wang, 2002), the modeling of quality function deployment (Wu, 2002), the detection of silicon wafer slicing defects (Lin et al., 2006), the selection of power plant types (Nenem, 2009), the selection of the best facility layouts and dispatching rule selections (Kuo, Yang & Huang, 2008) etc.

Grey relational analysis (GRA) procedure comprises four stages: grey relational generating, reference sequence definition, grey relational coefficient calculation, grey relational grade calculation (Kuo, Yang & Huang, 2008). In grey relational generating, the performance of all alternatives is translated into a comparability sequence. In reference sequence definition, a reference sequence (ideal target sequence) is defined according to these sequences. In grey relational coefficient calculation, the grey relational coefficient between all comparability sequences and the reference sequence is calculated. In grey relational grade calculation, the grey relational grade between the reference sequence and every comparability sequences is calculated based on the grey relational coefficients. The best alternative choice will be the alternative whose comparability sequence has the highest grey relational grade between the reference sequence and itself. The stages of GRA procedure are as follows:

The units of performance measures may be different for different attributes. Some performance attributes may have a very large range, as well. Also, the goals and directions of different attributes may be different, leading to incorrect results or interpretations. So, all attribute performance values for every alternative should be processed into a comparability sequence, in other words a normalization process should be carried out. This normalization process is called grey relational generating (Kuo, Yang & Huang, 2008).

If there are m alternatives and n attributes, the ith alternative can be expressed as $Y_i = (y_{i1}, y_{i2}, \ldots, y_{ij}, \ldots, y_{in})$, where y_{ij} is the performance value of attribute j of alternative i. The term Y_i can be translated into the comparability sequence $X_i = (x_{i1}, x_{i2}, \ldots, x_{ij}, \ldots, x_{in})$ by using one of Equations 1, 2, 3 (Kuo, Yang & Huang, 2008).

$$X_{i,j} = \frac{y_{i,j} - Min\left[y_{ij},\ i=1,2,...,m\right]}{Max\left[y_{ij},\ i=1,2,...,m\right] - Min\left[y_{ij},\ i=1,2,...,m\right]} \quad \text{for } i=1,2,...,m \quad j=1,2,...,n \quad (1)$$

$$X_{i,j} = \frac{Max\left[y_{ij},\ i=1,2,...,m\right] - y_{i,j}}{Max\left[y_{ij},\ i=1,2,...,m\right] - Min\left[y_{ij},\ i=1,2,...,m\right]} \quad \text{for } i=1,2,...,m \quad j=1,2,...,n \quad (2)$$

$$X_{i,j} = 1 - \frac{y_{i,j} - y_j^*}{Max\left[Max\left[y_{ij},\ i=1,2,...,m\right] - y_{ij}^*,\ y_{ij}^* - Min\left[y_{ij},\ i=1,2,...,m\right]\right]}$$

for i=1,2,...,m j=1,2,...,n (3)

The larger the better attributes use Equation 1, the smaller the better attributes use Equation 2, the closer to the desired value y_j* the better attributes use Equation 3.

As a result of the grey relational generating procedure, all performance values will be scaled into [0, 1]. After the grey relational generating, if the value x_{ij} for an attribute j of alternative i, is equal to 1 or nearer to 1 than the value for any other alternative, the performance of alternative i will be the best one for the attribute j. Therefore an alternative whose performance values are the closest to or equal to 1 will be the best choice. The reference sequence X_0 is defined as (x_{01}, x_{02}, . . ., x_{0j}, . . ., x_{0n}) = (1, 1,..,1), and the alternative whose comparability sequence is the closest to the reference sequence will be the best alternative.

Grey relational coefficient is used for determining how close x_{ij} is to the reference sequence x_{0j}. The larger the grey relational coefficient, the closer x_{ij} and x_{0j} are. The grey relational coefficient can be calculated by Equation 4 (Kuo, Yang & Huang, 2008).

$$\gamma\,(x_{0j}, x_{ij}) = \frac{\Delta \min + \zeta\,\Delta\max}{\Delta\,ij + \zeta\,\Delta\max} \qquad \text{for } i=1,2,...,m \quad j=1,2,...,n \qquad (4)$$

In Equation 4, γ (x_{0j}, x_{ij}) is the grey relational coefficient between x_{ij} and x_{0j}

$\Delta_{ij} = |\ x_{0j} - x_{ij}\ |$,

Δ_{min} = Min {Δ_{ij}, i=1,2,...,m j=1,2,...,n}

Δ_{max} = Max {Δ_{ij}, i=1,2,...,m j=1,2,...,n}

ζ is the distinguishing coefficient, $\zeta \in [0,1]$

The distinguishing coefficient aims to expand or compress the range of the grey relational coefficient. The decision maker can adjust the distinguishing coefficient by exercising judgment. Kuo, Yang & Huang (2008) sets the distinguishing coefficient as 0.5 initially, and then tests some other different distinguishing coefficients for analysis. In Kuo, Yang & Huang's (2008) study, the differences between γ (x_{0j}, x_{aj}), γ (x_{0j},x_{bj}) and γ (x_{0j}, x_{cj}) change when different distinguishing coefficients are adopted, but, the rank order of γ (x_{0j}, x_{aj}), γ (x_{0j},x_{bj}) and γ (x_{0j}, x_{cj}) is always the same.

After calculating the entire grey relational coefficient γ (x_{0j}, x_{ij}), the grey relational grade can be then calculated by using Equation 5 (Kuo, Yang & Huang, 2008).

$$\Gamma\left(X_0, X_i\right) = \sum_{j=1}^{n} w_j \, \gamma\left(x_{oj}, x_{ij}\right) \qquad \text{for i=1,2,...,m} \quad (5)$$

The grey relational grade Γ (X_0, X_i) represents degree of similarity between the reference sequence and the comparability sequence. w_j is the weight of attribute j and usually depends on decision makers' judgment or the structure of the proposed problem. In addition,

$$\sum_{j=1}^{n} w_j = 1$$

As mentioned above, on each attribute, the reference sequence represents the best performance that could be achieved by any among the comparability sequences. Therefore the comparability sequence for an alternative whose grey relational grade is the highest would be the best choice.

The attributes and performance values of these attributes should be determined for every alternative technology. The major attributes are cost efficiency, cost volatility risk, supply security, climate change & other pollution and supply-demand mismatch.

Cost efficiency considers the cost of generating 1 MWh of electricity by taking into account capital (investment) costs, operation & maintenance costs, fuel costs, system integration infrastructure costs and income from heat sales. In this study, the costs per MWh electricity will be calculated on the assumptions and projections of IEA (2007) RECABS project and IEA's World Energy Outlook 2009.

RECABS has been prepared for the IEA's Implementing Agreement on Renewable Energy Technology Deployment by Energy Analyses (Ea). The objective of RECABS is to assess the costs and benefits of electricity from renewable energy sources compared to conventional technologies. All economic and technological assumptions of RECABS project rely on internationally respected sources. Information about RECABS project in this section is obtained from RECABS main report (2007).

RECABS project is an analytical tool that provides a cost-benefit analysis. The cost-benefit analysis can be grouped into two as the financial cost-benefit analysis and economic cost-benefit analysis. The financial cost-benefit analysis takes into account the concerns of a private investor, while the economic cost-benefit analysis takes into account national benefits and costs. The financial cost-benefit analysis includes all taxes and subsidies while the economic cost-benefit analysis ignores all taxes and subsidies, but includes external costs, which have no direct impact on the financial viability of the project. The economic cost-benefit analysis is often used by government agencies to justify subsidies. RECABS project is based on economic cost-benefit analysis.

RECABS uses year 2010 as representing current costs and performances for the technologies decided and ordered in 2007, RECABS was built in, since these will be in operation around 2010. This study will use 2015 as representing current costs and performances since technologies decided today in 2010 will be in operation around 2015 for most of the technologies. Since the main difference among capital (investment) costs and O&M costs for different years come from the learning effects for renewable energy technologies, comparing and analyzing alternative technologies for the year 2015 by using the assumptions of RECABS's investment cost and O&M cost assumptions for 2010 would be a more conservative approach for renewable energy technologies and so would lead to more robust conclusions for the year 2015. This study will employ other assumptions related to costs such as fuel costs as 2015 price projections of IEA's World Energy Outlook 2009 to reach more reliable conclusions.

RECABS uses the constant-money levelized lifetime cost method. This method provides the costs per unit of electricity generated that is the ratio of total lifetime expenses' net present value to total expected electricity generation (IEA, 2007). The formula to calculate the levelized electricity generation cost is as follows (IEA, 2007):

$$EGC = \frac{\sum_{n=1}^{N} (I_n + OM_n + F_n) * (1 + \frac{r}{100})^{-n}}{\sum_{n=1}^{N} E_N * (1 + \frac{r}{100})^{-n}}$$

where:

EGC = Constant-money levelized lifetime electricity generation cost (€/MWh)

N = Technical lifetime of the power plant (years)

n = The year when the actual costs are incurred (from 1 for the first year of operation to N for the final year of operation)

I_n = Investment expenditures in the year n (€); includes reinvestment and other major rehabilitation costs not accounted for as maintenance costs

OM_n = Operation and maintenance expenditures in the year n (€)

F_n = Fuel expenditures in the year n (€)

r = Discount rate (% per year)

E_n = Net electricity generation in the year n (MWh)

This study will use technical lifetime of each technology as discount periods and economic discount rate like RECABS. Discount rate is very important for the calculation results of RECABS since this directly influences the net present values of expenses and incomes. The economic discount rate may be a rate required by public regulators derived from national macroeconomic analysis; or it may be related to other concepts of the trade-off between costs and benefits for present and future generations (IEA, 2007). Since the economic assessments are based on fixed prices in this study as is the case in RECABS, the discount rate is also determined in real discount rate without the effect of the inflation. This study will use an economic real discount rate of 5% per annum, compatible with RECABS as well. This discount rate can be changed to make sensitivity analysis as well.

This study will use constant money approach and will take the base year 2006 that is compatible with RECABS. Therefore all costs and benefits will be defined at the price level for 2006 and data obtained in other price levels will be inflated or deflated to 2006 price level. All economic data will be in Euro to be compatible with RECABS. The result of converting exchange rates depends on which date is used for the conversion. Therefore, the purchasing power parity exchange rates are used to be compatible with RECABS. Since purchasing power parity is accepted to be the long-run equilibrium exchange rate of two currencies to equalize the currencies' purchasing power, this approach is compatible with the long run nature of this study. Purchasing power parity of 0.870 USD/EUR in 2006 will be used in this study that is used by RECABS as well.

RECABS analysis assesses costs and benefits of alternative electricity generation technologies in two major groups: Basic costs and Externalities. In RECABS, basic costs consist of capital (investment) costs, fuel costs, operation & maintenance costs and income from heat generation. Externalities taken into account by RECABS are as follows: climate change, other environmental pollution, system integration, security of fuel supply, and local benefits (rural employment).

Within climate change, the cost of reducing GHG emissions is taken into account. In the context of other environmental pollution, the impacts of local air pollution of SOx, NOx and particles from burning of fossil fuels and the impacts of radioactive emissions and nuclear accidents on human health are considered (IEA, 2007). Regarding system integration, costs related to the integration of power plants into the electricity system comprising infrastructure costs, balancing costs and capacity credit costs are taken into account (IEA, 2007). Security of fuel supply covers the macro-economic benefits of using domestic (renewable) energy sources to counter economic losses (inflation and unemployment) from volatile oil prices (IEA, 2007). Rural job creation is focused in the context of local benefits (IEA, 2007).

Analysis of Major Attributes

Regarding the recent developments and feasibility of alternative electricity generation technologies, this study will assess the performances of natural gas combined cycle power plants, coal power combined heat plants, wind onshore power plants, small hydro (run of river) power plants, nuclear power plants and solar PV power plants.

The selection of electricity generation technology is vital due to the fact that electricity generation technologies have significant impacts on cost efficiency, cost volatility risk, supply security, climate change & other pollution and supply-demand mismatch. These main attributes can be summarized as follows:

Cost Efficiency: The cost of generating 1 MWh electricity by taking into account capital (investment) costs, operation & maintenance costs, fuel costs, system integration infrastructure costs and income from heat sales (IEA, 2007).

Cost Volatility Risk: The risk related to the electricity generation costs arising from fuel price fluctuations.

Climate Change & Other Pollution: The impacts of alternative technologies on climate change and local air pollution from burning of fossil fuels and the impacts of radioactive emissions and nuclear accidents on human health (IEA, 2007).

Supply Security: The combined risk of import dependency and import concentration taking into account the share of imports in the consumption of the fuel used in electricity generation and Hirschmann-Herfindahl index of supplier countries.

Supply-Demand Mismatch: The problems for technologies with intermittent outputs appearing in the form of balancing costs arising from handling deviations from planned production and additional investments in reserves required and capacity credit costs arising from not being able to produce power when the electricity system needs it the most (IEA, 2007).

In this study, the cost efficiency attribute will include basic costs defined in RECABS and additionally system integration infrastructure costs. Climate change and other environmental pollution will be aggregated in this study and will be considered as the attribute climate change & other pollution. This study will not take into account the security of fuel supply and local benefits. Because, security of fuel supply is somehow related to “cost volatility risk” that is an attribute of this MADM and GRA avoids multiple attributes that are highly correlated. When it comes to local benefits, the assigned values for the alternative technologies considered in this study are assigned 0 in RECABS. So, local benefits will not be considered in this study.

Cost Efficiency

Cost efficiency is based on capital costs (investment costs), operation & maintenance costs, fuel costs, system integration infrastructure costs (IEA, 2007). Income from heat sales is considered as a negative cost and deducted from these costs. The assumptions related to these costs and technologies are based on RECABS whereas fuel price projections are based on IEA’s World Energy Outlook 2009.

Capital (investment) costs used in this study are the investment costs for commercially proven and best available technologies in 2010 used by RECABS. They include planning and design, feasibility analysis, approvals by authorities, site work, connections of electricity, water, and equipment, transport to arrival port and transport from port to site, assembly and commissioning, etc (IEA, 2007). Interest payments during construction period, costs of land acquisition, costs of project management and administration, taxes and duties, costs of dismantling decommissioned plants are not included (IEA, 2007). Capital costs, full load duration hours and technical lifetime assumptions that will be used in this study are compatible with assumptions of RECABS and are as shown in Table 70:

Table 70. Assumptions About Capital Costs, Full Load Duration Hours and Technical Lifetime of RECABS (IEA, 2007)

Electricity Generation Technology	Capital Costs (€/MW)	Full Load Duration Hours/Year or Electricity Efficiency (%)	Technical Lifetime (Years)
Natural Gas Combined Cycle Power Plants	501,000	58%	25
Coal Power Combined Heat Plants	1,400,000	46%	40
Wind Onshore Power Plants	900,000	2,500	20
Small (10-30 MW) Hydro (Run of River) Power Plants	2,400,000	6,000	35
Nuclear Power Plants	2,200,000	7,600	40
Solar PV Power Plants	4,800,000	1,400	30

A major output of RECABS project is the interactive energy calculator, REcalculator. The REcalculator enables the calculation of electricity generation costs for alternative technologies.

When the REcalculator is employed, based on assumptions about capital costs, full load duration hours and technical lifetime in Table 3, capital (investment) costs per MWh for alternative technologies are calculated as shown in Table 71:

Table 71. Capital (Investment) Costs Per MWh For Alternative Technologies

Electricity Generation Technology	Capital Costs (€/MWh)
Natural Gas Combined Cycle Power Plants	6.14
Coal Power Combined Heat Plants	16.24
Wind Onshore Power Plants	28.89
Small Hydro (Run of River) Power Plants	24.43
Nuclear Power Plants	17.09
Solar PV Power Plants	223.03

Operation and Maintenance (O&M) Costs consist of three parts: the fixed O&M costs, variable O&M costs and re-investment costs (IEA, 2007). The fixed share O&M costs (€/MW/year) are independent of the amount of electricity generation and include costs such as administration costs, insurance, etc. The variable O&M costs (€/MWh) are dependent on the amount of electricity generation and include costs such as consumption of auxiliary materials, spare parts, etc. Re-investment costs are incurred at periodic intervals of several years. Since O&M costs change over time, RECABS uses the average costs during the entire lifetime of the technology and this study will use the average costs as well. Operation and maintenance cost assumptions that will be used in this study are compatible with the assumptions of RECABS project and are as shown in Table 72:

Table 72. Assumptions About Operation and Maintenance Costs in RECABS (IEA, 2007)

Electricity Generation Technology	O & M Costs (€/MW)
Wind Onshore Power Plants	20,000 €/MW/year
Small Hydro (Run of River) Power Plants	50,000 €/MW/year
Nuclear Power Plants	70,000 €/MW/year
Natural Gas Combined Cycle Power Plants	12,500 €/MW/year + 1.7 €/MWh
Coal Power Combined Heat Plants	18,200 €/MW/year + 2 €/MWh
Solar PV Power Plants	48,000 €/MW/year

When the REcalculator is employed based on assumptions about operation and maintenance costs in Table 73, operation and maintenance costs per MWh for alternative technologies are calculated as shown in Table 73:

Table 73. Operation and Maintenance Costs Per MWh For Alternative Technologies

Electricity Generation Technology	O&M Costs (€/MWh)
Natural Gas Combined Cycle Power Plants	3.86
Coal Power Combined Heat Plants	5.25
Wind Onshore Power Plants	8.00
Small Hydro (Run of River) Power Plants	8.33
Nuclear Power Plants	9.33
Solar PV Power Plants	34.29

Fuel costs is the most important cost component for conventional technologies such as coal power combined heat plants and natural gas combined cycle power plants. This study uses the economic fuel cost without any subsidies and taxes, while the financial fuel cost is the price at which it is sold and purchased, including all subsidies, taxes. For internationally tradable fuels, the economic costs are normally assumed to be equal to world market prices, since any fuel demand can be met by import at world market prices, and any surplus of domestic fuel production can be exported at world market prices (IEA, 2007). RECABS assumes that fuel price projection for a specific year will be the same for the succeeding years during the technical lifetime of the technology and so REcalculator does not allow to enter different fuel price assumptions for different years. Different from RECABS, this study will use different fuel price assumptions for different years to reach more reliable results and to take into the differences in fuel price projections of IEA World Energy Outlook 2009's Reference Scenario and 450 Scenario fully.

RECABS used fuel price estimates of IEA's World Energy Outlook 2006 for the years 2010 and 2025 in its original project. Today in 2010, it is understood that fuel price assumptions in World Energy Outlook 2006 for 2010 is much lower than the world market prices realized although fuel prices decreased significantly due to the economic crisis in the world. Different from RECABS original project, this study analyses and compares alternative technologies for the year 2015. Also, IEA has revised its fuel price projections upward considerably in World Energy Outlook 2009 for the future. Therefore, this study will employ fuel price projections of IEA's World Energy Outlook 2009 for the year 2015 and succeeding years.

World Energy Outlook 2009 involves two scenarios that are namely the Reference Scenario and the 450 Scenario and so different fuel price projections for each scenario. The Reference Scenario provides a baseline picture of how energy markets would evolve if the underlying trends in energy demand and supply are not changed (IEA, 2009a). So, it is assumed that governments are assumed to make no changes to their existing policies and measures insofar as they affect the energy sector. IEA (2009a) assumes in the 450 Scenario that governments adopt commitments to limit the long-term concentration of GHGs in the atmosphere to 450 parts per million of CO_2 equivalent, an objective that is gaining widespread support in the world. This study will employ price projections for each scenario separately and then compare the outcomes. The price projections of IEA (2009a) in World Energy Outlook 2009 are derived from a large-scale mathematical model, the World Energy Model, that has been updated with the most recent historical data and revised assumptions. The fuel prices are based on ensuring global balance of supply and projected demand. The international fuel prices projections in the Reference Scenario are as shown in Table 74:

Table 74. Fuel Price Projections In the Reference Scenario of the World Energy Outlook 2009, (In Real Terms, 2008 USD) (IEA, 2009a)

Fossil Fuels	Unit	2008	2015	2020	2025	2030
Crude Oil Imports	Barrel	97.19	86.67	100.00	107.50	115.00
Natural Gas Imports						
United States	MBtu	8.25	7.29	8.87	10.04	11.36
Europe	MBtu	10.32	10.46	12.10	13.09	14.02
Japan LNG	MBtu	12.64	11.91	13.75	14.83	15.87
OECD Steam Coal Imports	Tonne	120.59	91.05	104.16	107.12	109.40

The international fuel prices projections in the 450 Scenario are as shown in Table 75.

Table 75. Fuel Price Projections In the 450 Scenario of the World Energy Outlook 2009, (In Real Terms, 2008 USD) (IEA, 2009a)

Fossil Fuels	Unit	2008	2015	2020	2025	2030
Crude Oil Imports	Barrel	97.19	86.67	90.00	90.00	90.00
Natural Gas Imports						
United States	MBtu	8.25	7.29	8.15	9.11	10.18
Europe	MBtu	10.32	10.46	11.04	11.04	11.04
Japan LNG	MBtu	12.64	11.91	12.46	12.46	12.46
OECD Steam Coal Imports	Tonne	120.59	85.55	80.09	72.46	64.83

As seen in Table 74 and 75, IEA World Energy Outlook involves fuel price projections for the years, 2015, 2020, 2025 and 2030. However technical lifetime of natural gas combined cycle power plants is assumed to be 25 years and so Europe natural gas price assumptions should be extended beyond 2030 until 2039. Technical lifetime of coal power combined heat plants is assumed to be 40 years and so OECD steam coal price assumptions should be extended beyond 2030 until 2054. Natural gas price assumptions for the years 2031-20039 and steam coal price assumptions for the years 2031-2054 will be derived by using linear extrapolation method taking by creating a tangent line between data points in 2020 and 2030 extending it beyond 2030. Because IEA's (2009a) fuel price assumptions for 2020-2025-2030 show nearly a linear trend. World Energy Outlook 2009 does not involve fuel price projections for the years remaining between 2015-2020-2025-2030. Fuel price assumptions for these years will be derived by using linear interpolation method. Table 76 shows fuel price assumptions between 2015-2054 that will be used in this study, derived from IEA World Energy Outlook 2009 price projections by using linear interpolation and linear extrapolation methods.

Table 76. Fuel Price Assumptions Between 2015-2054 (In Real Terms, 2008 USD)

	Reference Scenario		450 Scenario	
Year	Natural Gas	Coal	Natural Gas	Coal
2015	10.460	91.050	10.460	85.550
2016	10.788	93.672	10.576	84.458
2017	11.116	96.294	10.692	83.366
2018	11.444	98.916	10.808	82.274
2019	11.772	101.538	10.924	81.182
2020	12.100	104.160	11.040	80.090
2021	12.298	104.752	11.040	78.564
2022	12.496	105.344	11.040	77.038
2023	12.694	105.936	11.040	75.512
2024	12.892	106.528	11.040	73.986
2025	13.090	107.120	11.040	72.460
2026	13.276	107.576	11.040	70.934
2027	13.462	108.032	11.040	69.408
2028	13.648	108.488	11.040	67.882
2029	13.834	108.944	11.040	66.356
2030	14.020	109.400	11.040	64.830
2031	14.212	109.924	11.040	63.304
2032	14.404	110.448	11.040	61.778
2033	14.596	110.972	11.040	60.252
2034	14.788	111.496	11.040	58.726
2035	14.980	112.020	11.040	57.200
2036	15.172	112.544	11.040	55.674
2037	15.364	113.068	11.040	54.148
2038	15.556	113.592	11.040	52.622
2039	15.748	114.116	11.040	51.096
2040	-	114.640	-	49.57
2041	-	115.164	-	48.044
2042	-	115.688	-	46.518
2043	-	116.212	-	44.992
2044	-	116.736	-	43.466
2045	-	117.26	-	41.94
2046	-	117.784	-	40.414
2047	-	118.308	-	38.888
2048	-	118.832	-	37.362
2049	-	119.356	-	35.836
2050	-	119.88	-	34.31
2051	-	120.404	-	32.784
2052	-	120.928	-	31.258
2053	-	121.452	-	29.732
2054	-	121.976	-	28.206

Since only one fuel price value can be entered into REcalculator, the fuel price assumptions in Table 76 will be converted to a single fuel price that will give the same results in as follows: The fuel price assumptions for each year is discounted by $(1+r)^n$ and these discounted values are summed. Then the sum of these discounted fuel prices will be divided by the coefficient of the annuity formula $[1-(1+r)^{-n}) / r]$. The result will be a single price but will create the same results with the fuel price assumptions in Table 76. This single fuel price for the REcalculator is calculated in Table 77.

Table 77. Calculation of Single Fuel Price for the REcalculator

	Reference Scenario		450 Scenario	
	Natural Gas	Coal	Natural Gas	Coal
Sum of Fuel Prices Discounted by $(1+0,05)^n$	181.043	1,835.479	154.042	1,149.089
Annuity Coefficient for n Years and r=0,05	14.094	17.159	14.094	17.159
Single Fuel Price ($)	12.845	106.968	10.930	66.967

RECABS is based on net calorific values while the gas prices are expressed on gross calorific value basis. The net calorific value of natural gas is usually below the gross calorific value by 10% (IEA, 2007). So, to convert from prices based on gross to net calorific value, gross values will be divided by 0.90. For natural gas, the energy unit MBtu will be converted to GJ with the conversion factor of 1.055 GJ/MBtu (IEA, 2007). For coal, conversion factor of 31.4 GJ/tonne will be used to find net calorific values (IEA, 2007). These conversion factors are compatible with RECABS. For the sake of being compatible with RECABS, the single fuel prices in Table 10 will be converted to prices EUR (2006 price level) per GJ in Table 78 as follows:

Table 78. Conversion* of Fuel Price Projections In the Reference Scenario and the 450 Scenario (In Real Terms, 2006 EUR)

Fossil Fuels	Unit	Reference Scenario	450 Scenario
Europe Natural Gas Imports	EUR/GJ	11.28	9.60
OECD Steam Coal Imports	EUR/GJ	2.84	1.78

*According to Bureau of Labor Statistics, CPI increase in the USA in 2007 and 2008 is 4.3%. So, 2008 $ prices in the World Energy Outlook 2009 has been deflated by 4.3% to reach 2006 $ values.

Fuel costs of nuclear power plants are different from fossil fuels. Fuel costs in nuclear power plants cover full fuel cycle costs including conversion, enrichment and fabrication of natural uranium, reprocessing and wastes disposal (IEA, 2007). This study will employ RECABS default value of 0.50 €/GJ. Since fuel costs comprise only a small cost portion for nuclear power, deviation from these price assumptions do not create significant outcomes.

When the REcalculator is employed, based on assumptions about fuel prices in Table 79, fuel costs per MWh for alternative technologies are calculated as shown in Table 79:

Table 79. Fuel Costs Per MWh For Alternative Technologies

Electricity Generation Technology	Fuel Costs In the Reference Scenario (€/MWh)	Fuel Costs In the 450 Scenario (€/MWh)
Natural Gas Combined Cycle Power Plants	70.28	59.81
Coal Power Combined Heat Plants	22.33	13.99
Wind Onshore Power Plants	0.00	0.00
Small Hydro (Run of River) Power Plants	0.00	0.00
Nuclear Power Plants	6.55	6.55
Solar PV Power Plants	0.00	0.00

System integration infrastructure costs in RECABS involves infrastructure costs, balancing costs and capacity credit costs and are defined as costs related to the integration into the surrounding energy system of technologies with intermittent output such as wind power, solar PV and hydro run of river. Infrastructure costs arise from expanding and adjusting the electricity infrastructure (IEA, 2007). Balancing costs arise from handling deviations from planned production and additional costs for investments in reserves for handling of outages of power plants (IEA, 2007). Capacity credit costs arise from not being able to produce power when the electricity system needs it the most (IEA, 2007). This study will use infrastructure costs within the attribute “cost efficiency” since this is more compatible with the purposes of this study.

This study employs assumptions of RECABS original project for infrastructure costs that will be mentioned as follows: the infrastructure costs for grid connection of wind onshore will be assumed as 8% of total project investment costs that corresponds to infrastructure costs of 2.2 €/MWh; the infrastructure costs for hydro run of river are estimated to be the same as for onshore wind power, that is 2.2 €/MWh; and solar PV may defer transmissions and distribution upgrades investments. This cost avoidance is assumed as 14 €/MWh. Solar PV may also avoid line losses in transmission and distribution grid since production of electricity close to the load and consumption point can reduce these losses (IEA, 2007). This cost avoidance in line losses is assumed as 4.4 €/MWh. So, these infrastructure cost reductions of solar power sum up to 18.4 €/MWh. It is assumed that new nuclear power will be established within the framework of the existing infrastructure and will not need further infrastructure investments that is usually the fact in many cases (IEA, 2007). So system integration infrastructure costs per MWh for alternative technologies are as shown in Table 80:

Table 80. System Integration Infrastructure Costs Per MWh For Alternative Technologies in RECABS (IEA, 2007)

Electricity Generation Technology	System Integration Infrastructure Costs (€/MWh)
Natural Gas Combined Cycle Power Plants	0.0
Coal Power Combined Heat Plants	0.0
Wind Onshore Power Plants	2.2
Small Hydro (Run of River) Power Plants	2.2
Nuclear Power Plants	0.0
Solar PV Power Plants	-18.4

Income from heat sales comes as an additional source. In addition to electricity, some technologies produce heat that can be sold to a heating system. This income should be deducted from the costs to reach more reliable results. The value of this heat can be determined in two ways. In the first approach, the value includes all costs of a heat plant since this is the alternative baseline (IEA, 2007). In the second approach, the value includes only the marginal fuel costs since the heat is a waste product of electricity generation (IEA, 2007). This study will use the second approach and assumes like RECABS that district heat will substitute heat generated from a fuel mix of 60% coal and 40% natural gas. When the REcalculator is employed based on assumptions of RECABS, income from heat sales per MWh for alternative technologies are calculated as shown in Table 81:

Table 81. Income From Heat Sales Per MWh For Alternative Technologies (IEA, 2007)

Electricity Generation Technology	Income From Heat Sales (€/MWh)
Natural Gas Combined Cycle Power Plants	-3.05
Coal Power Combined Heat Plants	-4.72
Wind Onshore Power Plants	0.00
Small Hydro (Run of River) Power Plants	0.00
Nuclear Power Plants	0.00
Solar PV Power Plants	0.00

Total electricity generation costs per MWh for each alternative technology by using the REcalculator of RECABS are as shown in Table 82:

Table 82. Performance Values of Cost Efficiency For Alternative Technologies in €/MWh

Electricity Generation Technology	Electricity Generation Cost in the Reference Scenario (€/MWh)	Electricity Generation Cost in the 450 Scenario (€/MWh)
Natural Gas Combined Cycle Power Plants	77.23	66.76
Coal Power Combined Heat Plants	39.10	30.76
Wind Onshore Power Plants	39.09	39.09
Small Hydro (Run of River) Power Plants	34.96	34.96
Nuclear Power Plants	32.97	32.97
Solar PV Power Plants	238.92	238.92

Cost Volatility Risk

Price volatility is an important factor in assessing the energy vulnerability of a country in that fluctuations in the energy prices increase the vulnerability levels. Reliance on energy types that has more price volatility increases the vulnerability of a country. Fluctuations in fuel prices that will be used in electricity generation alter the marginal electricity generation costs significantly. The uncertainty of the fuel prices during the technical lifetime of the power plants creates significant risk especially when high sunk costs of investment is considered with the long technical lifetime of power plants. This cost risk arising from fuel price volatility stands as a crucial issue in selecting electricity generation technology. Since investment costs are incurred at the beginning of the investment and operational and maintenance costs are much more predictable and small, fuel prices becomes the only input that may change average electricity generation costs significantly. Therefore different fuel price assumptions during the technical lifetime of power plants that are usually more than 20 years, alter the financial indicators of the power plant installation project and may turn a feasible project into an unfeasible one and vice versa. As fuel price volatility changes the financial feasibility of a power plant project significantly for a private investor, it may also change the change economic feasibility of a power plant project for society. So, fuel price volatility stands as a significant risk in assessing alternative electricity generation technologies. Table 83 shows annual averages of natural gas EU CIF prices and coal Northwest Europe marker prices between 1989 and 2008 as follows:

Table 83. Natural Gas EU CIF Prices and Coal Northwest Europe Marker Prices Between 1989-2008 (BP, 2009)

Years	Natural Gas EU CIF Prices (USD/million Btu)	Coal Northwest Europe Marker Prices (USD/tonne)
1989	2.09	n.a.
1990	2.82	43.48
1991	3.18	42.80
1992	2.76	38.53
1993	2.53	33.68
1994	2.24	37.18
1995	2.37	44.50
1996	2.43	41.25
1997	2.65	38.92
1998	2.26	32.00
1999	1.80	28.79
2000	3.25	35.99
2001	4.15	39.29
2002	3.46	31.65
2003	4.40	42.52
2004	4.56	71.90
2005	5.95	61.07
2006	8.69	63.67
2007	8.93	86.60
2008	12.61	149.78

Based on annual average prices in 83, the standard deviation of natural gas prices is 2.832 and the standard deviation of coal prices is 28.322. Dividing standard deviations by average prices, calculated by taking averages of prices available during 1989-2008 period, gives more comparable results to assess volatility of natural gas and coal. The volatilities of natural gas and coal as ratio of standard deviations to their average prices are as shown in Table 84:

Table 84. Volatility of Natural Gas and Coal Prices

Natural Gas	Coal
0.681	0.558

Performance values of cost volatility risk for alternative technologies are as shown in Table 85:

Table 85. Performance Values of Cost Volatility Risk For Alternative Technologies

Electricity Generation Technology	Cost Volatility Risk (%)
Natural Gas Combined Cycle Power Plants	68.1%
Coal Power Combined Heat Plants	55.8%
Wind Onshore Power Plants	0.0%
Small Hydro (Run of River) Power Plants	0.0%
Nuclear Power Plants	0.0%
Solar PV Power Plants	0.0%

Climate Change & Other Pollution

This attribute takes into account the impacts of alternative technologies on climate change and local air pollution from burning of fossil fuels and the impacts of radioactive emissions and nuclear accidents on human health, altogether. In RECABS, climate change and other environmental pollution are two separate externalities considered. But for the purposes of this study it is more compatible to combine these externalities and take them as a single attribute. First of all, climate change and other pollution will be explained and performance values of climate change and other pollution for each alternative technology will be assigned separately. Then performance values of climate change and other pollution will be combined for each alternative technology to create a single attribute.

Climate change, and particularly the dominating GHG CO_2 is important for electricity generation technologies. The emission is directly related to fuel consumption. Possible other greenhouse gases are converted to CO_2 equivalents.

Economic consequences of climate change have been analyzed extensively by the European Commission research project Externalities of Energy (ExternE). ExternE recommends that an avoidance cost, in other words the costs of reducing the emission of greenhouse gases, should be used when pricing the greenhouse gas emissions. RECABS and this study accepts this approach and uses the market value of CO_2 as the cost of reducing GHG emissions. RECABS uses the emission factors recommended by the IPCC as shown in Table 86:

Table 86. Emission Factors of Fuels (IPCC) (IEA, 2007)

Fuel	Emission Factor (tCO2/GJ)
Steam Coal	0.098
Lignite	0.101
Natural Gas	0.056
Gas/Diesel Oil	0.074

The economic value of greenhouse gas emissions from an electricity generating plant (€/MWh) is the specific cost (€/tCO_2) times the emission coefficient (tCO_2/GJ) times the fuel consumption (GJ/MWh). So, the most important variable in calculating the externality of climate change is future prices of CO_2. In the Reference Scenario of World Energy Outlook 2009, CO_2 prices is projected to reach 43$ per tonne in 2020 and 54$ per tonne in 2030 in OECD in 2008 $ values. To contain emissions at the levels required in the 450 Scenario, CO_2 prices are projected to reach 50$ per tonne in 2020 and 110$ per tonne in 2030 in OECD in 2008 $ values. Since the carbon markets in OECD and Other Major Economies will be linked to create a single carbon market in the long run especially after 2030 this is likely to have depressing impacts on carbon prices after 2030 and this study assumes that this will compensate the upward trend in carbon prices leaving carbon prices unchanged after 2030.

In January 2010, European Union Allowance average spot prices is 12.9 € per tonne of CO_2 on European Climate Exchange. According to Eurostat, Harmonized Indices of Consumer Prices

(HICP) increased by 5.7% between the end of 2006 and the end of 2009 in the Euro area. So, 12.9 € will be deflated to (12.9 / 1.057=) 12.2 € in 2006 € values. Since the price assumptions in World Energy Outlook 2009 are in 2008 $ values, these price assumptions will be deflated by the 4.3% that is the Consumer Price Index (CPI) increase in the USA in 2007 and 2008 and then will be converted to the Euro at 0.87 $/€. In the Reference Scenario, these are deflated and converted to 35.9 € for 2020 and 45.0 € for 2030. In the 450 Scenario, CO_2 prices is deflated to 41.7 € for 2020 and 91.8 € for 2030. CO_2 prices for the years 2015 and succeeding years until 2030 are derived by using linear interpolation method and CO_2 prices for the years after 2030 are assumed to have the prices in 2030. The average CO_2 prices for natural gas combined cycle power plants are calculated by taking the average of CO_2 prices during 2015-2039 period, and the average CO_2 prices for coal power combined heat plants are calculated by taking the average of CO_2 prices during 2015-2054 period. These average prices for natural gas combined cycle power plants and coal power combined heat plants in the Reference Scenario and the 450 Scenario are as shown in Table 87:

Table 87. Average CO_2 prices During 2015-2039 Period and 2015-2054 Period in the Reference Scenario and the 450 Scenario

Electricity Generation Technology	Average CO_2 Prices In the Reference Scenario (€/MWh)	Average CO_2 Prices In the 450 Scenario (€/MWh)
Natural Gas Combined Cycle Power Plants (2015-2039)	39.7	69.0
Coal Power Combined Heat Plants (2015-2054)	41.4	77.9

When the REcalculator is employed, based on assumptions about the CO_2 prices in Table 87, climate change costs per MWh for alternative technologies are calculated as shown in Table 88:

Table 88. Climate Change Costs Per MWh for Alternative Technologies

Electricity Generation Technology	Climate Change Costs In the Reference Scenario (€/MWh)	Climate Change Costs In the 450 Scenario (€/MWh)
Natural Gas Combined Cycle Power Plants	13.6	24.1
Coal Power Combined Heat Plants	31.9	60.0
Wind Onshore Power Plants	0.0	0.0
Small Hydro (Run of River) Power Plants	0.0	0.0
Nuclear Power Plants	0.0	0.0
Solar PV Power Plants	0.0	0.0

Other Pollution includes air emissions and environmental impact of the nuclear power. Air pollution causes many impacts on ecosystems and human health, with health impacts making up the largest economic externality. The highest costs of the air pollution originate from chronic mortality and the costs largely depend on how increased mortality is valued in the society (IEA, 2007). Value of Statistical Life (VSL) approach argues that the lives of elderly people are as valuable as the lives of younger people whereas Value of Life Years Lost (VLYL) argues that the value should be reduced for the elderly people since they have fewer years left to live (IEA, 2007). RECABS original project and this study uses the VLYL methodology as the reference methodology in accordance with the ExternE project.

In addition to air emissions, RECABS analyses the environmental impact of nuclear power. The environmental impact of nuclear power is very difficult to monetize with high precision. RECABS original project uses 2.5 €/MWh as an estimate for the potential cost of a nuclear accident based on an analysis taking into account historic records especially the Chernobyl accident, and safety probability assessments for new power plants. This estimate takes into account that the future plants are assumed to be considerably safer than the existing plants, and the public anxiety about nuclear power is assigned an economic value (IEA, 2007). The estimate is higher than ExternE's estimates, but this is reasonable since new risks such as terrorism have arisen since ExternE's assessments were made (IEA, 2007). This study will use RECABS default value of 2.5 €/MWh as well. In addition, 1.5 €/MWh is added to take into account the long-term health costs of radioactive emissions from abandoned mill tailings, that applies primarily to Radon 222, which is emitted from mill tailings for a period of at least 10,000 years (IEA, 2007). RECABS estimates the external costs of abandoned uranium mines as 1.5 €/MWh. This study will use this value, too.

When the REcalculator is employed, based on assumptions of VLYL methodology, other pollution costs per MWh for alternative technologies are calculated as shown in Table 89:

Table 89. Other Pollution Costs Per MWh for Alternative Technologies

Electricity Generation Technology	Other Pollution (€/MWh)
Natural Gas Combined Cycle Power Plants	0.4
Coal Power Combined Heat Plants	1.7
Wind Onshore Power Plants	0.0
Small Hydro (Run of River) Power Plants	0.0
Nuclear Power Plants	4.0
Solar PV Power Plants	0.0

To sum up, the performance values of climate change & other pollution attribute for each alternative technology in the Reference Scenario and the 450 Scenario are shown in Table 90:

Table 90. Performance Values of Climate Change & Other Pollution for Alternative Technologies in €/MWh

Electricity Generation Technology	The Reference Scenario			The 450 Scenario		
	Climate Change	Other Pollution	Total	Climate Change	Other Pollution	Total
Natural Gas Combined Cycle Power Plants	13.6	0.4	14.0	24.1	0.4	24.5
Coal Power Combined Heat Plants	31.9	1.8	33.7	60.0	1.8	61.8
Wind Onshore Power Plants	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro (Run of River) Power Plants	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear Power Plants	0.0	4.0	4.0	0.0	4.0	4.0
Solar PV Power Plants	0.0	0.0	0.0	0.0	0.0	0.0

Supply Security

In the face of the increases in the cost of energy, and the increasing demand for the electricity, many countries are now taking new measures to ensure supply security. Within this scope, the Electricity Energy Market and Supply Security Strategy Paper was drafted by Higher Board of Planning in May 2009 to define and announce the steps necessary for ensuring the supply security, and targets for the resources to be used in the electricity supply in medium and long term.

Since taking effect of Law No 4628 on March 3, 2001, Turkey has taken substantial steps towards creating a competitive and functioning market in the electricity energy sector and implementing market rules that will ensure liberalization of the sector. Being based on the liberalization in the electricity energy sector, the main purpose of the restructuring initiative is to create an investment environment which allows those investments that are required for supply security, and to reflect onto consumers all gains that will be made through efficiency increase to be brought about by a competitive environment (Higher Board of Planning, 2009).

Short, medium and long term supply security will be continuously monitored and assessed under Additional Article 3 titled “Supply Security” added to Law No 4628 by Law No 5784, and measures will be taken whenever deemed as necessary. Primary focus in such assessment will be to ensure supply-demand balance with sufficient redundancy, source diversity, external dependency, environmental impacts, sector development which is in line with targets defined according to the price formation in markets, and take measures to redirect the market in case of deviation from targets (Higher Board of Planning, 2009).

The risk of the blackout in the electricity is a very crucial issue in energy vulnerability. The non-storable nature of electricity increases the overall vulnerability that may arise from simpler issues. Moreover, in case of unexpected spike in demand, the risk of electricity supply-demand mismatch that may result in an energy failure stands as a vital issue. Although it may be argued that the unexpected demand can be met from other countries to some degree, reliance on foreign countries for electricity supply poses a very high risk for overall energy vulnerability due to non-storable nature of electricity and limited interconnection rates with other countries may stand as an impediment in electricity imports. This study considers supply security as the combined security risk of import dependency and import concentration for the primary energy source to be used in electricity generation.

Import dependency is the share of imports in the consumption of the primary energy resource considered. As the share of imports in consumption increases, the supply security decreases and as a result the energy vulnerability of the country increases. Table 91 shows Turkey’s energy imports and consumption of natural gas, mineral coal, lignite, total energy consumption and total energy imports between 2003-2007 as follows:

Table 91. Turkey’s Energy Imports and Consumption by Fuel Types and Their Total Values Between 2003-2007 in toe (Nenem, 2009) (Ministry of Energy and Natural Resources (MENR), 2008)

Years	Consumption (toe)				Imports (toe)			
	Natural Gas	Mineral Coal	Lignite	General Total	Natural Gas	Mineral Coal	Lignite	General Total
2003	19,450	11,461	9,471	83,826	19,104	10,430	0	63,304
2004	20,426	12,356	9,450	87,818	19,997	10,598	0	67,190
2005	24,726	12,693	9,326	91,074	24,304	11,200	0	70,210
2006	28,867	14,901	11,188	99,642	27,727	13,088	5	77,513
2007	32,683	16,593	14,015	107,625	31,888	14,767	0	82,985

Table 92 shows general energy import dependency of Turkey between 2003-2007 as follows:

Table 92. Import Dependency of Turkey (Nenem, 2009) (MENR, 2008)

Year	Imports (toe)	Consumption (toe)	Import Dependency (%)
2003	63,304	82,074	77.13%
2004	67,190	86,200	77.95%
2005	70,210	89,199	78.71%
2006	77,513	98,138	78.98%
2007	82,985	107,625	77.11%

As seen in Table 92, Turkey is highly dependent on external energy resources and her domestic energy production is far away from being sufficient. This is one of the main problems of Turkey's energy balance. The import dependency of natural gas and coal will be mentioned further as follows:

The share of natural gas in Turkish energy consumption is 31.2% in 2007 and the share of natural gas in electricity generation of Turkey is 48.5% in 2009 and has never fallen below 45% for the last five years. Therefore, the natural gas is the most important primary energy source used in electricity generation. The import dependency of Turkey for natural gas between 2003-2007 is as follows:

Table 93. Turkey's Natural Gas Import Dependency Between 2003 - 2007

Year	2003	2004	2005	2006	2007
Natural Gas Dependency (%)	97.4%	97.1%	97.5%	96.9%	97.7%

As seen in Table 93, Turkey imports nearly all of her natural gas consumption that poses a very serious, challenging issue in Turkey's energy vulnerability.

Coal comprises both mineral coal and lignite. As seen in Table 91, Turkey imports nearly nine tenth of her mineral coal consumption, while she does not import lignite. Since, coal power combined heat plants can use either mineral coal or lignite, the import dependency of the coal will be calculated by using aggregated values of mineral coal and lignite. Table 94 shows the coal import dependency of Turkey as follows:

Table 94. Turkey's Coal Import Dependency Between 2003 - 2007

Year	2003	2004	2005	2006	2007
Coal Dependency (%)	51.2%	50.4%	47.3%	49.3%	48.4%

Turkey's import dependency for natural gas and coal has been assessed above. The other variable that will be taken into account in the supply security is the import concentration. The import concentration of Turkey for natural gas and coal will be assessed as follows:

Import concentration is as important as the import dependency in evaluating the supply security. Importing energy resources from a small number of suppliers decreases the supply security that increases the energy vulnerability of the country significantly. The import concentration measures the extent of diversity of energy suppliers. In calculating import concentration of a country for an energy resource, Hirschmann – Herfindahl index (HHI) is employed as a technique in the literature (Nenem, 2009).

$$HHI = \sum_{i=1}^{n} s^2$$

where n is the total number of countries that energy resources are imported from and s represents the market share in the energy supply of the country.

Table 95 shows natural gas suppliers of Turkey between 2003-2007.

Table 95. Natural Gas Suppliers of Turkey and Their Shares Within Whole Gas Imports (Nenem., 2009) (TSI, 2008)

Years	Azerbaijan	Algeria	Iran	Nigeria	Russia	Others
2003	0.0%	17.6%	16.3%	6.8%	59.3%	0.0%
2004	0.0%	15.6%	15.5%	4.9%	64.0%	0.0%
2005	0.0%	15.2%	16.4%	3.7%	64.7%	0.0%
2006	0.0%	13.5%	18.8%	3.4%	64.3%	0.0%
2007	1.4%	11.6%	17.6%	3.5%	65.6%	0.3%

As seen in Table 95, Russia has always provided more than half of Turkey's natural gas imports. Algeria and Iran have been the other important natural gas suppliers of Turkey. Table 96 shows the coal suppliers of Turkey between 2003-2007. Russia has been the major coal supplier of Turkey. However, other coal suppliers are quite diversified ranging between 7% and 10% in 2007.

Table 96. Coal Suppliers of Turkey and Their Shares within Whole Coal Imports (Nenem, 2009) (TSI, 2008)

Years	USA	Australia	South Africa	Canada	Russia	China	Colombia	Others
2003	8.3%	7.8%	13.7%	5.0%	45.3%	7.1%	7.3%	5.5%
2004	8.5%	3.3%	10.3%	5.7%	46.5%	11.8%	7.3%	6.6%
2005	14.9%	6.1%	7.3%	5.7%	40.2%	9.0%	9.9%	6.9%
2006	9.5%	8.4%	9.3%	8.3%	41.3%	9.1%	8.6%	5.5%
2007	8.6%	8.8%	9.6%	7.2%	45.3%	8.7%	6.8%	5.0%

In HHI calculation for an energy resource, the percentage of each supplier country contributing to imports of this energy resource is used (Table 97).

Table 97. HHI Values For Natural Gas and Coal Between 2003-2007

Years	Natural Gas	Coal
2003	4,137	2,483
2004	4,602	2,602
2005	4,704	2,166
2006	4,680	2,191
2007	4,763	2,483

As seen in Table 97, Turkey's natural gas HHI values have always been above 4,000 that are far above the criticalness borderline of 2,500 and Turkey's coal HHI value is very close to the critical value of 2,500 in 2007 (Nenem, 2009).

When high import dependency is combined with high import concentration, the supply security becomes more of an issue. To measure the supply security, this study will multiply the import dependency and the import concentration. Table 98 shows the supply security of natural gas and coal for Turkey between 2003-2007.

Table 98. Supply Security of Natural Gas and Coal For Turkey Between 2003-2007

Years	Natural Gas	Mineral Coal
2003	4,029	1,271
2004	4,469	1,311
2005	4,586	1,025
2006	4,535	1,080
2007	4,653	1,202
Average	4,454	1,178

Natural gas supply is about four times less secure than coal supply, when the combined impact of import concentration and import dependency is taken into account. This comes from the fact that the natural gas import dependency is twice as much as the coal import dependency and the natural gas is twice as concentrated as the coal in terms of supplier diversification. Performance values of supply security for each alternative technology are shown in Table 99:

Table 99. Performance Values of Supply Security For Alternative Technologies

Natural Gas Combined Cycle Power Plants	4,454
Coal Power Combined Heat Plants	1,178
Wind Onshore Power Plants	0
Small Hydro (Run of River) Power Plants	0
Nuclear Power Plants	0
Solar PV Power Plants	0

Supply-Demand Mismatch

Technologies with intermittent output such as wind power, solar PV and hydro run of river, also have costs related to the integration into the surrounding energy system. Nuclear power also has an impact on system costs due to its large and inflexible nature. These are called system integration costs in RECABS and they involve infrastructure costs, balancing costs and capacity credit costs. As mentioned in the preceding sections, system integration infrastructure costs are taken into account within the attribute of cost efficiency for the purposes of this study. As will be explained further, balancing costs and capacity credit costs are related to the supply-demand mismatch and the supply-demand mismatch is indirectly related to the supply security. Since the supply security is a very key issue in this study, the supply-demand mismatch arising from the intermittent nature of renewable and nuclear energy should be evaluated separately for the purposes of this study rather than taking balancing costs and capacity credit costs into account as simple costs.

The system integration costs largely depend on the technology type, the share of intermittent power in the electricity system, whether the needed alternative flexible resources are already accessible (IEA, 2007). RECABS assumes a typical electricity system based mainly on traditional fossil fuel fired power plants, some hydro power and some intermittent electricity sources up to 10%. Balancing and capacity credit costs are important issues for technologies like wind and hydro (run of river) power since their electricity generation nature is less controllable. However solar PV has a negative system integration cost since their diurnal generation nature fits well with the demand for electricity (IEA, 2007).

Balancing costs arise from deviations from the planned operation during the day. Also, a certain amount of disturbance reserves should be maintained in the electricity system, to sustain the balance in case of electricity outages (IEA, 2007). These two costs comprise the balancing costs. This study will employ assumptions of RECABS project for balancing costs that will be mentioned as follows: Planning wind power production one day ahead is very difficult because of the unpredictable nature of the wind. RECABS uses 4 €/MWh for balancing costs of onshore wind power, solar PV and hydro run of river by taking into account the studies and researches in this issue. RECABS assumes that these technologies other than nuclear power have a size that can be handled by the existing disturbance reserves. Since nuclear power plants installed become quite large, additional disturbance reserves are required. RECABS estimates this cost roughly as 0.7 €/MWh for the nuclear power.

Capacity credit costs are related to the flexibility of the power plants to adjust their production according to the system demand and related to the capacity that must be retained on the system with intermittent generation to maintain a reliable supply during a peak demand (IEA, 2007). The capacity credit cost is a long-term issue and related to system reliability, while the balancing costs are related to the periods from seconds to hours (IEA, 2007).

This study will employ assumptions of RECABS project for the capacity credit costs as follows: RECABS uses 5 €/MWh for capacity credit cost of onshore wind power and hydro run of river by taking into account the studies based on spot prices and required back up capacities; RECABS uses the added benefit of solar PV as 10 €/MWh due to its diurnal electricity generating nature; RECABS uses 5 €/MWh for the capacity credit costs of nuclear power like wind power, due to the fact that the first priority base-load nuclear power plants inflicts capacity constraints on the system and its generation time-profile differs from the electricity demand time-profile so much.

To sum up, the costs for the supply-demand mismatch for different technologies are shown in Table 100 as follows:

Table 100. Supply-Demand Mismatch Costs for Alternative Technologies in €/MWh

	Balancing Costs	Capacity Credit Costs	Total Supply-Demand Costs
Natural Gas Combined Cycle Power Plants	0.0	0.0	0.0
Coal Power Combined Heat Plants	0.0	0.0	0.0
Wind Onshore Power Plants	4.0	5.0	9.0
Small Hydro (Run of River) Power Plants	4.0	5.0	9.0
Nuclear Power Plants	0.7	5.0	5.7
Solar PV Power Plants	4.0	-10	-6.0

Since using negative and positive values for the same attribute is not compatible with the nature of GRA, solar PV's performance value will be taken as the best case of 0, and other technologies' performance values will be increased by 6. Performance values of the supply-demand mismatch for each alternative technology are shown in Table 101:

Table 101. Performance Values of Supply-Demand Mismatch for Alternative Technologies

Natural Gas Combined Cycle Power Plants	6.0
Coal Power Combined Heat Plants	6.0
Wind Onshore Power Plants	15.0
Small Hydro (Run of River) Power Plants	15.0
Nuclear Power Plants	11.7
Solar PV Power Plants	0.0

Empirical Analysis and Findings

The main purpose of grey relational generating is transferring the original data into comparability sequences. All performance measures have the smaller the better attribute in this study. So, the grey relational generating process adopts Equation (2) for the data of these performance values. The performance values of attributes for alternative technologies in the Reference Scenario are shown in Table 102.

Table 102. Performance Values of Attributes for Alternative Technologies In the Reference Scenario

Electricity Generation Technology	Cost Efficiency (The Reference Scenario)	Cost Volatility Risk	Climate Change & Other Pollution (The Reference Scenario)	Supply Security	Supply-Demand Mismatch
Natural Gas Combined Cycle Power Plants	77.23	0.681	14.0	4,454	6.0
Coal Power Combined Heat Plants	39.10	0.558	33.7	1,178	6.0
Wind Onshore Power Plants	39.09	0.0	0.0	0	15.0
Small Hydro (Run of River) Power Plants	34.96	0.0	0.0	0	15.0
Nuclear Power Plants	32.97	0.0	4.0	0	11.7
Solar PV Power Plants	238.92	0.0	0.0	0	0.0

For example, in the case of the cost efficiency attribute, the maximum value is 238.92 from solar PV power plant and the minimum value is 32.97 from nuclear power plant. Using Equation (2) the results of grey relational generating of wind onshore power plant is equal to (238.92 – 39.09) / (238.92 – 32.97) = 0.97028. The entire results of grey relational generating are shown in Table 103.

Table 103. Results of Grey Relational Generating for the Problem In the Reference Scenario

Electricity Generation Technology	Cost Efficiency (The Reference Scenario)	Cost Volatility Risk	Climate Change & Other Pollution (The Reference Scenario)	Supply Security	Supply-Demand Mismatch
X_0	1.00000	1.00000	1.00000	1.00000	1.00000
Natural Gas Combined Cycle Power Plants	0.78509	0.00000	0.58457	0.00000	0.60000
Coal Power Combined Heat Plants	0.97024	0.18062	0.00000	0.73552	0.60000
Wind Onshore Power Plants	0.97028	1.00000	1.00000	1.00000	0.00000
Small Hydro (Run of River) Power Plants	0.99034	1.00000	1.00000	1.00000	0.00000
Nuclear Power Plants	1.00000	1.00000	0.88131	1.00000	0.22000
Solar PV Power Plants	0.00000	1.00000	1.00000	1.00000	1.00000

In Table 103, X_0 is the reference sequence. After calculating Δ_{ij}, Δ_{max} and Δ_{min}, all grey relational coefficients can be calculated by Equation (4). For example,

Δ_{31} = 1- 0.97028 = 0.02972,

$\Delta_{max} = 1$

$\Delta_{min} = 0$, if $\zeta = 0.5$, then $\gamma (x_{01}, x_{31}) = (0 + 0.5 * 1) / (0.02972 + 0.5 * 1) = 0.94390$.

The entire results for the grey relational coefficients are shown in Table 104.

Table 104. Results of Grey Relational Coefficients for the Problem In the Reference Scenario

Electricity Generation Technology	Cost Efficiency (The Reference Scenario)	Cost Volatility Risk	Climate Change & Other Pollution (The Reference Scenario)	Supply Security	Supply-Demand Mismatch
Natural Gas Combined Cycle Power Plants	0.69939	0.33333	0.54619	0.33333	0.55556
Coal Power Combined Heat Plants	0.94382	0.37896	0.33333	0.65404	0.55556
Wind Onshore Power Plants	0.94390	1.00000	1.00000	1.00000	0.33333
Small Hydro (Run of River) Power Plants	0.98104	1.00000	1.00000	1.00000	0.33333
Nuclear Power Plants	1.00000	1.00000	0.80815	1.00000	0.39063
Solar PV Power Plants	0.33333	1.00000	1.00000	1.00000	1.00000

In this process, specific weights are given for each performance attribute according to their importance. The sum of weights of these attributes should be equal to 1. By using Equation (5) the grey relational grade can be calculated. The weights of each attribute should be given according to their importance. Cost efficiency and supply security are the most important attributes and supply-demand mismatch comes after them due to Turkey's limited financial sources and high energy vulnerability. Cost volatility risk, climate change & other pollution are less important than the others. Therefore the weights for each attribute will be given as follows:

Table 105. The Weights for Each Attribute

Attributes	Weight
Cost Efficiency	0.3
Cost Volatility Risk	0.1
Climate Change and Other Pollution	0.1
Supply Security	0.3
Supply-Demand Mismatch	0.2

By using Equation (5) and the weights in Table 106, the grey relational grades are calculated as shown in Table 106.

Table 106. The Results of Grey Relational Analysis for the Problem in the Reference Scenario

Electricity Generation Technology	Grey Relational Grade	Ranking Results of GRA
Natural Gas Combined Cycle Power Plants	0.50888	6
Coal Power Combined Heat Plants	0.66170	5
Wind Onshore Power Plants	0.84984	3
Small Hydro (Run of River) Power Plants	0.86098	1
Nuclear Power Plants	0.85894	2
Solar PV Power Plants	0.80000	4

In the Reference Scenario, small hydro power plants are ranked the first, followed by nuclear power plants and wind onshore power plants as the second and third respectively. Grey relational grades of these attributes are very close to each other ranging between 0.85 and 0.86. Solar PV power plant is ranked the fourth with grey relational grade of 0.80. Coal power combined heat plants and natural gas combined cycle power plants are the least attractive technologies ranking fifth and sixth respectively with grey relational grades of 0.66 and 0.51.

Since renewable energies are often at an early stage of development compared to conventional technologies, renewable energies may become more attractive due to technological progress and learning effect in the long term. Renewable technologies are expected to have the highest learning rates, thereby increasing their competitiveness in the future.

When the REcalculator is employed by using assumptions of RECABS for power plants to be commissioned in 2025, electricity generation cost per MWh decreases by 6.43 €/MWh for onshore wind power, 2.04 €/MWh for small hydro power, 0.49 €/MWh for natural gas combined cycle power plants, 128.66 €/MWh for solar PV power when capital (investment) costs and operation & maintenance costs are considered.

The study also analyzes the impact on the results of GRA when the distinguishing coefficient is set at 0.1, 0.3, 0.5, 0.7, and 0.9, respectively in the "Reference Scenario" (Table 107).

Table 107. The Impact of Distinguishing Coefficient on the Results of GRA For the Problem

Electricity Generation Technology	ζ=0.1		ζ=0.3		ζ=0.5		ζ=0.7		ζ=0.9	
	GR Grade	Rank	GR Grade	Rank	GR Grade	Rank	GR Grade	Rank	GR Grade	Rank
Natural Gas Combined Cycle Power Plants	0.191	6	0.395	6	0.509	6	0.584	6	0.639	6
Coal Power Combined Heat Plants	0.373	5	0.568	5	0.662	5	0.720	5	0.760	5
Wind Onshore Power Plants	0.749	3	0.819	3	0.850	3	0.870	3	0.885	3
Small Hydro (Run of River) Power Plants	0.792	1	0.837	1	0.861	1	0.878	2	0.892	2
Nuclear Power Plants	0.768	2	0.827	2	0.859	2	0.880	1	0.895	1
Solar PV Power Plants	0.727	4	0.769	4	0.800	4	0.824	4	0.842	4

Table 107 shows that the impact of the distinguishing coefficient on the result of GRA is very small. For all tested distinguishing coefficients, alternatives wind onshore, solar PV, coal power combined heat plants and natural gas combined cycle power plants are always ranked the third, fourth, fifth and sixth respectively. The ranks of small hydro power plants and nuclear power plants change between the first and the second depending on the distinguishing coefficients. This change comes from the fact that grey relational grades of small hydro power plants and nuclear power plants are very close to each other and the grey relational grade of nuclear power plants exceed small hydro power plants by only 0.2 and 0.3% when the distinguishing coefficients are 0.7 and 0.9 respectively.

Sensitivity Analysis

In order to reach robust results, sensitivity analysis are performed for the 450 Scenario in addition to the "Reference Scenario". The performance values of attributes for alternative technologies in the 450 Scenario are shown in Table 108.

Table 108. Performance Values of Attributes for Alternative Technologies in the 450 Scenario

Electricity Generation Technology	Cost Efficiency (The 450 Scenario)	Cost Volatility Risk	Climate Change & Other Pollution (The 450 Scenario)	Supply Security	Supply-Demand Mismatch
Natural Gas Combined Cycle Power Plants	66.76	0.681	24.50	4454.00	6.00
Coal Power Combined Heat Plants	30.76	0.558	61.80	1178.00	6.00
Wind Onshore Power Plants	39.09	0.000	0.00	0.00	15.00
Small Hydro (Run of River) Power Plants	34.96	0.000	0.00	0.00	15.00
Nuclear Power Plants	32.97	0.000	4.00	0.00	11.70
Solar PV Power Plants	238.92	0.000	0.00	0.00	0.00

GRA procedure will use the data in Table 108 as follows: After applying grey relational generating procedure, the results of grey relational generating are shown in Table 109.

Table 109. Results of Grey Relational Generating for the Problem In the 450 Scenario

Electricity Generation Technology	Cost Efficiency (The 450 Scenario)	Cost Volatility Risk	Climate Change & Other Pollution (The 450 Scenario)	Supply Security	Supply-Demand Mismatch
X_0	1.00000	1.00000	1.00000	1.00000	1.00000
Natural Gas Combined Cycle Power Plants	0.82706	0.00000	0.60356	0.00000	0.60000
Coal Power Combined Heat Plants	1.00000	0.18062	0.00000	0.73552	0.60000
Wind Onshore Power Plants	0.95998	1.00000	1.00000	1.00000	0.00000
Small Hydro (Run of River) Power Plants	0.97982	1.00000	1.00000	1.00000	0.00000
Nuclear Power Plants	0.98938	1.00000	0.93528	1.00000	0.22000
Solar PV Power Plants	0.00000	1.00000	1.00000	1.00000	1.00000

The grey relational coefficients for the problem are shown in Table 110.

Table 110. Results of Grey Relational Coefficients For The Problem In the 450 Scenario

Electricity Generation Technology	Cost Efficiency (The 450 Scenario)	Cost Volatility Risk	Climate Change & Other Pollution (The 450 Scenario)	Supply Security	Supply-Demand Mismatch
Natural Gas Combined Cycle Power Plants	0.74300	0.33333	0.55776	0.33333	0.55556
Coal Power Combined Heat Plants	1.00000	0.37896	0.33333	0.65404	0.55556
Wind Onshore Power Plants	0.92590	1.00000	1.00000	1.00000	0.33333
Small Hydro (Run of River) Power Plants	0.96121	1.00000	1.00000	1.00000	0.33333
Nuclear Power Plants	0.97921	1.00000	0.88539	1.00000	0.39063
Solar PV Power Plants	0.33333	1.00000	1.00000	1.00000	1.00000

The weights for each attribute will be given as follows:

Table 111. The Weights for Each Attribute

Attributes	Weight
Cost Efficiency	0.3
Cost Volatility Risk	0.1
Climate Change and Other Pollution	0.1
Supply Security	0.3
Supply-Demand Mismatch	0.2

By using the weights in Table 111, the grey relational grades are calculated as shown in Table 112:

Table 112. The Results of Grey Relational Analysis for the Problem in the 450 Scenario

Electricity Generation Technology (The 450 Scenario)	Grey Relational Grade	Ranking Results of GRA
Natural Gas Combined Cycle Power Plants	0.52312	6
Coal Power Combined Heat Plants	0.67855	5
Wind Onshore Power Plants	0.84444	3
Small Hydro (Run of River) Power Plants	0.85503	2
Nuclear Power Plants	0.86043	1
Solar PV Power Plants	0.80000	4

As seen in Table 112, in the 450 Scenario, nuclear power plants are ranked the first, followed by small hydro power plants and wind onshore power plants as the second and third respectively. Grey relational grades of these attributes are very close to each other ranging between 0.84 and 0.86. Solar PV power plant is ranked the fourth with grey relational grade of 0.80. Coal power combined heat plants and natural gas combined cycle power plants are the least attractive technologies ranking the fifth and sixth respectively with grey relational grades of 0.68 and 0.52. Therefore, different from the outcomes of GRA in the Reference Scenario, nuclear power plant is ranked the first and small hydro power plant the second in the 450 Scenario. The rankings of other alternative technologies in the 450 Scenario are the same with the rankings in the Reference Scenario.

In the sensitivity analysis, specific weights are given for each performance attribute according to their importance in from different viewpoints. The outcomes of GRA process for the Reference Scenario when the weights of attributes change extremely on behalf of a single attribute or issue .

When supply security and supply-demand mismatch are given the highest importance with 0.35 weight for each and all other attributes are given weight of 0.1, the weights for each attribute are as follows:

Table 113. The Weights of Grey Relational Analysis for the Problem

Attributes	Weight
Cost Efficiency	0.1
Cost Volatility Risk	0.1
Climate Change and Other Pollution	0.1
Supply Security	0.35
Supply-Demand Mismatch	0.35

By using Equation (5) and the weights in Table 113, the grey relational grades are calculated as shown in Table 114:

Table 114. The Results of Grey Relational Analysis for the Problem

Electricity Generation Technology (The Reference Scenario)	Grey Relational Grade	Ranking Results of GRA
Natural Gas Combined Cycle Power Plants	0.46900	6
Coal Power Combined Heat Plants	0.58897	5
Wind Onshore Power Plants	0.76106	4
Small Hydro Power Plants	0.76477	3
Nuclear Power Plants	0.76753	2
Solar PV Power Plants	0.93333	1

As seen in Table 114, in the Reference Scenario, solar PV power plant is ranked first with grade of 0.93. This is followed by nuclear power plants, small hydro power plants and wind onshore power plants as the second, third and fourth respectively. Grey relational grades of these attributes are very close to each other ranging between 0.76 and 0.77. Coal power combined heat plant is ranked the fifth with grey relational grade of 0.59. Natural gas combined cycle power plants are the least attractive technology ranking the sixth with grey relational grade of 0.47.

When cost efficiency is given the highest importance with 0.6 weight and all other attributes are given the weight of 0.1, the weights for each attribute are as follows:

Table 115. The Weights of Grey Relational Analysis for the Problem

Attributes	Weight
Cost Efficiency	0.6
Cost Volatility Risk	0.1
Climate Change & Other Pollution	0.1
Supply Security	0.1
Supply-Demand Mismatch	0.1

By using Equation (5) and the weights in Table 115, the grey relational grades are calculated as shown in Table 116:

Table 116. The Results of Grey Relational Analysis for the Problem in the Reference Scenario

Electricity Generation Technology (The Reference Scenario)	Grey Relational Grade	Ranking Results of GRA
Natural Gas Combined Cycle Power Plants	0.59648	6
Coal Power Combined Heat Plants	0.75848	4
Wind Onshore Power Plants	0.89967	3
Small Hydro (Run of River) Power Plants	0.92196	1
Nuclear Power Plants	0.91988	2
Solar PV Power Plants	0.60000	5

As seen in Table 116, in the Reference Scenario, small hydro power plant is ranked the first, followed by nuclear power plants and wind onshore power plants as the second and third respectively. Grey relational grades of these attributes are very close to each other ranging between 0.90 and 0.92. Coal power combined heat plant is ranked the fourth with grey relational grade of 0.76. Solar PV power plants and natural gas combined cycle power plants are the least attractive technologies ranking the fifth and sixth respectively with grey relational grades of 0.600 and 0.596.

When all of the attributes are given equal importance with 0.20 weight for each, the weights for each attribute are as follows:

Table 117. The Weights of Grey Relational Analysis for the Problem

Attributes	Weight
Cost Efficiency	0.2
Cost Volatility Risk	0.2
Climate Change and Other Pollution	0.2
Supply Security	0.2
Supply-Demand Mismatch	0.2

By using Equation (5) and the weights in Table 117, the grey relational grades are calculated as shown in Table 118:

Table 118. The Results of Grey Relational Analysis for the Problem in the Reference Scenario

Electricity Generation Technology (The Reference Scenario)	Grey Relational Grade	Ranking Results of GRA
Natural Gas Combined Cycle Power Plants	0.49356	6
Coal Power Combined Heat Plants	0.57314	5
Wind Onshore Power Plants	0.85545	3
Small Hydro Power Plants	0.86287	2
Nuclear Power Plants	0.83976	4
Solar PV Power Plants	0.86667	1

As seen in Table 118, in the Reference Scenario, solar PV power plant is ranked first with grade of 0.867 and small hydro power plant is ranked the second with grade of 0.863. They are followed by wind onshore power plants and nuclear power plants as the third and fourth with grades of 0.855 and 0.840 respectively. Coal power combined heat plant is ranked the fifth with grey relational grade of 0.573. Natural gas combined cycle power plants are the least attractive technology ranking the sixth with grey relational grade of 0.494.

Comparision of GRA Results with DEA Results

Data Envelopment Analysis (DEA), proposed by Charnes, Cooper and Rhodes (1978), is a well-established non-parametric frontier approach to assess the relative efficiency of a set of comparable things featured with multiple inputs and outputs. DEA has been used extensively to study efficiency in a wide range of areas including banking, manufacturing, health care, universities, cities, regions, and countries. Zhou, Ang and Poh (2008a) lists in a literature survey, 100 studies published from 1983 to 2006 using DEA in the area of energy and environmental analysis and shows the rapid increase in the utilization of DEA methodology.

Hu and Wang (2006) and Hu and Kao (2007) developed a total-factor energy efficiency index by using DEA. Zhou and Ang (2008b) presented several DEA-type linear programming methods for measuring economy - wide energy efficiency performance. Boyd and Pang (2000) used DEA to investigate the relationship between productivity and energy efficiency. Ramanathan (2000) used DEA to compare the energy efficiencies of alternative transport modes in the Indian transport sector. Lam and Shiu (2001) applied DEA to measure the technical efficiency of China's thermal power generation. Wei, Liao and Fan (2007) used DEA to evaluate the energy efficiency change of iron and steel sectors in China. Mukherjee (2008) used DEA to evaluate the energy efficiency of the US manufacturing sector.

Sarıca and Or (2007) analyzed and compared efficiency of Turkish power plants by using data envelopment analysis using real data as inputs from 65 thermal, hydro and wind power plants. Two basic models were formed, reflecting operational and long-term investment performance and for the operational efficiency model, two different models have been developed; one for thermal power plants the other for renewable power plants (Sarıca and Or, 2007). The parameters in the model for the operational performance of thermal power plants were fuel cost, production, availability, thermal efficiency, environmental cost, and carbon monoxide while the parameters in the model for the operational performance of renewable power plants were operating cost as input and production and utilization as outputs (Sarıca and Or, 2007). Four parameters were used in the DEA model for the long term investment performance: investment cost, installed power capacity, construction time and average utilization (Sarıca and Or, 2007). Constant returns to scale, variable returns to scale and assurance region type DEA models were used in the analysis also considering scale efficiency, with performance comparisons of public versus private sector plants, and natural gas versus coal versus oil fired plants (Sarıca and Or, 2007). The study of Sarıca and Or (2007) reveals that regarding renewable source power plants wind power plants have the highest efficiency values in operational and investment performance models indicating their high future potential, regarding thermal power plants investment performance the private sector plants perform significantly better than the public sector plants and natural gas fired power plants have higher investment performance efficiency than coal-fired plants. Regarding evaluations and comparisons involving renewable source plants, fewer conclusions could be drawn because of higher performance variation of renewable source plants due to their higher sensitivity to natural factors resulting in small and insignificant relationships (Sarıca and Or, 2007).

As the global concerns about environmental issues increase, undesirable outputs of electricity production and other activities such as air pollutants and hazardous wastes are being increasingly recognized as undesirable. Electricity generation also results in the generation of some undesirable outputs such as GHG emissions as by-products of producing desirable outputs.

Consider a production process in which desirable and undesirable outputs are jointly produced and assume that x, e, y and u are, respectively, the vectors of non-energy inputs, energy inputs, desirable outputs and undesirable outputs, where energy inputs consist of L different energy sources (Zhou and Ang, 2008b). So the production technology can be described as T={(x; e, y u) : (x, e) can produce (y,u)} (Zhou and Ang, 2008b).

T is assumed to be a closed and bounded set, which guarantees the output closeness and implies that finite amounts of inputs can only produce finite amounts of outputs and inputs and desirable outputs in T are often assumed to be strongly disposable (Zhou and Ang, 2008b). Accordingly, if (x,e,y,u) ϵ T and (x',e') ≥ (x,e) (or y'≤ y) then (x',e',y,u) ϵ T (or (x,e,y',u) ϵ T) (Zhou and Ang, 2008b).

Additionally the following two conditions on T are imposed to reasonably model the joint production of both desirable and undesirable outputs (Zhou and Ang, 2008b):

1. Outputs are weakly disposable, i.e., if (x,e,y,u) Є T and $0 \leq \theta \leq 1$, then (x,e, θy, θu) Є T.

2. Desirable outputs and undesirable outputs are null-joint, i.e., if (x,e,y,u) Є T and u = 0, then y = 0.

The first condition implies that the reduction of undesirable outputs is not free but the proportional reduction in both desirable and undesirable outputs is feasible, and the second condition implies that the only way to eliminate all the undesirable outputs is to cease the production process (Zhou and Ang, 2008b).

In the case where there are K entities whose energy efficiency performances are to be measured, and for the kth entity the observed data on non-energy inputs, energy inputs, desirable and undesirable outputs are $x_k=(x_{1k},...,x_{Nk})$, $e_k=(e_{1k},...,e_{lk})$, $x_k=(x_{1k},...,x_{Nk})$, $y_k=(y_{1k},...,y_{Mk})$ and $x_k=(x_{1k},...,x_{Nk})$, $u_k=(u_{1k},...,u_{Jk})$, the environmental DEA technology exhibiting constant returns to scale (CRS) can be expressed as (Zhou and Ang, 2008b)

$$EEPI_1 = (x_0, e_0, y_0, u_0) = \text{Min } \theta$$

Subject to

$\sum_{k=1}^{K}(z_k x_{nk} \leq x_{n0})$ n=1, …n

$\sum_{k=1}^{K}(z_k e_{lk} \leq \theta e_{l0})$ l=1, …L

$\sum_{k=1}^{K}(z_k y_{mk} \leq y_{m0})$ m=1, …M

$\sum_{k=1}^{K}(z_k u_{jk} \leq u_{j0})$ j=1, …J

$z_k \geq 0$, k=1,…,K

where the subscript ''0'' represents the entity to be evaluated. It can be seen that this model attempts to proportionally contract the amounts of energy inputs as much as possible for a given level of non-energy inputs, desirable and undesirable outputs (Zhou and Ang, 2008b). If an entity has a larger $EEPI_1$, this entity performs better in terms of efficiency and an entity with EEPI1 equal to unity means that it is located at the frontier of best practice (Zhou and Ang, 2008b).

This study will use single input multiple output DEA-model in order to analyze the efficiency of electricity generation technologies. The model to be used in the study will be input-oriented DEA-model and constant returns to scale is assumed.

In the model, input will be a sum of money allocated by the state for electricity generation. The amount of money is not important, the important thing is to take the same amount of money for all electricity generation technologies to compare their performances. The study will assume a 5 billion € of money allocated for electricity generation. The outputs of the model will be the amount of electricity generation, climate change & other pollution, cost volatility risk, supply security and suppy-demand mismatch. These outputs are compatible with the attributes of the grey relational analysis. For the empirical analysis, the study will use data that has been used in the grey relational analysis. Table 119 shows empirical data to be used in DEA:

Table 119. Empirical Data to Be Used in DEA

Electricity Generation Technology	(I)Allocated Money (million €)	(O)Electricity Production (MWh)	(OBad) Cost Volatility Risk	(OBad)Climate Change & Other Pollution (€)	(OBad) Supply Security	(OBad) Supply-Demand Mismat.
Natural Gas Combined Cycle Power Plants	5,000	64,741,681	0.681	906,383,530	4,454	6
Coal Power Combined Heat Plants	5,000	127,877,238	0.558	4,309,462,916	1,178	6
Wind Onshore Power Plants	5,000	127,909,951	0	0	0	15
Small Hydro (Run of River) Power Plants	5,000	143,020,595	0	0	0	15
Nuclear Power Plants	5,000	151,653,018	0	606,612,072	0	11.7
Solar PV Power Plants	5,000	20,927,507	0	0	0	0

Model is used by employing different ratios of weights to total bad outputs versus total good outputs as (1:1) (1:2) and (1:4). This means that as weight moves from good to bad, the emphasis of the DEA changes from enlargement of the good output to reduction of the bad output. The results of the model are shown in Table 120:

Table 120. Efficiency Scores of the Undesirable-Output Model with Different Ratios of Weights To Total Bad Outputs Versus Total Good Outputs

	1:1		1:2		1:4	
DMU	Score	Rank	Score	Rank	Score	Rank
Natural Gas Combined Cycle Power Plants	0.31385	6	0.34424	6	0.37314	6
Coal Power Combined Heat Plants	0.72704	5	1	1	1	1
Wind Onshore Power Plants	1	1	0.87887	5	0.88500	5
Small Hydro (Run of River) Power Plants	1	1	1	1	1	1
Nuclear Power Plants	1	1	1	1	1	1
Solar PV Power Plants	1	1	1	1	1	1

When the ratio of weights to total bad outputs versus total good outputs is employed as (1:1), the model results that wind onshore power plants, small hydro power plants, nuclear power plants and solar PV power plants are efficient while coal power combined heat plant is ranked as the fifth with a score of 0.72704 and natural gas combined cycle power plant is ranked as the least efficient with a score of 0.31385.

This result is compatible with the result of the grey relational analysis when all the attributes are given equal weights.

Discussion and Policy Implications

In the preceding sections, the problem of ranking and selecting the best electricity generation technology has been analyzed and solutions have been proposed by using grey relational analysis procedure for the Reference Scenario and the 450 Scenario of IEA's World Energy Outlook 2009. The outcomes of GRA procedure have been very similar for both scenarios.

Since supply security and cost efficiency are the most important factors for Turkey due to her high energy vulnerability and limited financial sources, giving the highest weights to these attributes is a reliable and sound option. For the Reference Scenario, when these weights are used, GRA proposed small hydro power plants, wind onshore power plants and nuclear power plants as the first, second and third best technologies respectively with grey relational grades ranging between 0.85 and 0.86. Solar PV power plant is ranked the fourth with grey relational grade of 0.80. Coal power combined heat plants and natural gas combined cycle power plants are the least attractive technologies ranking the fifth and sixth respectively with grey relational grades of 0.66 and 0.51.

The outcomes of GRA have also been tested for the 450 Scenario and nuclear power plant is ranked the first, small hydro power plant the second and wind onshore power plant the third in the 450 Scenario while the rankings of other alternative technologies are the same with the rankings in the Reference Scenario. Although the rankings of nuclear power plants and small hydro power plants change in the 450 Scenario, their relational grades are very close to each other ranging between 0.85 and 0.86.

The outcomes of GRA has also been tested for three cases. Two of these cases give extreme priorities on behalf of a single attribute or issue in the Reference Scenario. In the first case, supply security and supply-demand mismatch attributes are given extreme importance and so very high weights compared to other attributes. For this case GRA proposed solar PV power plants, nuclear power plants, small hydro power plants and wind onshore power plants as the first, second, third and fourth best technologies respectively, while ranking coal power combined heat plants and natural gas combined cycle power plants as the worst alternatives. In the second case, cost efficiency attribute is given extreme importance and so very high weight compared to other attributes. For this case GRA proposed small hydro power plants, nuclear power plants and wind onshore power plants as the first, second and third best technologies respectively with grey relational grades very close to each other. Coal power combined heat plants, solar PV power plants and natural gas combined cycle power plants are ranked as the fourth, fifth and sixth with grey relational grades far below the best three alternative technologies. In the third case, all of the attributes is given equal importance and so equal weights. For this case GRA proposed solar PV power plants, small hydro power plants, wind onshore power plants and nuclear power plants as the first, second, third and fourth best technologies respectively with grey relational grades very close to each other. Coal power combined heat plants and natural gas combined cycle power plants are ranked as the fifth and sixth with grey relational grades far below these best four alternative technologies.

Considering supply security and cost efficiency attributes as the highest priorities is the most reliable and sound option for Turkey because of her high energy vulnerability and limited financial sources rather than giving an extreme importance to one single attribute or giving equal weights to all attributes. For this case in the Reference Scenario, GRA proposed small hydro power plants, nuclear power plants and wind onshore power plants as the first, second and third best technologies respectively with grey relational grades very close to each other but far above other alternative technologies.

The rankings of these hydro power plants, nuclear power plants and wind onshore power plants have also been tested for different scenarios and for different extreme priorities on single attributes. The grey relational grades of hydro power plants, nuclear power plants and wind onshore power plants are very close to each other and are within the fourth best alternatives even in very extreme priorities on a single issue.

As a conclusion Turkey should focus on installing small hydro power plants, nuclear power plants and wind onshore power plants. Since hydro power and wind power are related to geographic and climatic conditions, Turkey's potential for these sources should be assessed as well.

In the First National Communication of Turkey on Climate Change (2007), economic hydropower potential of Turkey is estimated to be 130 TWh. According to PricewaterhouseCoopers (2009a), Turkey has a technical hydroelectricity potential of 37.1 GW. When Turkey's 37.1 GW potential is compared to 13.8 GW installed hydro power capacity at the end of 2008, only 38% of Turkey's technical hydroelectricity potential capacity is utilized. Installed hydropower capacity comprises 33% of Turkey's total 41,817.2 installed capacity at the end of 2008. In 2009, hydro power plants generate 35.904,8 GWh of total electricity generation comprising 18.5% of Turkey's total 194,112.1 GWh electricity generation. This shows that Turkey has an immense untapped potential in hydro power to be utilized.

Turkey has an immense wind power potential due to its climatic and geographic conditions as well. Turkey's technical potential for wind energy is 83,000 MW and 166,000 GWh/year and she has the highest technical potential among the European OECD countries (Erdoğdu, 2009). In the First National Communication of Turkey on Climate Change (2007), technical wind power potential of Turkey is estimated to be 88,000 MW, while economically viable potential is 10,000 MW. According to PricewaterhouseCoopers (2009), given the current grid infrastructure constraints, the highest feasible wind-power generation capacity is estimated at 20,000 MW. Despite Turkey's high wind energy potential, her total installed capacity at the end of 2009 is only 801 MW and this generates 1,963 GWh comprising 1% of her total 194,112.1 GWh electricity generation in 2009. This shows that Turkey has an immense untapped potential in wind power to be utilized.

Conclusion

Turkey is likely to confront with electricity energy deficiency around 2014-2015 and to prevent such a deficiency Turkey should start to install new power plants as soon as possible when the long construction periods of power plants are considered. Therefore, Turkey has a problem to rank and select the best electricity generation technology for the society from natural gas combined cycle power plants, coal power combined heat plants, wind onshore power plants, small hydro power plants, nuclear power plants and solar PV power plants by taking into account cost efficiency, cost volatility risk, supply security, climate change & other pollution and supply-demand mismatch.

Grey relational analysis procedure has been used to analyze this problem and propose solutions. Because this problem considers both quantitative and qualitative attributes and quantifying qualitative attributes creates grey areas, and the importance of these attributes may change according to the priorities of the decision maker.

This study has analyzed this problem and proposed solutions by using grey relational analysis procedure for the Reference Scenario and the 450 Scenario of IEA's World Energy Outlook 2009. The outcomes of GRA procedure have been analyzed by giving different priorities to different attributes as well. The impact of the distinguishing coefficient on the result of GRA has been tested and concluded that this impact is small. According to the outcomes of GRA, it has been concluded that Turkey should focus on installing small hydro power plants, nuclear power plants and wind onshore power plants. Since hydro power and wind power are related to natural potentials of a country, Turkey's potential for these sources has been investigated and concluded that Turkey has an immense untapped potential for these renewable energy resources.

It should not be forgotten that hydro power plants, nuclear power plants and wind onshore power plants are the best electricity generation technologies from the viewpoint of society. Leaving the electricity market to free market may not create these best solutions to be realized for Turkey because the financially most attractive technologies for the private investors are not likely to be the best ones for society. Therefore, the outcomes of this study may provide guidelines for ranking these alternative electricity generation technologies and may serve as a baseline in designing market structure and necessary incentives by the government to encourage private sector investment in the socially best technologies.

Since renewable energies are often at an early stage of development compared to conventional technologies, renewable energies will be more attractive due to technological progress and learning effect in the long term. Renewable energy technologies are expected to have the highest learning rates, thereby increasing their competitiveness in the future. Fuel prices are likely to increase in the future thereby decreasing the competitiveness of conventional technologies. Supply security and supply-demand mismatch issues for alternative technologies may change in the future as well. Therefore the ranking and selection of alternative electricity generation technologies should be analyzed by using GRA procedure periodically for about five year's periods.

CHAPTER V

REGULATED CARBON MARKET OUTLOOK

The aim of this chapter is to understand the basis of the regulated carbon market in the world. The first section explains in details the Kyoto Protocol with a comperative analysis of Annex I parties' greenhouse gas (GHG) emissions and the relationship between electricity generation and GHG emissions. The second section focuses on the The European Union Greenhouse Gas Emission Trading System (EU ETS) that is an emission allowance cap and trade system and the first international trading system for CO_2 emissions in the world and evaluates its performance. The third section surveys the regulations about Clean Development Mechanism (CDM) that may have significant consequences on sustainable development of developing countries. The fourth section will explain emissions trading, carbon taxes, the European Climate Exchange and synthesis approaches such as revenue-neutral carbon taxes and hybrid schemes.

The Kyoto Protocol

The United Nations Framework Convention on Climate Change (UNFCCC) sets the first intergovernmental efforts to deal with climate change. The Kyoto Protocol is the first and international treaty subsidiary to the UNFCCC setting quantitative GHG emission reduction or limitation targets. In the beginning of this section, Annex I Parties, their commitments, assigned amount units, Kyoto mechanisms (Emissions Trading, Joint Implementation and Clean Development

Mechanism) and determination of compliance will be described. Then the succeeding subtitle will analyse emission trends and sources in Annex I Parties in details.

The United Nations Framework Convention on Climate Change (UNFCCC) sets an overall framework for intergovernmental efforts to deal with climate change with 192 countries having ratified. The Convention entered into force on 21 March 1994. The ultimate objective of the UNFCCC is determined in Article 2 as achieving stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. According to the same article, such a level should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner. The important portion of the commitments determined in Article 4 of the UNFCCC was undertaken by Annex I Parties. Annex I Parties are as follows: Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, European Economic Community, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, United Kingdom of Great Britain and Northern Ireland, United States of America. Countries that are undergoing the process of transition to a market economy in Annex I Parties are Belarus, Bulgaria, Croatia, Czech Republic, Estonia, Hungary, Latvia, Liechtenstein, Lithuania, Monaco, Poland, Romania, Russian Federation, Slovakia, Slovenia and Ukraine.

The Kyoto Protocol is an international treaty subsidiary to the United Nations Framework Convention on Climate Change (UNFCCC). Negotiations for the Kyoto Protocol started at the first Conference of the Parties (COP 1) of the UNFCCC in 1995 and it was agreed in 11 December 1997 at the third Conference of the Parties (COP 3) in Kyoto, Japan. The Protocol was ready for ratification after COP 7, in Marrakesh in 2001. The detailed rules for the implementation of the Protocol called the "Marrakesh Accords" were also adopted at COP 7 in Marrakesh. The Protocol entered into force on 16 February 2005, the ninetieth day after at least 55 Parties to the Convention, incorporating Annex I Parties which accounted in total for at least 55 % of the total carbon dioxide emissions for 1990 from that group ratified the Protocol. Until the end of 2009, 184 Parties of the Convention have ratified the Kyoto Protocol.

The importance of the Kyoto Protocol is that it sets quantified emission limitation or reduction targets for 38 industrialised countries and the European Community (Annex B countries) that ratify the Protocol for reducing six greenhouse gases (GHG) – carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons and perfluorocarbons –emissions by an aggregate 5.2% against 1990 levels over the five year period 2008–2012, the so-called "first commitment period".

According to Article 3, paragraph 1 of the Kyoto Protocol;

"The Parties included in Annex I shall, individually or jointly, ensure that their aggregate anthropogenic carbon dioxide equivalent emissions of the greenhouse gases listed in Annex A do not exceed their assigned amounts, calculated pursuant to their quantified emission limitation and reduction commitments inscribed in Annex B and in accordance with the provisions of this

Article, with a view to reducing their overall emissions of such gases by at least 5 percent below 1990 levels in the commitment period 2008 to 2012."

Annex I (to the UNFCCC) and Annex B (to the Kyoto Protocol) should not be confused. The list of industrialised countries in each is the same, except that Turkey and Belarus are in Annex I but not in Annex B. Belarus applied to join Annex B at COP 12 and has been submitted to the Parties for ratification of the amendment to Annex B. Turkey has recently ratified the Kyoto Protocol but not applied to join Annex B. Liechtenstein, Slovenia, Slovakia, Croatia and the Czech Republic are in Annex B but not in Annex I.

The Annex B emissions target and the Party's emissions of GHGs in the base year determine the Party's initial assigned amount for the Kyoto Protocol's first commitment period of 2008-2012. The quantity of the initial assigned amount is denominated in individual units, called assigned amount units (AAUs), each of which represents an allowance to emit one metric tonne of carbon dioxide equivalent (tCO_2e). Table 121 shows quantified emission limitation or reduction targets of Annex B Parties as a percentage of total GHG emissions in the base year.

Table 121. Quantified Emission Limitation or Reduction Targets as Contained in Annex B to the Kyoto Protocol (UNFCCC, 2008)

Annex I Parties	Emission limitation or reduction (expressed in relation to total GHG emissions in the base year or period inscribed in Annex B to the Kyoto Protocol)[a]
Austria, Belgium, Bulgaria, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greee, Italy, Latvia,Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, Portugal, Romania,Slovakia,Slovenia, Spain, Sweden, Switzerland, United Kingdom of Great Britain and Northern Ireland	-8%
United States of America [b]	-7%
Canada, Hungary, Japan, Poland	-6%
Croatia	-5%
New Zealand, Russian Federation, Ukraine	0%
Norway	1%
Australia	8%
Iceland	10%

[a] Countries with economies in transition have flexibility in choice o the base year
[b] Country which has declared its intention not to ratify the Kyoto Protocol

Most of the EU countries committed to reduce their GHG emissions 8% according to 1990 emission levels, and according to the chosen base years for economies in transition. Since United States of America (USA) has declared its intention not to ratify the Kyoto Protocol, the USA does not have any commitment to reduce GHG emissions. The commitments of Norway, Australia and Iceland are not to reduce their GHG emissions, rather to limit the increase of their GHG emissions according to 1990 levels by 1%, 8% and 10% respectively.

The determination of assigned amount units (AAUs) for the first commitment period of 2008-2012 is crucial in the implementation of the Kyoto Protocol. Paragraph 7 and 8 of Article 3 of the Kyoto Protocol describes the general guideline about the calculation of AAUs. According to paragraph 7; in the first commitment period, from 2008 to 2012, the assigned amount for each Party included in Annex I shall be equal to the percentage inscribed for it in Annex B of its aggregate anthropogenic carbon dioxide equivalent emissions of the greenhouse gases listed in Annex A in 1990, or the base year or period determined for economies in transition, multiplied by five. And parties included in Annex I for whom land-use change and forestry constituted a net source of greenhouse gas emissions in 1990 includes in their 1990 emissions base year their carbon dioxide equivalent emissions by sources minus removals by sinks in 1990 from land-use change in the calculation of their AAUs. Paragraph 8 gives an option for any Party included in Annex I to use 1995 as its base year for hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride in the calculation of their AAUs.

The Kyoto Protocol has three mechanisms that will be mentioned in the succeeding paragraphs of this section. These mechanisms result in increase or decrease of Parties' allowed emissions in determination of the compliance of the Parties with their commitments. Paragraph 10-12 of Article 3 of the Kyoto Protocol shows the effects of these mechanisms on AAUs.

According to these paragraphs; any emission reduction units (ERUs), or any part of an assigned amount (AAUs), which a Party acquires from another Party in accordance with the provisions of Article 6 that regulates Joint Implementation or of Article 17 that regulates Emissions Trading, will be added to the AAUs for the acquiring Party. And any ERUs, or any part of an AAUs, which a Party transfers to another Party in accordance with Joint Implementation and Emissions Trading mechanisms will be subtracted from the AAUs for the transferring Party. Any certified emission reductions (CERs) which a Party acquires from another Party in accordance with the provisions of Article 12 that regulates Clean Development Mechanism will be added to the AAUs for the acquiring Party.

Paragraph 13 of Article 3 of the Kyoto Protocol states that; "if the emissions of a Party included in Annex I in a commitment period are less than its assigned amount under this Article, this difference shall, on request of that Party, be added to the assigned amount for that Party for subsequent commitment periods."

As mentioned above, the Kyoto Protocol has three mechanisms effective for the Parties to reach their emission reduction targets. These mechanisms directly affect AAUs of Parties to determine their compliance. These Kyoto mechanisms can be explained as follows:

Since the ultimate aim is to reduce global emission level, the source of the emission reduction is not important. So, the Kyoto Protocol provides flexibility mechanisms that may be more cost effective for the Parties to reach their emission reduction targets. These flexibility mechanisms are as follows:

1. Emissions trading;
2. Joint Implementation (JI); and
3. The Clean Development Mechanism (CDM).

These mechanisms provide to add to or subtract from parties' assigned amounts and so reach their emission reduction targets. Use of the Kyoto mechanisms must be supplementary to domestic action, meaning that a significant proportion of a Party's emission reductions should result from domestic emission reductions.

Emissions trading mechanism is regulated under Article 17 of the Kyoto Protocol. According to Article 17 of the Kyoto Protocol; Annex B Parties may participate in emissions trading to fulfill their commitments under Article 3. But, any such trading should be supplemental to domestic actions to meet quantified emission limitation and reduction commitments.

Emissions trading allows Parties that have emission units permitted but not used, to sell to Parties that are over their targets. Annex B Parties have committed to limit or reduce their emissions to reach specific targets. These targets are expressed as levels of allowed emissions, or assigned amounts over the 2008-2012 commitment period. These allowed emissions are divided into assigned amount units (AAUs). Emissions trading mechanism regulates the trade of AAUs under the Kyoto Protocol's emissions trading scheme.

The economies in transition in Annex B, such as Russia, Ukraine and CEE countries, have a too much surplus AAUs in the first commitment period, due to the collapse of the Warsaw Pact economies in the early 1990s. The EU and Japanese buyers were reluctant to purchase them unless the AAU revenue is associated with some greening activities, since these surplus AAUs were not created from active emissions reductions (EWEA, 2009). The problem is being solved by the introduction of a new mechanism called the Green Investment Scheme, in which the sales revenue from AAUs are channelled to projects with climate and/or environment benefits (EWEA, 2009). It is estimted that the total amount of AAUs entering the market through the GIS could be very large – much larger than the World Bank estimate of demand of between 400 million and 2 billion AAUs in the market (EWEA, 2009).

Transfers and acquisitions of the Kyoto units are tracked and recorded through the registry systems with an international transaction log ensuring secure transfer of Kyoto units between countries. To address the concern that Parties could oversell units, and be unable to meet their own emissions targets, each Party is required to maintain a reserve of ERUs, CERs, AAUs and/or Removal units (RMUs) in its national registry, called as the "commitment period reserve" (CPR), that should not drop below 90% of the Party's AAUs or 100% of five times its most recently reviewed inventory, whichever is lowest (UNFCCC, 2008). The CPR is the minimum level of units that a Party must always hold in its national registry. RMUs are generated in Annex B countries by Land Use, Land Use Change and Forestry (LULUCF) activities that absorb carbon dioxide.

Joint Implementation (JI) is regulated under Article 6 of the Kyoto Protocol. According to Article 6 of the Kyoto Protocol; to meet its commitment under Article 3, any Party included in Annex I may transfer to, or acquire from, any other such Party emission reduction units that result from projects reducing anthropogenic emissions by sources or enhancing anthropogenic removals by sinks of GHGs in any sector of the economy, provided that:

- Parties involved approve the project;

- Project provides a reduction in emissions by sources, or an enhancement of removals by sinks, that is additional to any that would otherwise occur;

- It does not acquire any ERUs if it is not in compliance with its obligations under Articles 5 and 7 of the Kyoto Protocol;

- The acquisition of ERUs are supplemental to domestic actions to meet commitments under Article 3.

Shortly, this mechanism allows an Annex B country to invest in emissions reduction projects in any other Annex B country as an alternative to reducing emissions domestically. The credits for JI emission reductions are called emission reduction units (ERUs), with one ERU representing a reduction of one tonne of CO_2 equivalent. JI does not affect the overall assigned amount of Annex B Parties collectively; rather it redistributes them among Annex B Parties.

Clean Development Mechanism (CDM) is regulated under Article 12 of the Kyoto Protocol. According to this Article; CDM has two main purposes: to assist non-Annex I Parties in achieving sustainable development and and to assist

Annex I Parties in achieving compliance with their quantified emission limitation and reduction commitments. Non-Annex I may benefit from project activities resulting in certified emission reductions and Annex I Parties may use the certified emission reductions (CERs) accruing from such project activities to contribute to compliance with part of their quantified emission limitation and reduction commitments. CERs obtained during the period from the year 2000 up to the beginning of the first commitment period (2008) can be used by Annex I Parties in the first commitment period to comply with their commitments.

According to the same Article, emission reductions resulting from such projects can be certified by operational entities provided that:

- Each Party involved approves voluntary participation;

- Benefits related to the mitigation of climate change are real, measurable, and long-term;

- Reductions in emissions are additional to any that would occur in the absence of this project.

Shortly CDM allows Annex I parties to reach their emission reduction or limitation targets by purchasing CERs from projects in non-Annex I countries. By this way, developing countries will have access to resources and technology for sustainable development. Unlike emissions trading and JI projects, CDM creates new assigned amounts and so increases the allowable emission units for Annex I Parties collectively. CDM projects must meet strict requirements by the following procedures for the validation and registration of projects and the verification and certification of emission reductions and removals. CDM projects creates three types of Kyoto units: Certified emission reductions (CERs), temporary CERs and long-term CERs. CERs are issued for projects that reduce emissions by non-forestry projects, whereas temporary CERs (tCERs) and long-term CERs (lCERs) are issued for afforestation and reforestation projects.

The CDM Executive Board is the most important body in CDM in that it supervises CDM, makes accredition of DOEs, registers projects, approves methodologies for determining project baselines and monitoring emission reductions, and issues CERs.

The determination of each Annex I Party's compliance with its emission commitment at the end of the commitment period, will be made by comparing its total GHG emissions to its available assigned amount. Each Party's available assigned amount units (AAUs) are equal to its initial AAUs, plus any additional Kyoto units that the Party has acquired from other Parties through the Kyoto mechanisms or issued for net removals from a Land Use, Land Use Change and Forestry (LULUCF) activity, minus any units that the Party has transferred to other Parties or cancelled for net emissions from a LULUCF activity (UNFCCC, 2008). If the Party's total emissions over the commitment period are less than or equal to its total available assigned amount, the Party will be in compliance with its commitment. Expression of compliance in formulae can be;

Initial AAUs + Acquired AAUs, RMUs, ERUs, CERs, – Transferred or cancelled AAUs, RMUs, ERUs, CERs, ≥ Total GHG emissions

The compliance mechanism holds national governments accountable for their emissions reduction obligations, imposing a penalty of 30% on countries for failing to meet their obligations by the end of the first commitment period (2012). This means that obligation of these countries in the second commitment period is increased by 1.3 tonnes for each tonne of shortfall in meeting their first commitment period obligation, in addition to the obligation of the country for the second commitment period. The Party in non-compliance will be requested to prepare and submit a compliance action plan assessing the reason for the Party's non-compliance and indicating actions with a timetable, to show how the Party intends to meet its emission commitment in the subsequent commitment period (UNFCCC, 2008). Furthermore, if the Protocol's Compliance Committee decides these countries to be out compliance, their right to use the flexible mechanisms of the Kyoto Protocol is suspended until they bring back into compliance.

Emission Trends in Annex I Parties

As explained, the Kyoto Protocol sets binding targets for Annex B countries. This subtitle will investigate where do these countries stand in terms of their commitments by comparing their GHG emissions in 2007 according to base year 1990. UNFCCC published National Greenhouse Gas Inventory Data for the Period 1990-2007 in 21 October 2009. Data of this subtitle is obtained from this document.

Table 122 shows GHG emissions including LULUCF and excluding LULUCF from all Annex I Parties with Annex I Economies in Transition (EIT) Parties and Annex I Non-EIT Parties in 1990, 2000 and 2007.

Table 122. GHG Emissions from Annex I Parties, 1990, 2000 and 2007 in 1,000 Mt CO_2e (UNFCCC, 2009a)

	Including LULUCF			Excluding LULUCF		
	1990 [a]	2000	2007	1990 [a]	2000	2007
Annex I EIT Parties	5.7	3.6	3.3	5.9	3.5	3.7
Annex I Non-EIT Parties	11.7	12.8	13.2	12.9	14.1	14.4
All Annex I Parties	17.5	16.4	16.5	18.8	17.6	18.1

[a] Unless otherwise specified, base year data are used in totals instead of 1990 data (in accordance with decisions 9/CP.2 and 11/CP.4) for Bulgaria (1988), Hungary (average of 1985, 1987), Poland (1988), Romania (1989) and Slovenia (1986).

Table 123 illustrates percentage changes in GHG emissions including LULUCF and excluding LULUCF from all Annex I Parties, Annex I EIT Parties and Annex I Non-EIT Parties from 1990 to 2007, and from 2000 to 2007 as follows:

Table 123 . Change in GHG Emissions from Annex I Parties, from 1990 to 2007, and from 2000 to 2007 (%) (UNFCCC, 2009a)

	Including LULUCF		Excluding LULUCF	
	1990-2007	2000-2007	1990-2007	2000-2007
Annex I EIT Parties	12.8%	-7.5%	11.2%	7.8%
Annex I Non-EIT Parties	-42.2%	0.9%	-37.0%	3.1%
All Annex I Parties	-5.2%	3.3%	-3.9%	2.0%

Total aggregate GHG emissions excluding emissions/removals from LULUCF for all Annex I Parties decreased by 3.9%, from 18,848.0 to 18,112.1 Mt CO_2e from 1990 to 2007. Total aggregate emissions including LULUCF decreased by 5.2% from 17,459.6 to 16,547.1 Mt CO_2e. For Annex I EIT Parties, total aggregate emissions excluding LULUCF decreased by 37.0%, from 5,907.6 Mt CO_2e in 1990 to 3,721.5 Mt CO_2e in 2007; GHG emissions including LULUCF decreased by 42.2% over the same period; GHG emissions from Annex I Parties increased by 3.1% (excluding LULUCF) and by 0.9% (including LULUCF) between 2000 and 2007. From 2000 to 2007, GHG emissions from Annex I EIT Parties increased by 7.8% excluding LULUCF and decreased by 7.5% including LULUCF.

From 1990 to 2007, total aggregate GHG emissions excluding LULUCF for Annex I non-EIT Parties increased by 11.2% and emissions including LULUCF increased by 12.8%. From 2000 to 2007, emissions excluding LULUCF from these Annex I non-EIT Parties increased by 2.0% and emissions including LULUCF increased by 3.3%. So, when EIT Parties are excluded, non-EIT Annex I Parties together are far away from their commitments.

The changes in total aggregate GHG emissions varied considerably among countries between 1990 and 2007. Latvia has the largest decrease in emissions: 54.7% for emissions excluding LULUCF and 478.3% for emissions including LULUCF. Turkey has the greatest increase in emissions: 119.1% excluding LULUCF and 136.7% including LULUCF. Table 124 shows total GHG emissions excluding emissions or removals from LULUCF in 1990, 2000, 2007 and changes in GHG emissions from 1990 to 2007 and from 2000 to 2007.

Table 124. Total Aggregate GHG Emissions Excluding Emissions / Removals from LULUCF, 1990 and 2007 in Kt CO_2e and Change from 1990 to 2007 (UNFCCC, 2009a)

Party	1990	2000	2007	1990-2007	2000-2007
Australia	416,214	494,855	541,179	30.0%	9.4%
Austria	79,037	81,078	87,958	11.3%	8.5%
Belarus*	129,129	70,995	80,010	-38.0%	12.7%
Belgium	143,249	145,100	131,301	-8.3%	-9.5%
Bulgaria*[a]	133,747	69,223	75,793	-43.3%	9.5%
Canada	591,793	717,101	747,041	26.2%	4.2%
Croatia*	31,374	25,955	32,385	3.2%	24.8%
Czech Republic*	194,712	147,234	150,823	-22.5%	2.4%
Denmark	70,414	69,167	68,092	-3.3%	-1.6%
Estonia	41,935	18,379	22,019	-47.5%	19.8%
European Community[b]	4,232,900	4,107,639	4,051,964	-4.3%	-1.4%
Finland	70,862	69,544	78,345	10.6%	12.7%
France	565,495	560,581	535,772	-5.3%	-4.4%
Germany	1,215,209	1,008,164	956,113	-21.3%	-5.2%
Greece	105,562	127,126	131,854	24.9%	3.7%
Hungary	116,453	78,016	75,944	-34.8%	-2.7%
Iceland	3,400	3,730	4,482	31.8%	20.2%
Ireland	55,383	68,951	69,205	25.0%	0.4%
Italy	516,318	549,509	552,771	7.1%	0.6%
Japan	1,269,657	1,345,997	1,374,256	8.2%	2.1%
Latvia	26,679	10,103	12,083	-54.7%	19.6%
Liechtenstein	230	255	243	6.1%	-4.7%
Lithuania	49,075	19,186	24,738	-49.6%	28.9%
Luxembourg	13,118	9,971	12,914	-1.6%	29.5%
Monaco	108	120	98	-9.3%	-18.3%
Netherlands	211,997	214,427	207,504	-2.1%	-3.2%

Party	1990	2000	2007	1990-2007	2000-2007
New Zealand	61,853	70,598	75,550	-22.1%	7.0%
Norway	49,695	53,358	55,050	10.8%	3.2%
Poland	569,510	389,011	398,881	30.0%	2.5%
Portugal	59,269	81,710	81,841	38.1%	0.2%
Romania*[a]	276,050	135,524	152,29	-44.8%	12.4%
Russian Federation*	3,319,327	2,030,431	2,192,818	-33.9%	8.0%
Slovakia*	73,255	48,424	46,591	-35.9%	-3.8%
Slovenia*[a]	20,340	18,912	20,722	1.9%	9.6%
Spain	288,135	385,768	442,322	53.5%	14.7%
Sweden	71,934	68,159	65,412	-9.1%	-4.0%
Switzerland	52,709	51,648	51,265	-2.7%	-0.7%
Turkey**	170,059	279,956	372,638	119.1%	33.1%
Ukraine*	926,033	389,714	436,005	-52.9%	11.9%
United Kingdom	774,164	677,138	640,273	-17.3%	-5.4%
United States	6,084,490	6,975,180	7,107,162	16.8%	1.9%

[a] Data for the base year defined by decisions 9/CP.2 and 11/CP.4 (Bulgaria (1988), Hungary (average of 1985, 1987), Poland (1988), Romania (1989), Slovenia (1986)) are used for this Party instead of 1990 data.
[b] Emission estimates of the European Community are reported separately from those of its member States.
[c]Decision 26/CP.7 invited Parties to recognize the special circumstances of Turkey, which place Turkey in a situation different from that of other Annex I Parties.
* A Party undergoing the process of transition to a market economy

GHG emissions (excluding LULUCF) from the United States, European Community, Russian Federation and Japan comprise 39.2%, 22.3%, 12.1% and 7.6% of GHG emissions (excluding LULUCF) of Annex I Parties respectively in 2007. This means that more than four fifth of GHG emissions (excluding LULUCF) of Annex I Parties come from these four regions GHG emissions (excluding LULUCF) from United States increased by 16.8% from 1990 to 2007 and by 1.9% from 2000 to 2007. So, the increase has slowed down since 2000 in the United States. But, GHG emissions (excluding LULUCF) in United States increased incredibly between 1990 and 2000. GHG emissions (including LULUCF) from United States increased by 15.8% from 1990 to 2007 and decreased by 3.2% from 2000 to 2007.

GHG emissions (excluding LULUCF) from Japan increased by 8.2% from 1990 to 2007 and by 2.1% from 2000 to 2007. So, the increase has slowed down since 2000 in Japan as was the case for United States. But, Japan is still far away from its commitment of decreasing GHG emissions 6% according to base year 1990. GHG emissions (including LULUCF) from Japan increased by 8.2% from 1990 to 2007 and by 2.2% from 2000 to 2007. So, including or excluding LULUCF does not change the picture for Japan.

GHG emissions (excluding LULUCF) from Russian Federation decreased by 33.9% from 1990 to 2007 but increased by 8.0% from 2000 to 2007. So, Russian Federation has already too much excess AAUs according to its commitment of limiting GHG emissions to base year 1990. This sharp decrease from 1990 to 2007 largely comes from the collapse of the Warsaw Pact economies in the early 1990s. But, GHG emissions (excluding LULUCF) started to increase and reached 8.0% increase from 2000 to 2007, especially due to economic recovery. Economies in transition other than Russian Federation are simiar to Russian Federation, too. GHG emissions (excluding LULUCF) from Belarus, Bulgaria, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland, Romania, Slovakia and Ukraine decreased by 38.0%, 43.3%, 22.5%, 47.5%, 34.8%, 54.7%, 49.6%, 30.0%, 44.8%, 35.9% and 52.9% respectively from 1990 to 2007. Croatia and Slovenia are the only two economies in transition whose GHG emissions (excluding LULUCF) increased by 3.2% and 1.9% respectively during the same period.

GHG emissions (excluding LULUCF) from European Community decreased by 4.3% from 1990 to 2007, and by 1.4% from 2000 to 2007. GHG emissions (including LULUCF) from European Community decreased by 5.6% from 1990 to 2007, and by 1.4% from 2000 to 2007. European Community has still some way to comply with its commitment of 8.0% decrease according to base year 1990. GHG emissions (excluding LULUCF) from Germany, United Kingdom and France decreased by 21.3%, 17.3% and 5.3% respectively whereas GHG emissions (excluding LULUCF) from Itay increased by 7.1% during the same period. GHG emissions (including LULUCF) from Germany, United Kingdom and France decreased by 20.8%, 17.8% and 11.8% respectively whereas GHG emissions (excluding LULUCF) from Itay increased by 7.4% during the same period. So, including LULUCF has the most effect on France.

Table 125 shows total GHG emissions including emissions or removals from LULUCF in 1990, 2000, 2007 and changes in GHG emissions from 1990 to 2007 and from 2000 to 2007.

Table 125. Total Aggregate GHG Emissions Including Emissions / Removals from LULUCF in 1990 and 2007 in Kt CO_2e and Change from 1990 to 2007 (UNFCCC, 2009a)

Party	1990	2000	2007	1990-2007	2000-2007
Australia	453,794	404,392	825,888	82.0%	104.2%
Austria	65,859	64,104	70,835	7.6%	10.5%
Belarus*	107,101	43,747	55,068	-48.6%	25.9%
Belgium	141,827	143,568	129,827	-8.5%	-9.6%
Bulgaria*[a]	128,697	60,314	68,991	-46.4%	14.4%
Canada	540,227	636,782	792,495	46.7%	24.5%
Croatia*	27,189	20,675	26,082	-4.1%	26.2%
Czech Republic*	190,148	138,661	149,103	-21.6%	7.5%
Denmark	70,965	70,797	66,965	-5.6%	-5.4%
Estonia	35,567	16,920	14,116	-60.3%	-16.6%
European Community[b]	4,016,307	3,847,717	3,792,548	-5.6%	-1.4%
Finland	53,089	51,126	53,080	0.0%	3.8%
France	525,450	515,697	463,433	-11.8%	-10.1%
Germany	1,186,959	976,065	939,985	-20.8%	-3.7%
Greece	102,369	124,673	128,203	25.2%	2.8%
Hungary	112,857	77,188	71,806	-36.4%	-7.0%
Iceland	4,906	5,085	5,694	16.1%	12.0%
Ireland	55,635	69,093	68220	22.6%	-1.3%
Italy	448,825	470,279	481,862	7.4%	2.5%
Japan	1,195,370	1,265,360	1,292,903	8.2%	2.2%
Latvia	5,261	-14,290	-19,902	-478.3%	-39.3%
Liechtenstein	221	250	237	7.1%	-5.2%
Lithuania	38,336	10,496	15450	-59.7%	47.2%
Luxembourg	13,326	9,500	12,523	-6.0%	31.8%
Monaco	108	120	98	-9.3%	-18.3%
Netherlands	214,594	216,939	210,041	-2.1	-3.2%

Party	1990	2000	2007	1990-2007	2000-2007
New Zealand	43,714	50,626	51,714	18.3%	2.1%
Norway	37,406	36,280	29,168	-22.0%	-19.6%
Poland	536,584	364,775	358,384	-33.2%	-1.8%
Portugal	60,812	75,732	79,517	30.8%	5.0%
Romania*[a]	243,617	97,525	116,068	-52.4%	19.0%
Russian Federation*	3,359,567	2,368,009	2,005,776	-40.3%	-15.3%
Slovakia*	70,867	46,038	43,754	-38.3%	-5.0%
Slovenia*[a]	18,750	13,736	14,948	-20.3%	8.8%
Spain	266,844	359,515	414,325	55.3%	15.2%
Sweden	39,881	32,555	44,952	12.7%	38.1%
-Switzerland	50,369	52,399	50,617	0.5%	-3.4%
Turkey[c]	125,188	212,398	296,364	136.7%	39.5%
Ukraine*	852,887	338,093	392,549	-54.0%	16.1%
United Kingdom	777,118	676,829	638,493	-17.8%	-5.7%
United States	5,257,278	6,290,721	6,087,487	15.8%	-3.2%

[a] Data for the base year defined by decisions 9/CP.2 and 11/CP.4 (Bulgaria (1988), Hungary (average of 1985, 1987), Poland (1988), Romania (1989), Slovenia (1986)) are used for this Party instead of 1990 data.
[b] Emission estimates of the European Community are reported separately from those of its member States.
[c]Decision 26/CP.7 invited Parties to recognize the special circumstances of Turkey, which place Turkey in a situation different from that of other Annex I Parties.
* A Party undergoing the process of transition to a market economy

Turkey has seen the highest percentage of 119.1% increase in GHG emissions (excluding LULUCF) from 1990 to 2007. When LULUCF is included Turkey is again the most GHG emissions increasing country with 136.7% increase. And Spain has been the second highest GHG emissions (excluding LULUCF) increasing country with 53.5% increase during the same period. When LULUCF is included Australia gets the second with 82.0% increase in GHG emissions from 1990 to 2007.

For the period 2000 – 2007, Turkey has been again poorly performed with 33.1% increase in GHG emissions (excluding LULUCF). And when LULUCF is included Australia takes the lead with 104.2% increase in GHG emissions from 2000 to 2007.

Table 126 shows GHG emissions from Annex I Parties by type of GHGs and their changes from 1990 to 2007 as follows:

Table 126. GHG Emissions from Annex I Parties by Gas in 1,000 Mt CO_2e in 1990 and 2007 and Percentage Change from 1990 to 2007 (UNFCCC, 2009a)

	1990	2007	Change (%)
CO_2	15.08	15.00	-0.5%
CH_4	2.25	1.86	-17.3%
N_2O	1.25	0.94	-24.7%
HFC + PFC + SH_6	0.27	0.31	14.8%

CO_2 accounts for the largest share of total aggregate GHG emissions with 15,080 Mt CO_2e, comprising 80.0% of GHGs in 1990 and with 15,000 Mt CO_2e, comprising 82.8% of GHGs in 2007. N_2O decreased by 24.7% from 1990 to 2007, that is the largest decrease. During the same period, CH_4 and CO_2 decreased by 17.3% and 0.5% respectively, whereas HFC, PFC and SH_6 together increased by 14.8%.

The Kyoto Protocol was approved by the European Union Council Decision 2002/358/EC of 25 April 2002, the Community and its Member States committing to reduce their GHG emissions by 8% compared to 1990 levels during 2008 - 2012. The Sixth Community Environment Action Programme established by Decision No 1600/2002/EC of the European Parliament and of the Council provides for the establishment of a Community-wide emissions trading scheme by 2005 by recognising that the Community is committed to achieving an 8% GHG emissions reduction during 2008 - 2012 compared to 1990 levels. The aim of the European Union Greenhouse Gas Emission Trading System (EU ETS) is to help EU Member States achieve compliance with their commitments under the Kyoto Protocol less costly by letting participating companies buy or sell emission allowances (Text of Directive 2003/87/EC, paragraph 2). The EU ETS is an emission allowance cap and trade system and the first international trading system for CO_2 emissions in the world, EU ETS is based on Directive 2003/87/EC. Due to the high importance of the

EU ETS in the global carbon market, it will be explained in details in the succeeding section.

European Union Emissions Trading System

The European Union Greenhouse Gas Emission Trading System (EU ETS) is an emission allowance cap and trade system and the first international trading system for CO_2 emissions in the world, EU ETS is based on Directive 2003/87/EC. The first subtitle will introduce the general outlook of the system such as the aim of the EU ETS, gases in the scope of the EU ETS, the recommendations for candidate countries, GHG emission permits. The second subtitle will explain the activities in the scope of the EU ETS and the new regulation about aviation activities will be mentioned since this may have important effects on other countries, too. The third subtitle will state how the Kyoto mechanisms are linked to the EU ETS. The fourth subtitle will mention important stages in the EU ETS like monitoring, reporting, verification and accreditation of emissions. The fifth subtitle will state penalties in case of non-compliance. The last subtitle will analyse the performance of the EU ETS and the amendments to the Directive 2003/87/EC to increase its performance; by focusing on free allocation, auctioning, windfall profits of electricity operators, and carbon leakage.

General Outlook

The EU ETS is an emission allowance cap and trade system, that caps the overall level of emissions allowed and participants in the system can buy and sell allowances within that limit, as they need. In this system, the amount of emission allowances each installation in the scheme will receive is determined. Since a limited number of allowances below the expected emissions levels will be allocated, this will create scarcity in the system and generate a market value for the emission permits. A company that emits less than its allowances can sell its surplus allowances and make profit; and a company that emits more than its allowances can buy the extra allowances rather than pay the penalty for non-compliance, or take measures to reduce its emissions.

The EU ETS that is the first international trading system for CO_2 emissions in the world started to operate on 1 January 2005. The EU ETS is based on Directive 2003/87/EC, that entered into force on 25 October 2003. According to Article 1 of this Directive; "this Directive establishes a scheme for greenhouse gas emission allowance trading within the Community (hereinafter referred to as the 'Community scheme') in order to promote reductions of greenhouse gas emissions in a cost-effective and economically efficient manner." There have been two trading periods in the implementation of the EU ETS: the first trading period covers 2005-2007, and the second trading period covers 2008-2012 that is compatible with the first commitment period of the Kyoto Protocol. The third trading period will start in 2013.

The aim of the EU ETS is to help EU Member States achieve compliance with their commitments under the Kyoto Protocol less costly by letting participating companies buy or sell emission allowances. The Kyoto Protocol was approved by Council Decision 2002/358/EC of 25 April 2002, the Community and its Member States committing to reduce their GHG emissions by 8% compared to 1990 levels during 2008 - 2012. The Sixth Community Environment Action Programme established by Decision No 1600/2002/EC of the European Parliament and of the

Council provides for the establishment of a Community-wide emissions trading scheme by 2005 by recognising that the Community is committed to achieving an 8% GHG emissions reduction during 2008 - 2012 compared to 1990 levels (Text of Directive 2003/87/EC, paragraph 2).

According to paragraph 5 of text of Directive 2003/87/EC, this Directive "aims to contribute to fulfilling the commitments of the European Community and its Member States more effectively, through an efficient European market in greenhouse gas emission allowances, with the least possible diminution of economic development and employment."

The activities, this Directive wil be applied, are listed in Annex I and greenhouse gases in the scope of the Directive are listed in Annex II of the Directive. While carbon dioxide (CO_2) is the main gas for the first and second trading periods, the gases listed in Annex II have been expanded for the third trading period to be compatible with the Annex A of the Kyoto Protocol: These gases are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_20), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6).

The EU ETS is applied in the 27 EU Member States and Norway, Iceland, Liechtenstein that are the other three members of the European Economic Area. In the EU ETS, the commodity traded are the allowances. Allowance is defined in Article 3/a of the Directive 2003/87/EC as "an allowance to emit one tonne of carbon dioxide equivalent during a specified period, which shall be valid only for the purposes of meeting the requirements of this Directive and shall be transferable in accordance with the provisions of this Directive."

Paragraph 40 - 42 of text of Directive 2009/29/EC that amended the Directive 2003/87/EC, makes explanations that may be quite important for neighbour countries or candidate countries like Turkey. According to this; neighbour countries of the Union should be encouraged to join the Community scheme if they comply with this Directive. Also, the Commission should make every effort in negotiations with candidate countries, potential candidate countries and countries covered by the European neighbourhood policy, including financial and technical assistance to these countries, that would facilitate technology and knowledge transfer. Also, this Directive encourages agreements to be made for the recognition of allowances between the Community scheme and other mandatory greenhouse gas emissions trading systems with absolute emissions caps, which are compatible with the Community scheme in environmental ambition and comparable emissions monitoring, reporting and verification and compliance system. According to Article 25 of the Directive 2003/87/EC; agreements should be made with third countries listed in Annex B to the Kyoto Protocol which have ratified the Protocol to provide for the mutual recognition of allowances between the Community scheme and other greenhouse gas emissions trading schemes.

Greenhouse gas emissions permit is one of the most important instruments in the EU ETS since the Directive prohibits installations carrying out activities listed in Annex I without this GHG emissions permit. Greenhouse gas emissions permit is defined in Article 3/d of the Directive 2003/87/EC as “the permit issued in accordance with Articles 5 and 6.”

According to Article 5; “from 1 January 2005, no installation can carry out any activity listed in Annex I resulting in emissions specified in relation to that activity unless its operator holds a permit issued by a competent authority or the installation is excluded from the Community scheme pursuant to Article 27.” Article 27 regulates exclusion of small installations that have the necessary conditions.

According to Article 27; “Member States may exclude from the Community scheme installations which have reported to the competent authority emissions of less than 25,000 tonnes of carbon dioxide equivalent and, where they carry out combustion activities, have a rated thermal input below 35 MW, excluding emissions from biomass, in each of the three years preceding the notification to the Commission, if the Member State complies with the conditions stated in Article 27.” This procedure enables Member States to exclude such small installations from the emissions trading system as long as equivalent measures to reduce greenhouse gas emissions, in particular taxation are applied. The aim of this threshold is to provide administrative simplicity and so reduce administrative costs for each tonne of CO_2 equivalent excluded from the system.

Activities in the Scope of the EU ETS

Annex I includes categories of activities to which this Directive will be applied. These activities can be grouped into two categories: Aviation activities and other activities. Chapter II of the Directive applies to the allocation and issue of allowances in respect of aviation activities listed in Annex I. Chapter III of the Directive headlined as “Stationary Installations” applies to greenhouse gas emissions permits and the allocation and issue of allowances in respect of activities listed in Annex I other than aviation activities. These activities are;

-Combustion of fuels in installations with a total rated thermal input exceeding 20 MW

-Refining of mineral oil

-Production of coke

-Metal ore (including sulphide ore) roasting or sintering

-Production of pig iron or steel with a capacity exceeding 2,5 tonnes per hour

-Production or processing of ferrous metals where combustion units with a total rated thermal input exceeding 20 MW are operated

-Production of primary aluminium

-Production of secondary aluminium where combustion units with a total rated thermal input exceeding 20 MW are operated

-Production or processing of non-ferrous metals, where combustion units with a total rated thermal input exceeding 20 MW are operated

-Production of cement clinker in rotary kilns with a production capacity exceeding 500 tonnes per day or in other furnaces with a production capacity exceeding 50 tonnes per day

-Production of lime or calcination of dolomite or magnesite in rotary kilns or in other furnaces with a production capacity exceeding 50 tonnes per day

-Manufacture of glass including glass fibre with a melting capacity exceeding 20 tonnes per day

-Manufacture of ceramic products by firing, in particular roofing tiles, bricks, refractory bricks, tiles, stoneware or porcelain, with a production capacity exceeding 75 tonnes per day

-Manufacture of mineral wool insulation material using glass, rock or slag with a melting capacity exceeding 20 tonnes per day

-Drying or calcination of gypsum or production of plaster boards and other gypsum products, where combustion units with a total rated thermal input exceeding 20 MW are operated

-Production of pulp from timber or other fibrous materials

-Production of paper or cardboard with a production capacity exceeding 20 tonnes per day

-Production of carbon black involving the carbonisation of organic substances such as oils, tars, cracker and distillation residues, where combustion units with a total rated thermal input exceeding 20 MW are operated

-Production of nitric acid, adipic acid, glyoxal and glyoxylic acid, ammonia, soda ash (Na_2CO_3) and sodium bicarbonate ($NaHCO_3$)

-Production of bulk organic chemicals with a production capacity exceeding 100 tonnes per day

-Production of hydrogen (H_2) and synthesis gas by reforming or partial oxidation with a production capacity exceeding 25 tonnes per day

-Production of Capture of greenhouse gases from installations covered by this Directive for the purpose of transport and geological storage

-Transport of greenhouse gases by pipelines for geological storage in a storage site

-Geological storage of greenhouse gases in a storage site

Installation is defined in Article 3/e as “a stationary technical unit where one or more activities listed in Annex I are carried out and any other directly associated activities which have a technical connection with the activities carried out on that site and which could have an effect on emissions and pollution.” Directive 2008/101/EC of the European Parliament and of the Council of 19 November 2008 taking effect of 2 February 2009, amended Directive 2003/87/EC so as to include aviation activities in the scheme for greenhouse gas emission allowance trading within the Community. Emissions from all flights arriving at and departing from Community aerodromes will be included from 2012, to avoid distortions of competition and improve environmental effectiveness. So, many aircraft operators outside the EU will be effected from this regulation. This regulation will be mentioned briefly as follows:

Certain flights will be exempt from the Community scheme to avoid disproportionate administrative burdens. In line with this principle, commercial air transport operators operating, for three consecutive four-month periods, fewer than 243 flights per period should be exempt from the Community scheme. This would benefit airlines operating limited services within the scope of the Community scheme, including airlines from developing countries (Paragraph 18 of Text of Directive 2008/101/EC). One Member State will be responsible for each aircraft operator to reduce the administrative burden on aircraft operators. In case of non-compliance, the administering Member State can request the Commission to decide on the imposition of an operating ban at Community level on the aircraft operator concerned, as a last resort. Allowances allocated to the aviation sector will only be used to meet the obligations placed on aircraft operators to surrender allowances under this Directive.

Article 3c of the Directive 2003/87/EC regulates total quantity of allowances for aviation and Article 3d regulates method of allocation of allowances for aviation through auctioning. According to these Articles, the total quantity of allowances to be allocated, for the period from 1 January 2012 to 31 December 2012, to aircraft operators will be equivalent to 97% of the historical aviation emissions. 15% of these allowances will be auctioned. For the period 2013-2020, beginning on 1 January 2013, the total quantity of allowances to be allocated to aircraft operators shall be equivalent to 95% of the historical aviation emissions multiplied by the number of years in the period. From 1 January 2013, 15 % of allowances will be auctioned, but this percentage may be increased as part of the general review of this Directive. During this period, 3 % of the total quantity of allowances to be allocated will be set aside in a special reserve for aircraft operators who start performing an aviation activity falling within Annex I or whose tonne-kilometre data increases by an average of more than 18% annually between the monitoring year for which tonne-kilometre data was submitted and the second calendar year of that period (Article 3f of the Directive 2003/87/EC).

According to Paragraph 17 of Text of Directive 2008/101/EC; if a third country adopts measures, which have an environmental effect at least equivalent to that of this Directive to reduce emissions, the Commission should consider optimal interaction between the Community scheme and that country's measures. If bilateral arrangements on linking the Community scheme with other trading schemes to form a common scheme are made, the Commission may adjust the total quantity of allowances to be issued to aircraft operators.

Paragraph 17 of Text of Directive 2008/101/EC mentions the allocation methodology will be harmonised to avoid distortions of competition. A proportion of allowances will be allocated by auction and a special reserve of allowances will be set aside for new aircraft operators and to assist aircraft operators which increase sharply the number of tonne-kilometres that they perform. Aircraft operators that end operations will continue to be issued with allowances until the end of the period for which free allowances have already been allocated. According to Paragraph 17 of Text of Directive 2008/101/EC; full harmonisation of the proportion of allowances issued free of charge to all aircraft operators participating in the Community scheme is appropriate in order to ensure a level playing field for aircraft operators.

Use of Kyoto Mechanisms in the EU ETS

The EU ETS is linked to the Kyoto Protocol's flexible mechanisms by Directive 2004/101/EC that amended Directive 2003/87/EC in respect of the Kyoto Protocol's project mechanisms. Directive 2003/87/EC states that the recognition of credits from project-based mechanisms will increase the cost-effectiveness of reducing GHG emissions and be provided by linking the Kyoto project-based mechanisms, joint implementation (JI) and the clean development mechanism (CDM), with the Community scheme (Text of Directive 2004/101/EC, paragraph 2). This also helps to improve the liquidity of the Community market in GHG emission allowances (Text of Directive 2004/101/EC, paragraph 3).

Member States may allow operators to use CERs from 2005 and ERUs from 2008; and Member States specify the allocation to use CERs and ERUs from 2008 as a percentage of the allocation to each installation in its national allocation plan (Text of Directive 2004/101/EC, paragraph 5). Member States also decide on the limit for the use of CERs and ERUs to maintain that the use of these mechanisms are supplemental to domestic action (Text of Directive 2004/101/EC, paragraph 7). According to Article 30 paragraph 3, each Member State publishes in its national allocation plan its intended use of ERUs and CERs and the allocation to each installation by 28 February of each year.

An important question has been the future of CERs and ERUs after the end of the first commitment period of the Kyoto Protocol, namely after 2012. Although the Kyoto Protocol does not enable ERUs to be created from 2013 onwards without a new international agreement, CDM credits can continue to be generated. Directive 2009/29/EC that amended Directive 2003/87/EC regulates this issue. Important explanations were made in Paragraph 28-33 of text of Directive 2009/29/EC. According to this, in case of an international agreement on climate change, additional use of CERs and ERUs will be provided for, from countries which have ratified that agreement, but in the absence of an international agreement, providing for further use of CERs and ERUs would make it more difficult to achieve the objectives of the Community to increase renewable energy use. So, the rules regarding the use of CERs and ERUs is determined consistent with the goal of generating 20% of energy from renewable sources by 2020, and promoting energy efficiency, and technological development. In case of approval by the Community of a satisfactory international agreement on climate change, use of credits from projects in third countries will be increased simultaneously with the increase in emission reductions to be achieved through the Community scheme. Operators are provided with certainty about the possibility to use after 2012 CERs and ERUs up to the remainder of the level which they were allowed to use in the period from 2008 to 2012, to provide predictability. LDCs are in a special position than other third countries. Because, they are vulnerable to the effects of climate change, although they are responsible only for a very low level of greenhouse gas emissions. The Directive provides certainity on the acceptance of credits from projects started in LDCs after 2012, even in the absence of an international agreement on climate change, if these projects are additional and contribute to sustainable development. This entitlement will apply to LDCs until 2020 if they have by then ratified an international agreement on climate change or a bilateral or multilateral agreement with the Community.

Use of CERs and ERUs from project activities in the Community scheme before the entry into force of an international agreement on climate change is regulated in Article 11a of Directive 2003/87/EC. According to paragraph 5 of this

Article; to the extent that the levels of CER and ERU use, allowed to operators or aircraft operators by Member States for the period from 2008 to 2012, have not been used up or an entitlement to use credits is granted under paragraph 8 and in the event that the negotiations on an international agreement on climate change are not concluded by 31 December 2009, credits from projects or other emission reducing activities may be used in the Community scheme in accordance with agreements concluded with third countries, specifying levels of use. In accordance with such agreements, operators shall be able to use credits from project activities in those third countries to comply with their obligations under the Community scheme.

Paragraph 7 regulates the position of credits from projects after an international agreement. And according to this; once an international agreement on climate change has been reached, only credits from projects from third countries that have ratified this agreement will be accepted in the Community scheme from 1 January 2013.

According to Paragraph 8 of this Article; all existing operators will be allowed to use credits during the period 2008 – 2020 up to the highest one of either the amount allowed to the during the period 2008 – 2012, or to an amount corresponding to a percentage, that will not be set below 11% of their allocation during the period 2008 – 2012. New entrants, that received neither free allocation nor an entitlement to use CERs and ERUs in the period 2008 – 2012, will be able to use credits up to an amount corresponding to a percentage, that will not be set below 4.5% of their verified emissions during the period 2013 – 2020. For aircraft operators, this percentage will not be set below 1.5%, of their verified emissions during the period 2013 – 2020. It should be ensured that the overall use of credits allowed does not exceed 50% of the Community-wide reductions below the 2005 levels of the existing sectors under the Community scheme over the period 2008 - 2020 and 50% of the Community-wide reductions below the 2005 levels of new sectors and aviation over the period from the date of their inclusion in the Community scheme to 2020.

To the extent that the levels of CER and ERU use, allowed to operators or aircraft operators by Member States for the period from 2008 to 2012, have not been used up or an entitlement to use credits is granted under paragraph 8,

- operators may request the competent authority to issue allowances to them valid from 2013 onwards in exchange for CERs and ERUs issued in respect of emission reductions up until 2012 from project types which were eligible for use in the Community scheme during the period from 2008 to 2012;

- competent authorities shall allow operators to exchange CERs and ERUs, from projects that were registered before 2013 issued in respect of emission reductions from 2013 onwards for allowances valid from 2013 onwards, or CERs issued in respect of emission reductions from 2013 onwards for allowances from new projects started from 2013 onwards in LDCs.

Monitoring, Reporting,Verification and Accreditation of Emissions

Allowances issued from 1 January 2013 onwards will be valid for emissions during period from 2013 to 2020.

According to Article 12 of the Directive 2003/87/EC; Member States ensures that, by 30 April each year, each aircraft operator and the operator of each installation surrenders a number of allowances equal to the total emissions during the preceding calendar year from activities listed in Annex I as verified in accordance with Article 15 and and that these suurrendered allowances are subsequently cancelled.

Monitoring and reporting of emissions is regulated under Article 14. According to paragraph 3 of this Article, each operator of an installation or an aircraft operator should monitor and report the emissions from that installation during each year, or, from 1 January 2010, the aircraft operated to the competent authority.

According to Article 15 of the Directive 2003/87/EC; Member States ensures that the monitoring reports submitted by operators and aircraft operators are verified in accordance with the criteria set out in Annex V and any provisions adopted by the Commission. Operator or aircraft operator whose report has not been verified as satisfactory by 31 March each year for emissions during the preceding year cannot make further transfers of allowances until the report has been verified as satisfactory. By 31 December 2011, the Commission will adopt a regulation for the verification of emission reports based on the principles set out in Annex V and for the accreditation and supervision of verifiers.

Annex IV determines principles for monitoring and reporting referred to in Article 14 as follows:

Carbon dioxide emissions from stationary installations can be monitored by calculating or measuring the emissions. The formula to calculate emissions is:

Activity data × Emission factor × Oxidation factor

Activity data (fuel used, production rate etc.) is obtained by supply data or measurement. Accepted emission factors, acceptable activity-specific emission factors for all fuels or default factors for commercial fuels may be used as an emission factor.

If the emission factor does not take oxidation into account, an additional oxidation factor is used. If emission factors have taken oxidation into account, it is unnecassary to use an oxidation factor.

Carbon dioxide emissions from aviation activities are monitored by calculation. The formula to calculate emissions is calculated by multiplying fuel consumption and emission factor.

If possible, actual fuel consumption for each flight is calculated by using the formula:

"Amount of fuel contained in aircraft tanks once fuel uplift for the flight is complete" – "amount of fuel contained in aircraft tanks once fuel uplift for subsequent flight is complete" + "fuel uplift for that subsequent flight."

If actual fuel consumption data are not available, a standardised tiered method is used. Default IPCC emission factors are used if activity-specific emission factors are not more accurate.

<u>Penalties</u>

Penalties are determined under Article 16. According to Paragraph 3 of this Article; any operator or aircraft operator who does not surrender sufficient allowances by 30 April of each year to cover its emissions during the preceding year should be held liable for the payment of a penalty that is 100 € per tonne of CO_2e for the excess emissions of which allowances were not surrendered. Payment of this penalty does not release the operator or aircraft operator from the obligation to surrender allowances equal to excess emissions in the following year. Paragraph 4 of this Article states that, this penalty will increase in accordance with the European index of consumer prices for excess emissions related to allowances issued from 1 January 2013 onwards.

According to paragraph 5 and 10 of this Article, if an aircraft operator fails to comply with the requirements of this Directive and other enforcement measures have failed to ensure compliance, its administering Member State may request the Commission to decide on the imposition of an operating ban on the aircraft operator concerned, and the Commission may impose an operating ban on the aircraft operator concerned.

Performance of the EU ETS

The EU ETS was not much successful in achieving some of its objectives, such as encouraging investment in clean technologies, that largely comes from some adverse incentives related to EU ETS design. They are over-allocation of permits as a result of political national influence on the allocation process and counterproductive allocation methods (EWEA, 2009).

For real trading to emerge, total amount of allowances issued to installations should be less than the amount that would have been emitted under a business-as-usual scenario. During the first and second trading periods, Member States retained an important degree of freedom over the elaboration of the national allocation plans (NAPs). Decisions concerning allocation were dependent on emission projections, national interests and business efforts to increase the number of allowances, that led the government allocation to be based on over-inflated projections of economic growth and overestimation of the participants' needs. So, in 2005 allowances exceeded actual verified emissions by about 80 million tonnes of CO_2, that is equivalent to 4% of the EU's intended maximum level. As a consequence, CO_2 prices collapsed to less than 10 €/t in spring 2006 and; by the end of 2006 and in early 2007, it fell below 1 €/t CO_2 and even to 0.08 €/t CO_2 in September 2007 for the first phase of the EU ETS. The over-allocation of permits and the consequent collapse of CO_2 prices prevented clean technology investment, since companies didn't need to change their production processes to meet their allowance targets.

Free allocation based on absolute historical emissions (grandfathering) in the first phase, favoured de facto fossil fuel generation rather than renewable energies. Another controversial feature was the fact that, electric power sector could pass along the the marginal cost of freely allocated emissions to the price of electricity since the power generation sector sets prices relative to marginal costs of production. Since marginal costs include the opportunity costs of CO_2 allowances, even if allowances are received for free, electric power sector made substantial profits. These profits are called windfall profits. Fossil fuel power producers determine the price of electricity on the basis of marginal costs and so they include the opportunity costs of CO_2 allowances in sales price although the costs of emitting CO_2 comprises only a small part of their costs.

According to a study of Point Carbon (2008), assessing the potential and scale of windfall profits in the power sector in UK, Germany, Spain, Italy and Poland during the second phase of the ETS, windfall profits are estimated to be between 23 and 71 billion euros in these five countries totally, during the second phase of the EU ETS (2008–2012), based on an EUA price of 21 to 32 €/t CO2 and some pass-through assumptions. Windfall profit is defined in the study as the CO2 emitting power plants' additional revenue earned from the pass-through of CO2 (opportunity) costs to power prices exceeding the level of compliance costs incurred under the EU

ETS. Windfall profits increase in countries more as the country has a high level of pass-through of CO_2 costs into wholesale power prices, the country allocates the highest percentage of free allowances to the power sector and the country has plant setting in which emissions intensive (coal) plants set the price the majority of the time. Point Carbon (2008) estimates highest levels of windfall profits for Germany (between 14 billion and 34 billion €) and UK (between 6 billion and 15 billion €), because of the high level of pass-through and relatively high level of emission intensity of marginal plant.

The main reason behind windfall profits is the allocation of EUAs free of charge. The European Commission is planning to remove the free allocation of EUAs to the power sector from 2013 onwards and replace free allocation with auctioning of allowances, so windfall profits will disappear from 2013 onwards. Grandfathering approach in the allocation of allowances, that takes into account historic emission levels, encourages installations not to reduce their emissions, since this would result in fewer allowances in the future.

Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 taking effect of 25/06/2009, amended Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community. Paragraph 8 of text of Directive 2009/29/EC mentions that, a review undertaken in 2007 has confirmed a more harmonised emission trading system as imperative to better exploit the benefits of emission trading and to avoid distortions in the internal market; and experience gathered during the first trading period shows the potential of the Community scheme and the finalisation of national allocation plans for the second trading period will deliver significant emission reductions by 2012.

According to Article 9 of Directive 2003/87/EC that was amended by Directive 2009/29/EC, the Community-wide quantity of allowances will decrease in a linear manner calculated from the mid-point of the period from 2008 to 2012, and annual decrease of allowances will be equal to 1.74 % of the allowances issued by Member States pursuant to Commission Decisions on Member States' national allocation plans for the period from 2008 to 2012, to achieve the commitment of the Community to an overall reduction of at least 20% emissions by 2020. This contribution is equivalent to a reduction of emissions in 2020 in the Community scheme of 21% below reported 2005 levels, meaning an issue of a maximum of 1,720 million allowances in 2020. Member States will issue allowances pursuant to Commission decisions on their national allocation plans for the period from 2008 to 2012. 5% of the Community-wide quantity of allowances determined over the period from 2013 to 2020 will be set aside for new entrants, as the maximum that may be allocated to new entrants.

Paragraph 15 of text of Directive 2009/29/EC states that auctioning should be the basic principle for allocation, as it is the simplest, and generally considered to be the most economically efficient, system. This will also eliminate windfall profits and put new entrants and economies growing faster than average on the same competitive position as existing installations.

According to Article 10 of Directive 2003/87/EC that was amended by Directive 2009/29/EC; from 2013 onwards, Member States will auction all allowances which are not allocated free of charge and the Commission will determine and publish the estimated amount of allowances to be auctioned by 31 December 2010. The composition of allowances that will be auctioned by each Member State will be as follows: 88 % of the total quantity of allowances to be auctioned will be distributed among Member States according to their relative share of emissions in the Community scheme for 2005 or the average of the period from 2005 to 2007, whichever one is the highest; 10% of the total quantity will be distributed to the benefit of certain Member States for the purpose of solidarity and growth in the Community, by taking into account levels of income per capita in 2005 and the growth prospects of Member States. A further 2% of the total quantity of allowances to be auctioned will be distributed among Member States, the greenhouse gas emissions of which were, in 2005, at least 20% below their emissions in the base year applicable to them under the Kyoto Protocol. Member States will determine how to use revenues generated from auctioning of allowances. But, at least 50% of these revenues should be used to reduce greenhouse gas emissions, including by contributing to the Global Energy Efficiency and Renewable Energy Fund and to the Adaptation Fund, to adapt to the impacts of climate change and to fund research and development for reducing emissions and for adaptation to climate change, to develop renewable energies to meet the commitment of the Community to using 20% renewable energies by 2020, to increase energy efficiency by 20 % by 2020, etc.

Paragraph 19-22 of text of Directive 2009/29/EC describes auctoning and free allowances to be allocated. According to this, full auctioning will be the rule from 2013 onwards for the power sector, taking into account its ability to pass on the increased cost of CO_2, and no free allocation will be given for the capture and storage of CO_2 as the incentive for this arises from allowances not being required to be surrendered in respect of emissions which are stored. Article 10a of Directive 2003/87/EC states explicitly that, no free allocation will be given to electricity generators, to installations for the capture of CO_2, to pipelines for transport of CO_2 or to CO_2 storage sites. According to Paragraph 4 of the same Article, free allocation will be given to district heating as well as to high efficiency cogeneration, for economically justifiable demand, in respect of the production of heating or cooling. For other sectors covered by the Community scheme, a transitional system will be implemented. In this system, free allocation in 2013 will be 80 % of the amount that corresponded to the percentage of the overall Community-wide emissions during 2005 – 2007 period that those installations emitted as a proportion of the annual Community-wide total quantity of allowances. Then, the free allocation will decrease each year by equal amounts resulting in 30 % free allocation in 2020, with a view to reaching no free allocation in 2027. In order to ensure an orderly functioning of the carbon and electricity markets, the auctioning of allowances for the period from 2013 onwards will start by 2011 and be based on clear and objective principles.

The large price fluctuations may also have significant negative effects on the performance of the EU ETS and so should be avoided. Measures to be taken in the event of excessive price fluctuations are explained in Article 29a of the Directive 2003/87/EC. According to this; if, for more than six consecutive months, the allowance price is more than three times the average price of allowances during the two preceding years on the European carbon market, the Commission immediately convenes a meeting. If this price evolution does not correspond to changing market fundamentals, the auctioning of a part of the quantity to be auctioned can be brought forward, or up to 25 % of the remaining allowances in the new entrants reserve can be auctioned.

Paragraph 24 and 25 of text of Directive 2009/29/EC handles carbon leakage problem. According to this Paragraph, the Community will continue to take the lead in the negotiation of an ambitious international agreement on climate change, but if other developed countries and other major emitters of greenhouse gases do not participate in international agreement, certain energy-intensive sectors and subsectors in the Community will be subject to international competition at an economic disadvantage. The analysis to determine sectors exposed to carbon leakage is based on the assessment of the inability of industries to pass on the cost of allowances in product prices without significant loss of market share to installations outside the Community which do not take comparable action to reduce their emissions. These sectors or subsectors could receive a higher amount of free allocation or an effective carbon equalisation system could be introduced putting these sectors and those from third countries on a comparable footing. Such a system could apply requirements to importers, for example requiring the surrender of allowances. Any action taken needs to conform to the principles of the UNFCCC, such as common but differentiated responsibilities and respective capabilities, taking into account the situation of least developed countries (LDCs). It should also conform to the international obligations of the Community, including the obligations under the World Trade Organization (WTO) agreement.

Paragraph 12-18 of Article 10a of Directive states detailed rules for carbon leakage. According to this; installations in sectors or subsectors which are exposed to a significant risk of carbon leakage will be allocated allowances free of charge at 100 % of the quantity annually during 2013-2020 period. The Commission will determine a list of the sectors or subsectors on the basis of the criteria that will be stated as follows by 31 December 2009 and every five years thereafter; and every year the Commission may, add a sector or subsector to the list meeting the criteria. This list will be determined after taking into account; the extent to which third countries, representing a decisive share of global production of products in sectors or subsectors concerned, firmly commit to reducing greenhouse gas emissions in the relevant sectors or subsectors and the extent to which the carbon efficiency of installations located in these countries is comparable to that of the Community.

In order to determine carbon leakage and so sectors exposed to carbon leakage, the Commission will assess, at the Community level, the extent to which it is possible for the sector or subsector, at the relevant level of disaggregation, to pass on the direct cost of the required allowances and the indirect costs from higher electricity prices resulting from the implementation of Directive 2003/87/EC into product prices without significant loss of market share to less carbon efficient installations outside the Community.

A sector or subsector will be deemed to be exposed to a significant risk of carbon leakage if:

- the sum of direct and indirect additional costs induced by the implementation of this Directive would lead to an increase of production costs, as at least 5% of the gross value added, and

- the intensity of trade with third countries, defined as the ratio between the total value of exports to third countries plus the value of imports from third countries and the total market size for the Community (annual turnover plus total imports from third countries), is above 10 %.

Notwithstanding this criteria, a sector or subsector is also deemed to be exposed to a significant risk of carbon leakage if:

- the sum of direct and indirect additional costs induced by the implementation of this Directive would lead to an increase of production costs, as at least 30% of the gross value added, or

- the intensity of trade with third countries, defined as the ratio between the total value of exports to third countries plus the value of imports from third countries and the total market size for the Community (annual turnover plus total imports from third countries), is above 30%.

Clean Development Mechanism

Clean Development Mechanism (CDM) has been mentioned in the section about the Kyoto Protocol briefly as a Kyoto mechanism. Since CDM is an important issue for developing countries, this section will explain CDM in details in the light of Marrakesh Accords that brings detailed regulations on CDM. Article 12 of the Kyoto Protocol does not regulate CDM in details. To implement CDM in real life necessiates detailed regulations and institutions. The detailed rules for the implementation of the Protocol called the Marrakesh Accords were adopted at COP 7 in Marrakesh in 2001. Decision 17 at the seventh session of the Conference of the Parties in Marrakesh brings detailed regulations on the modalities and procedures for CDM. Data about the regulations of CDM in this section is obtained from Annex of this Part J/3.

The beginning of this section introduces aim of the CDM, types of Kyoto units generated by CDM projects, participation requirements, and some important entities in CDM implementation. Then the first subtitle will describe the CDM project cycle stages composed of project design; validation and registration; monitoring; verification and certification; issuance of CERs. The second subtitle will analyse application of CDM projects in the world.

According to Article 12 of the Kyoto Protocol; CDM has two main purposes: to assist non-Annex I Parties in achieving sustainable development and to assist Annex I Parties in achieving compliance with their quantified emission limitation and reduction commitments. Non-Annex I may benefit from project activities resulting in certified emission reductions and Annex I Parties may use the certified emission reductions (CERs) accruing from such project activities to contribute to compliance with part of their quantified emission limitation and reduction commitments. Shortly CDM allows Annex I parties to reach their emission reduction or limitation targets by purchasing CERs from projects in non-Annex I countries. By this way, developing countries will have access to resources and technology for sustainable development.

CDM projects creates three types of Kyoto units: CERs, temporary CERs and long-term CERs. Certified emission reductions (CERs) are issued for projects that reduce emissions by non-forestry projects, whereas temporary CERs (tCERs) and long-term CERs (lCERs) are issued for afforestation and reforestation projects.

Participation in a CDM project activity is voluntary. There are some eligibility requirements for the countries to participate in the CDM. These participation requirements are regulated under Marrakesh Accords/Decision 17. CP.7/Annex/F. According to these provisions of Marrakesh Accords:

- Parties participating in the CDM should designate a national authority for the CDM.

- A Party not included in Annex I may participate in a CDM project activity if it is a Party to the Kyoto Protocol.

- A Party included in Annex I with a commitment inscribed in Annex B is eligible to use CERs, if it complies with the following eligibility requirements:

    - It should be a Party to the Kyoto Protocol;

    - It should have established its assigned amount in accordance with the modalities for the accounting of assigned amounts;

- It should have a national system for the estimation of anthropogenic emissions by sources and anthropogenic removals by sinks of GHGs;

- It should have a national registry;

- It should have submitted annually the most recent required inventory, including the national inventory report and the common reporting format.

- It should submit the supplementary information on assigned amount in accordance with Article 7, paragraph 1 of the Kyoto Protocol.

The CDM Executive Board is an important entity for the implementation of CDM and is regulated under Marrahesh Accords/Decision 17. CP.7Annex/C. The executive board supervises the CDM under the authority and guidance of the Conference of the Parties (COP) serving as the meeting of the parties and be fully accountable to the COP/MOP. The executive board makes recommendations to the COP/MOP about CDM, accredits operational entities. The executive board also maintains CDM registry that accounts the issuance, holding and transer of CERs. The Designated Operational Entities are also important entities during the CDM project cycle. They validate proposed CDM projects; verify and certify the resulting emission reductions.

The CDM Project Cycle

The CDM project cycle starts with the project design and ends up with the issuance of CERs. This cycle comprises five stages as follows:

1. Project Design
2. Validation and Registration

3. Monitoring
4. Verification and Certification
5. Issuance of CERs

The first two stages take place before the implementation of the project,while the latter three stages take place during the lifetime of the project. These stages will be explained as follows:

<u>Project Design</u>

In designing the project; firstly, the project description and the project purpose is determined with the project boundary. Then, the project describes how technology will be transferred, if any. A project design document is prepared. The project design documents (PDD) mainly involve the following issues:

- Project Description
- Baseline Methodology
- Project Timeline and Crediting Period
- Environmental Impact Statement
- Stakeholder Comments
- Monitoring Methodology and Monitoring Plan
- Calculation of GHG Emissions

The information required to outline in project design document is regulated under Appendix B of Marrahesh Accords/Decision 17. CP.7Annex in details. According to Appendix B;

Project description involves the project purpose, the project boundary and a technical description of the project.

Proposed baseline methodology involves statement of which approved methodology has been selected and description of how the approved methodology will be applied.

The estimated operational lifetime of the project and which crediting period was selected are stated in PDD. Also, PDD describes how GHG emissions are reduced below those that would have occurred in the absence of the registered CDM project activity.

Environmental impacts and stakeholder comments are included as well. Information on sources of public funding for the project activity from Annex I Parties that provides an affirmation that such funding does not result in a diversion of official development assistance is also stated.

Monitoring plan in the PDD identifies data needs and data quality and includes methodologies to be used for data collection and monitoring.

Calculation of GHG emissions in the PDD involves description of formula used to calculate and estimate GHG emissions within the project boundary; description of formula used to calculate project leakage, which is the net change of GHG emissions which occurs outside the CDM project activity boundary, and that is measurable and attributable to the CDM project activity. The sum of these two emissions comprise the CDM project activity emissions. PDD also includes description of formula used to calculate and to project GHG emissions and project leakage. These comprise the baseline emissions. The emission reductions of the CDM project activity is the difference between the CDM project activity emissions and the baseline emissions.

Validation and Registration

Validation and registration is regulated under Marrakesh Accords/Decision 17. CP.7Annex/G. According to these provisions of Marrakesh Accords;

Validation is independent evaluation of a project activity by a designated operational entity against the requirements of the CDM on the basis of the project design document.

Registration is the formal acceptance of a validated project by the executive board as a CDM project activity. Registration is the prerequisite for the verification, certification and issuance of CERs.

According to the provisions of Marrakesh Accords; the designated operational entity selected by project participants to validate a project activity, reviews the project design document and any supporting documentation to confirm that the following requirements have been met:

- The participation requirements are satisfied;

- Comments by local stakeholders have been invited, a summary of the comments received has been provided;

- Project participants have submitted to the designated operational entity documentation on the analysis of the environmental impacts of the project activity, including transboundary impacts and, if those impacts are considered significant by the project participants or the host Party, have undertaken an environmental impact assessment;

- The project activity is expected to result in GHG emissions reducions that are additional to any that would occur in the absence of the proposed project activity,

- The baseline and monitoring methodologies comply with requirements pertaining to methodologies previously approved by the executive board; or modalities and procedures for establishing a new methodology,

- The project activity conforms to all other requirements for CDM project activities.

As mentioned, GHG emission reductions resulting from CDM projects must be additional. A CDM project activity is additional if GHG emissions by sources are reduced below those that would have occurred in the absence of the registered CDM project activity. So, the determination of the baseline is crucial in additionality.

The baseline for a CDM project activity is the scenario that reasonably represents the GHG emissions by sources that would occur in the absence of the proposed project activity. Project participants select a baseline methodology for a project activity among the following approaches the one deemed most appropriate for the project activity, and justify the appropriateness of their choice:

- Existing actual or historical emissions; or

- Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment; or

- The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20% of their category.

If the designated operational entity determines that the project activity intends to use a new baseline or monitoring methodology, it forwards the proposed methodology together with the draft project design document to the executive board for review. The executive board reviews the proposed new methodology in accordance with the modalities and procedures of Marrakesh Accords/Decision 17.

CP.7Annex. Once approved by the executive board, the designated operational entity proceeds with the validation of the project activity and submits the project design document for registration.

In accordance with the provisions of Marrakesh Accords/Decision 17. CP.7Annex/G; the designated operational entity (DOE) follows the following steps during the validation process:

1. DOE receives from the project participants written approval of voluntary participation from the designated national authority of each Party involved, including confirmation by the host Party that the project activity assists it in achieving sustainable development;

2. DOE makes publicly available the project design document;

3. DOE receives comments on the validation requirements from Parties, stakeholders and UNFCCC accredited non-governmental organizations and make them publicly available;

4. DOE makes a determination as to whether the project activity should be validated, on the basis of the information provided and taking into account the comments received;

5. DOE informs project participants of its determination on the validation of the project activity, including confirmation of validation and date of submission of the validation report to the executive board, or an explanation of reasons for non-acceptance if the project activity is not accepted;

6. DOE submits to the executive board a request for registration in the form of a validation report;

7. DOE makes this validation report publicly available.

The registration by the executive board is deemed final 8 weeks after the date of receipt by the executive board of the request for registration, unless a Party involved in the project activity, or at least three members of the executive board, requests a review of the proposed CDM project activity.

There are two alternative crediting periods that may be seected by project participants for for a proposed project activity:

- A maximum of seven years which may be renewed at most two times, provided that, for each renewal, a DOE determines that the original project baseline is still valid or has been updated according to new data; or
- A maximum of ten years with no option of renewal.

Monitoring

When the CDM project is implemented, the real emission reductions are required to be monitored before they are verified and certified. Monitoring is regulated under Marrahesh Accords/Decision 17. CP.7Annex/H. According to this; subsequent to the monitoring and reporting of GHG emissions reductions, CERs resulting from a CDM project activity are calculated, applying the registered methodology, by subtracting the actual GHG emissions by sources from baseline emissions and adjusting for leakage. The project participants provide to the DOE, for the verification, a monitoring report in accordance with the registered monitoring plan for the purpose of verification and certification.

Reductions in GHG emissions by sources is adjusted for leakage in accordance with the monitoring and verification provisions. Leakage is defined as the net change of GHG emissions by sources which occurs outside the project boundary, and which is measurable and attributable to the CDM project activity.

Project participants include a monitoring plan as part of the project design document. Monitoring plan provides for the collection and archiving of all relevant data necessary for estimating or measuring GHG emissions and determining the baseline of GHG emissions within the project boundary during the crediting period, and procedures for the periodic calculation of the GHG emissions reductions by the proposed CDM project activity, and leakage effects.

A monitoring plan for a proposed project activity should be based on a previously approved monitoring methodology or a new methodology, that is determined by the DOE as appropriate to the circumstances of the proposed project activity and has been successfully applied elsewhere. The implementation of the registered monitoring plan is a condition for verification, certification and the issuance of CERs.

Verification and Certification

The real emission reductions should be determined as a result of the CDM project after they are monitored. This process is done by DOEs during the verification process. After verification, it becomes ready for certification. The verification and certification processes are regulated under Marrakesh Accords/Decision 17. CP.7Annex/I.

Verification is the periodic independent review and ex post determination of the monitored reductions in GHG emissions by DOEs during the verification period.

Certification is the written assurance by DOEs that, the project activity achieved the reductions in GHG emissions during a specified time period, as verified.

DOE conducts on-site inspections, as appropriate, that may comprise interviews with project participants and local stakeholders, reviews monitoring results and verifies that the monitoring methodologies for the estimation of GHG emissions have been applied correctly and their documentation is complete and transparent; and determines the GHG emissions reductions that would not have occurred in the absence of the CDM project activity by using calculation procedures in the registered project design document and in the monitoring plan. And then DOE provides a verification report to the project participants, the Parties involved and the executive board. Based on this verification report, DOE certifies in writing that, the project activity achieved the verified amount of GHG emissions reductions that would not have occurred in the absence of the CDM project activity, during the specified time period. Then, DOE informs the project participants, Parties involved and the executive board of its certification decision in writing a certification report.

Issuance of CERs

These certified emission reductions should be issued as CERs to be used. The issuance of CERs is regulated under Marrakesh Accords/Decision 17. CP.7Annex/J. According to these povisions of Marrakesh Accords, the certification report constitutes a request for issuance to the executive board of CERs equal to the verified amount of GHG emissions reductions. The issuance should be considered final 15 days after the date of receipt of the request for issuance. Upon being instructed by the executive board to issue CERs for a CDM project activity, the

CDM registry administrator issues the specified quantity of CERs into the pending account of the executive board in the CDM registry. Upon such issuance, the CDM registry administrator forwards 2% of CERs to CDM Adaptation Fund as share of proceeds to cover administrative expenses and to assist in meeting costs of adaptation, and forwards the remaining CERs to the registry accounts of Parties and project participants involved, in accordance with their request.

The issuance of CERs is not enough for the implementation of CDM projects effectively. The issuance, holding, transfer and acquisition of CERs should be accurately registered and accounted by a registry. CDM registry requirements are regulated under Appendix D of Marrakesh Accords/Decision 17. CP.7Annex. According to Appendix D;

The executive board establishes and maintains a CDM registry in the form of a standardized electronic database to ensure the accurate accounting of the issuance, holding, transfer and acquisition of CERs by non-Annex I Parties. Each CER can be held in only one account in one registry at a given time. Each CER has a unique serial number comprising the following elements:

- Commitment period: the commitment period for which the CER is issued;

- Party of origin: the Party which hosted the CDM project activity,

- Type: this identifies the unit as a CER;

- Unit: a number unique to the CER for the commitment period CER is issued and Party of origin;

- Project identifier: a number unique to the CDM project activity.

Application of CDM Projects in the World

This subtitle provides statistical data on CDM projects and comments about these data. The data of this section is obtained from the statitistical data on official website of the UNFCCC as of 18 December 2009.

Table 127 shows number of registered projects by region as follows:

Table 127. Registered Projects by Region (UNFCCC, 2009b)

Region	Number of Projects
NAI-Asia and the Pacific	1,466
NAI-Latin America and the Caribbean	450
NAI-Africa	36
NAI-Other	11

Non Annex I Asia and the Pacific region hosts 1,466 CDM projects that comprises 75% of projects. Non Annex I Latin America and the Caribbean region comes the second with 450 projects. Non Annex I Africa hosts only 36 projects.

Number of registered projects by host countries and their percentage shares are as shown in Table 128.

Table 128. Registered Project Activities by Host Country as of 18 December 2009 (UNFCCC, 2009b)

Country	Number Of Projects	Percentage Share
China	694	35.35%
India	474	24.15%
Brazil	165	8.41%
Mexico	120	6.11%
Malaysia	77	3.92%
Indonesia	41	2.09%
Philippines	40	2.04%
Chile	36	1.83%
Republic of Korea	35	1.78%
Thailand	29	1.48%
Peru	21	1.07%

Country	Number Of Projects	Percentage Share
Colombia	20	1.02%
South Africa	17	0.87%
Argentina	16	0.82%
Israel	16	0.82%
Honduras	15	0.76%
Viet Nam	15	0.76%
Ecuador	13	0.66%
Guatemala	11	0.56%
Costa Rica	6	0.31%
Panama	6	0.31%
Sri Lanka	6	0.31%
Uzbekistan	6	0.31%
Armenia	5	0.25%
Cyprus	5	0.25%
El Salvador	5	0.25%
Morocco	5	0.25%
Cambodia	4	0.20%
Egypt	4	0.20%
Nicaragua	4	0.20%
Republic of Moldova	4	0.20%
United Arab Emirates	4	0.20%
Bolivia	3	0.15%
Mongolia	3	0.15%
Nigeria	3	0.15%
Pakistan	3	0.15%
Uruguay	3	0.15%
Bangladesh	2	0.10%
Cuba	2	0.10%
Georgia	2	0.10%
Nepal	2	0.10%
Syrian Arab Republic	2	0.10%
Tunisia	2	0.10%
Uganda	2	0.10%
Bhutan	1	0.05%
Côte d`Ivoire	1	0.05%
Dominican Republic	1	0.05%
Fiji	1	0.05%
Guyana	1	0.05%
Iran (Islamic Republic of)	1	0.05%
Jamaica	1	0.05%
Jordan	1	0.05%

Country	Number Of Projects	Percentage Share
Kenya	1	0.05%
Lao People's Democratic Republic	1	0.05%
Papua New Guinea	1	0.05%
Paraguay	1	0.05%
Qatar	1	0.05%
Singapore	1	0.05%
United Republic of Tanzania	1	0.05%
Total Number of Registered Projects	1,963	100.00

There are 1,963 CDM projects as of 18 December 2009 and 694 of them are in China comprising 35% of total CDM projects and 474 of them are in India comprising 24% of total CDM projects. So, these two countries host nearly 60% of CDM projects. Other important host countries are Brasil, Mexico and Malaysia hosting nearly 8%, 6% and 4% of CDM projects respectively. Although one of the most important purposes of CDM is to help developing countries to maintain sustainable development by increasing financing opportunities and technology transfer, African countries that need them heavily, do not host much CDM projects. Additional measures should be taken for developing countries or least developed countries in Africa to increase their attractiveness to host CDM projects.

The expected average annual CERs from registered projects by host countries and their respective percentage shares are shown in Table 129 as follows:

Table 129. Expected Average Annual CERs from Registered Projects and Respective Percentage Shares by Host Country as of 18 December 2009 (UNFCCC, 2009b)

Country	Average Annual Reductions	Percentage Share
China	197,792,890	59.24%
India	38,308,631	11.47%
Brazil	20,867,610	6.25%
Republic of Korea	14,865,846	4.45%
Mexico	9,385,734	2.81%
Malaysia	4,765,926	1.43%

Country	Average Annual Reductions	Percentage Share
Chile	4,702,400	1.41%
Argentina	4,162,237	1.25%
Nigeria	4,154,978	1.24%
Indonesia	3,980,941	1.19%
Colombia	3,096,242	0.93%
South Africa	2,959,270	0.89%
Qatar	2,499,649	0.75%
Peru	2,466,382	0.74%
Thailand	1,872,331	0.56%
Israel	1,848,879	0.55%
Egypt	1,794,907	0.54%
Philippines	1,434,956	0.43%
Pakistan	1,280,167	0.38%
Viet Nam	1,238,028	0.37%
Uzbekistan	1,020,478	0.31%
Guatemala	864,760	0.26%
Tunisia	687,573	0.21%
Ecuador	682,824	0.20%
Nicaragua	577,381	0.17%
El Salvador	475,444	0.14%
Cuba	465,397	0.14%
Iran (Islamic Republic of)	463,122	0.14%
Georgia	411,897	0.12%
Jordan	397,163	0.12%
United Arab Emirates	348,645	0.10%
Honduras	293,703	0.09%
Costa Rica	293,640	0.09%
Panama	291,579	0.09%
Morocco	287,447	0.09%
Papua New Guinea	278,904	0.08%
Uruguay	251,213	0.08%
Bolivia	228,712	0.07%
Republic of Moldova	226,585	0.07%
Armenia	223,063	0.07%
United Republic of Tanzania	202,271	0.06%
Sri Lanka	196,684	0.06%
Bangladesh	169,259	0.05%
Syrian Arab Republic	132,927	0.04%
Kenya	129,591	0.04%
Cambodia	124,356	0.04%
Dominican Republic	123,916	0.04%

Country	Average Annual Reductions	Percentage Share
Cyprus	113,035	0.03%
Nepal	93,883	0.03%
Mongolia	71,904	0.02%
Côte d`Ivoire	71,760	0.02%
Jamaica	52,540	0.02%
Guyana	44,733	0.01%
Uganda	41,774	0.01%
Fiji	24,928	0.01%
Singapore	15,205	0.00%
Lao People's Democratic Republic	3,338	0.00%
Paraguay	1,523	0.00%
Bhutan	524	0.00%
Total Annual Reductions	333,861,685	100.00%

Total annual reductions from these registered CDM projects are 333,861,685 CERs. As was the case for number of projects, China again takes the lead with 197,792,890 CERs comprising 59% of CERs annually and India is the second with 11% of CERs. When these shares of CERs are compared with number of projects on country basis, it is seen that Chinese CDM projects generate much more than average per project, while Indian projects generate less than average per project. Because, Chinese projects that comprise 35% of projects generate 59% of CERs, while Indian projects that comprise 24% of projects generate 11% of CERs. Brazil, Republic of Korea and Mexico are other important countries with generating nearly 6%, 4% and 3% of CERs respectively.

Number of registered projects by scale and their respective percentage shares are as shown in Table 130.

Table 130. Number of Registered Project Activities By Scale as of 18 December 2009 (UNFCCC, 2009b)

Scale	Number of Registered Projects	Percentage Share
Large	1,081	55.07%
Small	882	44.93%

55% of CDM projects are large projects whereas 45% of them are small projects. So, the distribution of CDM projects on the basis of scale are quite balanced. Table 131 shows number of projects invested by investor countries as follows:

Table 131. Registered Projects by Annex I and Non-Annex I Investor Parties as of 18 December 2009 (UNFCCC, 2009b)

Country	Number of Projects
United Kingdom of Great Britain and Northern Ireland	664
Switzerland	485
Netherlands	279
Japan	270
Sweden	151
Germany	135
Spain	68
Italy	45
Canada	44
Austria	43
France	43
Denmark	39
Finland	30
Norway	28
Belgium	20
Luxembourg	15
Brazil	1
Ireland	1
Portugal	1

United Kingdom of Great Britain and Northern Ireland takes the lead with 664 projects. Switzerland, Netherlands, Japan, Sweden and Germany invest in 485, 279, 270, 151 and 135 projects respectively. Other than Japan and Brazil, all investing countries are the EU countries.

Number of projects registered by sectoral scope are as shown in Table 132.

Table 132. Distribution of Registered Project Activities by Scope as of 18 December 2009 (UNFCCC, 2009b)

Sectoral Scope*	Number of Registered Projects
Energy industries (renewable - / non-renewable sources)	1,435
Waste handling and disposal	435
Fugitive emissions from fuels (solid, oil and gas)	136
Agriculture	123
Manufacturing industries	112
Chemical industries	64
Mining/mineral production	26
Energy demand	25
Fugitive emissions from production and consumption of halocarbons and sulphur hexafluoride	22
Afforestation and reforestation	10
Metal production	6
Transport	2
Energy distribution	0
Construction	0
Solvent use	0

*Note that a project activity can be linked to more than one sector.

1,435 CDM projects are in energy industries (renewable sources, non-renewable sources) that comprises more than half of the projects. 450 projects were waste handling and disposal projects, 136 projects were related to fugitive emissions from fuels (solid, oil and gas). Number of projects related to agriculture and manufacturing industries were 123 and 112 respectively. Other sectors totally comprise less than 10% of projects. As most of GHG emissions come from energy industry, the dominance of CDM projects in energy industries (renewable sources, non-renewable sources) is not surprising. Number of CERs requested as of 18

December 2009 is 373,198,319 and number of CERs issued is 359,730,952. CERs issued by host parties as of 18 December 2009 are as shown in Table 133:

Table 133. CERs Issued by Host Party as of 18 December 2009 (UNFCCC, 2009b)

Country	CERs	Percentage Share
China	172,118,569	47.85%
India	72,920,819	20.27%
Republic of Korea	46,740,758	12.99%
Brazil	36,230,718	10.07%
Mexico	6,084,525	1.69%
Viet Nam	4,487,743	1.25%
Egypt	4,301,160	1.20%
Chile	4,039,191	1.12%
Argentina	2,347,667	0.65%
Pakistan	1,723,570	0.48%
South Africa	1,138,467	0.32%
Bolivia	933,719	0.26%
Guatemala	852,236	0.24%
Thailand	815,224	0.23%
Malaysia	673,857	0.19%
Colombia	592,192	0.16%
Ecuador	550,643	0.15%
Nicaragua	534,886	0.15%
El Salvador	416,517	0.12%
Indonesia	325,800	0.09%
Honduras	275,765	0.08%
Israel	272,680	0.08%
Jordan	215,513	0.06%
Papua New Guinea	215,424	0.06%
Sri Lanka	195,924	0.05%
Peru	186,305	0.05%
Jamaica	172,206	0.05%
Cuba	166,744	0.05%
Philippines	95,428	0.03%
Uruguay	40,613	0.01%
Morocco	26,213	0.01%
Costa Rica	21,226	0.01%
Fiji	18,176	0.01%
Bhutan	474	0.00%
Total Number of CERs	359,730,952	100.00%

China has issued 172,118,569 CERs that comprise nearly 48% of issued CERs. And India has issued 72,920,819 CERs that are 20% of issued CERs. Republic of Korea and Brazil has issued 13% and 10% of CERs respectively. So, these four countries has issued slightly more than 90% of issued CERs.

Figure 20 shows settlement prices of ECX CER Dec12 future contracts between 14 March 2008 and 13 May 2010.

Figure 20. ECX CER Dec12 settlement prices in € between 14 March 2008 and 15 May 2010 (ECX, 2010)

ECX CER Dec12 settlement prices reached to as high as 26.34 € in 07.07.2008 and declined to as low as 7.74 € in 12.02.2009 beacuse of the economic crisis. CER prices are highly related to expectations about global economic growth. The average settlement prices has been 14.58 € during 14.03.2008 – 13.05.2010 period. ECX CER Dec12 settlement price is 12.69 € in 13.05.2010 while ECX CER Daily Futures (Spot) Contracts settlement price is 13.55 € in 13.05.2010. Although CER spot prices have generally been below future prices, spot prices have been higher than future prices since March 2010 reflecting the expectations of players to decline.

Since EUAs are more valuable than CERs, EUA future contracts have price premiums over CER future contracts. Figure 21 shows spread between ECX EUA Dec12 future contracts and CER Dec12 future contracts between 02 January 2009 and 13 May 2010:

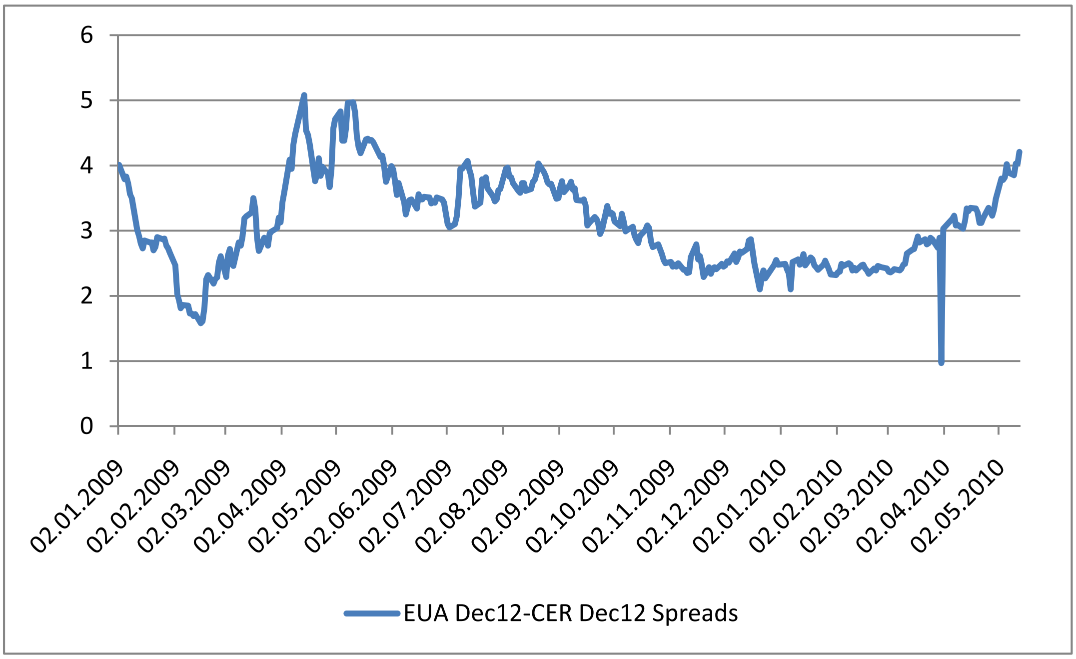

Figure 21. ECX EUA Dec12 – CER Dec12 spreads in € between 02 January 2009 and 15 May 2010 (ECX, 2010)

Spreads between EUA Dec12 future contracts and CER Dec12 future contracts has reached 5.08 € in 14.04.2009 and 0.97 € in 31.03.2010. The average spreads have been 3.1 € during 02.01.2009 – 13.05.2010 period.

Emissions Trading, Carbon Taxes and Synthesis Approaches

There are two main options to to set a price for CO_2 emissions: carbon taxes and emissions trading. There is also a synthesis approach combining the features of these two main options: a hybrid approach (PricewaterhouseCoopers, 2009b). Also revenue-neutral taxes are the result of a synthesis approach decreasing the political unpopularity of carbon taxes and increasing the effectiveness of subsidies from general funds. These market based policies will be explained and compared in this section in details.

Before comparing carbon taxes and emissions trading, a more general comparison will be made between command and control policies and market based policies. Command and control policies set a uniform target or standard across an industry for each firm; forcing each firm to limit its emissions to a uniform level, rather than most of the abatement being undertaken by the firms that can do it most cost effectively (PricewaterhouseCoopers, 2009b). Market based policies reach the same target across an industry less costly and efficiently by allowing firms respond optimally to a price signal that may be created either in emissions market or via carbon taxes. If reducing emissions is cheaper than emissions allowance price determined in the market or the carbon tax, then the firm reduces its emissions. If reducing emissions is more expensive than emissions allowance price or the carbon tax, then the firm does not reduce its emissions. Rather, another firm that can reduce its emissions in a cost below the emissions allowance price reduces its emissions, thereby increasing the social welfare. So, it is obivous that market based policies are superior to command and control policies in terms of efficiency and social welfare.

But, it should not be assumed that market based policies are always superior to command and control policies to increase social welfare. Especially, market based policies do not solve the problems in case of asymmetric information. Consumer myopia and inertia may prevent some cost-saving emission reduction opportunities, so justifying some degree of direct regulation (PricewaterhouseCoopers, 2009b). But providing better information could help in such cases when combined with appropriate market based policies and instruments as well. Market based policies that are emissions trading and carbon taxes will be explained in this section. The first subtitle will explain emissions trading. The second subtitle will mention European Climate Exchange. The third subtitle will explain carbon taxes and the fourth subtitle will compare emissions trading with carbon tax. In the fifth and sixth subtitles revenue-neutral carbon taxes and hybrid schemes will be illustrated respectively as synthesis approaches.

Emissions Trading

Emissions trading takes place in an emissions trading scheme that is based on a “cap and trade” principle. In this system, a cap is set for the total emissions in the overall scheme. Then emission allowances are issued totalling the overall cap and allocated to participants in the system. The allocation of allowances may be free of charge based on past emissions named grandfathering method, or based on auctioning. These allowances are traded in the scheme and allowance prices determined in the market provides signals for the participant to reduce emissions in the most cost effectively. For instance, if the emissions reducton cost is lower than the allowance price, the participant reduces emissions and sells the exccess allowances. If, the emissions reducton cost is higher than the allowance price, the participant chooses not to reduce emissions, but buy allowances in the market place from the participants that can reduce its emissions less costly. Emissions trading is balanced when the allowance price is equal to the marginal cost of emissions reductions.

There are two conditions precedent for an emissions trading scheme to function effectively. Firstly, participants must be sufficiently varied to gain from trading allowances (PricewaterhouseCoopers, 2009b). If all the participants become very similar in terms of emissions reduction costs especially marginal costs, then there would be no trade. But this is a simple condition to be met since the pariticipants usually become quite different especially in terms of emission reduction opportunities, if the scheme does not involve only a small specific group of subsector. Secondly, the emissions trading scheme must contain sufficient number of participants to ensure a liquid market and participants should not have extensive market power to influence the market prices considerably (PricewaterhouseCoopers, 2009b). If the market is not liquid or the price is artificial by the affect of strong participants, the market price does not provide efficient signals and may discourage participants to make long term investments to reduce emissions.

One of the most important aspects of emissions trading schemes are determining how the allowances will be allocated. There are two methods to allocate allowances, grangfathering and auctioning. In grandfathering method, allowances are allocated free of charge on the basis of past emissions, whereas in auctioning method allowances are allocated to the participants offering the highest prices. Auctioning is a more effective method for the success of the emissions trading scheme because it impedes windfall profits, creates price signals for allowances and increases government revenue that may be used in further incentivising clean technologies (PricewaterhouseCoopers, 2009b).

Another important issue of emissions trading schemes is whether banking and borrowing is allowed. Banking and borrowing prevents huge price fluctuations that may distort long term investments (PricewaterhouseCoopers, 2009b). When allowance prices increase too much participants borrow allowances from future periods and the increase in supply of allowances decrease allowance prices. When allowance prices decrease too much, participants bank their unused allowances for future use and the decrease in supply of allowances increase allowance prices. However, the limit for borrowing and banking of allowances should not be set too high. Because, if banking limit is set too high, this creates less effort for emissions reductions in the future; and if borrowing limit is set too high, this creates less effort for emissions reductions in the current period.

Other important features for an emissions trading scheme to be effective are the length of the period the scheme covers and the strictness of the scheme. The length of the emissions trading schemes should be long enough to make long term investments for emissions reductions. Also, the allowances to be allocated should not be determined high, since this reduces incentives to reduce emissions. The penalties for non-compliance should be set high enough as well, to ensure compliance with the caps and a well-designed monitoring system shoud be established.

Whether an emissions trading scheme or carbon tax should follow an upstream or downstream approach is another important issue in designing these market based policies. Both of these appoaches have pros and cons. Upstream approach proposes policies to be implemented at the point of extraction, import, processing or distribution of fossil fuels (PricewaterhouseCoopers, 2009b). Upstream approach seems to be simple to administer and covers more emissions than a downward approach. However, fossil fuel supplies may not lead to significant emissions in some cases such as power plants with carbon capture and storage, or where crude oil is used to make petrochemicals rather than used as fossil fuels (PricewaterhouseCoopers, 2009b). So, upstream approach may be more complex than it seems in practice. Downstream approach has drawbacks as well such as covering only a limited portion of emissions and inability to cover sectors in which there are too many emitters. The European Union Emissions Trading Scheme follows a downward approach.

The European Union Emissions Trading Scheme is the first and largest international emissions trading scheme. The European Climate Exchange (ECX) is the major marketplace for trading CO_2 emissions allowances in Europe and internationally that will be described further below.

European Climate Exchange

There are four main player types in the carbon market: Compliance players (e.g. power plants, heavy industry installations), project developers (e.g. CDM, JI investors), intermediaries / investors (banks) and speculators (e.g. hedge funds) (ECX, 2010b). Carbon market transactions take place in two markets: Over the Counter Markets and Carbon Exchanges. Wtihin carbon exchanges, most of the carbon market transactions take place in the European Climate Exchange and ECX has been the leading carbon exchange since 2005. The shares of carbon exchanges in terms of transaction values are shown in Figure 22.

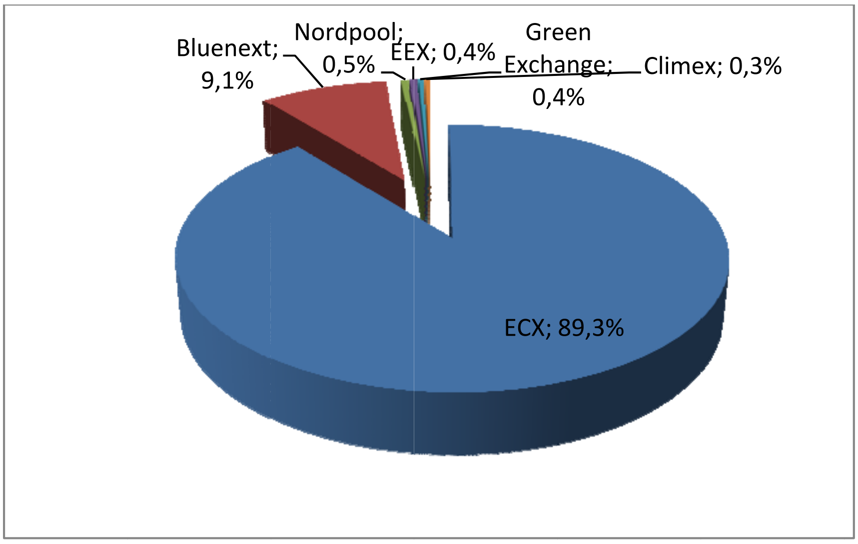

Figure 22. The shares of carbon exchanges in terms of transactions values in March 2010 (ECX, 2010)

ECX is the leading carbon exchange with 89.3% of carbon market transactions and is followed by Bluenext that has a market share of 9.1%. Carbon market transaction values of other climate exchanges such as Nordpool, European Energy Exchange (EEX), Green Exchange and Climex are too small with shares ranging between 0.3% and 0.5%.

Carbon market transactions volume and value in ECX are shown in Table 134.

Table 134. Carbon Market Transactions Volume and Value in ECX (ECX, 2010)

	Transaction Volume (Mt CO_2)	Transaction Value (Bilion €)
2005	94	2.1
2006	452	9.0
2007	1,000	17.5
2008	2,800	55.9
2009	5,100	68.0

Transaction value in the ECX has grown tremendously from 2.1 billion € in 2005 to 68.0 billion € in 2009 and transaction volume has also increased from 94 million tonnes of CO_2 in 2005 to 5.1 billion tonnes of CO_2 in 2009.

ECX is owned by Climate Exchange plc (CLE) that is a company listed on the AIM section of the London Stock Exchange that is engaged in owning, operating and developing exchanges to facilitate trading in environmental financial instruments, including emissions reduction credits. Climate Exchange plc has three core operating businesses: European Climate Exchange (ECX), Chicago Climate Exchange (CCX) and Chicago Climate Futures Exchange (CCFE). European Climate Exchange focuses on compliance certificates for mandatory EU ETS while Chicago Climate Exchange (CCX) operates the world's first voluntary, but contractually binding cap and trade system for GHG emissions reductions. Chicago Climate Futures Exchange (CCFE) is a regulated exchange in the USA with a growing portfolio of environmental futures contracts. Climate Exchange plc is also investing in other geographic regions: China, Canada and Australia. ECX and ICE (Intercontinental Exchange) Futures Europe have a partnership whereby ECX manages the product development and marketing of its emissions contracts and ICE lists those contracts on its electronic trading platform.

There are two types of carbon credits traded in the ECX; that are EU allowances (EUAs) and Certified Emission Reductions (CERs). Trading on ECX began in April 2005, with the introduction of EUA futures contracts. In October 2006, options on EUAs were launched, followed by futures and options on CERs in 2008. The EUA and CER Daily Futures contracts that are like spot contracts were introduced in 2009.

There are six main types of ICE ECX Contracts: EUA Futures Contracts, CER Futures Contracts, EUA Daily Futures Contracts, CER Daily Futures Contracts, EUA Options and CER Options.

ICE ECX EUA and CER Futures Contracts and Daily Futures Contracts will be mentioned as follows:

A futures contract gives the holder the right and the obligation to buy or sell a certain underlying instrument at a certain date in the future, at a pre-set price. For ICE ECX EUA Futures Contracts, the underlying unit of trading are EUAs. One lot ICE ECX EUA Futures Contract represents 1,000 EU allowances.

Table 135 shows ICE ECX EUA and CER Futures Contract specifications as follows:

Table 135. ICE ECX EUA and CER Futures Contract Specifications (ICE Futures Europe, 2010a)

Unit of Trading	EUA: One lot of 1,000 CO2 EUAs. Each EUA being an entitlement to emit one tonne of carbon dioxide equivalent gas. CER: One lot of 1,000 CERs (i.e. units issued pursuant to Article 12 of the Kyoto Protocol and the decisions adopted pursuant to the UNFCCC to the Kyoto Protocol with the exception of allowances generated by hydroelectric projects with a generating capacity exceeding 20MW, LULUCF activities and nuclear facilities). Each CER being an entitlement to emit one tonne of carbon dioxide equivalent gas.
Minimum trading size	1 lot.
Quotation	Euro (€) and Euro cent (c) per metric tonne.
Tick size	€0.01 per tonne (i.e. €10 per lot).
Min. / Max. Price fluctuation	€0.01 / No limit
Contract months	EUA: Contracts are listed on an quarterly expiry cycle such that March, June, September and December contract months are listed up to March 2013 and annual contracts with December expiries for 2013 and 2014. CER: Contracts are listed on an quarterly expiry cycle such that March, June, September and December contract months are listed up to March 2013.
Expiry day	At 17:00 hours UK local time on the last Monday of the Contract month. However, if the last Monday is a Non-Business Day or there is a Non-Business Day in the 4 days following the last Monday, the last day of trading will be the penultimate Monday of the delivery month. Where the penultimate Monday of the delivery month falls on a Non-Business Day, or there is a Non-Business Day in the 4 days immediately following the penultimate Monday, the last day of trading shall be the antepenultimate Monday of the delivery month.
Trading system	Trading will occur either on the ICE Futures electronic platform WebICE or through a conformed Independent Software Vendor including Aegis Software, Communicating Ltd, CQG, EasyScreen, Ffastfill, GL Trade, ION Trading, Neotick, Nyfix, Object Trading, Patsystems, Rolfe & Nolan, RTS, Stellar Trading Systems, Trading Technologies and Trayport.

Trading model	Continuous trading throughout trading hours.
Trading hours	07.00 to 17.00 hours UK local time
Settlement prices	Trade weighted average during the daily closing period (16:50:00 – 16:59:59 hours UK local time) with Quoted Settlement Prices if low liquidity.
Settlement and Delivery	The contracts are physically deliverable by the transfer of CERs from the Person Holding Account of the Selling Clearing Member at a Registry to the Person Holding Account of ICE Clear Europe at a Registry and from the Person Holding Account of ICE Clear Europe at that Registry to the Person Holding Account of the Buying Clearing Member at a Registry. Initially this will be restricted to the UK Registry. Delivery is between Clearing Members and ICE Clear Europe during a Delivery Period. The Delivery Period is the period beginning at 19:00 hours on the Business Day following the last trading day and ending at 19:30 hours on the third Business Day following that last trading day. There is provision for 'Late' and 'Failed' delivery within the contract Rules.
Clearing and contract security	ICE Clear Europe acts as central counterparty to all trades and guarantees the financial performance of the ICE Futures contracts registered in the name of its Members.
VAT and taxes	The UK's HM Revenue and Customs have confirmed that the trading of the ICE ECX EUA Futures on the Exchange between the Member and ICE Clear Europe has been granted interim approval to be zero-rated for VAT purposes under the terms of the Terminal Markets Order. Clearing Members are advised to seek their own advice in relation to the VAT treatment on the transfer of allowances between themselves and their client or for allowances used for their own purposes. Normal VAT rules apply between Clearing Members and their customers on delivery according to the rules of the country in which delivery occurs.
Margin	Initial and variation margin are charged in the usual manner by ICE Clear Europe.

For ICE ECX Futures Contracts and Daily Futures Contracts, Block Trade (large trades over 50 lots), Exchange for Physical (EFP) and Exchange for Swaps (EFS) facilities are available.

ICE ECX EUA and CER Daily Futures Contracts are daily contracts. Only one Daily Contract is listed at any one time. ICE ECX EUA and CER Daily Futures Contract specifications about unit of trading, minimum trading size, quatation, tick size, minimum / maximum price fluctuations, trading system, trading model, trading hours, clearing and contract security, VAT and taxes are the same with the ICE ECX EUA and CER Futures Contract specifications. ICE ECX EUA and CER Daily

Futures Contract specifications about the delivery period and margin & payment are different from the specifications for ICE ECX EUA and CER Futures Contracts.

Figure 23 shows the fully automatic delivery mechanism of ICE ECX EUA and CER Futures Contacts and Daily Futures Contracts and how it interacts with national registries and the clearing house. The delivery period is three days (T+3) after the contract's expiry date.

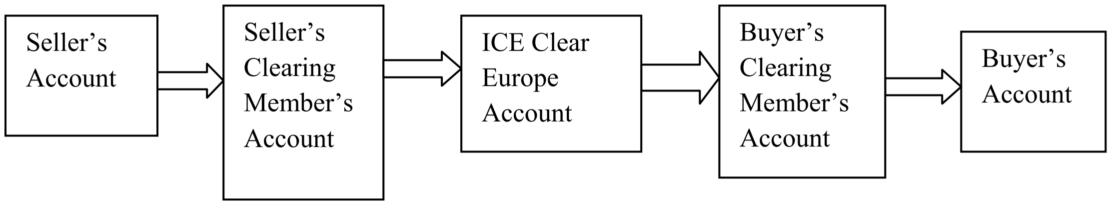

Figure 23. Delivery mechanism of ICE ECX EUA and CER Futures Contacts and Daily Futures Contracts (ECX, 2010)

EUAs are held in dematerialised form in national registries of the EU Member States connected to the Community Independent Transaction Log (CITL) in other words, the EU Umbrella Registry. CITL connects all the 27 national registries together and tracks EUA movements. The accounts in Figure 23 refer to the national registry account in the EU Member State.

Deivery period for daily futures contracts is the period beginning at 18:30 hours on the Contract Date and ending at 19:00 hours on the second Business Day following the relevant Contract Date. Delivery process of ICE ECX EUA and CER Daily Futures Contracts is as follows:

Table 136. Delivery Process of ICE ECX EUA and CER Daily Futures Contracts (ICE Futures Europe, 2010a)

	Contract Date	Contract Date + 1	Contract Date + 2
By 9.00		Buyer pays full contract value to Clearing House. Seller pays Seller Security to the Clearing House which will represent a percentage of the contract value.	Seller receives full contract value for good deliveries. Seller Security is released.
17.00	Trading ceases.		
By 17.30	Members will have assigned trades to accounts.		
By 17.45	Position maintenance will be complete		
By 18.00	Hit report.		
By 18.15	Member's will have submitted Seller's/Buyer's Daily CER/EUA Delivery Confirmation Form to the Clearing House giving lots/volume for each margin account.		
By 18.30		Clearing House will have received emissions allowances from the Seller.	
By 19.00			Buyer will have received emissions allowances from the Clearing House.
Outcome		Good delivery for Seller to Clearing House	Good delivery for Clearing House to Buyer

According to ICE ECX EUA and CER Daily Futures Contract specifications about margins and payment; ICE Clear Europe will charge Buyer/Seller Security in the following manner: The Buyer will pay full contract value by 09:00 on the first Business Day following the trade date. Full contract value is the Exchange Delivery Settlement Price (EDSP) multiplied by the number of lots held. A separate Variation Margin will be payed by 09:00 on the first Business Day following the trade date in order to reflect the profit/loss between the EDSP and the trade price. The Seller will pay Seller Security by 09:00 on the first Business Day following the trade date. Seller Security is a percentage of the EDSP multiplied by the number of lots held. Seller security protects ICE Clear Europe against non-delivery and/or Clearing

Member default. On the second Business Day following trade date, if the Seller has fulfilled its obligations under the contract, the Seller receives full contract value together with the Seller Security. A separate Variation Margin is payed by 09:00 on the first Business Day following the trade date to reflect the profit/loss between the EDSP and the trade price.

ICE ECX EUA and CER Options Contracts will be mentioned as follows:

An option is a contract whereby the buyer or holder of the contract has the right to exercise the contract on or before the expiry date and the writer or seller of the contract has the obligation to honour the specified feature of the contract. The amount the buyer pays the seller for the option is called the option premium. A put option is the right to sell a futures contract, and a call option is the right to buy a futures contract. There are two option styles: American style and European style. American style options allow exercise up to the expiry date whereas European style options allow exercise only on the expiry date. ICE ECX EUA and CER Options Contracts are of European style. The option is at-the-money if the underlying value is currently equal to the strike price, the option is in-the-money if it has positive intrinsic value, or out-of-the-money if it has negative intrinsic value. Additional to the intrinsic value an option has a time value.

Table 137 shows ECX EUA and CER Options Contract specifications:

Table 137. ECX EUA and CER Options Contract Specifications (ICE Futures Europe, 2010a)

Underlying	The underlying contract is the December Future of the relevant year. For example, the underlying contract for the March 10 option is the December 10 Future.
Unit of Trading	EUA: One ICE ECX EUA Options Contract. CER: One ICE ECX CER Options Contract.
Minimum trading size	1 lot.
Quotation	Euro (€) and Euro cent (c) per metric tonne
Tick size	€0.01 (Tick size capability to 3 decimal places).
Min. / Max. Price fluctuation	€0.01 / No limit

Contract months	EUA: Up to 8 contract months are listed on a quarterly expiry (March, June, September and December), with 4 new contract months listed on expiry of the December contract. Additional December contracts are listed out to Dec 12. CER: Up to 8 contract months are listed on a quarterly expiry (March, June, September and December), with 3 new contract months listed on expiry of the December contract. Additional December contracts are listed out to Dec 12.
Strike Price Increments	A range of one-hundred and nine strike prices are automatically listed for each contract month covering the price range from €1.00 - €100.00. The Exchange may add one or more strike prices nearest to the last price listed as necessary. Strike price intervals are €0.50.
Expiry day	Three Exchange trading days before the expiry of the relevant contract month of the ICE Futures ECX EUA and CER Futures Contract (which expires on the last Monday of the Contract month).
Options Style and Premium	European style. Premiums paid at the time of the transaction
Trading system	Trading will occur on ICE Futures' electronic trading platform (known as the ICE Platform) which is accessible via WebICE or through a conformed Independent Software Vendor.
Trading model	Continuous trading throughout the trading hours
Trading hours	07.00 to 17.00 hours UK local time.
Settlement prices	Trade weighted average of trades executed during the daily designated settlement period (16:50:00 – 16:59:59 UK Local Time).
Settlement and Delivery	EUA: ICE ECX EUA Options Contracts turn into ICE ECX EUA Futures Contracts at expiry, which are physically settled contracts. CER: ICE ECX EUA Options Contracts turn into ICE ECX EUA Futures Contracts at expiry, which are physically settled contracts.
Exercise and Automatic Exercise	ICE ECX EUA Options Contracts will be exercised into ICE ECX EUA Futures Contracts and are of European-style exercise, such that at expiry, automatic exercise will occur of options which are one or more ticks in-the-money. (At-the-money and out-of-the-money options will lapse).
Clearing and contract security	ICE Clear Europe acts as central counterparty to all trades and guarantees the financial performance of the contracts registered in the name of its Members.
VAT and taxes	The UK's HM Revenue and Customs have confirmed that the trading of the ICE ECX EUA Options contracts on the Exchange between the Clearing Member and ICE Clear Europe is zero-rated for VAT purposes under the terms of the Terminal Markets Order. Clearing Members are advised to seek their own advice in relation to the VAT treatment on the transfer of allowances between themselves and their client or for allowances used for their own purposes. Normal VAT rules apply between Clearing Members and their customers on delivery according to the rules of the country in which delivery occurs.
Margin	All open contracts are marked-to-market daily. Initial and variation margin are charged in the usual manner by ICE Clear Europe.

According to the Contract Rules of ICE ECX EUA and CER Options Contracts; after the cessation of trading on the expiry date, in-the-money options with reference to that day's official settlement price for the relevant futures will be automatically exercised, at-the-money options or out-of-the-money options with reference to that day's official settlement price for the relevant futures will automatically expire. The exercise of an ICE ECX EUA and CER Options will give rise to a December ICE ECX EUA and CER Futures Contract respectively between Buyer and Seller, in the corresponding year, at the strike price of the option.

There are two types of fees in ECX: trading fees and membership fees. Trading fees for ICE ECX EUA and CER Futures and Options Contracts are shown in Table 138:

Table 138. Trading fees for ICE ECX EUA and CER Futures and Options Contracts (ECX, 2010)

		€ per Lot per Side
Exchange Fee	Members' Proprietary Trades	2
	Order-routers (inc. Blocks, EFPs, EFSs)	2.5
ICE Clear Europe Clearing Fee	All Business (inc. Blocks, EFPs, EFSs)	1.5

For ICE Futures Europe Member, the transaction fee is 2.00 € per lot per side (including Block Trades, EFPs and EFSs) while it is 2.50 € for all other businesses (i.e. order routing customers and client business) per lot per side. The clearing fee is €1.50 per lot per side.

Trading fees for ICE ECX EUA and CER Daily Futures Contracts are shown in Table 139:

Table 139. Fee schedule of ECX EUA and CER Daily Futures Contracts (ECX, 2010)

		€ per Lot per Side
Exchange Fee (inc. Blocks, EFPs, EFSs)	Members	4
	Order-routers	5
ICE Clear Europe Clearing Fee (inc. Blocks, EFPs, EFSs)	All Business	3

For ICE Futures Europe Member, the transaction fee is 4.00 € per lot per side (including Block Trades, EFPs and EFSs) while it is 5.00 € for all other businesses (i.e. order routing customers and client business) per lot per side. The clearing fee is €3.00 per lot per side.

To be a member of ICE and an ECX requires one-off application fee and annual membership fee. Table 140 shows these membership fees:

Table 140. Membership Fees of ICE and ECX (ICE Futures Europe, 2010a)

	Annual Subscriptions		One-off Application Fee			
Participant	ICE Membership	ECX Emissions Trading Privilege	ICE Futures	ECX	Year 1 Total Fees	Year 2 Total Fees
General	11.500 $	2.500 €	4.500 $	2.500 €	16.000 $ + 5.000 €	11.500 $ + 2500 €
Trade	4.500 $	2.500 €	4.500 $	2.500 €	9.000 $ + 5.000 €	4.500 $ + 2500 €

Margins required by the ECX will be mentioned as follows:

The price fluctuations creates a credit risk to the exchange and the clearing house, since they acts as counterparty to the trades. The clearing house demands a form of collateral, to minimise this risk. This colleteral is called margin. There are two types of margins: Initial margin and variation margin. Initial margin is required when a futures position is opened, deposited by both buyer and seller and returned when the position is closed or expires. Initial margin is determined by taking into account possible losses on a usual day's trading from historical price changes. Since initial margin may run out due to a series of adverse price changes, an additonal margin is required that is called the variation margin. Variation margin is calculated according to the settlement price or mark-to-market price of the contract, so represents the profit/ loss in a position each day. Margins rates are determined by ICE Clear Europe and reviewed on a quarterly basis based on historic price fluctuations.

Table 141 shows outright margin rates (per lot) for ICE ECX EUA and CER Futures Contracts:

Table 141. Outright Margin Rates in € (per lot) for ICE ECX EUA and CER Futures Contracts (ECX, 2010)

	Mar10 to Dec10	Mar11 to Dec11	Mar12 to Dec12	Mar13 to Dec14	Intermonth Spread
EUA	770	800	800	830	325
CER	680	680	680	680	200

Due to the daily expiry schedule, ICE ECX EUA and CER Daily Futures Contracts are not margined in the same manner with Futures Contracts. The Buyer and Seller Security rates are shown in Table 142:

Table 142. The Buyer and Seller Security Rates for ICE ECX EUA and CER Daily Futures Contracts (ECX, 2010)

Contract Name	Sellers Security (per lot)	Buyers Security
ICE ECX CFI Futures	Original Margin (OM)	Full Contract Value + Original Margin
ICE ECX CER Futures	Original Margin (OM)	Full Contract Value + Original Margin
ICE ECX EUA Daily Futures	18% of the Contract Value (EDSP)	Full Contract Value
ICE ECX CER Daily Futures	18% of the Contract Value (EDSP)	Full Contract Value

The buyer pays full contract value and the Seller pays Seller Security on the first business day following the trade date. The Seller receives full contract value and the Seller Security will be returned on the second business day following the trade date.

How to trade in the ECX will be explained as follows:

There are two main ways of accessing ECX products on ICE Futures Europe: As an ICE Futures Europe Member enabled for ECX Contracts; or by order-routing as a client of an ICE Futures Europe Member (ICE, 2010a). There are two categories of membership under the ICE Futures Europe membership structure for ECX Emissions contracts: General Participants and Trade Participants (ICE, 2010a).

General participants may trade on their own account and on behalf of clients while trade participants may only trade on their own account. General participants and trade participants may be clearing or non-clearing members. A General participant clearing member can clear their own business, client business and business for non-Clearing Members while a trade participant clear member can clear only their own business. General participants and trade participants who are not clearing members should put in place a clearing agreement with a clearing member. General Participants who are Clearing Members must have a Net worth requirement to become a clearing member is 20 million £ for general participants while it is 5 million £ for trade participants. There is no net worth requirement for non-clearing general participants or non-clearing trade participants.

There have been two trading periods in the implementation of the EU ETS: the first trading period covers 2005-2007, and the second trading period is 2008-2012 that is compatible with the first commitment period of the Kyoto Protocol. The third trading period will start in 2013. Figure 24 shows EUA Futures settlement prices for December 2007 (Dec07), December 2012 (Dec12) and December 2014 (Dec14) on ECX in € between 22 April 2005-10 March 2010.

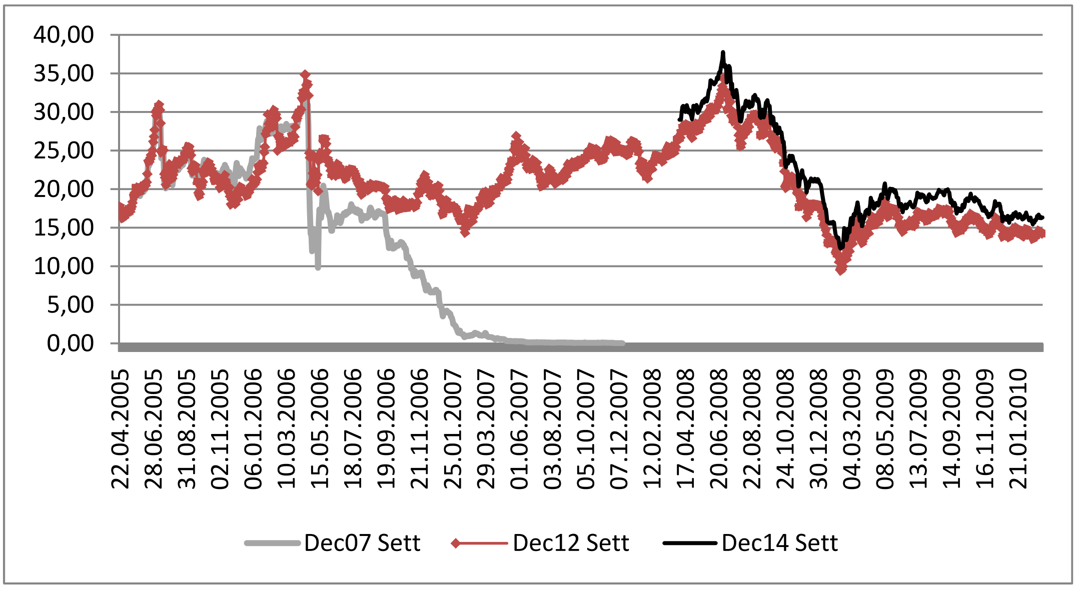

Figure 24. EUA Futures prices on ECX in € between 22 April 2005-10 March 2010 (ECX, 2010)

As seen in Figure 24, EUA prices for Phase I collapsed during April 2006-February 2007 period. Whereas EUA Dec07 futures prices was above 30 € in April 2006, from hereon it started to fall sharply and was below 1 € in February 2007. The collapse in prices came from the fact that the overallocation of allowances became apparent and the banking of allowances for Phase II was forbidden. So, EUA Dec12 future prices became nearly worthless. Since allocation of allowances was decided by national authorities, member states allocated more than necessary to protect their industries.

EUA Dec12 futures contract prices for Phase II remained steadier during 2006 and 2007 and never fell below 15 € during this period. They even reached as high as above 30 € in June 2008, joining the upward trend seen in commodity markets such as oil, natural gas. EUAs joined the collapse in commodity markets and energy markets in the fourth quarter of 2008 and started to fall sharply during this period and EUA Dec12 futures fell to around 9 € in February 2009. This sharp downturn largely came from the economic crisis that led to decline of economic activity and energy consumption projections for Phase II and decreases the scarcity of EUAs. After February 2009, EUA Dec12 futures prices rebounds and reaches upto 18 € in May 2009, joining the rebound in energy markets and commodity prices. Then EUA prices unwind slightly and declines to around 14 € in March 2009. Dec14 futures contracts that are for Phase III move parallel to Dec12 futures contract prices with nearly 2 € spreads.

Carbon Taxes

A carbon tax is a tax on the on the carbon dioxide emissions from burning fossil fuels. Since carbon content of every form of fossil fuel is known as the coal having the most, followed by petroleum products and natural gas, the tax burden should be according to this scala. Also, if the carbon is not released to the atmosphere, this carbon content should not be taxed. So, carbon in a plastic product should not be taxed since it won't be burned and if the carbon is sequestered rather than releasing to the atmosphere, this carbon should not be taxed as well. However it is difficult to distingush them in practice.

Carbon tax determines the price of CO_2 rather than determining the emissions quantity as is the case for cap and trade systems. So, carbon tax creates price signals but it does not ensure the emissions reductions. So, in carbon tax system emissions fluctuate instead of the prices as is the case in cap and trade systems. The main difference between carbon tax and normal tax is that although normal taxes may create distortionary effects on resource allocation, carbon tax eliminates negative externalities thereby increasing social welfare.

Carbon taxes that have been proposed or enacted around the world will be mentioned below. Information about these carbon taxes is obtained from the report called Where Carbon is Taxed prepared by Carbon Tax Center (2009).

Finland was the first country to enact a carbon tax, in 1990. According to the Ministry of the Environment of Finland (2008), the environmental tax component (i.e. carbon surtax), based on the carbon content of fuels used for heating and transportation is, since January 2008, 20 € per tonne of CO_2 (75 € per tonne of CO_2) and the share of the carbon tax revenue is around 500 million € annually.

Sweden enacted a tax on carbon emissions in 1991. Great Britain introduced a climate change levy in 2001 on the use of energy in the industry, commerce and public sectors. Revenues from this levy are used to provide offsetting cuts in employers' National Insurance Contributions and to support energy efficiency and renewable energy.

Boulder (Colorado) implemented the United States' first tax on carbon emissions from electricity on 1 April 2007, at a level of approximately 7 $ per ton of CO_2. The tax costs an average household about $1.33 per month, households that use renewable energy receivie an offsetting discount.

Quebec in Canada began collecting a carbon tax on hydrocarbons (petroleum, natural gas and coal) on 1 October 2007. British Columbia started to implement a revenue-neutral carbon tax on 1 July 2008 at an amount of 10 Canadian $ per metric ton of CO_2, that was set to rise by 5 Canadian $/tonne annually to reach 30 Canadian $ per tonne of CO_2 in 2012. This tax was first increased on 1 July 2009 to 15 Canadian $/tonne. Since this is a revenue-neutral carbon tax, revenues from this tax are returned to taxpayers through personal income and business income tax cuts.

Pros and cons of carbon taxes and emissions trading will be compared as follows:

Carbon Taxes versus Emissions Trading

The main difference between carbon tax and emissions trading is that carbon taxes set the carbon price and emissions change according to the market dynamics, while emissions trading sets the cap for the emissions quantity and carbon prices changes according to the market dynamics.

Uncertainity about future developments affecting abatement costs and uncertainity about environmental benefits of abatement affect the effectiveness of carbon taxes and emissions trading systems considerably (PricewaterhouseCoopers, 2009b). Uncertainity about future abatement costs may result in wrong estimations of actual costs for emissions reductions thereby leading to a point in which marginal benefits of emissions reduction is not equal to marginal costs and so resulting in social welfare losses. Uncertainity about environmental benefits of emissions reduction affects the impact of the policy on social welfare as well. If emissions reduction has only minor impacts on environmental benefits that is likely to be in the short term, carbon tax has less social loss than the emissions trading system. But if emissions reduction has enormous impacts on environmental benefits, emissions trading would be more effective since it sets a cap on emissions. These social losses under uncertainity for each policy will be illustrated by graphs in details and compared to hybrid approach in the succeeding subtitle about hybrid approach.

Price stability is another point distinguishing the effectiveness of carbon taxes and emissions trading. Carbon taxes creates price stability since it is set definitely whereas carbon prices fluctuate creating price unstability. But, carbon taxes may not guarantee price stability in the long term since carbon taxes may be altered significantly by the political authority. Banking and borrowing may impede large fluctuations and setting price floors and price ceilings may decrease price unstability in emissions trade as well.

Carbon taxes increase government revenue whereas in emissions trading government revenue may increase or may not change depending on the allocation method of emissions allowances. In case of following a grandfathering approach, emissions trading does not alter government revenue. But, if emissions allowances are allocated based on auctioning, this increases government revenue as was the case in carbon taxes. When it comes to administration and compliance costs, carbon taxes are less costly due to its simpler and more familiar nature than emissions trading (PricewaterhouseCoopers, 2009b).

Perhaps the most important difference in practical terms between carbon taxes and emissions trading is their political acceptability (PricewaterhouseCoopers, 2009b). Because carbon tax stands out with its impacts on energy price increases that may be seen unfavorable by the public. But emissions trading stands out with its environmental benefits that may be politically more acceptable although both instruments result in somehow similar consequences.

To sum up, carbon taxes and emissions trading schemes have some superiorities over each other and both have some drawbacks as well. So, new instruments to deal with climate change have been proposed to moderate disadvantages of carbon taxes and emissions trading. These are revenue-neutral carbon taxes and hybrid schemes that will be explained further below.

Revenue-neutral Carbon Taxes

Environmental taxes on energy are politically unpopular, because of increased energy prices, whereas subsidies for renewable energy from general funds are common. Galinato and Yoder (2009), introduces a tax and subsidy regime that could be considered a compromise between a standard Pigouvian tax and a traditional indirect subsidy, in which revenues from taxes on high-emitting energy sources are used to fund subsidies on low-emitting energy sources. Galinato and Yoder (2009) develop a model of GHG-based subsidies for low carbon energy sources that are funded solely by carbon taxes on high carbon energy sources, thereby decreasing the political concern over more taxes and higher consumer energy prices, and reducing the costliness of traditional subsidies as a means to decrease GHG emissions.

Three factors determine the tax schedule if a revenue neutrality constraint is imposed : the net tax revenue target, the share of output to total industry output from all energy sources, and the relative marginal damages from pollution per unit of the relative price of the good (Galinato and Yoder, 2009). If there are two goods, the good whose marginal damage per unit price is larger will be taxed while the other good will be subsidized.

According to Galinato and Yoder (2009), the proposed instrument has three main political advantages over a traditional Pigouvian tax: Firstly, it can be revenue neutral to alleviate concerns over additional taxes. Secondly, it can reduce the upward pressure on overall energy expenditures by lowering some energy prices. Lastly, it is a more cost-effective way of reducing GHG emissions than a subsidy from general funds.

The simulations result that revenue neutral tax/subsidy regime generally provides welfare gains between an optimal Pigouvian tax on emissions and the case of no policy intervention, with an improvement over indirect subsidies funded from general funds (Galinato and Yoder, 2009). But revenue-neutral tax is complicated than Pigouvian tax since these taxes and subsidies are not separable across sectors like Pigouvian taxes and changes in relative prices and the relative size of each sector in the economy affect the optimal tax/subsidy schedule (Galinato and Yoder, 2009).

Hybrid Schemes

Hybrid schemes are emissions trading schemes bounded with price floors and price ceilings representing a combination of pros and cons of pure carbon tax and emissions trading schemes (PricewaterhouseCoopers, 2009b). These price floors and price ceilings prevent large price fluctutations thereby smoothing the price unstability of emissions trading schemes. Also, hybrid schemes prevent the politically less acceptible nature of carbon taxes. As the price bands get narrower hybrid schemes more look like carbon taxes, as the price bands get wider hybrid schemes more look like emissions trading schemes.

If carbon price rises above the price ceiling government guarantees to sell emissions allowances at price ceiling. So, market prices can not rise above this price level. This impedes possible upward price jumps through the end of trading periods if allowances are short in supply or due to some other economic shocks. Since government sells any amount of allowances at this price, hybrid schemes do not guarantee an emissions cap as is the case for carbon taxes, thereby decreasing environmental certainity. Price floors can be set both in auctions and in the secondary market. Governmnent guarantees to buy allowances if the market price falls below the price floor. Price floors encourage emissions reduction efforts in case of over allocation of allowances that may lead to carbon prices falling near to zero as was the case in the first trading period of the EU ETS. So, emission reduction projects with a cost less than price floors will likely be undertaken.

These price ceilings and price floors are revised upwards over time as the overall emissions cap would be tightened to reduce carbon emissions (PricewaterhouseCoopers, 2009b). Short selling may be prohibited in carbon trading markets of hybrid schemes since this may encourage speculative attacks on price floors and resut in costly allowance purchases by the government to defend price floors. The superiority of hybrid schemes under uncertainity will be explained further by using marginal benefit curves and social marginal damages curves as follows:

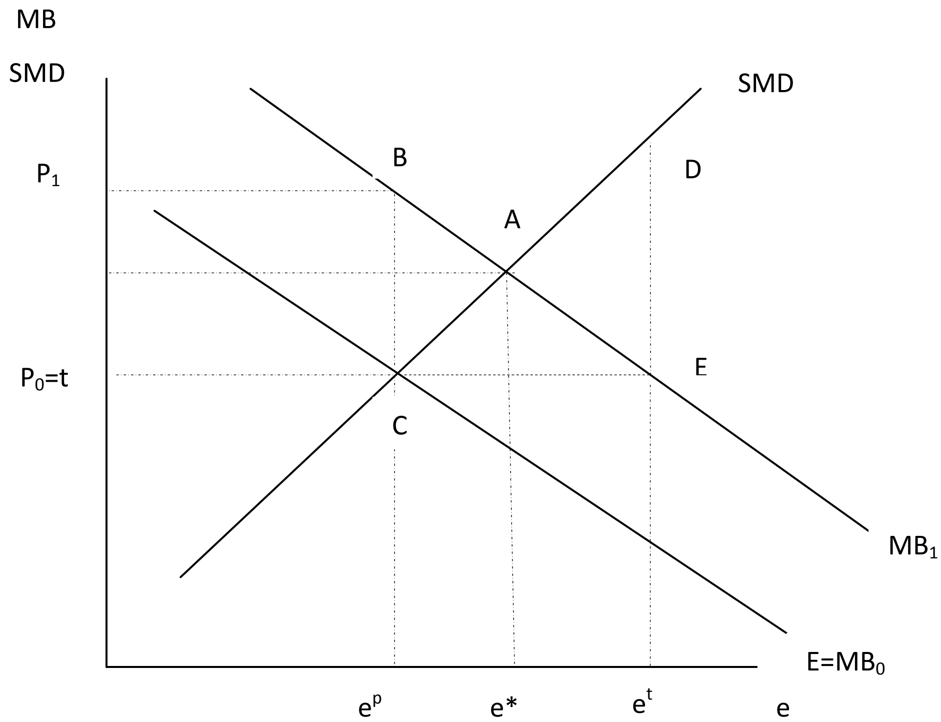

Figure 25. Market based policies under uncertainity of cost abatement (PricewaterhouseCoopers, 2009b)

In Figure 25, SMD represents social marginal damage, MB_0 represents ex-ante marginal benefit and MB_1 represents ex-post realized marginal benefit curves. If an emissions trading scheme is implemented, emissions cap is set at e^p and carbon prices rises to P_1, causing a social loss of the area represented by the triangle ABC. If carbon tax is implemented and carbon tax is determined at P_0, emissions occur at e_t where marginal benefits are equal to marginal cost that is the carbon tax; causing a social loss of the area represented by the triangle ADE (PricewaterhouseCoopers, 2009b).

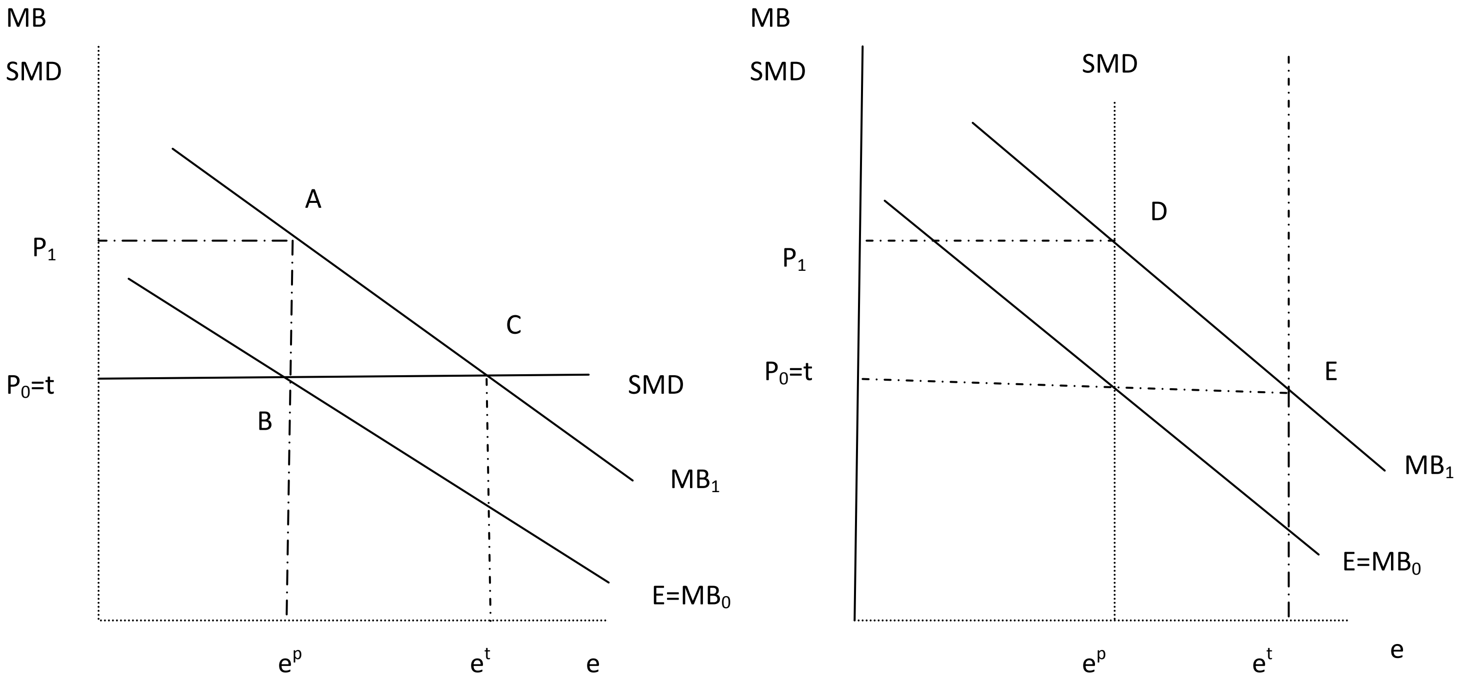

Figure 26. Market based policies under environmental uncertainity (PricewaterhouseCoopers, 2009b)

If environmental impacts of climate change is not certain, there exists uncertainity about the slope of the social marginal damage curves. Two extreme cases are shown in Figure 26, as SMD curve is horizontal in one case and SMD curve is vertical in the other case. If SMD curve is horizontal, carbon tax at the marginal damage is the optimal solution, whereas an emissions trading would lead to significant social losses represented by the area of the triangle ABC. If SMD curve is vertical, emissions trading scheme with a cap at the threshold level is the optimal solution, whereas a carbon tax would lead to huge unlimited social losses represented by the area above the DE line.

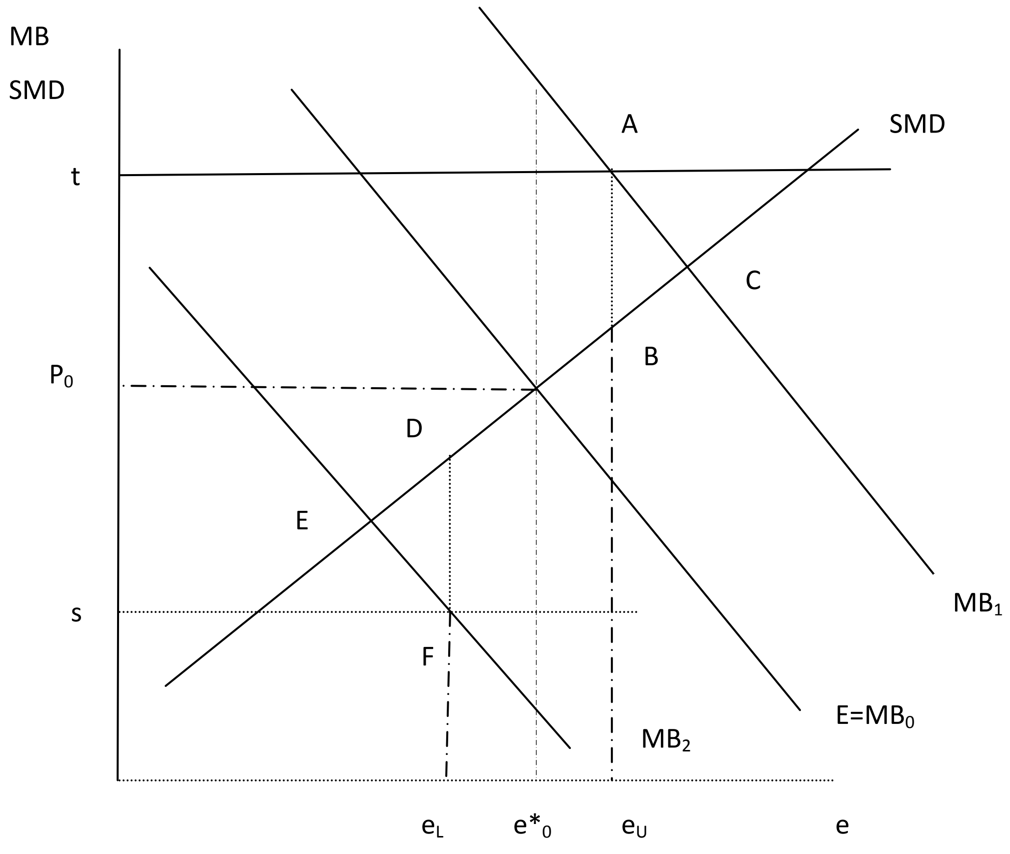

Figure 27. Hybrid schemes under uncertainity (PricewaterhouseCoopers, 2009b)

If hybrid schemes are used instead of carbon taxes or emissions trading schemes, social losses become the area of triangle ABC or triangle DEF. So, social losses under hybrid schemes are less than social losses under either of the pure carbon tax or pure emissions trading (PricewaterhouseCoopers, 2009b). So, designing emissions trading schemes with price floors and price ceilings can decrease social losses under uncertainity thereby increasing the effectiveness of the policy.

CHAPTER VI

VOLUNTARY CARBON MARKET OUTLOOK

The global carbon market is composed of two segments: the regulated (compliance) markets and the voluntary markets. Ecosystem Marketplace & New Carbon Finance (2009) defines the “voluntary carbon markets” as all purchases of carbon credits that are motivated by a driver other than regulatory compliance. This includes transactions involving credits created for the voluntary markets (such as Verified Emission Reductions or Carbon Financial Instruments) as well as transactions in which suppliers sell regulatory market credits (such as Certified Emission Reductions) to voluntary buyers.

This chapter provides an insight regarding voluntary carbon markets. The aim of this chapter is to comprehend a general outlook of the voluntary carbon market and enable to estimate the future of this market. The first section looks at where the voluntary carbon market stands in global carbon market and comprehends the size and growth of the voluntary carbon market and its components in transaction volume and values. After a general look at the components of the voluntary market, the succeeding sections focus on the voluntary OTC market. The second section analyses the sources of carbon offset credits in the voluntary OTC market in details. The third section analyses the prices of voluntary carbon offset credits in the OTC market by focusing on project types, project locations, utilised standards, seller categories as well as buyer-supplier profiles and contract structures. The statistical data of this chapter is obtained from the Ecosystem Marketplace & New Carbon

Finance's (2009) report "Fortifying the Foundation - State of the Voluntary Carbon Markets 2009".

Size and Growth of Voluntary Carbon Markets and Its Components

The voluntary market is mainly composed of two markets: The Chicago Climate Exchange (CCX) and the Over the Counter (OTC) market. Table 143 shows the transaction volumes and values of global carbon market that is composed of voluntary carbon markets and regulated carbon markets. So, Table 143 povides an insight about the position of voluntary carbon markets in global carbon markets and the components of voluntary carbon market.

Table 143. Transaction Volumes and Values of Global Carbon Market in 2007 and 2008 (Ecosystem Marketplace & New Carbon Finance, 2009)

Markets	Volume ($MtCO_2e$)		Value (million $)	
	2007	2008	2007	2008
Voluntary OTC	43.1	54.0	262.9	396.7
CCX	22.9	69.2	72.4	306.7
Other Exchanges	0.0	0.2	0.0	1.3
Total Voluntary Markets	66.0	123.4	335.3	704.8
EU ETS	2,061.0	2,982.0	50,097.0	94,971.7
Primary CDM	551.0	400.3	7,426.0	6,118.2
Secondary CDM	240.0	622.4	5,451.0	15,584.5
Joint Implementation	41.0	8.0	499.0	2,339.8
Kyoto (AAU)	0.0	16.0	0.0	177.1
New South Wales	25.0	30.6	224.0	151.9
RGGI		27.4		108.9
Alberta's SGER[a]	1.5	3.3	13.7	31.3
Total Regulated Markets	2,919.5	4,090.0	63,710.7	119,483.4
Total Global Markets	2,985.5	4,213.5	64,046.0	120,188.2

[a]Assume a CA$10 price for Alberta offsets and Emission Performance Credits based on interviews with market participants.

Other exchanges in Table 143 as a component of voluntary carbon market includes trading platforms like Asia Carbon Exchange, Climex and the Australian Climate Exchange, that do not comprise alltogether %1 of voluntary markets.

Table 143 shows that, global carbon market increased nearly %40 between 2007 and 2008 in transaction volume, whereas global carbon market nearly doubled in transaction value from 2007 to 2008. The discrepancy between the increase in volume and increase in value, comes from the price increase in 2008. The voluntary carbon market doubled in both volume and value terms between 2007 and 2008. So that, the average price may noy have changed much in the voluntary market between 2007 and 2008.

The voluntary carbon market comprises 2.9% of global carbon market in volume whereas it comprises only 0.6% of global carbon market in value in 2008, as a result of low credit prices in the voluntary market. Although the share of the voluntary carbon market is too small in global carbon market, the transaction volumes and values of voluntary carbon market may increase significantly in the coming years. Because, 2008 financial crisis did not let the prices go upwards as was the case in regulated carbon markets. As the global economy recovers, the demand of corporations for the voluntary carbon credits will increase. Also, the voluntary carbon market is a very new market and the financial instutions has just realised this market. As the presence of financial instutions in this market increases, the transaction volumes will increase too, increasing the liquidity of the market.

A discrepancy is seen between the components of the market (OTC and CCX) in volume and value terms. Namely, CCX comprises more than half (56.1%) of the voluntary market in volume terms whereas it comprises less than half (43.8%) of the market in value terms in 2008. This comes from 65% higher average prices (7.35 US$/ tCO_2e) in OTC market than average prices (4.43 US$/ tCO_2e) in CCX in 2008.

Growth of the voluntary carbon market and its components in transaction values from pre-2002 period to 2008 are shown in Figure 28.

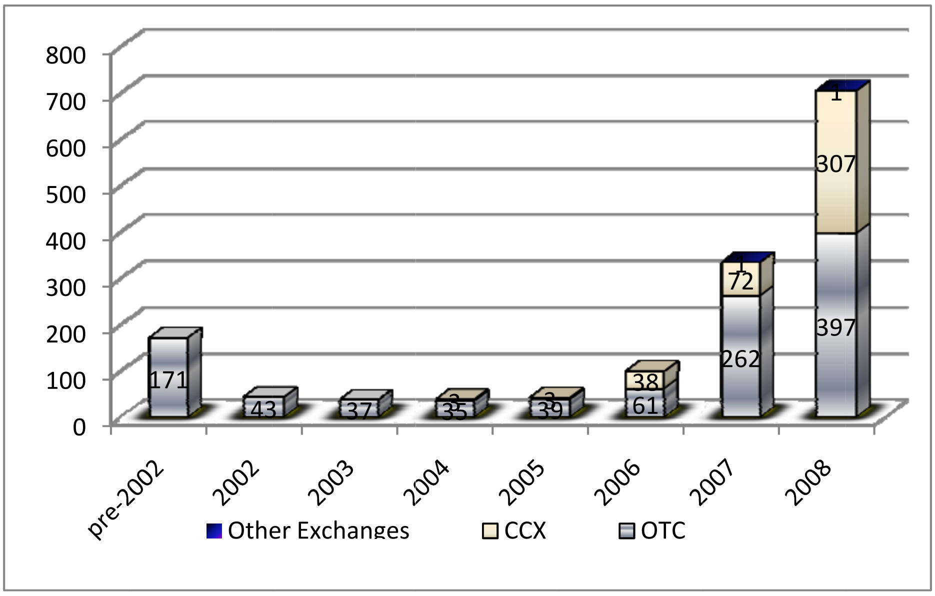

Figure 28. Historic values for the voluntary carbon markets in million $ (Ecosystem Marketplace & New Carbon Finance, 2009)

The voluntary carbon market stayed nearly the same between 2002 and 2005 in transaction values. But the voluntary carbon market started to grow incredibly after 2005 and has reached 705 million $ in 2008, whereas it was only 42 million $ in 2005, showing a nearly 256% average growth annually in transaction value.

Figure 29 shows growth of the voluntary carbon market and its components in transaction volumes from pre-2002 period to 2008.

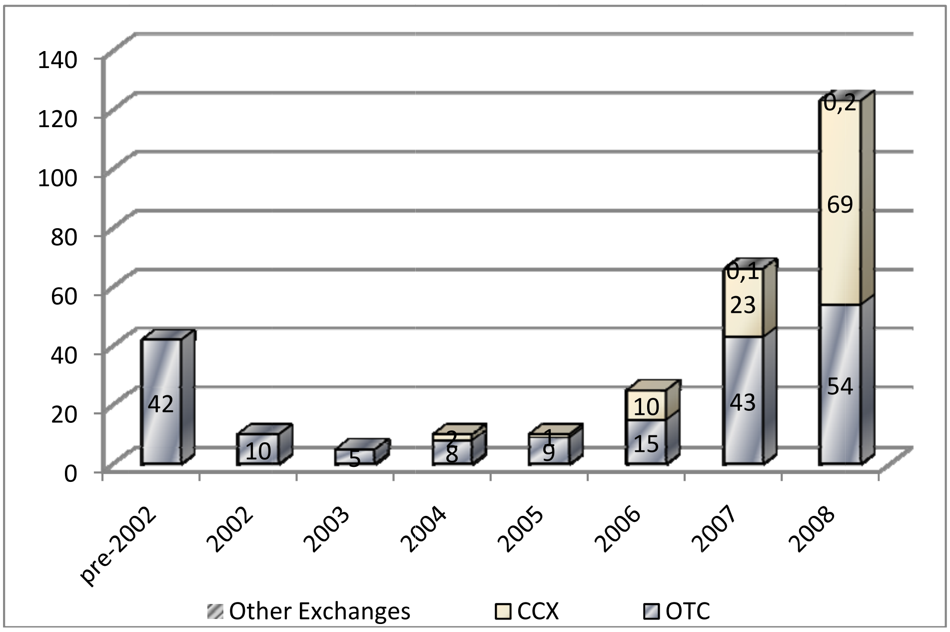

Figure 29. Historic Volume Growth in the Voluntary Carbon Markets in $MtCO_2e$ (Ecosystem Marketplace & New Carbon Finance, 2009)

The voluntary carbon market stayed nearly the same between 2002 and 2005 and started to grow significantly between 2005 and 2008 in transaction volume, as was the case for transaction value. The market has grown on average 224% annually between 2005 and 2008 reaching 123 $MtCO_2e$ in 2008 from the volume of 11 $MtCO_2e$ in 2005. Especially growth of CCX in transaction is surprising, in that outpacing OTC market in 2008 with 69 $MtCO_2e$ whereas it was only 1 $MtCO_2e$ in 2005. But CCX is still behind OTC market in 2008 in transaction values due to low prices in CCX.

Sources of Carbon Offset Credits

This section mainly analyses the sources of carbon offset credits in the voluntary OTC market according to their project type, location, project size and credit vintages. Within the context of project type renewable energy (hydro, wind, biomass), energy efficiency, landfill, geological sequestration and so on are referred. Other than providing an insight about project locations, this section also comprehends where the voluntary carbon offset projects are located, what size of projects are most transacted and credit vintages of these transactions with a comperative analysis between 2007 and 2008.

The sources of carbon offset credits in the voluntary OTC market according to their project types such as renewable energy projects (hydro, wind, biomass), energy efficiency projects, landfill projects, etc in 2008 and their transaction volume growth rates from 2007 to 2008 will be analysed as follows:

Figure 30 shows transaction volume percentages in voluntary OTC market in 2008 as per project types:

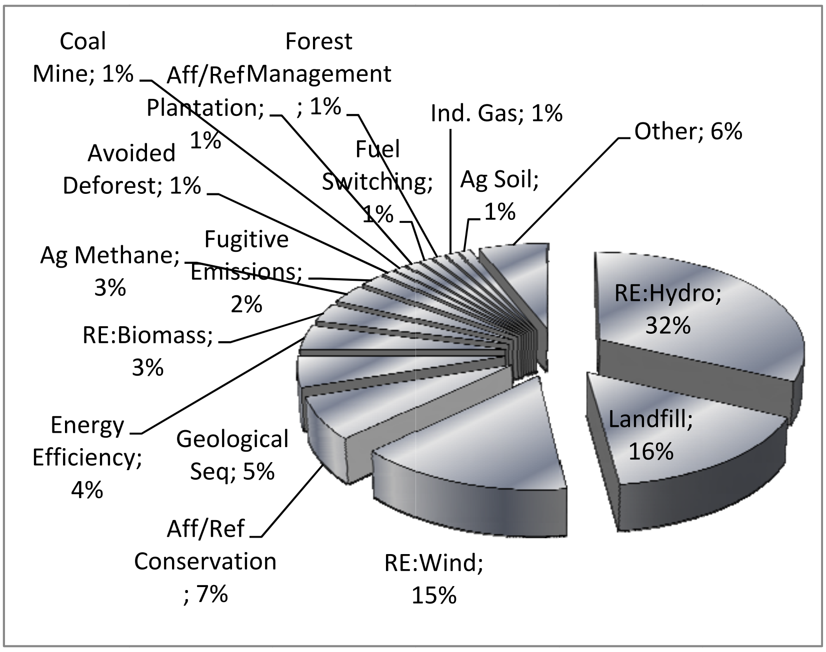

Figure 30. Transaction volume percentages by project types in OTC market in 2008 (Ecosystem Marketplace & New Carbon Finance, 2009)

In the voluntary OTC market, the dominant source of voluntary offset carbon credits in terms of project type is renewable energy projects, comprising %51 of voluntary OTC market. Hydropower projects comprise 32% (26 $MtCO_2e$), wind energy projects comprise 15% (7.7 $MtCO_2e$) and biomass energy projects comprise % 3 of total voluntary OTC market volume. Landfill comes the second with 16% of OTC market volume.

The attractiveness of renewable energy projects largely comes from their non-controversiality, measurability, understandability and being a long-term alternative to fossil fuel-based energy. A large portion of these credits came from a 9 $MtCO_2e$ single transaction in 2008. This single transaction of an Indian hydropower project comprises nearly one third of credits originated from renewable energy projects. The majority (63%) of wind energy credits originated from Turkey. The second source was India with 19% of wind energy credits. Solar energy sourced less than 0.1% (14,000 tCO_2e) in 2008. The main reasons behind this small share is high production costs and small project sizes.

The shares of poject types in 2008 are compared to their shares in 2007 in Figure 31 as follows:

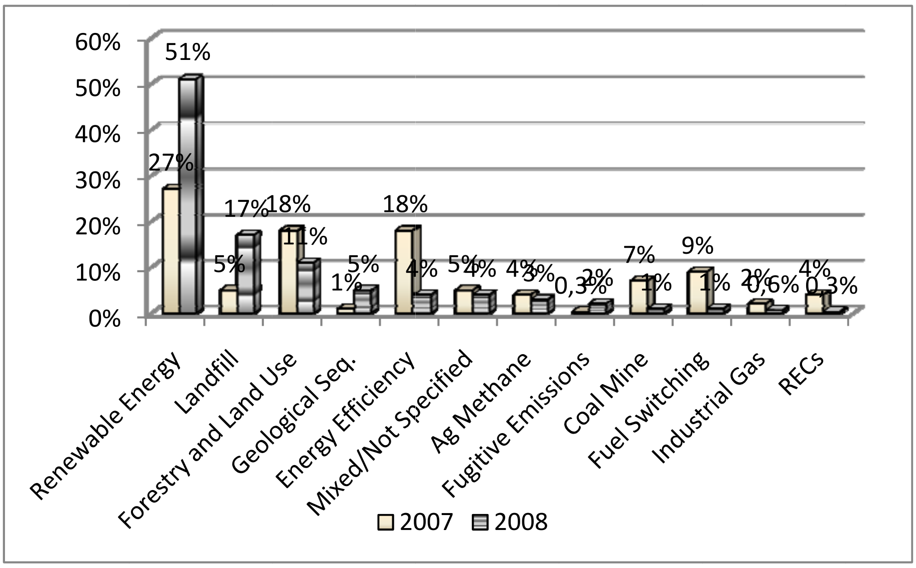

Figure 31. Transaction volume percentages by project types in OTC market in 2007 vs. 2008 (Ecosystem Marketplace & New Carbon Finance, 2009)

The share of renewable energy projects increased from 27% (in 2007) to 51% in 2008. Landfill gas also increased from %5 (in 2007) to %17 in 2008. The energy efficiency projects' market share dropped most significantly from %18 (in 2007) to %4 in 2008. Methane destruction project is the second most popular project type after renewable energy with a market share of 17% in 2008 (up from 5% in 2007). Agricultural methane has a market share of %3 in 2008 (down from 4% in 2007) and coal mine methane projects have %1 of transaction volume in 2008 (down from %7 in 2007). The increasing attractiveness of methane projects largely comes from the quantifiability of emission reductions easily, their inexpensive nature because of their high global warming potential as they cause global warming twenty three times more than carbon dioxide per molecule and pre-compliance motives since these projects are expected to be eligible for compliance in the US federal cap and trade market that is expected to come into existence in the near future.

Transaction volume percentages in the voluntary OTC market as per where the projects are located will be analysed as follows: Figure 32 compares these percentage shares according to project location between 2007 and 2008.

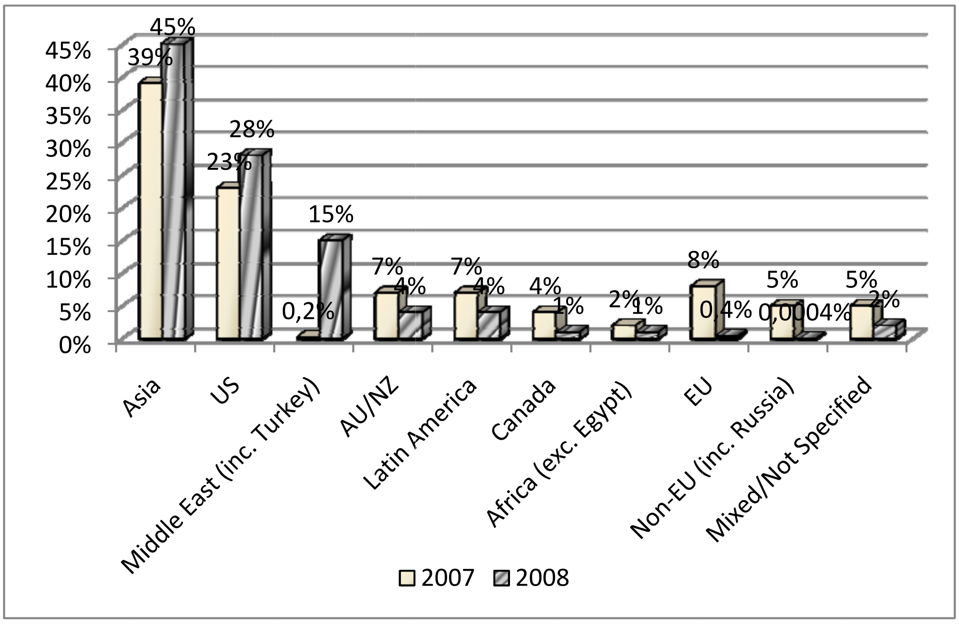

Figure 32. Transaction volume by project location in OTC market in 2008 (Ecosystem Marketplace & New Carbon Finance, 2009)

Asia is the dominant in source of project locations comprising 45% of OTC market volume in 2008 and 39% in 2007. United States is the largest source on country basis with %28 market share in 2008 and 23% in 2007. The share of Middle East (%15) is also significant in 2008, mainly resulting from the large projects in Turkey, that is included in the Middle East in the Ecosystem Marketplace & New Carbon Finance's (2009) report. The Middle East shows the most drastic change between 2007 and 2008 jumping from 0.2% to 15%. Asia increased its share from 39% (in 2007) to 45% in 2008, US from %23 (in 2007) to %28. The most drastic downward shift was in EU and non-EU that lost market shares from %13 to less than %1 because of double counting concerns about the Kyoto Protocol's accounting rules. Another striking point is the dominance of renewable energy projects in Asia and the Middle East, whereas methane destruction projects dominate the US market.

Asian projects increased from 11.1 $MtCO_2e$ (in 2007) to 22.7 $MtCO_2e$ in 2008. Of the 22.7 $MtCO_2e$ Asian projects, 13.9 $MtCO_2e$ (61%) was from India and 5.2 $MtCO_2e$ (23%) from China. Asia's dominance in voluntary market is similar to its dominance in CDM market. Its high market share largely comes from pre-registration CDM projects while struggling with delays. Especially hydropower projects dominated the Asian market, namely 60% of transactions volume in Asia in 2008 originated from hydropower projects.

US projects were 15 $MtCO_2e$ in 2008 and 7.5 $MtCO_2e$ (%50) of US projects were related to landfill gas methane projects. Most of US transactions seems to be related to pre-compliance concerns. Other popular project types in US was forestry projects with 1.7 $MtCO_2e$ (11%) and geological sequestration with 2.7 $MtCO_2e$ (18%).

The Middle East appeared in the voluntary market in 2008 with 7.5 $MtCO_2e$ volume (15%) whereas it was only 0.5 $MtCO_2e$ (0.2%) in 2007. The dominant country in the region's voluntary market is Turkey with 7.4 $MtCO_2e$ that comprises 99% of the Middle East originated projects. The remaining small part came from Egypt. Nearly all of the projects were related to renewable energy projects, especially wind and hydro projects. Turkey is dominant in the voluntary market in the region, and she is likely to maintain its dominant position in the near future due to some reasons as follows: Turkey is ineligible to supply CDM or JI credits at least until the end of first commitmet period 2012, because of its position in the Kyoto Protocol as an Annex I but a non-Annex B country. So, voluntary market is the only available market for Turkey at least until the end of 2012. Also Turkey has an incredible renewable energy potential waiting to be utilized and the government intends to transform the country's energy structure towards more renewable energy. These are likely to increase Turkey's presence in the voluntary carbon market in the future.

Ecosystem Marketplace & New Carbon Finance (2009) classifies the projects according to their sizes as follows:

- Micro (less than 5,000 tCO_2e/year)
- Small (5,000 to 19,999 tCO_2e/year)
- Medium (20,000 to 99,999 tCO_2e/year)
- Large (100,000 to 499,999 tCO_2e/year)
- Very large (500,000 tCO_2e/year or more)

Transaction volume of voluntary OTC market as per project sizes are shown in Figure 33 as follows:

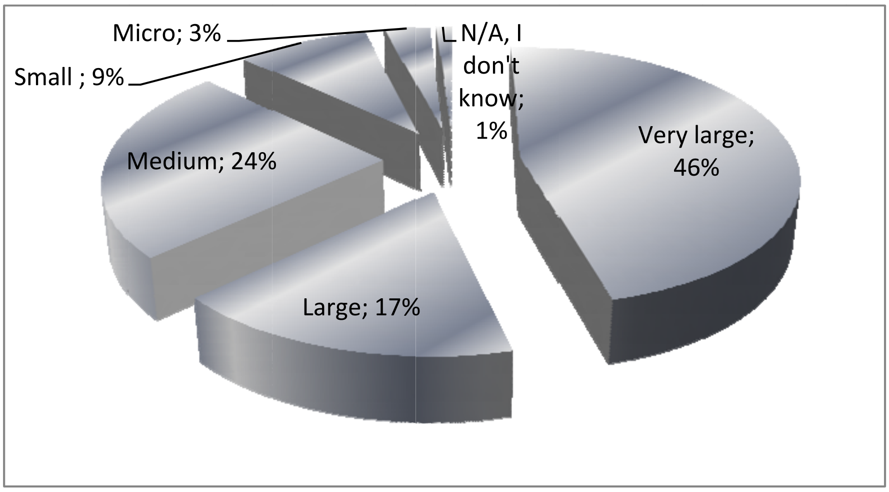

Figure 33. Transaction volume by project size in OTC market in 2008 (Ecosystem Marketplace & New Carbon Finance, 2009)

Very large projects dominate the market with 46% market share. This market share was %32 in 2007. And the medium sized projects decreased to %24 from %38. Other project size categories stayed nearly the same between 2007 and 2008. So, there has been a shift from large projects to very large projects from 2007 to 2008. This may be due to a largest single project transaction that was an Indian project with 9 $MtCO_2e$. Micro and small projects together comprise 12% of transaction volume in 2008. The share of these projects may decrease further in the future, due to the increased use of renewable energies and developments in energy efficiency that are usully large and very large projects. Also the revenues from micro scale projects may not be significant when standard fees and other works to issue carbon offset credits are considered.

The transaction volume percentages of the voluntary OTC market in 2007 and 2008 as per the credit vintages of the projects will be analysed as follows: Credit vintage shows the year the emission reduction occured. Figure 34 shows these transaction volume percentages as per their credit vintages.

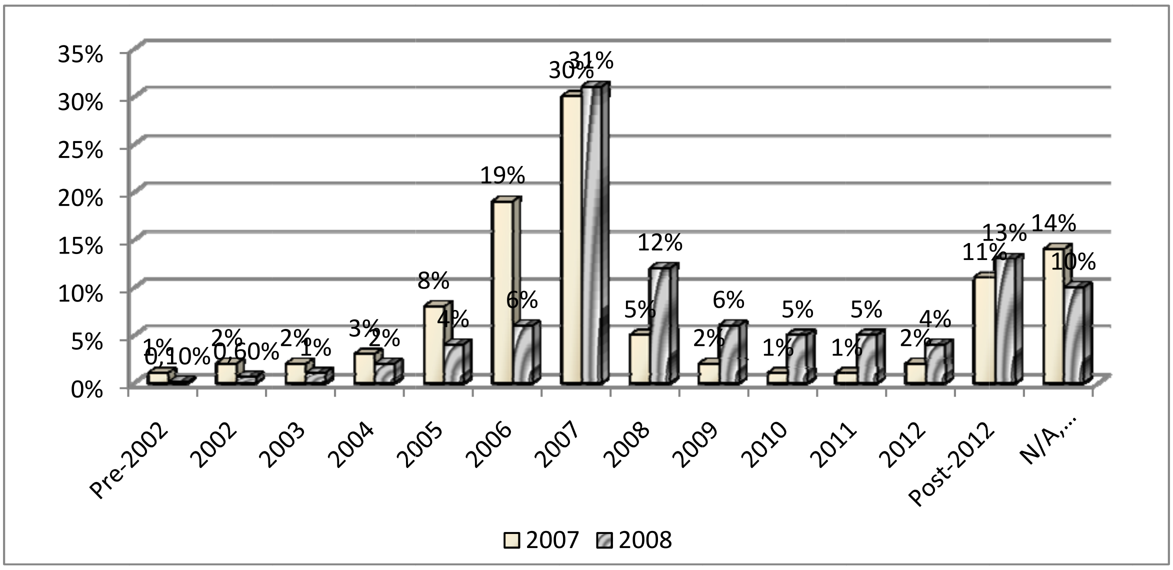

Figure 34. Transaction volume by credit vintage in OTC market in 2007 vs. 2008 (Ecosystem Marketplace & New Carbon Finance, 2009)

2007 vintage credits have the highest market shares in both 2007 and 2008, with 30% and 31% of transaction volume respectively. In 2008, 33% of transaction volume came from ex-ante projects, referring to vintages 2009 and beyond. In 2007 this ex-ante credit vintage transaction volume was 22%. This shows that people are more comfortable in 2008 to buy credits that have not realized emission reductions yet. Among ex-ante vintage credits post-2012 vintage credits take the lead both in 2007 and 2008 with 11% and 13% market shares respectively. This may be due to pre-compliance motives of buyers expecting a new period after 2012 that will cover them, too.

Prices in the Voluntary Carbon Market

This section investigates the price characteristics in the voluntary OTC market. After having a general outlook of the prices in OTC and CCX markets at the beginning of the section, price characteristics in the voluntary OTC market according to project type, project location, standards utilized and seller categories with a comperative analysis between 2007 and 2008 will be focused on. Then, other subordinate issues like buyer - supplier profiles, motives and contract structures will be explained. The aim of this section is to have a general idea about in what range prices would be when the type, location, standard of the project and the seller category is known.

A general outlook of average credit prices in the voluntary OTC market and CCX from pre-2002 period to 2008 will be given by comparing the prices in these two markets and demonstrating the increases in prices. These annual volume-weighted average prices in OTC and CCX markets are illustrated in Figure 35 as follows:

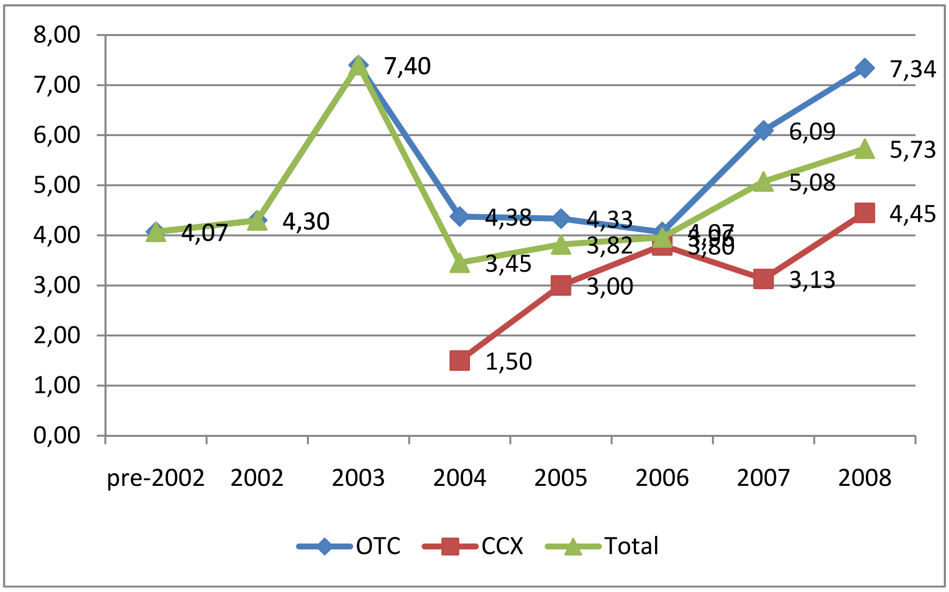

Figure 35. Volume-weighted average credit prices in $/tCO_2e$ by voluntary market components between pre2002-2008 periods (Ecosystem Marketplace & New Carbon Finance, 2009)

Average prices in the voluntary OTC market have always been above prices in the CCX annually. Since 2004, both OTC prices and CCX prices have increased significantly. The volume-weighted average price in the OTC market reached 7.34 $/tCO_2e$ in 2008 from 4.07 $/tCO_2e$ in 2006. This price of 7.34 $/tCO_2e$ shows 20% increase according to the average price of 6.10 $/tCO_2e$ in 2007 and 79% increase according to the average price of 4.07 $/tCO_2e$ in 2006.

Credit prices in the voluntary OTC market ranged in 2008 from 1.20$/tCO_2e$ to 46.90$/tCO_2e$. The price range was much higher in 2007, from 1.80$/tCO_2e$ to 300$/tCO_2e$. Credit prices differ according to many factors such as the heterogenity of emission reduction costs, the project type, the stage the credit was sold in the credit’s life, the utilized standards and registries, the size of deal and project location. The price characteristics of them is analysed below by focusing on the project type, location, utilized standards and seller category.

The average prices in the voluntary OTC market increased from 2007 to 2008, showing its effects in most of the project types as price increases. Figure 36 illustrates average credit prices according to project types with a comperative outlook between 2007 and 2008.

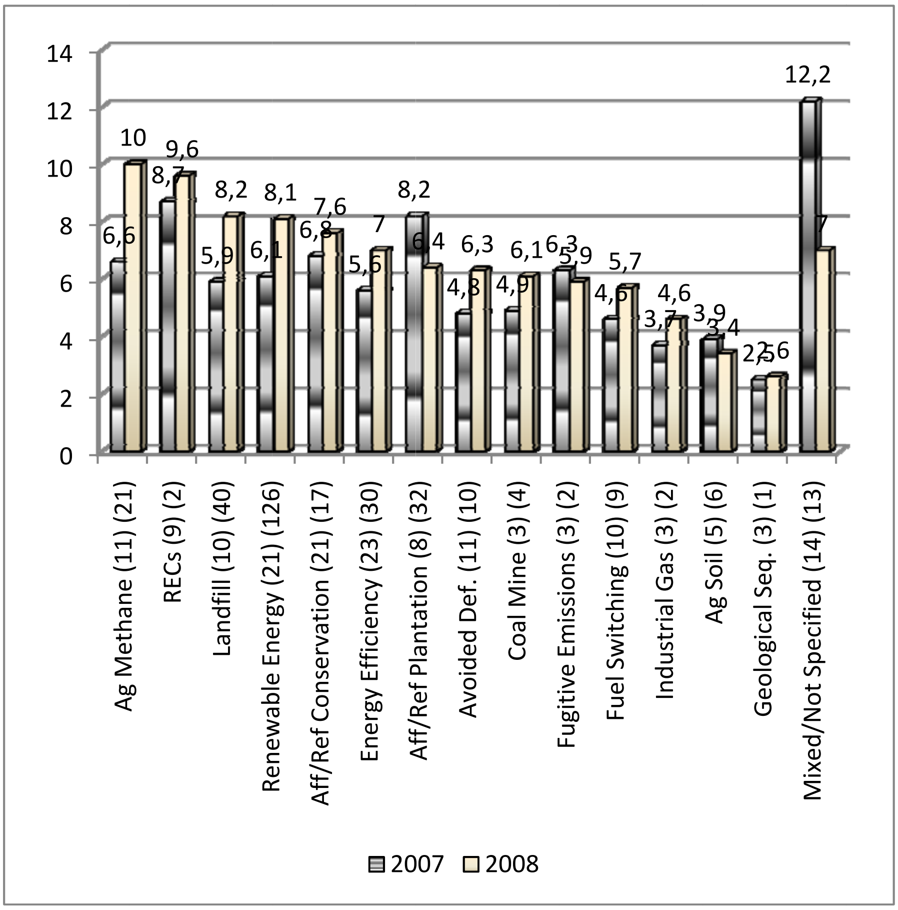

Figure 36. Average credit prices by project type in OTC market in 2007 vs. 2008 (Ecosystem Marketplace & New Carbon Finance, 2009)
Note: Numbers within the first parantheses indicate number of observations in 2007, numbers within the second parantheses indicate number of observations in 2008.

Methane destruction projects had the greatest percentage price increase by 54% due to pre-compliance motives. Carbon offset credit prices generated from renewable energy projects experienced 33% price increase between 2007 and 2008.

Figure 36 shows methane destruction projects as the most expensive project type in 2008 with 10 $/tCO_2e. Although renewable energy projects seem less expensive in 2008 with 8.1 $/tCO_2e, most of the renewable energy subcategories are more expensive than methane destruction projects in 2008. Average credit prices generated from solar energy, geothermal energy, biomass energy and wind energy projects in 2008 are 22 $/tCO_2e$, 18 $/tCO_2e$, 16.8 $/tCO_2e$ and 12.61 $/tCO_2e$ respectively. They are expensive because of high production costs and attractiveness to voluntary market buyers. The renewable energy project average price of 8.1 $/tCO_2e$ comes from the low prices of credits generated from hydro projects of 5.2 $/tCO_2e$. This low price largely comes from the less attractiveness of hydro projects to voluntary buyers due to less favourable environmental effects according to other renewable energy projects and the high credit size nature of these projects.

Although there may not be a strong correlation between the credit prices and project locations. Figure 37 compares average credit prices according to where the projects are located in 2007 and 2008.

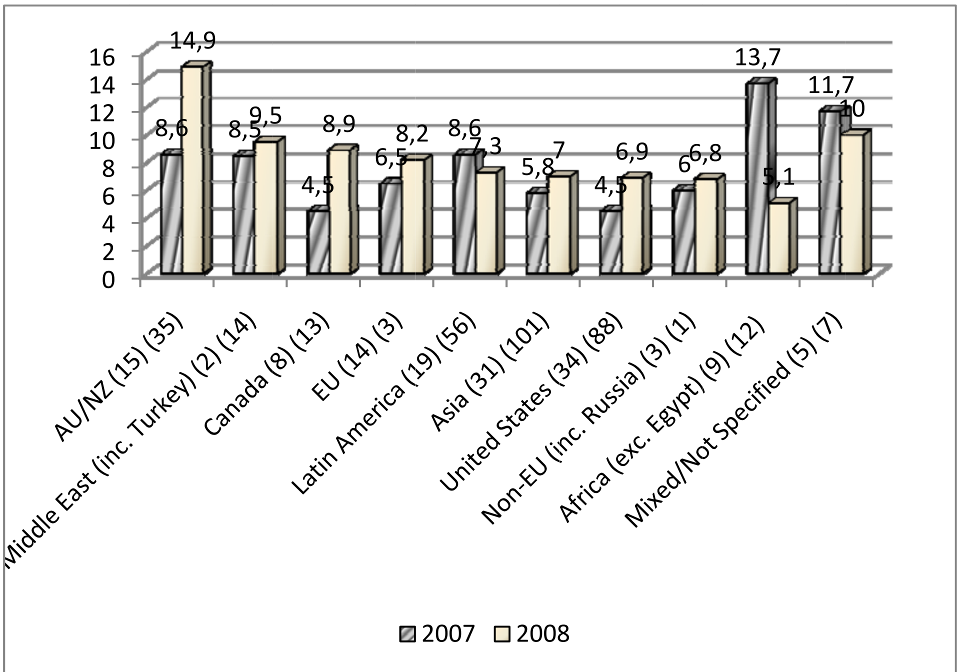

Figure 37. Average Credit Price by Project Location, OTC 2007 vs. 2008 in US$/tCO2e (Ecosystem Marketplace & New Carbon Finance, 2009)
Note: Numbers within the parantheses indicate number of observations.

Average credit prices in all regions other than Africa (excluding Egypt) increased betweeen 2007 and 2008. This is compatible with the general price increase in the voluntary OTC market between 2007 and 2008. The sharpest jump has been in Australia and New Zealand from 8.6 $ to 14.9 $ in nominal terms. And Canada experienced the highest percentage increase with nearly doubling prices. Prices in the Middle East (including Turkey) increased slightly from 8.5 $ to 9.5 $.

After having a general outlook to credit prices according to the regions where the projects are located, Figure 38 illustrates average credit prices in 2008 on country specific basis.

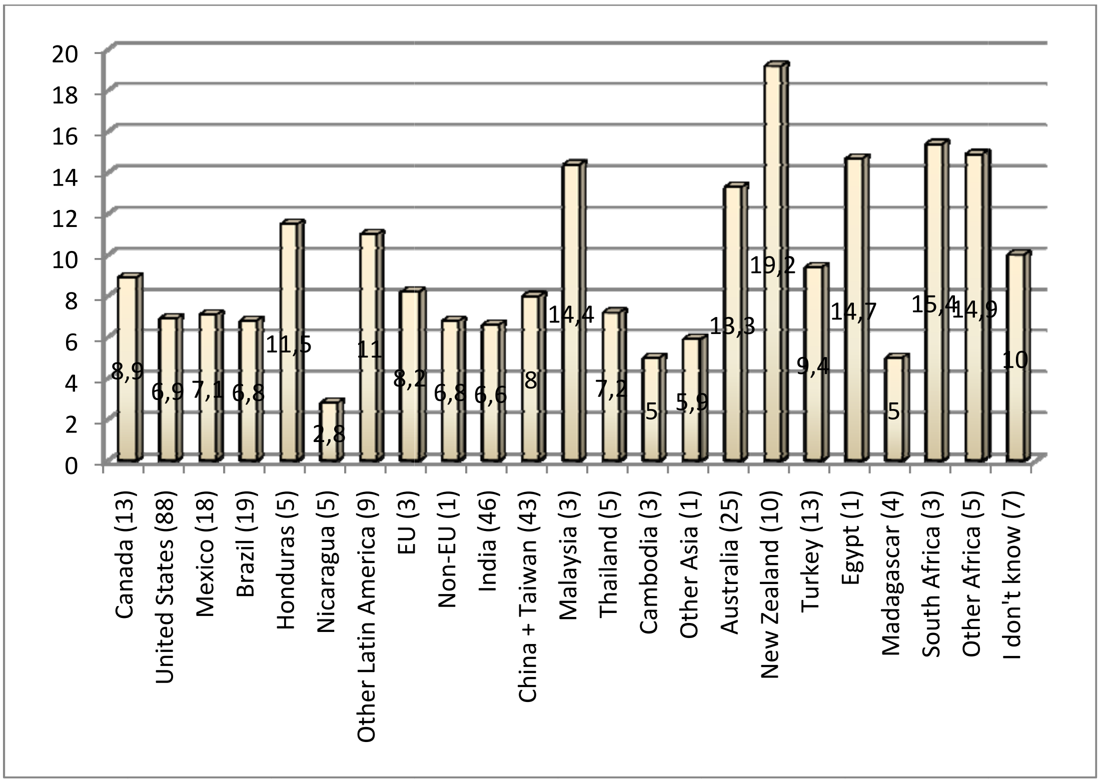

Figure 38. Volume-weighted average credit price by project location in OTC market in 2008 in US$/tCO2e (Ecosystem Marketplace & New Carbon Finance, 2009)
Note: Numbers within the parantheses indicate number of observations.

Credits from New Zealand, South Africa, Egypt, Malaysia, Australia, Honduras, Turkey, Canada and China+Taiwan has a premium over average OTC credit price of 7.34 $, earning 19.20 $, 15.40 $, 14.70 $, 14.40 $, 13.30 $, 11.5 $, 9.4 $, 8.9 $ and 8 $ per credit respectively in 2008. Although carbon offset credits generated from projects located in Turkey has had volume-weighted average price of 9.4 $ in 2008, transaction price of as high as nearly 30 $ has been realized in Turkish projects. However, the highest credit price has been 46.9 $ from an Australian renewable energy project in 2008.

Prices in the voluntary OTC market by standards utilized will be explained as follows:

According to Ecosystem Marketplace & New Carbon Finance Report (2009), more than 96% of transacted credits were third-party verified in 2008, up 9% from 2007. 2.6% of transacted credits were internally credited and 0.9% of transacted credits were not verified. This non-verified portion is much smaller than the 11% non-verified portion in 2007, showing a trend in favour of verification.

The standards of volutary carbon offset projects are as follows: American Carbon Registry Standard; The Climate Action Reserve Protocols; The CarbonFix Standard; Chicago Climate Exchange Offsets Program; Climate Community and Biodiversity Standards; EPA Climate Leaders Offset Guidance; Greenhouse Gas Services Standard; The Gold Standard for VERs; Greenhouse Friendly; ISO 14064 Standards; Plan Vivo; Social Carbon Standard; TUV NORD Climate Change Standard; VER+ Standard and The Voluntary Carbon Standard.

Figure 39 shows the standard utilization percentages of credits transacted in the voluntary OTC market in 2007 and 2008.

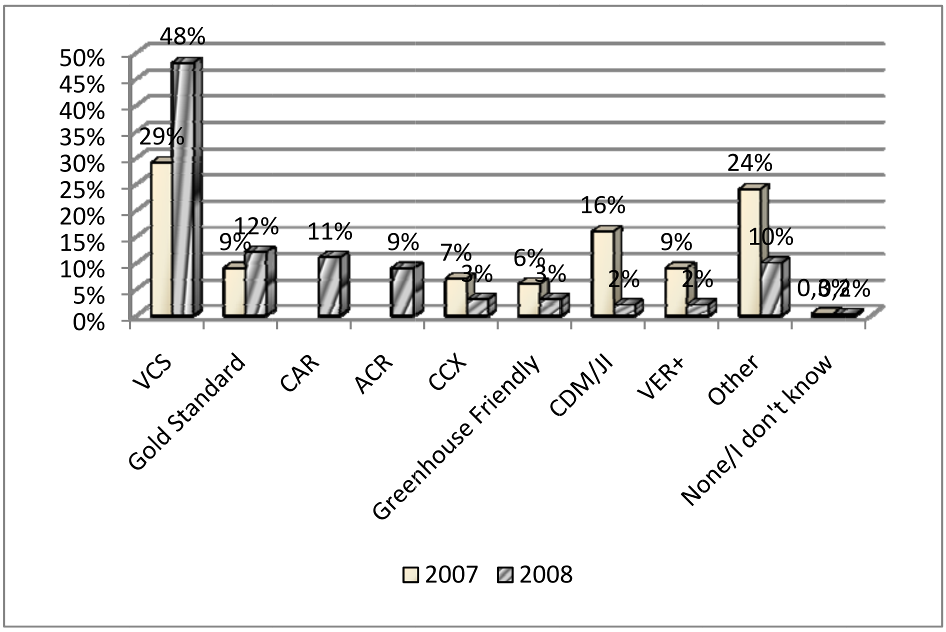

Figure 39. Standard utilization in OTC market in 2007 vs. 2008 (Ecosystem Marketplace & New Carbon Finance, 2009)

The most utilized standard in 2008 is Voluntary Carbon Standard (VCS) with 48% of OTC transaction volume, followed by Gold Standard with 12% and Carbon Registry Standard with 9%. Other standards have less than 5% each. The Voluntary Carbon Standard increased its share from 29% to 48% between 2007 and 2008. Gold Standard also increased its share from 9% to 12%. The most drastic decrease was on CDM/JI standards dropping to 2% from 16% between 2007 and 2008.

The standard utilized is one of the most important determinants of credit prices. After having a general look at standard utilization, Figure 40 illustrates credit prices according to the standards utilized in 2008 as follows:

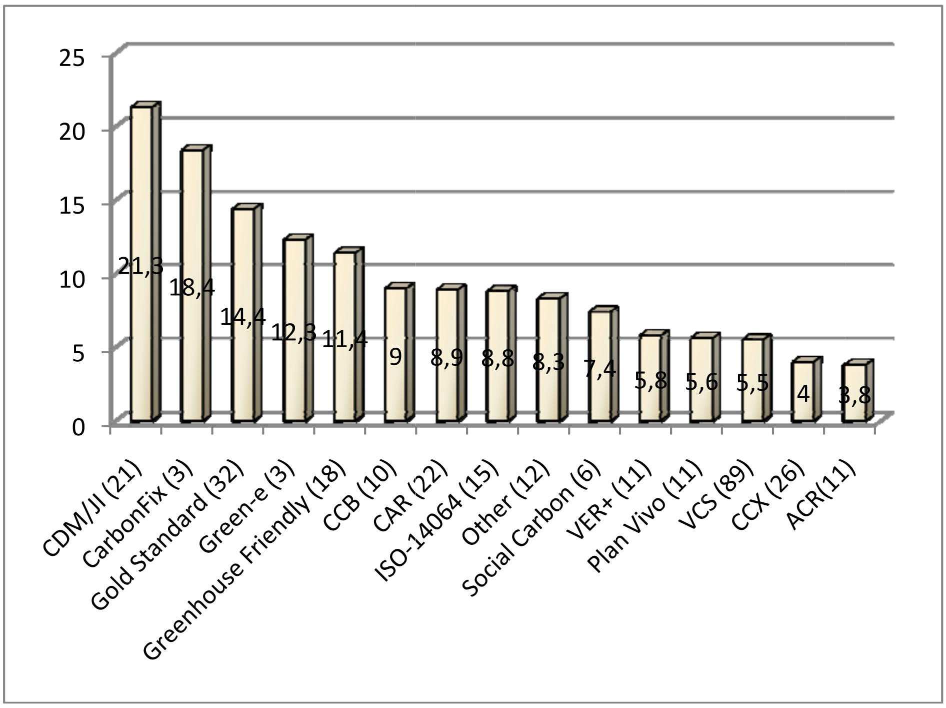

Figure 40. Average credit prices and price ranges by standard in OTC market in 2008 in $/tCO_2e$ (Ecosystem Marketplace & New Carbon Finance, 2009)
Note: Numbers within parantheses indicate number of observations.

Although the CDM/JI Standard lost significant market share in 2008, the credits having CDM/JI Standards have the most price premiums in 2008, with 21.3 $/tCO_2e$. When credit prices are compared according to the average prices of 7.34 $/tCO_2e$ in 2008; CarbonFix, Gold Standard, Green-e, GHG Friendly, CCB Standards, Climate Action Reserve (CAR), ISO-14064, Social Carbon and internally created standards have price premiums. The CCX with 4 $/tCO_2e$ and ACR with 3.8 $/tCO_2e$ are at the bottom of price range. According to Ecosystem Marketplace & New Carbon Finance (2009), this discount is related to the low prices on the CCX itself and inexpensive reductions achieved via geological sequestration, that is the most popular ACR project type in 2008.

When prices of credits utilized CDM/JI and CarbonFix standards are neglected due to their very low shares in the market in 2008, it is reasonable to say that Gold Standard utilized credits have the most price premiums with 14.4 $/tCO_2e$.

When prices of Gold Standard utilized credits are compared with prices of Voluntary Carbon Standard utilized credits of 5.5 $/tCO_2e$, the price premium of Gold Standard appears, too.

After having a general look at standards, registries that are usually linked to the standards will be mentioned briefly as follows: Registries are organizations that provide processes to issue, register, transfer or retire carbon credits, and track ownership of these credits. Registries are usually divided into two categories, according to issuance of credits: Emissions-tracking registries and credit-accounting registries.

Emissions-tracking registries do not issue carbon credits but they track the parties' GHG emissions and reductions. They are usually utilized for regulated or voluntary cap and trade systems. The Canadian GHG Challenge Registry, the Canadian Clean Start and Clean Projects Registries, the Carbon Disclosure Project, the American Carbon Registry and the Climate Registry fall into this category.

Credit-accounting registries issue carbon credits and track transactions of these credits. They usually use serial numbers as an accounting tool and usually require specific verification standards. They may be categorized as independent (not built for a specific standard or exchange), standard-specific, exchange-specific and infrastructure providers. The Registry Company (Regi), TZ1, GHG CleanProjects Registry and Traceable VER Registry are independent registries. American Carbon Registry, Bank of New York Mellon's Global Registry and Custody Service, BlueRegistry, Gold Standard Registry for VERs, VCS Registry System, Climate Action Reserve, Social Carbon Registry, Greenhouse Friendly Abatement Register, Plan Vivo Registry and CCB Standards Registry are standard-specific registries. Chicago Climate Exchange (CCX) Offset Registry, Asia Carbon Registry, Triodos

Climate Clearing House Registry and Australian Climate Exchange Registry are exchange-specific registries. TZ1, APX and Caisse des Depots are infrastructure providers.

Prices in the voluntary OTC market by seller categories will be mentioned as folows: There are four major categories of sellers in the voluntary carbon market. They are project developers, aggregators/wholesalers, retailers and brokers. Project developers develop emission reduction projects. Aggregators/wholesalers sell credits in bulk. Retailers sell credits in small amounts to final customers. Brokers facilitate transactions between buyers and sellers, and they do not possess credits. The credit prices change according to at which stage of this supply chain the transaction occurs. The weighted average sale prices in 2008 for project developers is 5.1 $/tCO_2e$, for wholesalers 5.4 $/tCO_2e$, for retailers 8.9 $/tCO_2e$ and for brokers 6 $/tCO_2e$. The prices increase significantly at the sale of the retailer up to 8.9 $/tCO_2e$ from 5.1 $/tCO_2e$ of the project developer sales price.

Prices in the voluntary OTC market is formed as a result of deals between buyers and sellers. So, the profiles and motives of buyers and sellers is mentioned briefly as follows:

EU countries are the dominant buyers with 52% of transaction volume in 2008, up from %47 in 2007. US also increased its share from 34% to 39% between 2007 and 2008. Australia/New Zealand and Canada are other buyers in 2008 with 6% and 2% market shares respectively. Motivations of these buyers have been investigated by Ecosystem Marketplace & New Carbon Finance (2009) and they asked respondents to rank their purchasing motivations ranking from 1 to 5. The results are shown in Figure 41 as follows:

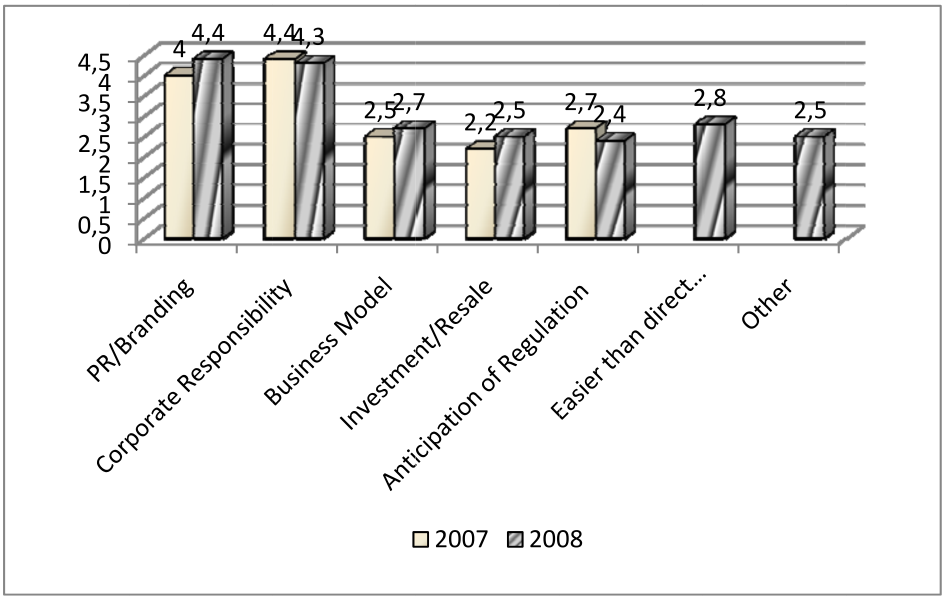

Figure 41. Customer motivations (importance ranking) (Ecosystem Marketplace & New Carbon Finance, 2009)
Note: "Easier than direct reductions" option was added in the 2008 survey.

Buyers' motivation did not change much between 2007 and 2008. PR/branding and corporate responsibity are the main motivations for buyers. Being easier and cheaper to buy than direct reductions was ranked as the third motivation. Investment/resale and anticipation of regulation are also important motives for the buyers.

After having a general look at buyer profiles and motives, supplier profiles are mentioned as follows: In the voluntary market, both non-profit organizations and for-profit organizations supply carbon credits. Until 2006 non-profit organizations outnumbered for-profit organizations. But the share of for-profit organizations have been steadily increasing since 2006. In 2008, 69% of suppliers are for-profit organizations. According to the transaction volumes, the dominance of for-profit organizations is obvious. For-profit organizations account for 93% of the transaction volume whereas non-profit organizations have only 7% in 2008.

Prices in the transactions take place in contracts. The characteristics of contract structures will be mentioned briefly as follows (Ecosystem Marketplace & New Carbon Finance, 2009): There are three main contract structures in the OTC market: Payment on delivery – unit contingent contracts, payment on delivery – firm delivery contracts, pre pay – unit contingent contracts and spot transactions.

In type of payment on delivery – unit contingent contracts; payment is made when the credits are verified and delivered (Ecosystem Marketplace & New Carbon Finance, 2009). The credit amount is not determined specifically in the contract, rather it is linked to the amount produced. In 2008, this type of contract dominates the OTC market with 51% of transaction volume. Most of these transactions are related to vintages sold for 2008 and beyond. These forward sales are usually made as unit contingent since the sellers do not want to take full specified delivery risk (Ecosystem Marketplace & New Carbon Finance, 2009).

In type of payment on delivery – firm delivery contracts; payment is made when the credits are verified and delivered (Ecosystem Marketplace & New Carbon Finance, 2009). The credit amount is determined specifically and stirictly in the contract. In 2008, this type of contract is made on 22% of transaction volume in the OTC market (Ecosystem Marketplace & New Carbon Finance, 2009).

In spot transactions; delivery and payment are made instantaneously related to the credits that have already been produced (Ecosystem Marketplace & New Carbon Finance, 2009). In 2008, this type of contract is made on 18% of transaction volume in the OTC market. The credits related to these contracts usually have already been issued.

In type of pre pay – unit contingent contracts; payment is made before the credits are verified and delivered (Ecosystem Marketplace & New Carbon Finance, 2009). The credit amount is determined specifically in the contract. This type is utilized in only 5% of transaction volume.

The indexed contracts that the prices are indexed to something are very rare (0.0005%) in the voluntary OTC market due to the lack of a liquid indicator for voluntary carbon credit prices (Ecosystem Marketplace & New Carbon Finance, 2009). There is only one exchange traded product that is the Climate Action Reserve Certified Reduction Ton derivative contract on the Chicago Climate Futures Exchange (CCFE) (Ecosystem Marketplace & New Carbon Finance, 2009). But its illiquidity prevents it to be an indicator (Ecosystem Marketplace & New Carbon Finance, 2009). So, this contract type may be neglected.

CHAPTER VII

GOLD STANDARD

Many companies and organizations are willing to reduce their carbon emissions voluntarily either by their own carbon offset projects or by financing partially carbon offset projects of others, that lead to the emergence and development of voluntary carbon markets. But they want to be sure about the quality of carbon offsets they are buying. The standards with credible methodologies, tools and monitoring plans help to provide confidence to the buyers by guarenteeing emission reductions. These voluntary carbon standards can be classified in two main categories: basic carbon standards that guarentee the credits issued to correspond to an emission reduction of one ton of CO_2 such as Voluntary Carbon Standard and multiple-benefit carbon standards that additionally involve environmental and social benefits such as Gold Standard (Guigon, Bellasen & Ambrosi, 2009). This chapter mainly focuses on Gold Standard. After a general comparison of Gold Standard (GS) with Voluntary Carbon Standard (VCS) that are the most widely used carbon standards, general outlook of Gold Standard will be explained. Then the first section will analyse Gold Standard VER projects in the light of the most recent statistical data and will show the Turkey's dominance in this market. The second section will explain the project eligibility criterias in details that may help to show the opportunities for project developers especially for renewable energy projects. The sections from the third to the seventh will explain the regulations for project cycles, Gold Standard documentation, fee structure, additionality assessment and sustainability assessment that are critical issues for project developers. The eight section will show how to calculate emission reductions in the light of Gold Standard regulations and as a case study, the combined emission factor for Turkish wind power projects will be calculated that may be used by wind power project developers in 2010, by using the most recent data available. Combined emission factor is the most important variable in calculating emission reductions and so the amount of GS VER credits. This value can also help to estimate the emission reductions originating from wind power projects in different wind power capacity installation scenarios. The last section will calculate how much revenue would Turkey's target of 20,000 MW wind power projects would generate by selling as VERs in the voluntary carbon market or as CERs in the EU ETS. In additon, the last section will calculate how many tonnes of CO_2 would be avoided in case 20,000 MW wind power capacity installation target is achieved.

GS and VCS will be compared as follows: VCS is a basic carbon standard whereas Gold Standard is a multiple-benefit carbon standard. Another important difference is the scope of the projects they involve: VCS registers all carbon offset projects whereas Gold Standard registers only renewable energy and end-use energy efficiency projects. The project types eligible for Gold Standard will be explained in details in the succeeding subtitle.

Retro-active crediting is forbidden for projects registered after 31 March 2007. Emission reductions originating from CDM projects can only be credited after project registration. These CDM projects certificate credits while they are waiting for registration by the CDM Executive Board. Pre-CDM credits comprise 71% of credits registered by VCS in 2007, and this share decreases to 60% in 2008; the share of pre-CDM credits was 59% registered by GS VER in 2007, but there is no pre-CDM credits registered by GS VER in 2008 since they are credited as GS CDM in 2008 (Guigon, Bellasen & Ambrosi, 2009).

Most of the professionals interviewed by researchers said that a Gold Standard credit is worth 50% to 100% more than its CDM or voluntary equivalent (VCS or VER+) because of its limited availability and strong corporate demand and its co-benefits (Guigon, Bellasen & Ambrosi, 2009).

When the transaction costs are compared, Table 144 shows that GS CDM is the most costly standard since this involves fees and works for both CDM and GS. Although the GS VER is more costly than VCS, the price difference seems to be negligible when the price premiums of GS VER are taken into account. CDM being more costly than GS VER largely comes from the 2% of CERs to adaptation fund, meaning 0.3 €/VER, when CER prices are assumed to be 15 €.

Table 144. Total Transaction Costs (in €/VER) for a Non-forestry Large Scale Project (50 ktCO2/year, Verified Every Year During 7 years) (Guigon, Bellasen & Ambrosi, 2009)

	CDM*	GS CDM*	GS VER	VCS
Total Certification (Validation, Verification, Registration and Registry Fees)	0.58	0.68	0.32	0.26
Total Including Consultancy/Internal (PDD Development and Management of Certification)	0.85	1.00	0.59	0.48

*To include 2% share of CERs issued to projects for the UN adaptation fund, CERs are assumed to trade at 15-€, that adds 15.000-€/year of forgone carbon revenues to the transaction costs.

To reach an IRR benchmark of 10%, the credit price ranges from 13.35 € (for VER+ that is the least costly 0.40 €/VER) to 13.72 € (for CDM GS that is the most costly 1.00 €/VER) for a case of CDM hydropower project of 50 ktCO_2e (Guigon, Bellasen & Ambrosi, 2009). So, the cost of the standard does not influence the IRR of a project.

Table 145 shows total transaction costs for a non-forestry small scale project as follows:

Table 145. Total Transaction Costs (in €/VER) for a Non-forestry Small Scale Project (5 ktCO2/year, Verified at Years 1, 3, 5 and 7) (Guigon P., Bellasen V. and Ambrosi P., 2009)

	CDM SSC*	GS VER Micro	VCS
Total Certification (Validation, Verification, Registration and Registry Fees)	1,16	0,35	0,94
Total Including Consultancy/Internal (PDD Development and Management of Certification)	3,10	2,60	2,37

*To include 2% share of CERs issued to projects for the UN adaptation fund, CERs are assumed to trade at 15-€, that adds 15,000-€/year of forgone carbon revenues to the transaction costs.

The transaction costs for small scale CDM, GS VER Micro and VCS are much more than large scale projects, mostly due to the fixed costs. Although CDM and GS VER have more favourable cost structures for small scale projects, VCS does not have significant cost-cuts according to project size. But these measures do not prevent them to be highly costly, largely coming from the consultancy/internal costs like PDD development and management of certification since they are usually fixed costs.

After a general comparison of VCS and GS, from hereon Gold Standard will be focused on in details as follows: Because, GS is more suitable and important for Turkey of which voluntary carbon market nearly completely depends on renewable energy. Carbon offsets with Gold Standard also have price premiums that seem more attractive for project developers.

A research by Mission Climat of Caisse des Depots tracked 64 projects all to be operational by 2010, of which 34 projects are wind projects, 22 hydro, two geothermal and two landfill gas, showing the great potential of renewable energy projects of Turkey (Guigon, Bellasen & Ambrosi, 2009). 45 projects of them were registered by GS VER, 12 projects by VCS, 6 projects by VER+ and 5 of them are not registered by any standard. The research has emission redution data for 54 projects, and they are expected to generate 5.1 MtCO_2e/year by 2010 and a total of 19.7 Mt CO_2e by 2012, and 22.6 Mt CO_2e emission reduction is estimated by 2012 when 64 projects are taken into account (Guigon, Bellasen & Ambrosi, 2009).

As seen above, Turkish voluntary market is characterized by renewable energy projects according to project type and GS VER according to standard utilized. Turkey is a dominant market for voluntary carbon offsets, that largey comes from the Turkey's status as an Annex-I but non-Annex B Party. So, Turkey is not eligible to host CDM or JI projects, leaving the voluntary market the only option for Turkey.

The Gold Standard Foundation, the Gold Standard Rules and Procedures, and its high-quality will be explained in the succeeding paragraph in the light of the information obtained from the official website of the Gold Standard.

The Gold Standard Foundation is a non-profit organization under Swiss law, owned by over 60 non-governmental organizations worldwide. The Gold Standard Foundation registers renewable energy and end-use efficient projects that reduce greenhouse gas emissions in ways that contribute to sustainable development and certifies their carbon credits (GS CER and GS VER) for sale on both compliance offset markets established by the Kyoto Protocol and in non-Kyoto voluntary offset markets. Gold Standard labels are issued for carbon credits of qualifying CDM and JI projects and these projects are tracked in the UNFCCC/CDM Registry, whereas projects developed under the voluntary carbon market rules are tracked in the Gold Standard Registry. The Gold Standard incorporates all five UNFCCC criteria for CDM carbon offset projects, namely: additionality of emissions reductions compared to the business as usual situation, no adverse environmental impact, consistency with host country sustainable development strategy, emissions reduction benefits that are real and measurable, and no diversion of official development assistance (ODA) to finance carbon offset projects. The Gold Standard provides an assurance that the carbon credits having its label are of high quality in the voluntary carbon market, and it adds value to the CDM criteria in the compliance market by its provision for documented local stakeholder involvement. The Gold Standard certification scheme involves carbon credits originating from only renewable energy and end-use energy efficiency projects that actively promote sustainable development. A firm or organization wishing to obtain GS certification follows the same steps as for the CDM, but must supply additional information. Carbon offset projects that satisfy Gold Standard requirements are granted permission to use the GS brand name and logo that is a trademarked brand that represents premium quality in the carbon market, assuring to buyers of carbon credits that planned emissions reductions are realistic, and that they will be generated in ways that contribute to sustainable development . Due to these assurances, carbon credits that are sold with the Gold Standard label fetch a premium price. Gold Standard documentation involves two main parts: the Gold Standard Requirements, and the Gold Standard Toolkit. The Gold Standard Requirements present the fundamental principles and the rules of Gold Standard certification. The Gold Standard Toolkit, describes the project cycle and provides examples and detailed instructions. The Toolkit comes with fixed templates which have to be used to report information. The Gold Standard Toolkit includes its annexed Gold Standard Terms & Conditions, templates and Cover Letter, the Gold Standard Registry Terms of Use, the Gold Standard VER Additionality Tools, and the Gold Standard VER Methodologies. The Gold Standard Rules and Procedures for CDM (GSv0) was launched in 2003. GSv0 was upgraded to become GSv1 for CDM projects in early 2006, and a GSv1 for use within the voluntary carbon market - the Voluntary Gold Standard (GS VER) - was launched in May 2006. The GSv1 documents were subsequently amended twice - Gold Standard Rules Updates and Clarifications, in July and December 2007. Both GSv1 documents were replaced in August 2008 by the Gold Standard Requirements and the Gold Standard Toolkit (GSv2). Then this was upgraded by the Gold Standard Requirements and the Gold Standard Toolkit Version 2.1 on 01 June 2009, that takes affect on 01 July 2009. According to Gold Standard Requirements Version 2.1; "all projects applying under the regular project cycle that have not submitted the complete LSC report and all projects applying under the retroactive project cycle that have not submitted the complete documentation required for a pre-feasibility assessment and have not paid the pre-feasibility assessment fee by August 1 2009, will be required to employ the entirety of Version 2.1 (p.12)." Version 2.1 takes effect on July 1, 2009 and is available for immediate use.

Rules of the Gold Standard Requirements Version 2.1 will be referred in this study to have a general idea about the fundamental principles and rules. Some important issues for our study like additionality, baseline scenarios, etc. will be explained by the help of the Gold Standard Toolkit and all its annexes. Rule I.a.1 states that, unless otherwise indicated within the Gold Standard documentation, all projects submitted to the Gold Standard for certification must be consistent with applicable UNFCCC rules for CDM or JI projects, as periodically updated. According to Rule I.b.1, all Gold Standard projects should be consistent with applicable Gold Standard documentation, namely Gold Standard Requirements; Gold Standard Toolkit and its annexes, including its annexed Gold Standard Terms & Conditions, templates and Cover Letter; Gold Standard Registry Terms of Use; Gold Standard VER Additionality Tools; and Gold Standard VER Methodologies.

Turkey’s Position in GS VER Projects as an Emerging Market

This subtitle will provide statistical data and analysis about Gold Standard VER Projects and these data are provided from Gold Standard Registry Database. Table 146 shows expected average annual amount of Gold Standard VER credits by status and their percentage shares as follows:

Table 146. Expected Average Annual Amount of Gold Standard VER Credits by Status and Their Percentage Shares as of 08 January 2010 (Gold Standard Registry Database, 2010)

Status	Amount of Credits	Percentage Share (%)
Listed	6,189,808	58.2%
Validated	1,775,896	16.7%
Registered	1,358,703	12.8%
Issued	1,309,435	12.3%
Total	10,633,842	100.0%

10,663,842 GS VER credits are expected to generate annually. More than half (58.2%) of the expected average annual amount of GS VER credits are only listed and issued credits comprise only 12.3% of total expected GS VER credits. So, the amount of issued credits can rise substantially in the near future.

Table 147 shows the expected average annual amount of Gold Standard VER credits and number of projects by project types and their percentage shares.

Table 147. Expected Average Annual Amount of Gold Standard VER Credits and Number of Projects by Project Types and Their Percentage Shares as of 08 January 2010 (Gold Standard Registry Database, 2010)

Project Type	Amount of Credits	Percentage Share of VER Credits (%)	Number of Projects	Percentage Share of Number of Projects (%)
Wind	6.303.752	59.3%	57	40.7%
Small, Low-Impact Hydro	741.681	7.0%	34	24.3%
Energy Efficiency – Industrial	351.453	3.3%	3	2.1%
Biomass, or Liquid Biofuel – Heat	306.333	2.9%	3	2.1%
Energy Efficiency – Domestic	255.014	2.4%	8	5.7%
Biogas – Heat	157.384	1.5%	6	4.3%
Energy Efficiency – Public Sector	139.702	1.3%	3	2.1%
Biomass, or Liquid Biofuel – Cogeneration	136.222	1.3%	2	1.4%
Biomass, or Liquid Biofuel – Electricity	105.453	1.0%	3	2.1%
Biogas – Electricity	102.552	1.0%	5	3.6%
Geothermal	75.000	0.7%	2	1.4%
Energy Efficiency – Commercial Sector	61.933	0.6%	1	0.7%
Solar Thermal – Heat	20.000	0.2%	1	0.7%
PV	6.300	0.1%	2	1.4%
Liquid Biofuel – Transportation	2.695	0.0%	1	0.7%
Other	1.868.368	17.6%	9	6.4%
Total	0	100.0%	140	100.0%

Wind power projects dominate in both the amount of VER credits (59.3%) and number of projects (40.7%). Small, low-impact hydro projects comes after wind projects with 34 projects comprising 24.3% of total projects. But the share of small, low-impact hydro projects in expected annual amount of credits is only 7.0%. The discrepancy between them comes from the fact that these hydro projects are quite small, as understood from its name of project type. Energy efficiency projects comprise only 7.6% of expected annual GS VER credits and 10.6% of total projects. So, renewable energy projects have a nonconsestable predominance in GS VER projects in both expected credits and number of projects.

Table 148 shows the expected average annual amount of Gold Standard VER credits and number of projects by project locations and their percentage shares.

Table 148. Expected Average Annual Amount of Gold Standard VER Credits and Number of Projects by Country of Project Locations and Their Percentage Shares as of 08 January 2010 (Gold Standard Registry Database, 2010)

Country	Amount of VER Credits	Percentage Share of VER Credits (%)	Number of Projects	Percentage Share of Project Numbers (%)
Turkey	5,912,972	55.6%	63	45.0%
China	1,810,574	17.0%	28	20.0%
United States	715,884	6.7%	4	2.9%
Taiwan	608,000	5.7%	3	2.1%
New Zealand	310,500	2.9%	2	1.4%
Russian Federation	268,448	2.5%	1	0.7%
Ghana	155,367	1.5%	2	1.4%
Malawi	142,700	1.3%	2	1.4%
India	95,739	0.9%	8	5.7%
South Africa	81,533	0.8%	2	1.4%
Uganda	74,083	0.7%	1	0.7%
Mali	72,112	0.7%	1	0.7%
Bolivia	66,222	0.6%	1	0.7%
Other	47,681	3.0%	22	15.7%
Total	10,361,815	100.0%	140	100.0%

Turkey is obviously the domimant market in terms of both expected annual credits with a 55.6% share of total credits and in terms of number of projects with 45% of total projects. Since the share of Turkey in annual credits is more than the share in project numbers, average expected credits per project is higher in Turkey than the general average. China is the second market with 17.0% share in total expected annual credits and 20.0% of total projects. So, Turkey and China together comprise nearly two thirds of GS VER market. United States, Taiwan, New Zealand and Russia’s average VER credits per project more than doubles the general average. The opposite is in place for Indian projects, with nearly one sixth of average credits per project, namely 5.7% of projects comprising only 0.9% of total credits.

Table 149 shows the expected average annual amount of Gold Standard VER credits and number of projects in Turkey by project types and their percentage shares.

Table 149. Expected Average Annual Amount of Gold Standard VER Credits and Number of Projects in Turkey by Project Types and Their Percentage Shares as of 08 January 2010 (Gold Standard Registry Database, 2010)

Project Type	Amount of VER Credits	Percentage Share of VER Credits (%)	Number of Projects	Percentage Share of Project Numbers (%)
Wind	3,550,035	60,0%	37	58,7%
Small, Low-Impact Hydro	649,937	10,9%	20	31,8%
Geothermal	75,000	1,3%	2	3,2%
Other	1,638,000	27,7%	4	6,3%
Total	5,912,972	100,0%	63	100,0%

Wind power projects dominate the Turkish GS VER market as is the global case. The percentage shares of GS VER credits and number of projects are near to each other with 60.0% and 58.7% shares respectively whereas the shares are 55.6% and 45.0% for global GS VER projects. So, Turkish amount of VER credits generated per wind power projects in Turkey is smaller than the general average. The other category is expected to generate the most VER credits per project, with 4 projects (6.3% of total) expected to generate 27.7% of total GS VER credits.

20 small, low-impact hydro projects comprise the second largest portion of total number of projects as is the case globally. But the share of small, low-impact hydro projects comes after other projects category in VER credits, different from the global case. Other category comprises 27.7% of total GS VERs and this high share largely comes from a huge project that comprises more than half of the other category: This is a project expected to generate 988,000 VER credits from a landfill gas extraction and electricity generation project in Turkey developed by Ortadoğu

Enerji A.Ş. This project is also the largest annual VER credits generating project in the Gold Standard Registry Database. Its status is listed as of 08 January 2010.

Table 150 shows the expected average annual amount of Gold Standard VER credits in Turkey by project types and status.

Table 150. Expected Average Annual Amount of Gold Standard VER Credits in Turkey by Project Types and Status as of 08 January 2010 (Gold Standard Registry Database, 2010)

Status	Project Type	Amount of VER Credits	Amount of VER Credits
Listed	Geothermal	43,000	3,415,883
	Other	1,388,000	
	Small, Low-Impact Hydro	601,335	
	Wind	1,383,548	
Validated	Small, Low-Impact Hydro	48,602	874,976
	Wind	826,374	
Registered	Geothermal	32,000	1,069,442
	Wind	1,037,442	
Issued	Other	250,000	552,671
	Wind	302,671	

63 projects in Turkey are expected to genarate 5,912,972 GS VER credits annually. 3,415,883 of these credits are expected to come from projects of which status is listed. Only 552,671 credits are issued of which 302,671 credits come from wind power and 250,000 credits come from other category. Another characteristic is the overmuch dominance of credits generated from wind power projects in the registered and validated status comprising nearly all of credits, whereas wind power projects share is dominant in the status of listed and issued. And small, low-impact hydro projects are all in the listed status.

Project Eligibility Criterias

Project eligibility criterias are determined in Rule III of Gold Standard Requirements Version 2.1. "Rules" in this chapter refer to rules of Gold Standard Requirements Version 2.1. General eligibility requirements, eligibility criterias about project activity locations, project activity gases, project types, project scales, methodologies and relationship between GS CDM/JI and GS VER will be stated in this subtitle as follows:

General eligibility requirements are determined in Rule III.a.1. According to this Rule; all Gold Standard projects must be

-additional,

-contribute to sustainable development and

-result in real, measurable and verifiable permanent emission reductions.

Eligibility criterias about project activity locations will be explained below:

Gold Standard CDM project activities must be located in a non-Annex I country, as defined by the UNFCCC (Rule III.b.1). Gold Standard JI project activities must be located in an Annex I country with a commitment inscribed in Annex B, as defined by the UNFCCC (Rule III.b.2). Gold Standard VER project activities may be located in any host country or state. However, where host countries or states have caps on GHG emissions, projects shall only be eligible if the Project Proponent has provided the Gold Standard Foundation with satisfactory assurances that an equivalent amount of allowances will be retired to back-up the GS VERs issued. Any AAUs may be retired for this purpose. Gold Standard credits will not be issued prior to confirmation by the relevant local authorities that an equivalent amount of allowances has been retired (Rule III.b.3).

Only Carbon Dioxide (CO_2), Methane (CH_4) and/or Nitrous Oxide (N_2O) are eligible for Gold Standard crediting (Rule III.c.1). Project activities involving the reduction of both eligible and noneligible greenhouse gases will be eligible under Gold Standard for the crediting of emission reductions associated with eligible gases only (Rule III.c.2).

Eligibility criterias about project types will be explained as follows:

Only two categories of project activities are eligible for Gold Standard registration: Renewable Energy Supply and End-use Energy Efficiency Improvement project activities (Rule III.d.1). Project activities of renewable energy supply is defined as the generation and delivery of energy services (e.g. mechanical work, electricity, heat) from non-fossil and non-depletable energy sources. Although making use of a depletable source, landfill gas projects are eligible under the Gold Standard (Rule III.d.2). Project activities of end-use energy efficiency improvement is defined as activities that reduce the amount of energy required for delivering or producing non-energy physical goods or services (Rule III.d.3). Energy supply and end-use energy efficiency improvement project activities must additionally comply with the specific eligibility criteria set out in Annex C of the Gold Standard Toolkit (Rule III.d.4).

Annex C of the Toolkit determines additional specific eligibility criteria for some of the eligible types of project activities, namely: Hydro; electricity and/or heat, and liquid biofuels from biomass resources; biogas (landfill gas and biogas from agro-processing, wastewater and other residues); waste heat recovery; waste gases recovery; fossil-fired cogeneration; waste incineration and gasification; relighting; end-use fossil fuel switching; improved distributed heating and cooking devices (e.g. biodigesters, cook-stoves), and distributed micro-scale electricity generation units (e.g. micro-hydro and PV for households).

Additional criterias about hydro projects are as follows:

- All hydro projects must at least discuss the relevance and implications of the full list of items provided in Table C.2 of Annex C as part of the sustainable assessment process.

- Project activities involving hydropower plants with an installed capacity of less than, or equal to 20 MWe shall be eligible for Gold Standard registration. This capacity threshold will apply to each one of the project activities part of a bundle, and not to the overall bundle.

- The eligibility of project activities involving a hydropower plant with an installed capacity greater than 20 MWe will be evaluated on a caseby-case basis by the Gold Standard Foundation, in the light of a Prefeasibility assessment. The project participant will provide a Local Stakeholder Consultation Report and a Compliance Report, as part of the documentation to be reviewed.

Unless otherwise specified in the Gold Standard documentation, and in particular in the list of additional eligibility criteria provided in Annex C of the Toolkit, activities making use of a mix of renewable and non-renewable energy sources will be eligible to claim credits for those emission reductions that are associated with the share of renewable energy sources in the total energy service delivered (Rule III.d.5).

Where project activities are submitted together for Gold Standard registration within a bundle of activities (bundled project activities), each project activity should individually be in compliance with the Gold Standard eligibility criteria. Eligibility criteria with regards to the scale of the project will apply to the bundle as a whole and not to the individual project activities (Rule III.d.6). Where a group of project activities is (programme of activities) submitted together for Gold Standard registration within a Programme of Activities, each of these activities must be in compliance with the Gold Standard eligibility criteria. Micro-scale project activities cannot apply under a Progamme of Activities (Rule III.d.7).

Eligibility criterias about project scales will be explained as follows:

Gold Standard CDM or JI project activities may be 'large-scale' or 'small-scale' project activities (Rule III.e.1), whereas Gold Standard VER project activities may be 'large-scale', 'small-scale' or 'micro-scale' project activities. 'Large-scale' and 'small-scale' project activities are defined in accordance with UNFCCC rules, as explained in Section 1.2.a of the Toolkit. 'Micro-scale' project activities are those project activities associated with annual emission reductions of less than 5,000 tCO2e in each year covered by the Gold Standard crediting period (Rule III.e.2).

Where the maximum level of allowable annual emission reductions for a small-scale or micro-scale project has been exceeded, that project will only be eligible for Gold Standard CERs, ERUs or VERs up to the maximum number of allowable credits under that project scale per annum. No GS VERs can be claimed for emission reductions generated over and above what is credited under a small-scale CDM or JI project (Rule III.e.3). GS VERs may be claimed for separate project elements not covered by a CDM project activity as long as they are validated separately as a VER project activity (Rule III.e.4).

Eligible methodologies for project activities will be explained as follows:

CDM and JI project activities must use an approved UNFCCC CDM methodology to be eligible for Gold Standard registration (Rule III.f.1). VER project activities must use either an approved UNFCCC CDM methodology or a GS VER methodology to be eligible for Gold Standard registration. All project activity documentation submitted to the Gold Standard must apply the most recent version of the selected methodology available at the time of first submission of the project activity for Gold Standard registration (Rule III.f.2). Unless there is a convincing case for an alternative choice of baseline methodology, Project Proponents must use the approved methodology, and the option within this methodology, that results in the lowest baseline emissions (Rule III.f.5). Applicable methodologies and guidelines about selecting baseline and monitoring are provided in section 2.2 of the Toolkit in details. These methods will be explained in succeeding sections in details.

There is a strong relationship between GS CDM/JI and GS VER. A project activity may be submitted for registration to both the Gold Standard CDM/JI stream and the Gold Standard VER stream in parallel. If the proposed CDM/JI project activity is successfully registered under the UNFCCC, the Gold Standard VER project activity will be cancelled. If the proposed CDM/JI project activity is rejected by the UNFCCC, in order to continue registration of the project activity under the GS VER stream the project proponent must apply for a feasibility assessment in accordance with the procedure provided in section 2.5 of the Toolkit (Rule III.h.1).

A Project Proponent may seek to upgrade a Gold Standard VER project activity to a Gold Standard CDM/JI project activity at any time during the crediting period with respect to future emission reductions, provided the Project Proponent either applies under the Gold Standard CDM/JI stream before any GS VERs have been issued, or enters into an agreement with the Gold Standard Foundation according to which the project applicant commits to surrender to the Gold Standard Foundation, for immediate retirement, CERs or ERUs that will be issued in respect of GHG Reductions generated by the Project in an amount equal to VERs already issued (Rule III.h.3).

Key Elements of the Regular Project Cycle

Key elements of the regular project cycle include (Rule IV.b.2):

Project planning, design and reporting (assessment of project eligibility, initial drafting of Project Design Document (PDD), selection of baseline and monitoring methodology, additionality assessment, sustainability assessment and creation of Sustainable Development Matrix and Sustainability Monitoring Plan, Local Stakeholder Consultation, drafting and submission of Stakeholder Consultation Report, project revisions as necessary, stakeholder feedback, and finalisation and submission of Gold Standard Passport and PDD; Validation; Gold Standard registration review; Project registration; Monitoring; Reporting; Gold Standard verification review; Project verification; Gold Standard certification; and Gold Standard crediting/issuance.

The six stages leading to issuance of Gold Standard carbon credits are explained in the official webiste of the Gold Standard as follows: The first stage is Planning and this stage involves getting familiar with GS method, assessing project eligibility; beginning drafting Project Design Document (PDD) and GS passport; and openning an account in the Gold Standard Registry and Project Administration System. The second stage Designing involves selecting baseline and monitoring methodologies, assessing additionality, assessing sustainability, applying for a pre-feasibility assessment if required, organizing and reporting on local stakeholder consultation, revising PDD and GS passport, obtaining Gold Standard applicant status and taking first round of Gold Standard stakeholder review. The third stage is validation and this stage involves validation by DOE, submitting completed and validated PDD and GS passport, and taking second round of Gold Standard stakeholder review. The fourth stage is Registration and this stage involves submitting registration documents and pay fee. The fifth stage is Verification and this stage involves monitoring and reporting on emissions reductions and sustainable development, and verification and certification by DOE. The sixth stage is certification and this stage involves Gold Standard review and certification, Gold Standard Foundation issuance of carbon credits and labels and, certification renewal.

The most important stages of this process are validation, verification and certification. These are defined in Rule II of Gold Standard Requirements as follows:

Validation is an independent evaluation by a Designated Operational Entity (DOE) or Accredited Independent Entity (or an internal evaluation by the Gold Standard in the case of a micro-scale project) that a project fulfils Gold Standard validation requirements. DOE is a private company that have been accredited by the United Nations as competent project evaluators responsible for validating a project. They validate that an offset project is designed in a credible way, and they control the projects themselves to make sure that the carbon emission reduction has actually been achieved.

Verification is the periodic independent review and ex post determination by a DOE of monitored reductions in anthropogenic emissions by sources of GHGs that have occurred as a result of a registered project activity during the verification period.

Certification is the written assurance by the designated operational entity that, during a specified time period, a project activity achieved the reductions in anthropogenic emissions by sources of GHGs as verified.

Additionality Assessment

All Gold Standard project activities must be demonstrated to be additional, meaning that they shall reduce anthropogenic emissions of greenhouse gases below those that would have occurred in the absence of the registered Gold Standard project activity (Rule VI.a.1).

Gold Standard CDM and JI project activities, of whatever scale and type, are required to use a UNFCCC-approved additionality tool to demonstrate project additionality (Rule VI.b.1). Project Proponents must use the latest version of the additionality tool that is available at the time of first submission to the Gold Standard (Rule VI.b.2).

Gold Standard VER project activities, of whatever scale and type, are required to use either a UNFCCC-approved or a Gold Standard-approved additionality tool to demonstrate project additionality (Rule VI.c.1). Project Proponents must use the latest version of the additionality tool available at the time of first submission to the Gold Standard. This tool may be used by the project activity until the project it is registered (Rule VI.c.2).

Proposals may be made for new Gold Standard VER additionality tools, following the procedures detailed in section 5.2 of the Toolkit. Additionality tools currently available are provided in section 2.3 of the Toolkit. The UNFCCC approved additionality tools are “combined tool to identify the baseline scenario and demonstrate additionality" and "tool for the demonstration and assessment of additionality".

Mandatory guidance for the use of the UNFCCC tools for demonstration of additionality is as follows (The Toolkit, section 2.3): Identification of alternative scenarios, barrier analysis, investment analysis and common practice analysis.

In identification of alternative scenarios; realistic alternatives that provide the same service output (e.g. kWh) as the project is presented and the legislation applicable to the project is stated.

In barrier analysis; how the income from carbon credits helps to overcome or alleviate the identified barriers is explained. Barriers should be credible and should prevent the project from occurring without registration as a CDM/JI or VER project. It is shown that these identified barriers would not prevent the implementation of at least one of the alternatives (except the project activity).

If investment analysis is used to demonstrate additionality, the PDD provides evidence that the project is economically/financially unattractive without the revenue from the sale of carbon credits because:

-There are costs associated with the project activity and it is demonstrated that the activity produces no economic benefits other than carbon credits related income;

-The proposed project activity is economically or financially less attractive than at least one other plausible alternative;

-The financial returns of the proposed project activity are insufficient to justify the required investment.

In common practice analysis; it is demonstrated that the project is not common practice in the region or country in which it is being implemented.

Annex G involves examples on demonstration of additionality. According to an example given in Annex G, the investment analysis is conducted in the following steps:

Determining appropriate analysis method

Applying benchmark analysis

Calculation and comparison of financial indicators:

Sensitivity analysis

In determining appropriate analysis method, tools for the demonstration and assessment of additionality (Version 03) suggest three analysis methods:

Simple cost analysis (option I),

Investment comparison analysis (option II),

Benchmark analysis (option III).

Since electricity generation from renewable energy resources earn the revenues not only the CDM but also electricity sales, the simple cost analysis method (option I) is not appropriate.

Investment comparison analysis method (option II) is applicable to projects whose alternatives are similar investment projects. The alternative baseline scenario of a power plant installation project is the Turkish Power Grid rather than new investment projects. Therefore investment comparison analysis method (option II) is not an appropriate method. These project types use benchmark analysis method (option III) based on the consideration that benchmark IRR and equity IRR of the power sector are both available.

Sustainability Assessment

In sustainability assessment, a Do No Harm Assessment and a Detailed Impact Assessment should be made, and a Sustainability Monitoring Plan should be prepared.

All Project Proponents are required to assess the risk that their project activities will have severe negative environmental, social and/or economic impacts through a 'Do No Harm' Assessment, to be completed in the project's Gold Standard Passport (Rule VII.a.1). All Project Proponents are required to demonstrate that their project activities will have clear sustainable development benefits through a Detailed Impact Assessment, to be completed in the project's Gold Standard Passport (Rule VII.a.2). All Project Proponents are required to elaborate a Sustainability Monitoring Plan to assist in monitoring the impact of project activities on sustainable development and in verifying that the project has indeed contributed to sustainable development (Rule VII.a.3).

Detailed information and guidelines about sustainability assessment are provided in section 2.4 of the Toolkit.

Gold Standard project activities should be in compliance with the list of safeguarding principles provided in section 2.4.1 of the Toolkit. Project proponents should assess their project against these safeguarding principles in accordance with the guidelines provided in Annex H (Rule VII.b.1). Project activities that violate or risk violating any of the safeguarding principles will not be eligible for Gold Standard registration unless the design of the project is adapted to restore compliance with these principles or convincing mitigation measures are put in place to ensure the harmful effect will not occur. The Project Proponent is required to ensure that appropriate mitigation measures are implemented and monitored over the crediting period of the project activity (Rule VII.b.2).

All Gold Standard projects must demonstrate clear benefits to sustainable development through completion of a Detailed Impact Assessment (Rule VII.c.1). Gold Standard project applicants will assess their project activities against a series of twelve Sustainable Development Indicators in three categories: Environment, Social Development and Economic and Technological Development (Rule VII.c.2). Gold Standard Project Proponents shall score each of the Sustainable Development Indicators either negative (-1), neutral (0), or positive (+1) in close collaboration with the local stakeholders, and against the baseline situation, i.e. the most likely situation if the project were not implemented. All indicators will be given the same weight. In order to qualify for Gold Standard registration, project activities must at a minimum contribute positively to two of the three categories and be neutral to the third category. Project activities that do not comply with the minimum scoring requirements will not be eligible unless the project design is altered to result in compliance, or mitigation measures are put in place to neutralise some of the indicators scoring negatively. These mitigation measures will be monitored over the crediting period of the project activity.

Crediting Period

Gold Standard crediting period is defined as the period of time for which Gold Standard project activities generate emission reductions that are eligible for crediting under the Gold Standard (Rule II). The total duration of the crediting period for Gold Standard project activities cannot exceed the duration of the Standard

UNFCCC crediting period, regardless of project cycle and start date (Rule V.a.3). Under the UNFCCC rules, standard UNFCCC crediting period is either a 7-year period that can be renewed twice, for a total of 21 years, or a one-off 10-year period. Where a Gold Standard project activity has been or is registered under one or more other voluntary carbon standards or certification schemes, the total crediting period under all schemes combined will not exceed the Gold Standard crediting period when all carbon credits sought by Project Proponents under the Gold Standard and under other standards or schemes are aggregated (Rule V.a.4).

Duration of gold standard crediting period is determined under Rule V.a.1. According to this Rule, Gold Standard project activities that generate emission reductions are eligible to claim credits for no more than a 7-year period that can be renewed twice, for a total of 21 years, or a one off 10-year period, consistent with the allowable Standard UNFCCC Crediting Period. Where a 7-year renewable period is chosen, the baseline and sustainability assessment must be renewed and revalidated after each 7-year period (Rule V.a.1).

For VER project activities proceeding under the regular project cycle, the start date of the Gold Standard Crediting Period will be the date of start of operation or a maximum of two years prior to Gold Standard registration, whichever occurs later (Rule V.a.2.1), and it will be the date of registration under CDM or JI or a maximum of two years prior to Gold Standard registration, whichever occurs later for CDM or JI project activities proceeding under the regular project cycle (Rule V.a.2.2). Project activities proceeding under the retroactive project cycle, may be eligible for retroactive crediting for realised emission reductions prior to Gold Standard registration of a maximum period of two years (Rule V.a.2.3). The start date of the Gold Standard Crediting Period may be postponed for one year without justification required, or for up to two years if convincing justification is provided (Rule V.a.2.4).

Fee Structures

There are two types of fee structures in the Gold Standard: Fixed cash-per credit fee structure and share of proceeds fee structure. The main features of these fee structures are stated in Chapter 6 of the Gold Standard Toolkit, Rule X of Gold Standard Requirements and Annex L.

Both the Gold Standard Foundation and the Gold Standard Registry Administrator levy various cash fees at different stages of the project development process, that may be seen in Annex L. Under this fee structure, the fees are usually calculated by multiplying the number of credits registered, issued or transferred by the pre-determined cash amount.

Effective 1 August 2009, new projects applying for the Gold Standard are no longer charged a per credit fixed cash registration or issuance fee. Instead of the fixed cash fees, the project proponent will deduct a pre-determined percentage of credits from the final credit issuance and transfer the deducted credits to the Gold Standard Foundation's registry account. Under this fee structure, the Gold Standard is entitled to 1.5% of CERs and 2% of VERs. According to Gold Standard Toolkit, for CERs, the number of CERs deducted under the Share of Proceeds will be net of the CERs dedicated to the Adaptation Fund. For example, if 1,000,000 CERs are issued, then 20,000 will be deposited into the Adaptation Fund. The Gold Standard will then deduct and effectuate the transfer of 14,700 credits, or 1.5% of the remaining 980,000 CERs, to its registry account.

The Share of Proceeds Fee Structure does not relieve the project proponent from paying other applicable fees as listed in both Annex L and the Gold Standard Registry Fee Schedule.

The Share of Proceeds fee structure will apply to all projects applying under the regular project cycle that have not submitted the complete LSC report by 1 August 2009, or all projects applying under the retroactive project cycle that have not submitted the complete pre-feasibility assessment documentation and have not paid the pre-feasibility assessment fee by 1 August 2009 (Rule X.b.1). Any GSv1 or GSv2 project not meeting the requirements in Paragraph X.b.1. may, at anytime, upgrade from the Fixed Cash-Per-Credit fee structure to the Share of Proceeds fee structure by notifying the Gold Standard Foundation (Rule X.b.2).

In addition to the fees described in Annex L, 1.5% of the net CERs or ERUs issued to the Project Proponent or 2.0% of the total VERs issued to the Project Proponent will be due and payable to the Gold Standard Foundation at the time of issuance (Rule X.b.3, 4). For micro-VERs, in addition to the fees described in Annex, 2.0% of the total VERs issued to the Project Proponent will be due and payable to the Gold Standard Foundation at the time of issuance (Rule X.b.5). Annex L describes fees as follows:

Table 151. Gold Standard Fee Structure (Gold Standard Toolkit Annex L)

	GSv2 CER/ERU	GSv2 VER	GSv2 micro VER
Account Subscription Fee	Registry Fee of 500 USD		
Pre-Feasibility Assessment Fee	GS Fee of 0.10 USD per credit for one year of expected average emission reductions		
Micro-scale Project Validation Fee			GS Flat Fee of 5,000 USD to initiate the internal validation
Project Registration Fee	GS Fee of 0.05 USD per credit for the anticipated amount of emission reductions certified after the first verification of a minimum of one year of monitoring (anticipation of the first issuance fee)		
CER/ERU Labeling Fee	GS Fee of 0.05 USD per label, to initiate labeling[1] GSv1/2 SoP: 1.5% of net credits labeled		
VER Issuance Fee		Total of 0.15 USD/credit (0.10 USD/credit for GS and 0.05 USD/credit for registry) GSv1/2 SoP: 2% of credits	Total of 0.15 USD/credit (0.10 USD/credit for GS and 0.05 USD/credit for registry) GSv1/2 SoP: 2% of credits
Micro-scale Project Verification Fee			GS Annual flat fee of 2,500 USD; first fee within 9 months after registration
Credit Transfer Fee	Registry Fee of 0.01 USD/credit on all secondary transfers, charged to the seller on a monthly basis		
Methodology Review	500 USD flat fee + cost of two experts		
Additionality Tool Review	10,000 USD flat fee + cost of two experts		

[1] The registration fee will be deducted from the GS fee portion of the issuance fee; for GS VERs the Registry fee of 0.05 USD will always bee aplicable.

The SoP benefits project developers by eliminating a cash cost like upfront registration fees. Also this model transfers some price risk: If prices of credits fall, the value of the share of proceeds will fall too compared with fixed fees. The SoP model emulates the financing mechanism used by the UNFCCC for the adoptation fund, since Gold Standard will charge a percentage of the credits from successful projects rather than a cash per credit fee.

Emission Reduction Calculations

Case: Turkish Wind Power for The Year 2010

To estimate the amount of emission reductions, a baseline methodology must be selected and then the new situation must be compared with the baseline. In this section, selection and application of baseline methodologies will be explained. To give an example on how to apply the methodology, the combined margin emission factor for wind projects in Turkey will be calculated using the most recent data available. This emission factor will be invaluable in estimating the potential of voluntary carbon credits in Turkey.

This section will use UNFCCC-Approved consolidated baseline and monitoring methodology ACM0002 version 11 “Consolidated baseline methodology for grid-connected electricity generation from renewable sources”; Tool to calculate the emission factor for an electricity system (Version 02) (valid as of 16 October 2009); Tool for the demonstration and assessment of additionality (Version 05.2) (valid as of 26 August 2008); Combined tool to identify the baseline scenario and demonstrate additionality (Version 02.2) (valid as of 26 August 2008); Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion (Version 02) (valid as of 02 August 2008).

Selecting Baseline Methodology

'Baseline' is defined in Rule II as the amount of greenhouse gas emissions that would be produced in the absence of the carbon credit project, also known as the business as usual scenario, which forms the basis for calculating a project's emissions reductions and helps determine additionality. Detailed information about selecting baseline and monitoring methodologies is provided in section 2.2 of the Toolkit and information of this subtitle is obtained from this Toolkit. Emission reductions under the Gold Standard should be real, measurable and verifiable. This can be assured by using an approved baseline and monitoring methodology. A baseline methodology estimates the emissions that would have been created without implementation of the project. A monitoring methodology calculates the actual emission reductions from the project, taking into account any emissions from sources within the project boundary, and also enables verification of the realised emission reductions in a transparent way.

The use of a UNFCCC or Gold Standard approved methodology is mandatory, for CDM, JI and VER projects. The latest version of the methodology at the time of first submission to the Gold Standard should be used. The time of first submission is the date of upload of the Local Stakeholder Consultation report or in case of pre-feasibility assessment, the day of the application for a pre-feasibility assessment.

According to the principle of conservativeness of the Gold Standard, the most conservative baseline approach should be chosen, unless there is strong evidence that another baseline is more convincing. As an example of conservativeness the following case is presented in section 2.2 of the Toolkit: If similar project activities in the region of the project have been registered with a certain baseline, a less conservative baseline should not be used unless there is a convincing case for an alternative choice of baseline methodology.

As mentioned, the use of a UNFCCC or Gold Standard approved methodology is mandatory, for CDM, JI and VER projects. The latest version of the methodology at the time of first submission to the Gold Standard should be used.

UNFCCC-Approved consolidated baseline and monitoring methodology ACM0002 version 11 that is the latest version, valid as of 12 February 2010, “Consolidated baseline methodology for grid-connected electricity generation from renewable sources” (from here on, it will be referred to as ACM0002) will be used in this study. This methodology also refers to the latest approved versions of the following tools:

• Tool to calculate the emission factor for an electricity system (Version 02) (valid as of 16 October 2009);

• Tool for the demonstration and assessment of additionality (Version 05.2) (valid as of 26 August 2008);

• Combined tool to identify the baseline scenario and demonstrate additionality (Version 02.2) (valid as of 26 August 2008);

• Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion (Version 02) (valid as of 02 August 2008).

Consolidated baseline methodology for grid-connected electricity generation from renewable sources (ACM0002) will be explained in details in the succeeding subtitle.

Consolidated Baseline Methodology for Grid-Connected Electricity Generation from Renewable Sources (ACM0002)

ACM0002 is applicable to grid-connected renewable power generation project activities that (a) install a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity (greenfield plant); (b) involve a capacity addition; (c) involve a retrofit of (an) existing plant(s); or (d) involve a replacement of (an) existing plant(s). Data about ACM0002 is obtained from "consolidated baseline methodology for grid-connected electricity generation from renewable sources" (ACM0002) published by UNFCCC CDM Executive Board.

This methodology is applicable under the following conditions:

(a) The project activity is the installation, capacity addition, retrofit or replacement of a power plant/unit of one of the following types: hydro power plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit;

(b) In the case of capacity additions, retrofits or replacements: the existing plant started commercial operation prior to the start of a minimum historical reference period of five years, used for the calculation of baseline emissions and defined in the baseline emission section, and no capacity expansion or retrofit of the plant has been undertaken between the start of this minimum historical reference period and the implementation of the project activity;

(c) In case of hydro power plants, one of the following conditions must apply:

- The project activity is implemented in an existing reservoir, with no change in the volume of reservoir; or

- The project activity is implemented in an existing reservoir, where the volume of reservoir is increased and the power density of the project activity, as per definitions given in the Project Emissions section, is greater than 4 W/m2; or

- The project activity results in new reservoirs and the power density of the power plant, as per definitions given in the Project Emissions section, is greater than 4 W/m2.

The methodology is not applicable to the following:

(a) Project activities that involve switching from fossil fuels to renewable energy sources at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site;

(b) Biomass fired power plants;

(c) Hydro power plants that result in new reservoirs or in the increase in existing reservoirs where the power density of the power plant is less than 4 W/m2.

In the case of retrofits, replacements, or capacity additions, this methodology is only applicable if the most plausible baseline scenario, as a result of the identification of baseline scenario, is the continuation of the current situation, i.e. to use the power generation equipment that was already in use prior to the implementation of the project activity and undertaking business as usual maintenance.

In this study, new wind power plants are assumed to be installed in sites where no renewable or fossil fuel power plants were operated prior to the project activity or capacity additions to existing renewable power plants. They do not involve switching from fossil fuels to renewable energy at the project sites. All of these projects are assumed to be grid connected. Identification of geographic and system boundaries is feasible in that all these projects will be inside the boundaries of Turkey and the general information about Turkish grid characterestics are available. So, ACM0002 applicability criterias are met.

The generic equation for the calculation of emission reduction is as follows:

$ER_y = BE_y - PE_y$

where ER_y= Emission reductions in year y (t CO_2/yr)

BE_y= Baseline emissions in year y (t CO_2/yr)

PE_y= Project emissions in year y (t CO_2/yr)

ACM0002 involves methods to calculate or estimate the parameters seperately and sometimes provides for generic assumptions allowed to make. Application of the baseline methodology procedure involves;

-Identification of the baseline scenario

-Assessing additionality

-Defining project boundary

-Calculation of project emissions

-Calculation of baseline emissions

-Calculation of leakage

-Calculation of emission reductions

These headlines will be explained as follows:

Identification of the baseline scenario

If the project activity is the installation of a new grid-connected renewable power plant/unit, the baseline scenario is the following:

Electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system".

Additionality

The additionality of the project activity is demonstrated and assessed using the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the CDM Executive Board, which is available on the UNFCCC CDM website. The latest version of this tool is "Tool for the demonstration and assessment of additionality Version 05.2" that is valid as of 26 August 2008.

Project Boundary

The spatial extent of the project boundary includes the project power plant and all power plants connected physically to the electricity system that the project power plant is connected to. The greenhouse gases and emission sources included in or excluded from the project boundary are shown in Table 152 as follows:

Table 152. Emissions Sources Included in or Excluded from the Project Boundary (ACM0002 Version 11, 2010)

Source		Gas	Included?	Justification/Explanation
Baseline	CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity	CO_2	Yes	Main emission source
		CH_4	No	Minor emission source
		N_2O	No	Minor emission source
Project Activity	For geothermal power plants, fugitive emissions of CH_4 and CO_2 from non-condensable gases contained in geothermal stream	CO_2	Yes	Main emission source
		CH_4	Yes	Main emission source
		N_2O	No	Minor emission source
	CO_2 emissions from combustion of fossil fuels for electricity generation in solar thermal power plants and geothermal power plants	CO_2	Yes	Main emission source
		CH_4	No	Minor emission source
		N_2O	No	Minor emission source
	For hydro power plants, emissions of CH_4 from the reservoir	CO_2	No	Minor emission source
		CH_4	Yes	Main emission source
		N_2O	No	Minor emission source

<u>Project Emissions</u>

For most renewable power generation project activities, project emissions are zero. However, some project activities may involve project emissions that can be significant. These project emissions may originate from these sources:

- Project emissions from fossil fuel combustion, for geothermal and solar thermal projects using also fossil fuels for electricity generation

- Project emissions from operation of geothermal power plants due to the release of non-condensable gases

- Project emissions from water reservoirs of hydro power plants

The procedure to calculate the project emissions from each of these sources is presented in ACM0002 in details. Since wind power plant projects do not result in emissions, project emissions of wind power plant projects will be assumed to be 0.

So, the final equation for our study will be;

$ER_y = BE_y$

Baseline Emissions

Baseline emissions include only CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity. The methodology assumes that all project electricity generation above baseline levels would have been generated by existing grid-connected power plants and the addition of new grid-connected power plants. The baseline emissions are calculated as follows:

$BE_y = EG_{PJ,y} * EF_{grid,CM,y}$

where BE_y = Baseline emissions in year y (t CO_2/yr)

$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y (MWh/yr)

$EF_{grid,CM,y}$ = Combined margin CO_2 emission factor for grid connected power generation in year y calculated using the latest version of the "Tool to calculate the emission factor for an electricity system" (t CO_2/MWh)

The calculation of $EG_{PJ,y}$ is different for (a) greenfield plants, (b) retrofits and replacements, and (c) capacity additions. Wind power plant projects will be assumed to be greenfield power plants or capacity additions. Because it is a realistic assumption and also data to calculate $EG_{PJ,y}$ for retrofits and replacaments are not available for this study.

$EG_{PJ,y}$ for greenfield renewable energy power plants is calculates as follows:

If the project activity is the installation of a new grid-connected renewable power plant/unit at a site where no renewable power plant was operated prior to the implementation of the project activity, then:

$EG_{PJ,y} = EG_{facility,y}$

where $EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y (MWh/yr)

$EG_{facility,y}$ = Quantity of net electricity generation supplied by the project plant/unit to the grid in year y (MWh/yr)

$EG_{PJ,y}$ for capacity addition to an existing renewable energy power plant is calculated as follows:

In the case of hydro or geothermal power plants, the addition of a new power plant or unit may significantly affect the electricity generated by the existing plant(s) or unit(s). For example, a new hydro turbine installed at an existing dam may affect the power generation by the existing turbines. Therefore, the same approach as for retrofits and replacements is used for hydro power plants and geothermal power plants.

In the case of wind, solar, wave or tidal power plants, it is assumed that the addition of new capacity does not significantly affect the electricity generated by existing plant(s) or unit(s). In this case, the electricity fed into the grid by the added power plant(s) or unit(s) could be directly metered and used to determine $EG_{PJ,y}$.

If the project activity is a capacity addition, project participants may use one of the following two options to determine EGPJ,y:

Option 1: Using the approach applied to retrofits and replacements. This option may be applied to all renewable power projects.

Option 2: For wind, solar, wave or tidal power plant(s) or unit(s), the following approach can be used provided that the electricity fed into the grid by the added power plant(s) or unit(s) addition is separately metered:

$EG_{PJ,y=}$ $EG_{PJ\_Add,y}$

where $EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y (MWh/yr)

$EG_{PJ\_Add,y}$ = Quantity of net electricity generation supplied to the grid in year y by the project plant/unit that has been added under the project activity (MWh/yr)

Since project activities in the study will be related to wind power plants, Option 2 will be used in the study. So, final equation will be

$EG_{PJ,y=}$ $EG_{facility,y}$ + $EG_{PJ\_Add,y}$

Since it is assumed that different quantities of net electricity will be produced and fed into the grid as a result of the implementation of the wind power plant project activities in different scenarios, the values of $EG_{PJ,y}$ will be determined later.

So, the most important determinant of equation remains to be $EF_{grid,CM,y}$ that is combined margin CO_2 emission factor for grid connected power generation in year y calculated using the latest version of the "Tool to calculate the emission factor for an electricity system" (tCO2/MWh).

Leakage

No leakage emissions are considered. The main emissions potentially giving rise to leakage in the context of electric sector projects are emissions arising due to activities such as power plant construction and upstream emissions from fossil fuel use (e.g. extraction, processing, transport). These emissions sources are neglected in ACM0002.

Emission Reductions

The generic equation for the calculation of emission reduction is as follows:

$ER_y = BE_y - PE_y$

where ER_y= Emission reductions in year y (t CO_2/yr)

BE_y= Baseline emissions in year y (t CO_2/yr)

PE_y= Project emissions in year y (t CO_2/yr)

As mentioned in the preceeding subtitles, project emissions will be 0 for wind power projects. So, emission reductions will be equal to baseline emissions. Since it is assumed that different quantities of net electricity will be produced and fed into the grid as a result of the implementation of the wind power plant project activities in different scenarios, the values of $EG_{PJ,y}$ will be determined according to the scenarios. So, the most important determinant of emission reductions remains to be $EF_{grid,CM,y}$ that is combined margin CO_2 emission factor for grid connected power generation in year y calculated using the latest version of the “Tool to calculate the emission factor for an electricity system” (tCO2/MWh). “Tool to calculate the emission factor for an electricity system” will be explained in details in the succeeding subtitle.

Tool to Calculate the Emission Factor for an Electricity System

In this study, "tool to calculate the emission factor for an electricity system (Version 02)" will be used, that is the latest version to determine $EF_{grid,CM,y}$ (Combined margin CO_2 emission factor for grid connected power generation in year y). Data about this methodological tool is obtained from "Tool to calculate the emission factor for an electricity system (Version 02)" published by UNFCCC CDM Executive Board. This subtitle will provide explanations obtained from "Tool to calculate the emission factor for an electricity system (Version 02)".

This methodological tool determines the CO_2 emission factor for the displacement of electricity generated by power plants in an electricity system, by calculating the combined margin emission factor (CM) of the electricity system. The CM is the result of a weighted average of two emission factors pertaining to the electricity system: the operating margin. (OM) and the build margin (BM). The operating margin is the emission factor that refers to the group of existing power plants whose current electricity generation would be affected by the proposed project activity. The build margin is the emission factor that refers to the group of prospective power plants whose construction and future operation would be affected by the proposed project activity.

Under this tool, the emission factor for the project electricity system can be calculated either for grid power plants only or, as an option, can include off-grid power plants. In the latter case, the conditions specified in Annex 2 of the Tool - Procedures related to off-grid power generation should be met. Namely, the total capacity of off-grid power plants (in MW) should be at least 10% of the total capacity of grid power plants in the electricity system; or the total power generation by off-grid power plants (in MWh) should be at least 10% of the total power generation by grid power plants in the electricity system; and that factors which negatively affect the reliability and stability of the grid is primarily due to constraints in generation and not to other aspects such as transmission capacity.

According to this methodological tool, application of baseline methodology procedure involves the following six steps:

Step 1. Identifying the relevant electricity systems.

Step 2. Choosing whether to include off-grid power plants in the project electricity system (optional).

Step 3. Selecting a method to determine the operating margin (OM).

Step 4. Calculating the operating margin emission factor according to the selected method.

Step 5. Identifying the group of power units to be included in the build margin (BM).

Step 6. Calculating the build margin emission factor.

Step 7. Calculating the combined margin (CM) emissions factor.

Combined margin emission factor for wind power projects in Turkey will be calculated by following these seven steps:

Step 1: Identifying the Relevant Electricity Systems

For determining the electricity emission factors, a project electricity system is defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity (e.g. the renewable power plant location or the consumers where electricity is being saved) and that can be dispatched without significant transmission constraints.

For imports from connected electricity systems located in another host country(ies), the emission factor is 0 tons CO_2 per MWh.

Electricity exports should not be subtracted from electricity generation data used for calculating and monitoring the electricity emission factors.

Table 153 shows peak load / transformer capacity ratios of Turkish national grid between 2006-2008 as follows:

Table 153. Peak Load / Transformer Capacity Ratios of Turkish National Grid Between 2006-2008 (TEIAS Statistics, 2010)

	2006	2007	2008
Interconnected Instantaneous Peak Load (MW)	27,594.4	29,248.5	30,516.8
Total Transformer Capacity (MVA)	78,062.0	82,056.0	89,476.0
Peak Load / Transformer Capacity	35.3%	35.6%	34.1%

Turkey's interconnected instantaneous peak load is only around 34-36% of total transformer capacities in the national interconnected system. So, Turkish national electricity transmission and distribution grid does not have significant transmission constraint for power to be dispatched.

Table 154 shows gross electricity generation, import, export and demand of Turkey between 2006-2008 as follows:

Table 154. Gross Electricity Generation, Import, Export and Demand of Turkey Between 2006-2008 (GWh) (TEIAS Statistics, 2010)

	2006	2007	2008
Gross Electricity Generation	176,299.8	191,558.1	198,418.0
Electricity Import	573.2	864.3	789.4
Electricity Export	2,235.7	2,422.2	1,122.2
Gross Demand	174,637.3	190,000.2	198,085.2

Import and export values are negligible when compared to gross electricity generation. So, the spatial extent for the build margin emission factor is the project electricity system, and the project electricity system is the Turkish national grid. Since connected electricity systems are located in other countries, the emission factor for the electricity imports is 0 tons CO_2 per MWh according to the methogological tool applied.

Step 2: Choosing whether to Include Off-grid Power Plants in the Project Electricity System (Optional)

Project participants may choose between the following two options to calculate the operating margin and build margin emission factor:

Option I: Only grid power plants are included in the calculation.

Option II: Both grid power plants and off-grid power plants are included in the calculation.

Option I corresponds to the procedure contained in earlier versions of this tool. Option II allows the inclusion of off-grid power generation in the grid emission factor. Option II aims to reflect that in some countries off-grid power generation is significant and can partially be displaced by CDM project activities, e,g, if off-grid power plants are operated due to an unreliable and unstable electricity grid. Option II requires collecting data on off-grid power generation as per Annex 2 and can only be used if the conditions outlined therein are met.

In this study, Option I will be used, since data on off-grid power generation are not available.

Step 3: Selecting a Method to Determine the Operating Margin (OM)

The calculation of the operating margin emission factor ($EF_{grid,OM,y}$) is based on one of the following methods:

(a) Simple OM, or

(b) Simple adjusted OM, or

(c) Dispatch data analysis OM, or

(d) Average OM,

Each method will be described under Step 4.

The simple OM method can only be used if low-cost/must-run resources constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production.

In this study, Simple OM method will be used. Because data to use Simple adjusted OM and Dispatch data analysis OM methods are not available and Simple OM method is more precise than Average OM method. The conditions to use Simple OM is met.

Low-cost/must-run resources are defined as power plants with low marginal generation costs or power plants that are dispatched independently of the daily or seasonal load of the grid. They typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation. If coal is obviously used as must run, it should also be included in this list. Coal is not used as must run in Turkey.

Table 155 shows electricity generation of Turkey by primary energy resources between 2004-2008 as follows:

Table 155. Electricity Generation of Turkey By Primary Energy Resources Between 2004-2008 in GWh (TEIAS Statistics, 2010)

Primary Energy Source	2004	2005	2006	2007	2008
Total Thermal	104,464	122,242	131,835	155,196	164,139
Total Hydro	46,084	39,561	44,244	35,851	33,270
Geothermal + Wind	151	153	221	511	1,009
Total	150,698	161,956	176,300	191,558	198,418

Since Table 155 involves electricity generation values in nominal amounts, share of thermal, hydro, geothermal and wind are calculated in Table 156 as follows:

Table 156. Share of Low-Cost/Must-Run Resources of Total Generation Grid Between 2004-2008 (%) (TEIAS Statistics, 2010)

Primary Energy Source	2004	2005	2006	2007	2008
Total Thermal	69.3%	75.5%	74.8%	81.0%	82.7%
Total Hydro	30.6%	24.4%	25.1%	18.7%	16.8%
Geothermal + Wind	0.1%	0.1%	0.1%	0.3%	0.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Low-cost/must-run resources constitute less than 50% of total grid generation in average of the five most recent years.

For the simple OM method, the emissions factor can be calculated using either of the two following data vintages: Ex ante option and ex post option.

Ex-ante option: If the ex ante option is chosen, the emission factor is determined once at the validation stage, thus no monitoring and recalculation of the emissions factor during the crediting period is required. For grid power plants, a 3-year generation-weighted average should be used, based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation. For off-grid power plants, a single calendar year should be used within the 5 most recent calendar years prior to the time of submission of the CDM-PDD for validation.

Ex-post option: If the ex post option is chosen, the emission factor is determined for the year in which the project activity displaces grid electricity, requiring the emissions factor to be updated annually during monitoring.

In this study, ex-ante option will be used. According to this method, 3-year generation-weighted average should be used for grid power plants, based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation. In this study, data of the years 2006-2008 will be used since they are the most recent data TEIAS provides.

Step 4: Calculating the Operating Margin Emission Factor According to the Selected Method

The simple OM emission factor is calculated as the generation-weighted average CO_2 emissions per unit net electricity generation (tCO2/MWh) of all generating power plants serving the system, not including low-cost/must-run power plants.

There are two options to calculate the simple OM: Option A and Option B.

In Option A, calculation is based on the net electricity generation and a CO_2 emission factor of each power unit.

In Option B, calculation is based on the total net electricity generation of all power plants serving the system and the fuel types and total fuel consumption of the project electricity system.

Option B can only be used if:

-The necessary data for Option A is not available; and

-Only nuclear and renewable power generation are considered as low-cost/must-run power sources and the quantity of electricity supplied to the grid by these sources is known; and

-Off-grid power plants are not included in the calculation (if Option I has been chosen in Step 2).

In this study, Option B will be used. All of the conditions mentioned to use Option B are met.

Under Option B, the simple OM emission factor is calculated based on the net electricity supplied to the grid by all power plants serving the system, not including low-cost/must-run power plants/units, and based on the fuel type(s) and total fuel consumption of the project electricity system, as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_{i=1} \left(FC_{i,y} * NCV_{i,y} * EF_{CO2,i,y}\right)}{EGy}$$

where $EF_{grid,OMsimple,y}$ = Simple operating margin CO_2 emission factor in year y (tCO2/MWh)

$FC_{i,y}$ = Amount of fossil fuel type i consumed in the project electricity system in year y (mass or volume unit)

$NCV_{i,y}$= Net calorific value (energy content) of fossil fuel type i in year y (GJ/mass or volume unit)

$EF_{CO2,i,y}$ = CO_2 emission factor of fossil fuel type i in year y (tCO2/GJ)

EG_y = Net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants/units, in year y (MWh)

i = All fossil fuel types combusted in power sources in the project electricity system in year y

y = The relevant year as per the data vintage chosen in Step 3

The subscript m refers to the power plants/units delivering electricity to the grid, not including low-cost/must-run power plants/units, and including electricity imports to the grid. Electricity imports should be treated as one power plant m.

Since fuel consuption data on a heating value base are available, NCVs are not necessary to calculate the OM emissions. But, data units provided by TEIAS are on Tcal and so these data will be converted from Tcal to TJ by using the conversion equation (1 Tcal = 4.1868 TJ).

Data on emission factors ($EF_{CO2,i,y}$) are not available on country or power plant specific base. So, IPCC default values at the lower limit of the uncertainity at a 95% confidence interval will be used in compliance with the grid factor tool.

The emissions (t CO_2) for the years 2006, 2007 and 2008 are calculated in Table 157 as follows:

Table 157. Calculation of Emissions in 2006-2008

Fuel Type	FC_{HV} (TJ)	$EF_{CO2,i,y}$ (tCO_2/TJ)	FC_{HV} * $EF_{CO2,i,y}$ (tCO_2)
Hard Coal+Imported Coal	123.527	89,5	11.055.698
Lignite	351.406	90,9	31.942.851
Fuel Oil	70.208	75,5	5.300.738
Diesel Oil	2.625	72,6	190.584
Lpg	0	61,6	0
Naphta	590	69,3	40.910
Natural Gas	630.482	54,3	34.235.164
Total 2006			82.765.944
Fuel Type	FC_{HV} (TJ)	$EF_{CO2,i,y}$ (tCO_2/TJ)	FC_{HV} * $EF_{CO2,i,y}$ (tCO_2)
Hard Coal+Imported Coal	134.459	89,5	12.034.088
Lignite	420.020	90,9	38.179.798
Fuel Oil	89.740	75,5	6.775.360
Diesel Oil	2.165	72,6	157.148
Lpg	0	61,6	0
Naphta	494	69,3	34.237
Natural Gas	752.092	54,3	40.838.576
Total 2007			98.019.207
Fuel Type	FC_{HV} (TJ)	$EF_{CO2,i,y}$ (tCO_2/TJ)	FC_{HV} * $EF_{CO2,i,y}$ (tCO_2)
Hard Coal+Imported Coal	139.462	89,5	12.481.877
Lignite	453.125	90,9	41.189.045
Fuel Oil	86.277	75,5	6.513.943
Diesel Oil	5.560	72,6	403.661
Lpg	0	61,6	0
Naphta	473	69,3	32.786
Natural Gas	791.544	54,3	42.980.831
Total 2008			103.602.142

In Table 157, the numerator of the formula of OM emissions between 2006-2008 is calculated as 284.387.293 tCO_2. Now, the denominator of the formula will be calculated, namely EG_y that is net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants/units, in year y (MWh).

To calculate gross electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants/units; gross electricity generated and delivered to the grid by low-cost/must-run power plants/units is subtracted from gross electricity generated and delivered to the grid by all power sources serving the system, and then electricity imports to the Turkish national grid is added.

The grid factor tool refers to net generation with respect to EG_y. But, data for net generation are not available for low-cost/must-run power plants/units. So, an approximation to estimate EG_y will be applied by using the ratio of net generation to gross generation by all power plants serving the system. Net generation values are calculated by this method in Table 158 as follows:

Table 158. Calculation of Net Electricity Generation Values by Primary Energy Sources in 2006-2008

	2006	2007	2008
Gross Genaration	176,300	191,558	198,418
Net Generation	169,543	183,340	189,762
Net to Gross Generation	0,962	0,957	0,956
Renewables + Waste	154	214	220
Hydro	44,244	35,851	33,270
Geothermal + Wind	221	511	1,009
Low-Cost/Must-Run Total	44,619	36,576	34,499
Import	573	864	789
Gross EG_y	132,254	155,847	164,709
EG_y	127,186	149,160	157,523

As calculated in Table 158, total EG_y between 2006-2008 is 433,869 GWh. The numerator of the equation for OM emission is 284,387,293 tCO_2. According to the formula, 284,387,293 tCO_2 is divided by 433,869,000 MWh, and so operating margin CO_2 emission factor is 0,655 t CO_2/MWh.

Step 5: Identifying the Group of Power Units to Be Included in the Build Margin

The sample group of power units "m" used to calculate the build margin consists of either:

(a) The set of five power units that have been built most recently;or

(b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently. (If 20% falls on part capacity of a unit, that unit is fully included in the calculation.)

Project participants should use the set of power units that comprises the larger annual generation. 20% of the system generation of 198,418 GWh in 2008 makes up 39,684 GWh. The set of power capacity additions in the electricity system that comprise 20% of the system generation will be used in this study, since this comprises larger than the set of five power units that have been built most recently. But, data on plant specific electricity generation are available for only the plants commissioned in 2008. So, for other plants, data on plant specific average (project) generation capacities provided in the Turkish electricity generation capacity projections of TEIAS published in 2008, 2007, 2006 and data from TEIAS statistics will be used in this study. These papers and statistics display project and firm generation capacities for each power plants. Project generation capacities will be used since positive deviations of project generation is more than firm generation for hydro, wind other low-carbon power plants. Using these project generation values leads to overestimating the share of low-carbon power plants, that is a conservative approach. Also project generation capacities for some power plants that comprise nearly 33 MW (less than 1% of the capacity included in the calculation of the build margin) installed capacity could not have been found. So, the average project generations of them have been estimated by using an approximation that takes into account the project generations of power plants using the same fuel type commissioned in 2007. The list of the power plants used to calculate build margin are provided in Appendix I of the study. Their electricity generation are 40,300 MWh comprising 20.3% of gross electricity generation in 2008. Since the last power plant in Annex I commissioned on 15 February 2005 can not be divided, they slightly exceed 20%. As a general guidance, a power unit is considered to have been built at the date when it started to supply electricity to the grid. Renewable power plants have been investigated whether they are registered as VER projects from registration databases of standards and the from the websites of the peoject developers. And power plants registered as VER project activities has been **e**xcluded from the sample group “m”.

Capacity additions from retrofits of power plants should not be included in the calculation of the build margin emission factor.

In terms of vintage of data, there are two options:

According to Option 1; for the first crediting period, the build margin emission factor ex ante is calcuated based on the most recent information available on units already built for sample group “m” at the time of CDM-PDD submission to the DOE for validation. For the second crediting period, the build margin emission factor will be updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period will be used. This option does not require monitoring the emission factor during the crediting period.

According to Option 2; for the first crediting period, the build margin emission factor will be updated annually, ex post, including those units built up to the year of registration of the project activity or, if information up to the year of registration is not yet available, including those units built up to the latest year for which information is available. For the second crediting period, the build margin emissions factor will be calculated ex ante, as described in Option 1 above. For the third crediting period, the build margin emission factor calculated for the second crediting period will be used.

In this study, Option 1 will be used, by calculating the build margin emission factor ex ante for the first crediting period.

Step 6: Calculating the Build Margin Emission Factor

The build margin emissions factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units "m" during the most recent year y for which power generation data is available, calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m (EG_{m,y} * EF_{EL,m,y})}{\sum_m EG_{m,y}}$$

where $EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year *y* (t CO_2/MWh)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)

$EF_{EL,m,y}$= CO_2 emission factor of power unit m in year y (t CO_2/MWh)

m = Power units included in the build margin

y = Most recent historical year for which power generation data is available

The CO_2 emission factor of each power unit m ($EF_{EL,m,y}$) will be determined according to the guidance in Step 4 (a) for the simple OM, using options B1, B2 or B3, using for y the most recent historical year for which power generation data is available, and using for "m" the power units included in the build margin.

For power units "m", only data on project generation capacities and the fuel types used are available. So, Option B2 will be used, and the emission factor will be determined based on the CO_2 emission factor of the fuel type used and the efficiency of the power unit, as follows:

$$EF_{EL,m,y} = \frac{EF_{co2,m,y} * 3.6}{\eta_{m,y}}$$

where $EF_{EL,m,y}$ = CO_2 emission factor of power unit m in year y (tCO2/MWh)

$EF_{CO2,\ m,y}$ = Average CO_2 emission factor of fuel type i used in power unit m in year y (tCO2/GJ)

$\eta_{m,y}$ = Average net energy conversion efficiency of power unit m in year y (ratio)

m = All power units serving the grid in year y except low-cost/must-run power units

y = The relevant year as per the data vintage chosen in Step 3

Where several fuel types are used in the power unit, the fuel type with the lowest CO_2 emission factor for $EF_{CO2,\ m,i,y}$ should be used.

Since data on average net energy conversion efficiency for each power plant are not available, the default efficiency factor values provided in Appendix A of the grid factor tool, will be used in this study. In determining these default values, it will be assumed that, coal fired plants are subcritical, fuel oil and diesel oil plants are open cycle plants and natural gas plants are combined cycle plants. So, default efficiency factor values for coal, fuel oil and natural gas plants are 39%, 39.5% and 60%.

CO_2 emission factors ($EF_{EL,m,y}$) are calculated below, according to the equation mentioned.

Table 159. CO_2 Emission Factors

Fuel Type	$\eta_{m,y}$	$EF_{CO2,\ m,i,y}$	$EF_{EL,m,y}$
Fuel Oil	39.5%	75.5	688.10
Imported Coal	39.0%	89.5	826.15
Lignite	39.0%	90.9	839.08
Naphta	39.5%	69.3	631.59
Natural Gas	60.0%	54.3	325.80

By taking into account the values in Appendix A, the numerator of the formula of build margin is calculated in Table 160 as follows:

Table 160. Calculation of Emissions in Build Margin

Fuel Type	EG_{my} (GWh)	$EF_{EL,m,y}$ (t CO2/GWh)	Emissions (t CO2)
Fuel Oil	1.055	688,10	725.946
Imported Coal	993	826,15	820.367
Lignite	9.103	839,08	7.638.145
Natural Gas	26.233	325,80	8.546.711
Total Emissions			17.731.169

The numerator of the formula of build margin is 17,731,169 t CO_2. The power plant set taken into account in the calculation of build margin in Appendix A of this study generates electricity of 40,300 GWh. To calculate build margin, 17,731,169 t CO_2 is divided by 40,300,000 MWh. As a result, the build margin is 0,440 t CO_2/MWh.

<u>Step 7: Calculating the Combined Margin Emissions Factor</u>

The combined margin emissions factor is calculated as follows:

$EF_{grid,CM,y} = EF_{grid,OM,y} * W_{OM} + EF_{grid,BM,y} * W_{BM}$

where $EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year y (tCO2/MWh)

$EF_{grid,OM,y}$ = Operating margin CO_2 emission factor in year y (tCO2/MWh)

W_{OM} = Weighting of operating margin emissions factor (%)

W_{BM} = Weighting of build margin emissions factor (%)

The following default values should be used for W_{OM} and W_{BM}:

For wind and solar power generation project activities: W_{OM} = 0,75 and W_{BM} = 0,25 (owing to their intermittent and non-dispatchable nature) for the first crediting period and for subsequent crediting periods;

For all other projects: wOM = 0,5 and wBM = 0,5 for the first crediting period , and W_{OM} = 0,25 and W_{BM} = 0,75 for the second and third crediting period, unless otherwise specified in the approved methodology which refers to this tool.

Alternative weights can be proposed, as long as $W_{OM} + W_{BM} = 1$, for consideration by the Executive Board, taking into account the guidance as described below. The values for $W_{OM} + W_{BM}$ applied by project participants should be fixed for a crediting period and may be revised at the renewal of the crediting period.

Since the combined emission factor for wind power projects in Turkey is the area of concern for this study; W_{OM} = 0,75 and W_{BM} = 0,25. So,

$EF_{grid,CM,y}$ = 0,75*0,655 + 0,25*0,440

$EF_{grid,CM,y}$ = 0,601 t CO_2/MWh.

Combined margin emission factor for wind power projects in Turkey has been calculated as 0,601 t CO_2/MWh. This means that 0,601 VER credit can be issued when 1 MWh electricity is generated from wind power. Emission reductions and so Gold Standard VER credits can be easily calculated when combined margin emission factor is known. For example, if a wind power project developer installs 100 MW wind power plant in 2010 with a load factor of 30%, then its expected electricity generation will be (100 X 365 X 24 X 0,30=) 262,800 MWh annually. If the project developer utilizes Gold Standard, it will be able to create (262,800 X 0,601=) 157,943 Gold Standard VER credits annually.

This combined margin emission factors may change due to changes required for methodology implementation in the second and the third crediting periods. This issue will be mentioned briefly as follows: At the start of the second and third crediting period project proponents have to address two issues: Assessing the continued validity of the baseline; and updating the baseline. In assessing the continued validity of the baseline, a change in the relevant national and/or sectoral regulations between two crediting periods has to be examined at the start of the new crediting period. If at the start of the project activity, the project activity was not mandated by regulations, but at the start of the second or third crediting period regulations are in place that enforce the practice or norms or technologies that are used by the project activity, the new regulation (formulated after the registration of the project activity) has to be examined to determine if it applies to existing plants or not. If the new regulation applies to existing project activities, the baseline has to be reviewed and, if the regulation is binding, the baseline for the project activity should take this into account. This assessment will be undertaken by the verifying DOE. For updating the baseline at the start of the second and third crediting period, new data available will be used to revise the baseline scenario and emissions.

Calculation of 20,000 MW Target Wind Power Projects' Potential Revenues from Carbon Market

Turkey has set her target for wind energy to increase installed wind energy power to 20,000 MW by 2023 in Electricity Energy Market and Supply Security Strategy Paper. Emission reductions from wind power projects can be sold in the carbon market as well. This section will calculate how much revenue would 20,000 MW wind power projects would generate by selling as VERs in the voluntary carbon market or as CERs in the EU ETS, and impact of installing wind power plants on Turkey's international trade balances. This section will calculate how many tonnes of CO_2 would be avoided in case 20,000 MW wind power capacity installation target is achieved as well.

This section will use UNFCCC-Approved consolidated baseline and monitoring methodology ACM0002 version 11 "Consolidated baseline methodology for grid-connected electricity generation from renewable sources"; Tool to calculate the emission factor for an electricity system (Version 02) (valid as of 16 October 2009); Tool for the demonstration and assessment of additionality (Version 05.2) (valid as of 26 August 2008); Combined tool to identify the baseline scenario and demonstrate additionality (Version 02.2) (valid as of 26 August 2008); Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion (Version 02) (valid as of 02 August 2008).

Turkey is a dominant market for voluntary carbon offsets, that largely comes from the Turkey's status as an Annex-I but non-Annex B Party. So, Turkey is not eligible to host CDM or JI projects, leaving the voluntary market the only option for Turkey. If Turkey becomes eligible to host CDM projects and so issue CERs in the future, the same combined margin emission factor can be used as well since this emission factor has been caculated by using UNFCCC approved CDM methodologies.

The generic equation for the calculation of emission reductions is as follows:

$ER_y = BE_y - PE_y$

where ER_y= Emission reductions in year y (t CO_2/yr)

BE_y= Baseline emissions in year y (t CO_2/yr)

PE_y= Project emissions in year y (t CO_2/yr)

To estimate the amount of emission reductions, a baseline methodology must be selected and then the new situation must be compared with the baseline.

UNFCCC-Approved consolidated baseline and monitoring methodology ACM0002 version 11 that is the latest version, valid as of 12 February 2010, “Consolidated baseline methodology for grid-connected electricity generation from renewable sources” (from here on, it will be referred to as ACM0002) has been used in the preceding section together with the latest approved versions of “Tool to calculate the emission factor for an electricity system” (Version 02) (valid as of 16 October 2009); “Combined tool to identify the baseline scenario and demonstrate additionality” (Version 02.2) (valid as of 26 August 2008) and “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion” (Version 02) (valid as of 02 August 2008).

ACM0002 is applicable to grid-connected renewable power generation project activities that install a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity (greenfield plant); involve a capacity addition. The project activity must be the installation, capacity addition, retrofit or replacement of a power plant/unit of one of the following types: hydro power plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit. In this study, new wind power plants are assumed to be installed in sites where no renewable or fossil fuel power plants were operated prior to the project activity or capacity additions to existing renewable power plants. They do not involve switching from fossil fuels to renewable energy at the project sites. All of these projects are assumed to be grid connected. Identification of geographic and system boundaries is feasible in that all these projects will be inside the boundaries of Turkey and the general information about Turkish grid characterestics are available. So, ACM0002 applicability criterias are met.

If the project activity is the installation of a new grid-connected renewable power plant/unit, the baseline scenario is the following: Electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system".

The procedure to calculate the project emissions from each of these sources is presented in ACM0002 in details. Since wind power plant projects do not result in emissions, project emissions of wind power plant projects will be assumed to be 0.

So, emission reductions of the wind power projects are equal to the baseline emissions. The baseline emissions are calculated as follows:

$BE_y = EG_{PJ,y} * EF_{grid,CM,y}$

where BE_y = Baseline emissions in year y (t CO_2/yr)

$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y (MWh/yr)

$EF_{grid,CM,y}$ = Combined margin CO_2 emission factor for grid connected power generation in year y calculated using the latest version of the "Tool to calculate the emission factor for an electricity system" (t CO_2/MWh)

The calculation of $EG_{PJ,y}$ is different for greenfield plants, retrofits and replacements, and capacity additions. Wind power plant projects will be assumed to be greenfield power plants or capacity additions. Because it is a realistic assumption and also data to calculate $EG_{PJ,y}$ for retrofits and replacaments are not available for this study.

$EG_{PJ,y}$ for greenfield renewable energy power plants is calculated as follows:

If the project activity is the installation of a new grid-connected renewable power plant/unit at a site where no renewable power plant was operated prior to the implementation of the project activity or wind power capacity addition to an existing wind power, then:

$EG_{PJ,y=}$ $EG_{facility,y}$

where $EG_{PJ,y=}$ Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y (MWh/yr)

$EG_{facility,y=}$ Quantity of net electricity generation supplied by the project plant/unit to the grid in year y (MWh/yr)

Combined margin CO_2 emission factor for the year 2010 has been calculated as 0.601 tCO_2/MWh in the preceding subtitle. Therefore,

ER_y=$EG_{PJ,y}$ * 0.601

where ER_y= Emission reductions in year y (t CO_2/yr)

$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y (MWh/yr)

The quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in a year can be calculated by multiplying the installed power capacity by the annual full load duration hours. In Chapter IV, annual full load duration hours for wind onshore power plants have been taken as 2,500 hours/year that corresponds to a capacity factor of around 28.5%. This is a conservative assumption since the first installed wind power plants will likely be the ones located in areas with the highest potentials. Although full load duration hours of a significant portion of these wind power plants may be more than 2,500 hours/year, 2,500 hours/year will be assumed for the sake of conservativeness.

Therefore, 20,000 MW installed wind power capacity is expected to generate (20,000 X 2,500=) 50,000,000 MWh electricity in a year. According to TEIAS's (2009) high demand scenario (7.4% increase) and low demand scenario (6.6% increase), electricity generation will be 510,429,000 MWh and 462,260,000 MWh respectively in 2023. 50,000,000 MWh is sustainable with wind power penetration of 9.8% in high demand scenario and 10.8% in low demand scenario.

Annual emission reductions are expected to be (50,000,000 X 0.601=) 30,050,000 t CO_2/yr. This means that 20,000 MW installed wind power capacity can generate 30,050,000 GS VER credits annually. If Turkey's Annex I position in the Kyoto Protocol changes or Turkey somehow becomes eligible to host CDM projects and so issue CERs, this means that Turkey can generate 30,500,000 CER credits annually.

Turkey's overall GHG emissions is 372,6 Mt CO_2e in 2007. Emission reduction of 30,050,000 t CO_2/yr is very impressive that this would help Turkey to combat with climate change considerably.

To calculate the VER or CER potential of wind power projects during the lifetime of the wind power plant, crediting period is an important variable. Gold Standard crediting period is defined as the period of time for which Gold Standard project activities generate emission reductions that are eligible for crediting under the Gold Standard (Rule II). The total duration of the crediting period for Gold Standard project activities cannot exceed the duration of the Standard UNFCCC crediting period, regardless of project cycle and start date (Rule V.a.3). Under the UNFCCC rules, standard UNFCCC crediting period is either a 7-year period that can be renewed twice, for a total of 21 years, or a one-off 10-year period. Duration of gold standard crediting period is determined under Rule V.a.1. According to this Rule, Gold Standard project activities that generate emission reductions are eligible to claim credits for no more than a 7-year period that can be renewed twice, for a total of 21 years, or a one off 10-year period, consistent with the allowable Standard UNFCCC Crediting Period. Where a 7-year renewable period is chosen, the baseline and sustainability assessment must be renewed and revalidated after each 7-year period (Rule V.a.1).

The technical lifetime of wind power plants have been taken as 20 years in Chapter IV. Choosing the 7-year period renewed twice is more advantageous for wind power projects. Since technical lifetime of wind power plants are assumed as 20 years, the crediting period will be 20 years. Therefore, 20,000 MW installed wind power capacity can generate (30,050,000 X 20=) 601,000,000 GS VER credits during the technical lifetime of the wind power projects. If Turkey's Annex I position in the Kyoto Protocol changes or Turkey somehow becomes eligible to host CDM projects and so issue CERs, this means that Turkey can generate 601,000,000 CERs for 20,000,000 MW installed wind power capacity.

In the calculation of GS VERs and CERs during the technical lifetime of the project, it is assumed that combined margin emission factor will not change during the technical lifetime of the wind power projects or for the wind power projects appliying after 2010. This assumption seems reasonable when the methodology to calculate combined margin emission factor is analysed and the prospective path of Turkish electricity system in the light of Supply Security Strategy Paper is evaluated.

The combined margin emissions factor is calculated as follows:

$EF_{grid,CM,y=} EF_{grid,OM,y} * W_{OM} + EF_{grid,BM,y} * W_{BM}$

where $EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year y (tCO2/MWh)

$EF_{grid,OM,y}$ = Operating margin CO_2 emission factor in year y (tCO2/MWh)

W_{OM} = Weighting of operating margin emissions factor (%)

W_{BM} = Weighting of build margin emissions factor (%)

The following default values should be used for W_{OM} and W_{BM}:

For wind and solar power generation project activities: W_{OM} = 0,75 and W_{BM} = 0,25 (owing to their intermittent and non-dispatchable nature) for the first crediting period and for subsequent crediting periods;

Combined margin (CM) is the result of a weighted average of two emission factors: the operating margin. (OM) and the build margin (BM).

The operating margin is the emission factor that refers to the group of existing power plants whose current electricity generation would be affected by the proposed project activity. The build margin is the emission factor that refers to the group of prospective power plants whose construction and future operation would be affected by the proposed project activity.

If Turkey follows a way towards the targets determined for each source in electricity generation in the Supply Security Strategy Paper, this will likely result in an increase in the share of renewables in electricity generation, a decrease in the share of natural gas in electricity generation and an increase in the share of coal in electricity generation. Since emission factor of lignite coal is 89.5 tCO_2/TJ while emission factor of natural gas is 54.3 tCO_2/TJ, it is reasonable to expect operating margin to increase in the future. When it comes to build margin, the build margin emission factor should be updated for for the second crediting period, based on the most recent information available at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used. This does not require monitoring the emission factor during the crediting period. Although the share of renewables as a source of electricity generation is expected to increase in the future, the expected decrease in the share of natural gas and the expected increase in the share of coal may balance the downward impact of renewables on build margin. To sum up, it seems reasonable not to expect a significant decrease in the combined margin emission factor for wind power projects in the future, rather combined emission factor may increase in the future. But for the sake of conservativeness, this study assumes that combined margin emission factor will not change significantly in the future for wind power projects.

As a conclusion, it is reasonable to expect that 20,000 MW installed wind power capacity can generate 601,000,000 GS VER credits during the technical lifetime of the wind power projects. Since 2% of these VERs should be transferred to the Gold Standard registry account as an issuance fee according to Gold Standard Toolkit Annex L, net VERs to be issued will be (601,000,000 X 0.98=) 588,988,000 VERs. If Turkey's Annex I position in the Kyoto Protocol changes or Turkey somehow becomes eligible to host CDM projects and so issue CERs, this means that Turkey can generate 601,000,000 CERs for 20,000,000 MW installed wind power capacity. Since 2% of these CERs should be transferred to the Adaptation Fund as an issuance fee, net CERs to be issued will be (601,000,000 X 0.98=) 588,988,000 CERs. If Turkey adopts 2003/87/EC and enters into the EU ETS Turkish wind power projects can generate neither VERs nor CERs.

If project developers sell these VERs abroad, this may create a significant fund transfer into Turkey depending on the price assumptions for VERs. As mentioned in Chapter VI about voluntary carbon market, the volume-weighted average price in the OTC market was 7.34 $/tCO_2e$ in 2008. This price of 7.34 $/tCO_2e$ shows 20% increase according to the average price of 6.10 $/tCO_2e$ in 2007 and 79% increase according to the average price of 4.07 $/tCO_2e$ in 2006. So, despite the economic crisis VER prices continued its increase. Price of VERs also change according to standards utilized, project types, host countries and seller categories. In 2008, average VER prices were 14.4 $ for Gold Standard credits, 12.6 $ for wind power projects, 9.4 $ for projects hosted in Turkey, 5.1 $ for project developers and 8.9 $ for retailers (Ecosystem Marketplace & New Carbon Finance, 2009).

Purchasing power parity exchange rate of 0.870 USD/EUR will be used in this study as has been used in Chapter IV about grey relational analysis. When average VER prices in 2008 are converted to euro with 0.870 USD/EUR, this corresponds to 12.5 € for Gold Standard credits, 11.0 € for wind power projects, 8.2 € for projects hosted in Turkey, 4.4 € for project developers and 7.7 € for retailers.

For ECX CER Daily Futures (Spot) contracts, average settlement prices have been 12.23 € during 13 March 2009-14 May 2010 period and 13.36 € on 14 May 2010.

Table 161 shows average Prices of ECX CER Future Contracts for Dec2010 and Dec2012.

Table 161. Average Prices of ECX CER Future Contracts (ECX, 2010)

Period	Dec2010 CER	Dec2012 CER
14.03.2008-31.12.2008	18.00	18.86
01.01.2009-31.12.2009	11.70	12.09
01.01.2010-14.5.2010	12.01	12.00

On 14 May 2010 settlement price of ECX CER Dec2010 Future Contract was 13.23 € and settlement price of ECX CER Dec2012 Future Contract was 12.57 €.

Costs of GS VERs until issuance have been explained in the preceding sections. Total transaction costs for a non-forestry large scale project verified every year during 7 years is 0.92 €/VER of which 0.32 €/VER for certification costs (validation, verification, registration and registry fees) and 0.59 €/VER for consultancy and internal costs (PDD development and management of certification) (Guigon, Bellasen & Ambrosi, 2009).

Costs of CERs until issuance have been explained in the preceding sections. Total transaction costs for a non-forestry large scale project verified every year during 7 years is 1.13 €/CER of which 0.28 €/CER for certification costs (validation, verification, registration and registry fees except issuance fee) and 0.85 €/CER for consultancy and internal costs (PDD development and management of certification) (Guigon, Bellasen & Ambrosi, 2009).

When VER and CER prices mentioned above are taken into account, it is reasonable and conservative to assume VER prices for Turkish wind power projects around 9 € and CER prices around 12 €. Although CER prices may increase considerably parallel with the increase in EUA prices, for the sake of conservativeness and the ambiguity of the future of CERs, average CER prices are assumed to be 12 € in the future. When increasing concern over global climate change, the incredible growth rates of both voluntary and regulated carbon markets are taken into account, it is reasonable to assume that there will be enough demand for these VERs or CERs to be sold in these average prices.

When the costs of 0.92 €/VER and 1.13 €/CER is deducted from these VER and CER prices, net revenue from the sale of 588,988,000 VERs would be (588,988,000 X 8.08=) 4,759,023,040 € and net revenue from the sale of 588,988,000 CERs would be 6,402,299,560 €.

Energy is an important item in Turkey's international trade balances. In 2008, Turkey's energy trade deficit is 40,750 million $ while Turkey's current account deficit is 41,416 million $. The impact of installing 20,000 MW wind power plants on Turkey's international trade balances will be analyzed as follows:

If Turkey does not install wind power capacity, as an alternative it can be assumed that Turkey would produce 50% from natural gas, % 30 from coal and %20 from hydro. This scenario is compatible with Turkey's last 5 years' electricity generation. As seen in Table 162, this baseline scenario leads to ((54.667 / 28.89)-1=) 89.2% more energy trade deficit than the wind power installation scenario.

Table 162. Calculation of Wind Power's Impact on Turkey's International Trade Balances

	A	B=Capital Cost (€/MWh)	C=AXB	D=Fuel Cost (€/MWh)	E=AXD	F=C+E (€/MWh)
Natural Gas	50%	6.14	3.07	70.28	35.14	
Coal	30%	16.24	4.872	22.33	6.699	
Hydro	20%	24.43	4.886	0	0	
Total (Baseline)	100%		12.828		41.839	54.667
Wind	100%	28.89	28.89	0	0	28.89

20,000 MW wind power installation amounts to (20,000 X 900,000=) 18,000,000,000 €. So, baseline scenario leads to (18,000,000,000 € X 89.2=) 16,056,000,000 € more trade deficit during the technical lifetime of wind power capacities in terms of capital and fuel costs. VER and CER revenues have been calculated as 4,759,023,040 € and 6,402,299,560 € respectively. When VERs and CERs are assumed to be exported, 20,000 MW wind power can lessen Turkey's trade deficit between 20,815,023,040 € – 22,458,299,560 € cumulatively during the wind power's techical lifetime of 20 years.

CHAPTER VIII

POLICY RECOMMENDATIONS AND CONCLUSION

Electricity energy is an important issue for economic development, climate change and energy vulnerability. Turkish electricity generation is characterized by her high dependence on fossil fuels that increases Turkey's energy import dependency, GHG emissions and trade deficits. The assessment of Turkey's current electricity generation structure together with her renewable energy potentials and global carbon markets reveals following policy recommendations:

Turkey should focus on installing hydro power, nuclear power, and wind power plants.

Turkey is likely to confront electricity energy deficiency around 2014-2015 and to prevent such a deficiency Turkey should start to install new power plants as soon as possible considering the long construction periods of power plants (TEIAS, 2009). Therefore Turkey has a problem to rank and select the best electricity generation technology for the society among natural gas combined cycle power plants, coal power combined heat plants, wind onshore power plants, small hydro power plants, nuclear power plants and solar PV power plants by taking into account cost efficiency, cost volatility risk, supply security, climate change & other pollution and supply-demand mismatch.

This study has analyzed this problem and proposed some solutions by using grey relational analysis procedure for the Reference Scenario and the 450 Scenario of IEA's World Energy Outlook 2009. The outcomes of GRA procedure have been analyzed by assigning different priorities to different attributes, as well. The impact of the distinguishing coefficient on the result of GRA has been tested and the impact found to be small. Based on the findings of GRA, it has been concluded that Turkey should focus on installing small hydro power plants, nuclear power plants and wind onshore power plants. Since hydro power and wind power are related to natural resources of a country, Turkey's potential for these sources has been investigated and concluded that Turkey has an immense untapped potential for these renewable energy resources.

When designing the market framework for the electricity sector, Turkey should take the costs and benefits of different energy resources into account considering the externalities and stimulate sustainable investments in the best technologies.

Externalities are impacts of the electricity generation that have no financial consequences on the owner of the power plant, but which result in economic costs or benefits to society. The difficulty is to quantify the costs and benefits in monetary terms so that the externalities can be included in the socio-economic evaluations. RECABS monetizes some of these externalities for different electricity generation technologies; thus enables comparison of them. This study monetizes the climate change externality using the REcalculator and most recent CO_2 price assumptions of IEA on World Energy Outlook 2009.

Turkey should design a market structure and provide the necessary incentives to encourage private sector investment in the socially best technologies.

It should not be forgotten that hydro power plants, nuclear power plants and wind onshore power plants are the best electricity generation technologies from the viewpoint of society. Leaving electricity market to the free market may not lead to the best solutions for Turkey, because the financially most attractive technologies for the private investors may not be the best ones for society. The findings of this study may provide guidelines for ranking these alternative electricity generation technologies and may serve as a baseline in designing a market structure and for government to design necessary incentives to encourage private sector investment in the socially best technologies.

The ranking and selection of alternative electricity generation technologies should be analyzed periodically.

Since renewable energies are often at an early stage of development compared to conventional technologies, in the long term renewable energies will be more attractive due to the technological progress and learning effect. Renewable energy technologies are expected to have the highest learning rates, thereby increasing their competitiveness in the future. Fuel prices are likely to increase in the future, thereby decreasing the competitiveness of conventional technologies. Supply security and supply-demand mismatch issues for alternative technologies may also change in the future. Therefore the ranking and selection of alternative electricity generation technologies should be analyzed using GRA procedure, periodically every five years.

Turkey should avoid to install coal and natural gas power plants.

The outcomes of GRA proposes that Turkey should avoid to install coal and natural gas power plants. Although this proposal is compatible with the targets determined in Electricity Energy Market and Supply Security Strategy Paper for natural gas as to reduce its share below 30%, it is not compatible with the targets determined in the same paper for domestic lignite and hard coal as to put to use proven lignite deposits and hard coal resources by 2023 in electricity energy generation.

Turkey should adopt the amendment proposal to the Renewable Energy Law No 5346 as soon as possible.

To reach the targets determined in Electricity Energy Market and Supply Security Strategy Paper necessiates legislative developments increasing incentives in favour of renewables. Although Turkey already has some incentives to increase the utilization of renewable sources in electricity generation, they are far from being sufficient.

The recent amendment proposal to the Renewable Energy Law No 5346 involves significant changes in feed-in tariff mechanism based on higher and differentiated tariffs for RES Certificate holders with power plants. This feed-in tariff structure suggests 7 €cent/kWh for small hydro power plants, 8 €cent/kWh for onshore wind power plants, 12 €cent/kWh for off-shore wind power plants, and 25 €cent/kWh for photovoltaic power plants for the first 10 years in operation. Additionally this feed-in tariff structure suggests 20 €cent/kWh for photovoltaic power plants for the second 10 years in operation. This feed-in tariff structure suggests different prices for other types of renewables as well.

An important aspect of this new feed-in tariff mechanism is that these feed-in tariff levels will be further upgraded with the rates determined in the proposal, if the mechanical and / or electromechanical equipment is procured from domestic suppliers. This incentive will be applicable over the first five years of operation. According to the Commission Report of the amendment proposal, this application aims to reduce energy dependency of Turkey, pioner technology transfer, and supplement employment.

Another important aspect of this new feed-in tariff mechanism is that licensees generating power for their own need, with power plants of a maximum installed capacity of 500 kW, will be eligible for these feed-in tariffs, except photovoltaic power plants. PVs with a maximum capacity of 500 kW will in turn be provided as follows: For generation upto 2,999 kWh/month, 35 €cent/kWh and for generation between 3,000 – 6,000 kWh/month, 30 €cent/kWh. This may increase the utilization of wind power and solar power by households in electricity generation for their own need.

Although these feed-in tariffs are likely to promote renewable energy, the amendment proposal has not been approved yet. This decreases the competitiveness of Turkish renewable market against European countries.

Turkey should not transpose Directive of Emissions Trading 2003/87/EC.

Turkey Progress Reports prepared by Commission of the European Communities between 2005-2009 criticise Turkey for not establishing a greenhouse gas emission allowance trade scheme, not transposing the Emissions Trading Directive and related decisions.

A national environmental approximation strategy (UCES) was adopted by the High Planning Council in 2006, that includes a plan for the transposition, implementation and enforcement of the EU environmental acquis. According to the timetable for legislative approximation about air sector, to transpose Directive of Emissions Trading 2003/87/EC, infrastructural investment and technical study are needed. Enforcement date will be designated by the legislation prepared according to the result of these technical studies.

Since Turkey is a developing country, Turkey's accession into the EU ETS may impede the economic development of Turkey. Therefore Turkey should state her own conditions as a developing country and reject to enter into the EU ETS.

If Turkey chooses to adopt to have an emissions trading system, allocation method should be auctioning, measures against large price fluctuations should be taken, carbon leakage should be identified, the liquidity of the market should be maintained, and the length of the emissions trading schemes should be long enough to make long term investments for emissions reductions.

The EU ETS was not much successful in achieving some of its objectives, such as encouraging investment in clean technologies, that largely come from some adverse incentives related to the EU ETS design such as over-allocation of permits and counterproductive allocation methods (EWEA, 2009).

Auctioning should be the basic principle for allocation to eliminate windfall profits and put new entrants on the same competitive position as existing installations.

The large price fluctuations may have significant negative effects on the performance of the emissions trading system. To prevent large price fluctuations hybrid schemes bounded with price floors and price ceilings may be an alternative. Or allowing banking and borrowing of allowances between different trading periods may decrease price fluctuations as well (PricewaterhouseCoopers, 2009b).

If other developing countries or developed countries do not participate in international agreement to limit their GHG emissions, some energy-intensive sectors may be subject to an economic disadvantage in international competition. Sectors exposed to carbon leakage should be identified and the negative impacts of emissions trading on these sectors should be compensated with effective measures.

The liquidity of the market should be maintained. Otherwise, the market price does not provide efficient signals and may discourage participants to make long term investments to reduce emissions.

Also the length of the emissions trading schemes should be long enough to make long term investments for emissions reductions (PricewaterhouseCoopers, 2009b).

Establishment of Designated Operational Entities in Turkey should be encouraged.

Designated Operational Entity (DOE) is a private company that has been accredited by the United Nations as competent project evaluator responsible for validating a project. They validate that an offset project is designed in a credible way, and they control the projects themselves to make sure that the carbon emission reduction has actually been achieved. Verification and certification stages of emission reduction projects are carried out by DOEs as well.

Because of DOE's high importance in emission reduction projects, establishment of Designated Operational Entities in Turkey should be encouraged to provide better guidelines for the project developers.

Turkey should encourage private sector to invest in manufacturing wind turbines and related equipments.

The recent gobal developments in wind power and the targets of the EU suggest that wind power capacity installations will reach enormous amounts in the near future. The global wind turbine market is dominated by a few companies, showing an oligopolistic structure. The increase in the number of orders of wind turbines have raised wind turbine prices and wind turbine manucafturers have increased profits considerably. Wind turbine manufacturing is a labor intensive subsector that may help Turkey to combat high unemployment rates. When Turkey's 20,000 MW wind power capacity target by 2023 is considered, only the domestic market is expected to be around 18,000,000,000 €. When labor intensity, profitability and huge market potential of wind turbine manufacturing are considered Turkey should encourage private sector to invest in manufacturing wind turbines and related equipments.

Turkey should establish the first voluntary carbon emissions exchange for VERs in the world.

Turkey is perhaps the most important country as a project developer in the voluntary market and she is likely to maintain its dominant position in the near future due to the reasons as follows: Turkey is ineligible to supply CDM or JI credits at least until the end of first commitment period 2012, because of her position in the Kyoto Protocol as an Annex I but a non-Annex B country. So, voluntary market is the only available market for Turkey at least until the end of 2012. Also Turkey has an immense renewable energy potential waiting to be utilized and the government intends to transform the country's energy structure towards more renewable energy. These are likely to increase Turkey's presence in the voluntary carbon market in the future. Therefore Turkey's domestic voluntary carbon market is expected to increase incredibly in the future. In case Turkey achieves her target of 20,000 MW wind power capacity this would create 588,988,000 VERs. Therefore Turkey should take the lead in the voluntary carbon market by establishing the first voluntary carbon emissions exchange for VERs in the world. This increases the liqudity of VERs in the world and so creates better price signals in evaluating project analysis.

Turkey should design a new Standard for VERs to quote in her voluntary emissions exchange.

In addition to the establishment of the first voluntary carbon emissions exchange for VERs, Turkey should also create a new standard for voluntary carbon offset credits. As an emerging market, the design of this new standard should stress the sustainable development of emerging markets as well as social aspects. This may help Turkey to increase her presence in the global carbon market and prosper her position among emerging markets.

The major contributions of this study are as follows: this study may serve as a guideline for Turkey to rank and select the socially best electricity generation technologies for different scenarios and from different viewpoints by only changing the weights of attributes. This study also compares the unit electricity generation cost of different technologies in detail by using the REcalculator with the assumptions of International Energy Agency's (IEA) Renewable Energy Costs and Benefits for Society (RECABS) project (2007) and fuel price and CO_2 price assumptions of World Energy Outlook 2009.

In addition, to our knowledge, this is the first academic study calculating potential revenues from sale of carbon offset credits in the carbon market, calculating the quantity of CO_2 that would be avoided in the light of Gold Standard regulations in case Turkey's 20,000 MW wind power target is achieved, and assessing the impact of installing 20,000 MW wind power plants on Turkey's international trade balances. This study shows that investors should take into account the revenue from carbon offset credits in electricity generation project analysis. This study can help the project developers in renewable electricity generation technologies to estimate the revenue they can get from the sale of carbon offset credits and also serve as a guideline about how they can participate in the carbon market. This study may also serve as a roadmap for the government in determining the characteristics of an emissions trading system and carbon emissions exchange.

The GHG emission reduction potential of Turkey in projects other than wind power might be a basis for further research. Although nuclear power seems to be a promising alternative as well as renewable energy according to the GRA analysis and RECABS, the EU is escaping from nuclear power for over a decade. The reason for this may be investigated as well. How emissions trading system can be designed as an incentive for preference of renewable energy technologies may be another area of study. The financial impacts of carbon offset credits in electricity generation project investment analysis might be studied as well. The possible results of establishing carbon emissions exchange in Turkey and how it should be designed would be an interesting study. The impact of global carbon markets on international trade balances might be an important subject for further research as well.

Appendix A: Latest Capacity Additions to the Electricity System that Forms 20% of Annual Electricity Generation in 2008 (TEIAS, 2006, 2007, 2008)

Date of Commissioning	Power Plant	Installed Capacity (MW)	Fuel Type	Average Generation (GWh)
2008	MB Şeker Nişasta San. A.Ş. (Sultanhanı)	88	Natural Gas	0
2008	Aksa Enerji (Antalya)	183.8	Natural Gas	1,337
2008	Aksa Enerji (Manisa)	52.38	Natural Gas	792
2008	Antalya Enerji (Capacity Addition)	17.46	Natural Gas	2,561
2008	Ataç İnşaat San. A.S.B. (Antalya)	5.4	Natural Gas	0
2008	Bahçıvan Gıda (Lüleburgaz)	1.165	Natural Gas	0
2008	Can Enerji (Çorlu-Tekirdağ) (Capacity Addition)	52.38	Natural Gas	2,743
2008	Four Seasons Otel (Atik Pasha Tur A.Ş.)	1.165	Natural Gas	0
2008	Fritolay Gıda San. Ve Tic. A.Ş. (Capacity Addition)	0.06	Natural Gas	0
2008	Karkey (Silopi-5) (154 KV) (Capacity Addition)	14.78	Fuel Oil	164
2008	Melike Tekstil (Gaziantep)	1.584	Natural Gas	0
2008	Misis Apre Tekstil Boya En. San.	2	Natural Gas	53
2008	Modern Enerji (Lüleburgaz)	13.4	Natural Gas	5,089
2008	Ortadoğu Enerji (Oda Yeri) (Eyüp/İstanbul)	2.83	Waste gas	0
2008	Polat Turz. (Polat Renaissance İst. Ort.)	1.6	Natural Gas	5
2008	Sarayköy Jeotermal (Denizli)	6.85	Geothermal	141
2008	Sönmez Elektrik (Capacity Addition)	8.73	Natural Gas	1
2008	Akköy Enerji (Akköy I HES)	101.94	Hydro	216
2008	Alp Elektrik (Tınzatepe) Antalya	7.689	Hydro	92
2008	Cansu Elektrik (Murgul/Artvin)	9.18	Hydro	125
2008	Çaldere Elk. (Çaldere HES) Dalaman-Muğla	8.74	Hydro	112
2008	Daren HES Elkt. (Seyrantepe Barajı ve HES)	49.7	Hydro	144
2008	Değirmenüstü En. (Kahramanmaraş)	25.7	Hydro	0
2008	Gözede HES (Temsa Elektrik) Bursa	2.4	Hydro	61
2008	HGM Enerji (Keklicek HES) (Yeşilyurt)	8.674	Hydro	1
2008	Hidro Knt. (Yukarı Manahoz Reg. Ve HES)	22.4	Hydro	138
2008	İç-En Elk. (Çalkışla Regülatörü ve HES)	7.66	Hydro	34
2008	Maraş Enerji (Fırnıs Regülatörü ve HES)	7.22	Hydro	0
2008	Sarmaşık I HES (Fetaş Fethiye Enerji)	21.04	Hydro	15
2008	Sarmaşık II HES (Fetaş Fethiye Enerji)	21.58	Hydro	12
2008	Torul	105.6	Hydro	186
2008	Yeşil Enerji Elektrik (Tayfun HES)	0.82	Hydro	0
2007	Habaş (Aliağa) (Capacity Addition)	9.1	Natural Gas	1
2007	Modern Enerji	5.2	Natural Gas	0
2007	Arenko	0.7	Natural Gas	0

Date of Commissioning	Power Plant	Installed Capacity (MW)	Fuel Type	Average Generation (GWh)
2007	Altınmarka Gıda	0,1	Natural Gas	1
2007	Arteks	0.8	Fuel Oil	6
2007	Ataer Enerji	0.1	Natural Gas	1
2007	Acıbadem Sağlık Hiz. Ve Tic. A.Ş. (Kadıköy Hast.)	0.5	Natural Gas	4
2007	Acıbadem Sağlık Hiz. Ve Tic. A.Ş. (Kozyatağı Hast.)	0.6	Natural Gas	5
2007	Acıbadem Sağlık Hiz. Ve Tic. A.Ş. (Nilüfer/Bursa)	1.3	Natural Gas	11
2007	Akateks Tekstil San. Ve Tic. A.Ş.	1.8	Natural Gas	14
2007	Flokser Tekstil San. A.Ş. (Çatalca-İstanbul) (Poliser)	2.1	Natural Gas	17
2007	Flokser Tekstil San. A.Ş. (Çatalca-İstanbul) (Süetser)	2.1	Natural Gas	17
2007	Fritolay Gıda San. Ve Tic. A.Ş.	0.5	Natural Gas	4
2007	Kıvanç Tekstil San. Ve Tic. A.Ş.	3.9	Natural Gas	33
2007	Kilsan Kil San. veTic. A.Ş.	3.2	Natural Gas	25
2007	Süperboy Boya San. Ve Tic. Ltd. Şti. (Büyükçekmece)	1	Natural Gas	8
2007	Swiss Otel (Anadolu Japan Turizm A.Ş.) (İstanbul)	1.6	Natural Gas	11
2007	TAV Esenboğa Yatırım Yapım ve İşletme A.Ş. (Ankara)	3.9	Natural Gas	33
2007	Nuh Enerji-2 (Nuh Çim.)	73	Natural Gas	514
2007	Bil Enerji	0.1	Natural Gas	1
2007	Uşak Şeker (Nuri Şeker)	1.7	Lignite	3
2007	Boğazlıyan Şeker	16.4	Natural Gas	122
2006	Denizli Çimento (Düzeltme)	0.445	Natural Gas	3
2007	Dentaş	0.3	Natural Gas	2
2007	Desa	0.7	Natural Gas	5
2007	Eskişehir End. Enerji	3.5	Natural Gas	26
2007	Eskişehir Şeker (Kazım Taşkent)	2.9	Natural Gas	22
2007	İGSAŞ	2.2	Natural Gas	16
2007	Kartonsan	5	Natural Gas	37
2007	Süper Filmcilik	0.1	Natural Gas	1
2007	Tekboy Enerji	0.1	Natural Gas	1
2007	BİS Enerji Üretim A.Ş. (Bursa) (Capacity Addition)	43	Natural Gas	355
2007	Aliağa Çakmaktepe Enerji A.Ş. (Aliağa/İzmir)	34.8	Natural Gas	278
2007	BİS Enerji Üretim A.Ş. (Bursa) (Düzeltme)	28.3	Natural Gas	234
2007	BİS Enerji Üretim A.Ş. (Bursa) (Capacity Addition)	48	Natural Gas	396
2007	Bosen Enerji Elektrik A.Ş.	142.8	Natural Gas	1,071
2007	Sayenerji Elektrik Üretim A.Ş. (Kayseri/OSB)	5.9	Natural Gas	47
2007	T Enerji Üretim A.Ş. (İstanbul)	1.6	Natural Gas	13

Date of Commissioning	Power Plant	Installed Capacity (MW)	Fuel Type	Average Generation (GWh)
2007	Zorlu En. Kayseri (Capacity Addition)	7.2	Natural Gas	55
2007	Siirt	25.6	Fuel Oil	190
2007	Mardin Kızıltepe	34.1	Fuel Oil	250
2007	Karen	24.3	Fuel Oil	175
2007	İdil 2 (PS3 A-2)	24.4	Fuel Oil	180
2006	Ekoten Tekstil Gr-I	1.932	Natural Gas	15
2006	Erak Giyim Gr-I	1.365	Natural Gas	12
2006	Alarko Altek Gr-III	21.89	Natural Gas	151
2006	Aydın Örme Gr-I	7.52	Natural Gas	60
2006	Nuh Enerji-2 Gr II	26.08	Natural Gas	224
2006	Marmara Elektrik (Çorlu) Gr-I	8.73	Natural Gas	71
2006	Marmara Pamuk (Çorlu) Gr-I	8.73	Natural Gas	71
2006	Entek (Köseköy) Gr IV	47.62	Natural Gas	411
2006	Else Tekstil (Çorlu) Gr I-II	3.16	Natural Gas	25
2006	Sönmez Elektrik (Çorlu) Gr I-II	17.46	Natural Gas	135
2007	Velsan Akrilik	0.1	Natural Gas	1
2006	Menderes Elektrik Gr I	7.951	Geothermal	56
2006	Kastamonu Entegre (Balıkesir) Gr I	7.52	Natural Gas	48
2006	Boz Enerji Gr I	8.73	Natural Gas	60
2006	Adana Atık Su Arıtma Tesisi	0.803	Biogas	6
2006	Amylum Nişasta (Adana)	14.25	Natural Gas	80
2006	Şık Makas (Çorlu) GR I	1.58	Natural Gas	13
2006	Elbistan B Gr III	360	Lignite	2,340
2006	Antalya Enerji Gr I-II-III-IV	34.92	Natural Gas	245
2006	Hayat Tem. Ve Sağlık Gr. I-II	15.04	Natural Gas	94
2006	Ekolojik En. (Kemerbugaz) Gr I	0.98	Waste gas	8
2006	Eroğlu Giyim (Çorlu) Gr I	1.165	Natural Gas	9
2006	Cam İşElektrik (Mersin) Gr I	126.1	Natural Gas	1,008
2006	Elbistan B Gr II	360	Lignite	2,340
2006	Yıldız Ent. Ağaç (Kocaeli) Gr I	6.184	Natural Gas	40
2006	Çerkezköy Enerji Gr I	49.164	Natural Gas	403
2006	Entek (Köseköy) Gr V	37	Natural Gas	319
2006	Elbistan B Gr IV	360	Lignite	2,340
2006	Çırağan Sarayı Gr I	1.324	Natural Gas	11
2006	Ertürk Elektrik Tepe Res Gr I	0.85	Wind	3
2006	Akmaya (Lüleburgaz) Gr I	6.91	Natural Gas	48
2006	Burgaz (Lüleburgaz) Gr I	6.91	Natural Gas	55
2006	Seyhan I-II	0.3	Hydro	2
2006	Şanlıurfa I-II	51.8	Hydro	124
2006	Bereket Enerji Gökyar HES 3 Grup	11.62	Hydro	43
2006	Molu En Zamantı Bahçelik Gr I-II	4.22	Hydro	30

Date of Commissioning	Power Plant	Installed Capacity (MW)	Fuel Type	Average Generation (GWh)
2006	Su Enerji (Balıkesir) Gr I-II	4.603	Hydro	19
2006	Bereket En. (mentaş Reg.) Gr I-II	26.6	Hydro	111
2006	Ekin (Başaran HES) (Nazilli)	0.6	Hydro	3
2006	Ere (Sugözü rg. Kızıldüz HES) Gr I-II	15.432	Hydro	55
2006	Ere (Aksu Reg. Ve Şahmallar HES) Gr I-II	14	Hydro	45
2006	Tektuğ (Kalealtı) Gr I-II	15	Hydro	52
2006	Bereket En. (Mentaş Reg) Gr III	13	Hydro	52
30.12.2005	Bosen Gr-III	51.02	Natural Gas	178
23.12.2005	Karkey (Silopi-4) Gr-V	6.75	Fuel Oil	47
14.12.2005	Akça Enerji Gr-III	8.73	Natural Gas	65
08.12.2005	Kahramanmaraş Kağıt Gr-I	6	Imported Coal	45
07.12.2005	Pakgıda (Kemalpaşa) Gr-I	5.67	Natural Gas	43
03.12.2005	Koruma Klor Gr I-II-III	9.6	Natural Gas	77
30.11.2005	İçdaş Çelik Gr-I	135	Imported Coal	948
27.11.2005	Küçükçalık Tekstil Gr I-II-III-IV	8	Natural Gas	64
26.11.2005	Zorlu Enerji Yalova Gr I-II	15.93	Natural Gas	122
24.11.2005	Habaş Aliağa Gr-V	23	Natural Gas	197
14.11.2005	Graniser Granit Gr-I	5.5	Natural Gas	42
11.11.2005	Manisa OSB Gr I-II-III-IV-V-VI-VII	84.83	Natural Gas	434
09.11.2005	Ak Enerji (K.Paşa) Gr III	40	Natural Gas	326
26.10.2005	Zorlu Enerji Kayseri Gr IV	38.63	Natural Gas	296
14.10.2005	Altek Alarko Gr I-II	60.1	Natural Gas	416
24.09.2005	Ayka Tekstil Gr-I	5.5	Natural Gas	41
21.09.2005	Habaş Aliağa Gr IV	44.62	Natural Gas	357
27.08.2005	Çebi Enerji Bt	21	Natural Gas	166
27.08.2005	Evyap Gr I-II	5.12	Natural Gas	30
25.08.2005	Can Enerji Gr-I	3.9	Natural Gas	32
24.08.2005	Noren Enerji Gr-I	8.73	Natural Gas	70
23.08.2005	Çebi Enerji Gt	43.37	Natural Gas	342
30.07.2005	Yamula Grup I-II	100	Hydro	336
22.07.2005	Zorlu Enerji Kayseri Gr I-II-III	149.87	Natural Gas	1,147
15.07.2005	Eti Mad. (Ban.asit) Gr-I	11.5	Waste heat	85
15.07.2005	Bereket En. (Dalaman) Gr XIII-XIV-XV	7.5	Hydro	36
07.07.2005	Zeynep Giyim San. Gr-I	1.17	Natural Gas	9
30.06.2005	Karkey (Silopi-4) Gr-IV	6.15	Fuel Oil	43
14.06.2005	Modern Enerji (DG) Gr-III	8.38	Natural Gas	63
13.06.2005	Modern Enerji (DG+LPG) Gr-II	7.68	Natural Gas	50
02.06.2005	Habaş Aliağa Gr III	44.62	Natural Gas	357
02.06.2005	Muratlı Gr I-II	115	Hydro	444
27.05.2005	Tezcan Galvaniz Gr I-II	3.66	Natural Gas	29

Date of Commissioning	Power Plant	Installed Capacity (MW)	Fuel Type	Average Generation (GWh)
27.05.2005	Hayat Kağıt Gr-I	7.53	Natural Gas	56
25.05.2005	Yongapan (Kaast. Entg) Gr-II	5.2	Natural Gas	33
24.05.2005	Nuh Enerji-2Gr I	46.95	Natural Gas	396
21.05.2005	İçtaş Enerji (Yukarı Mercan) Gr I-II	14.19	Hydro	44
30.04.2005	Ak Enerji (K.Paşa) Gr I-II	87.2	Natural Gas	716
24.04.2005	Tektuğ (Kargılık) Gr I-II	23.9	Hydro	83
22.04.2005	Sunjüt (RES) Gr I-II	1.2	Wind	2
07.04.2005	Karege Gr IV-V	18.06	Natural Gas	144
18.03.2005	Bis Enerji Gr VII	43.7	Natural Gas	361
15.03.2005	Çan Gr II	160	Lignite	1,040
15.02.2005	Çan Gr I	160	Lignite	1,040
			Total	40,300

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