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TURKISH ELECTRICITY SECTOR: A BOTTOM-UP APPROACH

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TURKISH ELECTRICITY SECTOR: A BOTTOM-UP APPROACH

Abstract

The importance of this study, roots from being the first attempt to model and examine Turkish energy system specific to electricity sector using TIMES modelling methodology to assess the future pathways of the system under various policy options.

As a fast-growing country, energy consumption has raised in Turkey due to economic developments by industrialization and urbanization. To meet the increasing demand, significant investments are required in electricity generation technologies. This study responds when to invest and which technologies to invest in a certain time period.

To determine future energy technology mix of Turkey, the current system is modeled as reference energy system with a well-balanced and detailed representation of electricity, transportation, industry and residential sectors. Based on reference scenario different policy scenarios has been carried at and compared with equivalent abatement scenarios. While the assessment will be focused on electricity sector such as investment strategies, and price dynamics also interactions with other sectors will also be elaborated.

As a result, a primary resource mix, a system-wide cost analysis, investment decisions for particular time period and technologies, potential electricity prices and reflections on other industries are generated. Results of proposed scenarios are compared with the reference case.

Keywords: Energy, Electricity, Bottom-up model, TIMES, Reference Energy System, Investment Decisions, Emission Reduction, Scenario Analysis, Minimum Cost Analysis, Linear Programming

TÜRKİYE ELEKTRİK SEKTÖRÜNE TEMELDEN-YUKARI YAKLAŞIM

Özet

Bu çalışmanın temel amacı, ilk kez TIMES modelleme metodolojisi kullanarak Türkiye enerji sisteminin ve özellikle elektrik sektörünün çeşitli enerji politikaları altında nasıl davrandığını gösteren sonuçlar sağlamak için senaryo analizleri gerçekleştirmektir.

Hızla gelişen bir ülke olarak, gözlenen ekonomik gelişmeler, endüstrileşme ve şehirleşme sebebiyle Türkiye'nin enerj tüketimi artmaktadır. Artan bu enerji ihtiyacını karşılayabilmek için yapılacak yatırım kararları önem arz etmektedir. Bu çalışma hangi teknolojilere hangi periyotlarda yatırım yapmak gerektiğiyle ilgili cevaplar ortaya koymaktadır.

Türkiye'nin gelecek enerji teknolojileri haritasını ortaya koymak adına, mevcut sistem referans enerji sistemi adı altına elektrik, endüstri, ulaştırma, konut ve tarım sektörleri incelenerek modellenmiştir. Oluşturulan baz senaryo üzerine yalnızca güneş enerjisi teknolojilerine, yalnızca rüzgar enerjisi teknolojilerine ve hem rüzgar hem de güneş enerjisi teknolojilerine devlet teşviği verilen çeşitli politikalara bağlı senaryolar ve modelin hem güneş hem de rüzgar teknolojilerine teşvik verilen senaryonun toplam karbondioksit değerlerine erişmeye zorlandığı ve modelin elektrik üretiminden kaynaklanan karbondioksit değerlerine erişmeye zorlandığı optimizasyon senaryoları oluşturularak bu politikaların elektrik sektörü yatırımlarına, fiyat dengelerine ve diğer sektörlerle ilişkilerine ne şekilde yansıyacağı incelenmiştir.

Çalışma sonucunda birincil kaynakların dağılımı, sistem bazında maliyet analizi, teknolojilerin yatırım kararları, olası elektrik fiyatları ve ilişkili sektörlere olan yansımaları incelenmiştir.

Anahtar kelimeler: Enerji Modelleme, Elektrik Sektrü, Temelden yaklaşım, Referans Enerji Sistemi, Yatırım Kararları, Senaryo Analizi, TIMES, Yenilenebilir Enerji, Maliyet Analizi , Lineer Programlama

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To my country...

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List of Abbreviations

CDD	**C**ooling **D**egree **D**ays
GDP	**G**ross **D**omestic **P**roduct
GHG	**G**reenhouse **G**as
HDD	**H**eating **D**egree **D**ays
IEA	**I**nternational **E**nergy **A**gency
M toe	**M**illion **t**onnes of **o**il **e**quivalent
OECD	The **O**rganisation for **E**conomic **C**o-operation and **D**evelopment
PJ	**P**eta **J**oule
RES	**R**eference **E**nergy **S**ystem
TL	**T**urkish **L**iras
TWh	**T**erawatt **h**our
USD	**U**nited **S**tates **D**ollar

Chapter 1

Introduction

1.1 Energy Outlook in the World

The growth of population, increasing deployment of the population in cities and economic growth (GDP) cause more energy demand. Energy use triggers the economic and the social evolution and therefore increases energy consumption [1]. According to IEA Key World Energy Statistics[2], worldwide final energy consumption in 1973 was 4,661 M toe and it is increased to 9,473 M toe in 2014. Total energy consumption is expected to increase 48% in 2040 mostly based on non-OECD countries [3]. In 2015 as can be seen from Figure 1.1, primary energy consumption was 13,147.3 M toe with 1% increase rate which is below the average of last 10 years 2%. As shown in Figure 1.2 the growth rates of world primary energy consumption is in the slowest pace since 1998 except the decline in 2009 which is a consequence of financial crisis with a following 5% increase in 2010. Due to lower GDP growth rates and low population growth rate in OECD countries, energy consumption of non-OECD countries is expected to be higher compared to the OECD countries, which is already constitutes the 58.1% of global energy consumption in 2015 [4].

Oil is the dominant fuel in global primary energy mix with 32.94% share in 2015. Coal with 29.21% follows oil and finally natural gas follows coal with 23.85% share. Therefore, fossil fuels which are coal, oil, petroleum, and natural gas

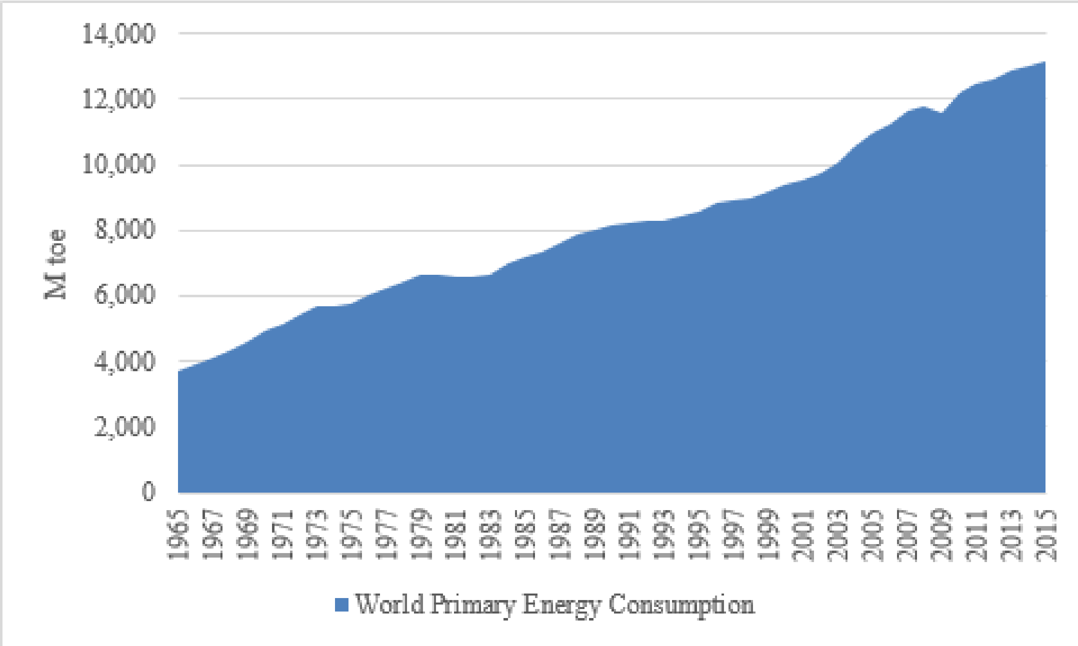


Figure 1.1: World primary energy consumption between years 1965 and 2015 (M toe) [4]

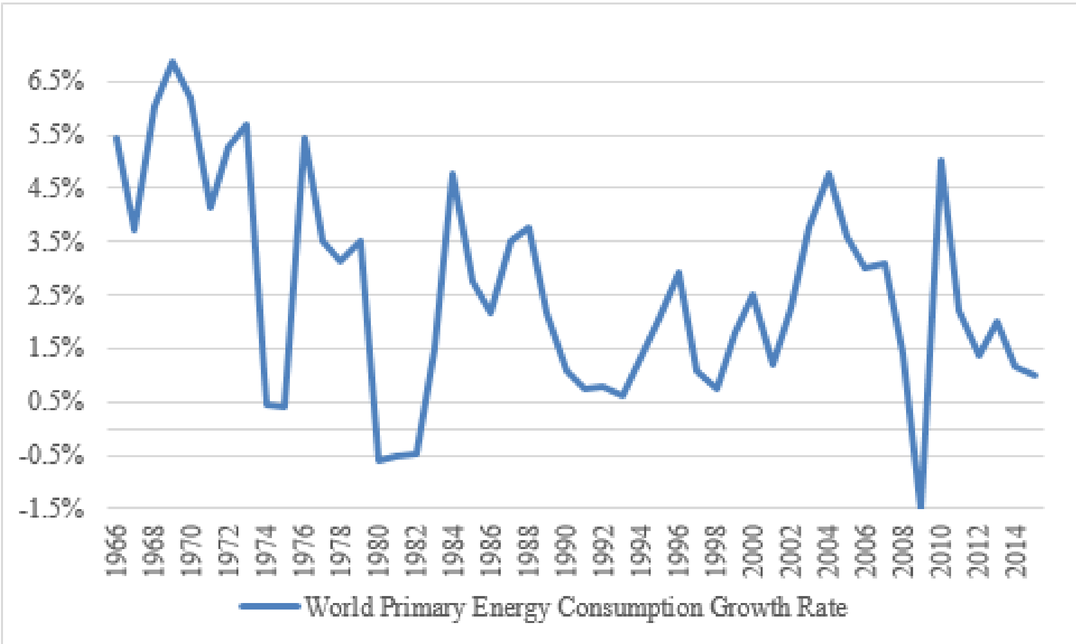


Figure 1.2: World primary energy consumption growth rate between years 1966 and 2015 (%) [4]

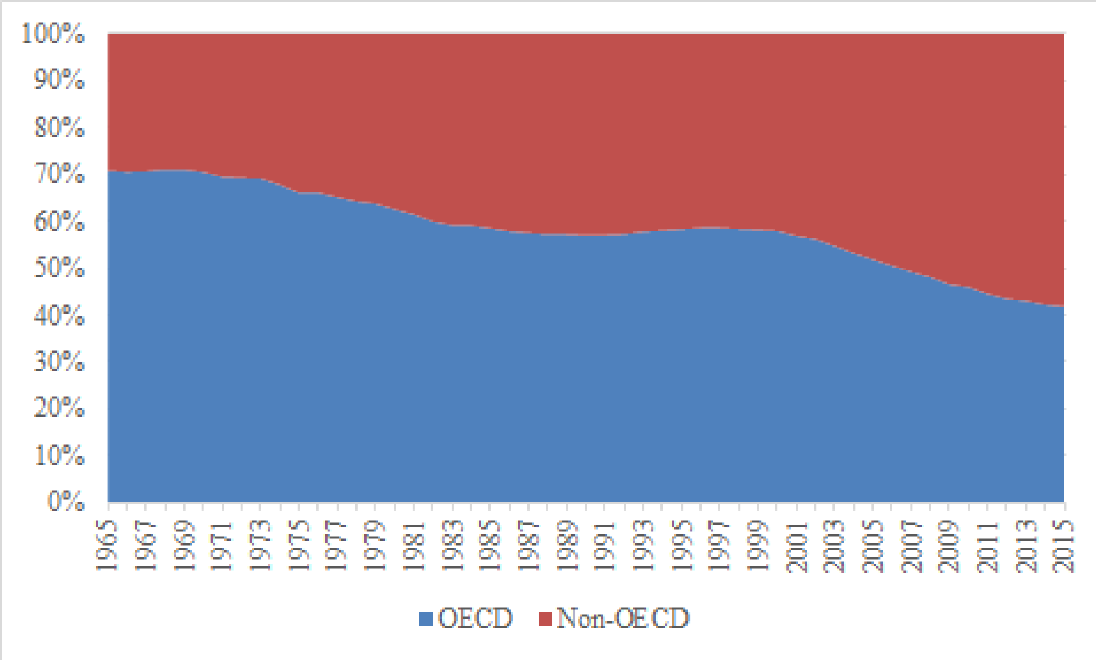


Figure 1.3: Percentage change of primary energy consumption of OECD and non-OECD countries between years 1965 and 2015 (M toe) [4]

products comprise 86% of world primary energy consumption. The remaining part is shared by hydroelectric, nuclear, and renewables as 6.79%, 4.44%, and 2.78% respectively [4]. Deployment of primary energy consumption by fuel types between 1990 and 2015 is shown in Figure 1.4.

Increase of energy consumption which is supplied mostly by fossil fuels affect the environment by generating significant amount of greenhouse gas emissions and cause climate change. Greenhouse gases mainly consist of carbon dioxide, methane, nitrous oxide, chlorofluorocarbons, tropospheric ozone and water vapor. Based on 2010 data, most of global greenhouse gas emissions raised as carbon dioxide and responsible for global warming. Top carbon dioxide generator countries are China, USA, and basically the non-OECD countries. Globally, 25% of greenhouse gas emissions roots from electricity and heat production due to high rates of coal, natural gas and oil consumption. Agriculture, forestry and land use activities accounted for 24% of global GHG emission while industry accounted for 21%. Transportation, other energy (fuel extraction, refining, processing etc.)

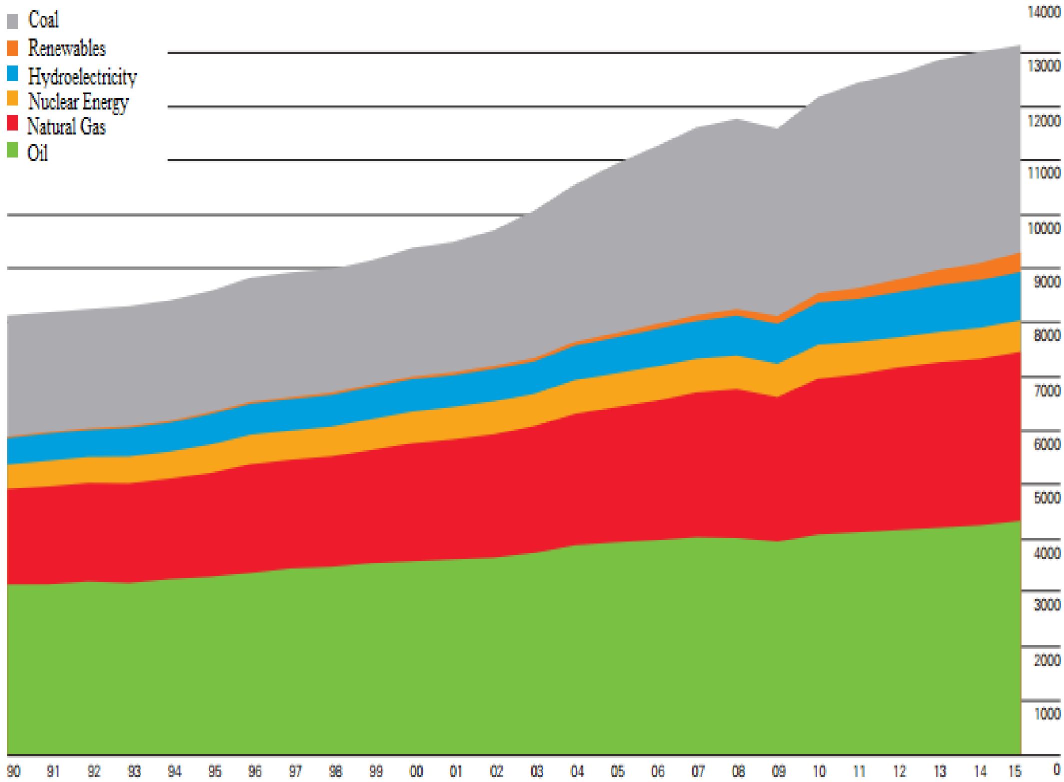


Figure 1.4: World primary energy consumption between years 1990 and 2015 by fuel type (M toe) [4]

and buildings accounted for 14%, 10%, and 6% respectively [5]. Since electricity sector is the largest contributor of GHG emissions, electricity generation fuel mix have great importance to decrease GHG emission levels. Increment of global carbon dioxide amount and growth rate can be found in Figure 1.5 and Figure 1.6.

Global warming and climate change are considered as global major problems and raised concern over countries, therefore to combat these effects the first World Climate Conference (WCC) took place in 1979. In 1991, first meeting of the Intergovernmental Negotiating Committee (INC) was conducted. In 1992, the United Nations Framework Convention Climate Change was formed to fight against climate change to limit average global temperature change. As the first important agreement, Kyoto Protocol was signed in 1997 and entered into force in 2005. Kyoto Protocol enforced emission reduction targets over 37 industrialized countries and the European community for an overall 5% emission reduction compared to

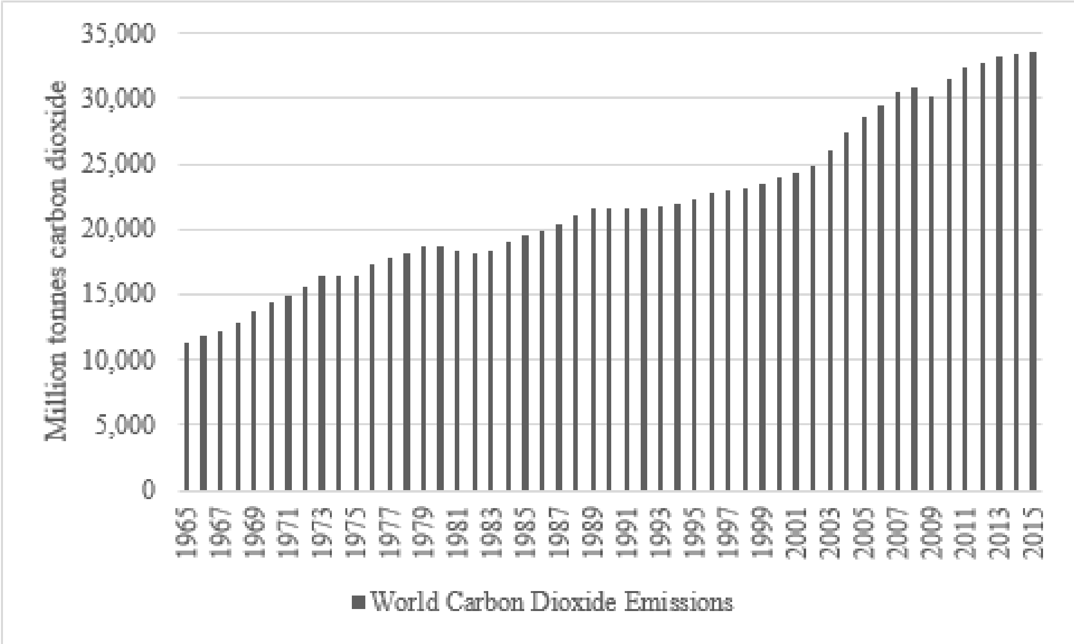


Figure 1.5: World Carbon Dioxide Emissions between years 1965-2015 (million tonnes carbon dioxide) [4]

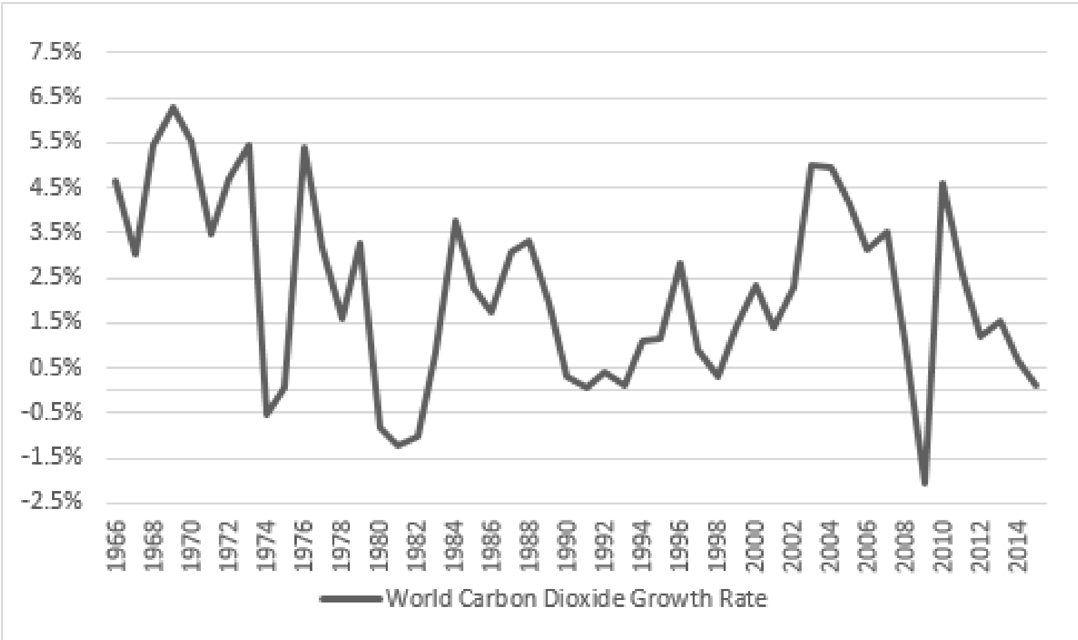


Figure 1.6: Growth Rate of World Carbon Dioxide Emissions between years 1966-2015 (%) [4]

1990 levels between years 2008 and 2012 [6]. Turkey became a party to the Kyoto Protocol in 2009, yet it did not undertake the commitments [7].

At the 21^{st} Conference of Parties (COP21), Paris agreement that entered into force in November 2016 was adopted. The main purpose of this agreement is to struggle climate change by keeping global temperature increase below 2 degrees Celsius. This agreement also requires to overcome impacts of climate change. So that, a new technology framework, financial flows and enhanced capacity building framework become crucial [8]. Turkey has declared a reduction of greenhouse gas emissions up to 21% from the business as usual by 2030 and signed agreement as a developing country [9].

1.2 Energy Outlook in Turkey

In 1990 general population census, population of Turkey was 56.47 million and in 2000 it has increased to 67.8 million. According to results of address based population registration system population was 75.62 million in 2012 [10]. Population is expected to reach 84.25 million in 2023 and 93.48 million in 2050. The increase of population and population projections between years 2013 and 2050 are illustrated in Figure 1.7. Population living in towns and villages are decreasing year by year. Proportion of population residing in province and district centres was 77.3% in 2012 and increased to 92.10% in 2015. The proportions of population residing in province and district centres between years 2007 and 2015 are illustrated in Figure 1.8.

Although GDP in TL was increasing during years between 1998 and 2015, GDP per capita decreased from 4129 $ to 3019 $ in 2001 by the local economic crisis and also decreased from 10444 $ to 8561 $ after global financial crisis in 2008. GDP per capita has also decreased in 2014 and 2015 [11]. More detailed information can be found in Figure 1.9 regarding the GDP per capita at and GDP values between 1998 and 2015.

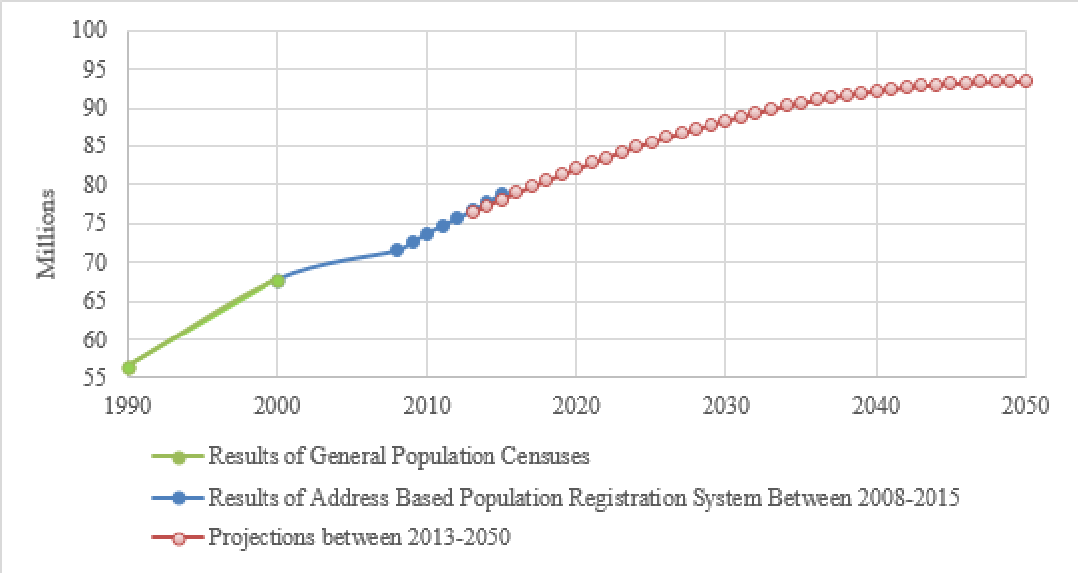


Figure 1.7: Projection of population in Turkey [10]

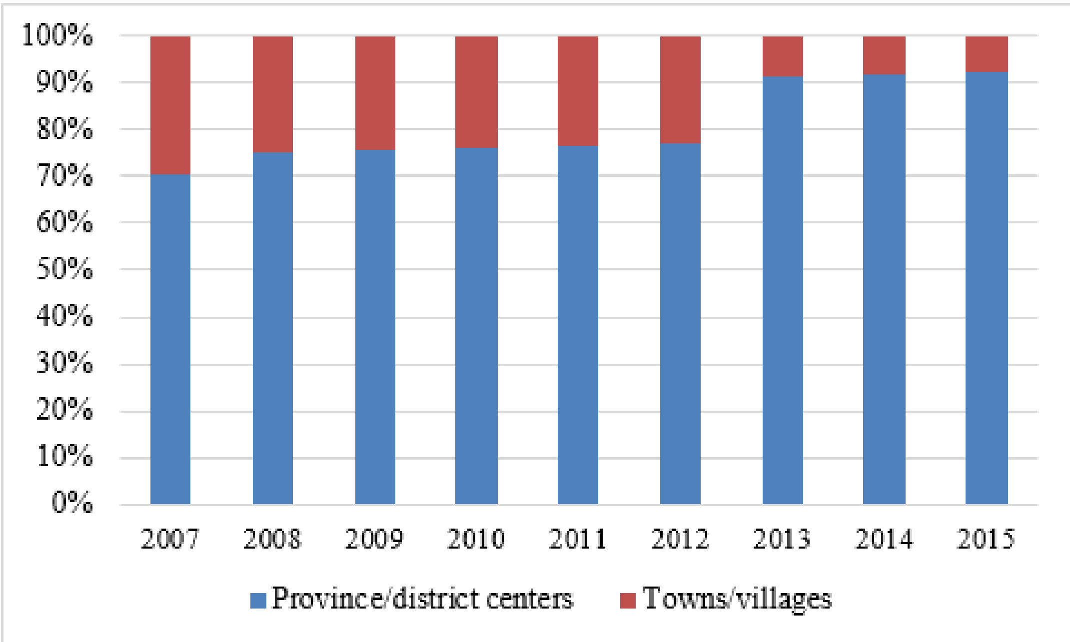


Figure 1.8: Population of province/district centers and towns/villages in 2007-2015 [10]

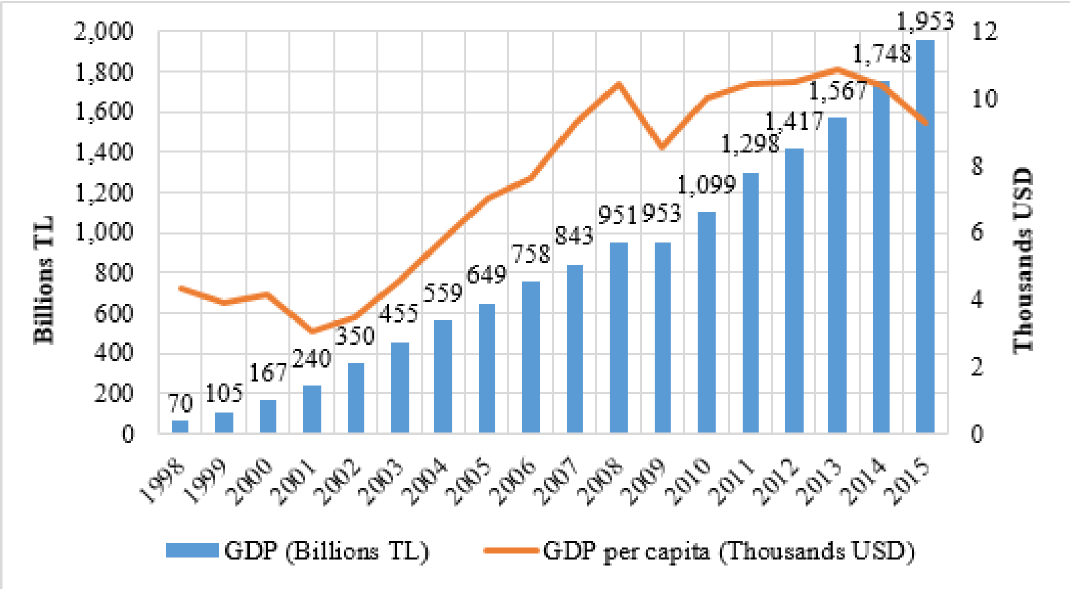


Figure 1.9: Gross domestic product of Turkey in current prices (billions TL) and GDP per capita (thousands USD) between years 1998 and 2015 [11]

As a fast developing country with increasing energy demand due to industrialization and increase in population, Turkey's future energy supply should be cautiously planned with respect to national resources, energy security and greenhouse gases emission rates and policies around the world. Rising primary energy demand and growth rate of Turkey can be found in Figure 1.10 and Figure 1.11, respectively.

In 2012, final energy consumption was dominated by residential, commercial and public services with a share of 35.4%. Industrial consumption accounted for 34.2% and transportation sector accounted for 23.3%. Most of the transportation sector energy consumption related to road haulage. Final energy consumption shares are shown in Figure 1.12.

Fossil fuels that are primary reason of greenhouse gas emissions have dominant share (88%) of energy consumption in Turkey. In 2013, coal accounted for 29%, petroleum accounted for 28% and natural gas accounted for 31% of total primary energy consumption. 4% of energy consumption supplied by hydro power and remaining part is supplied by other solid fuels, renewables etc. [12].

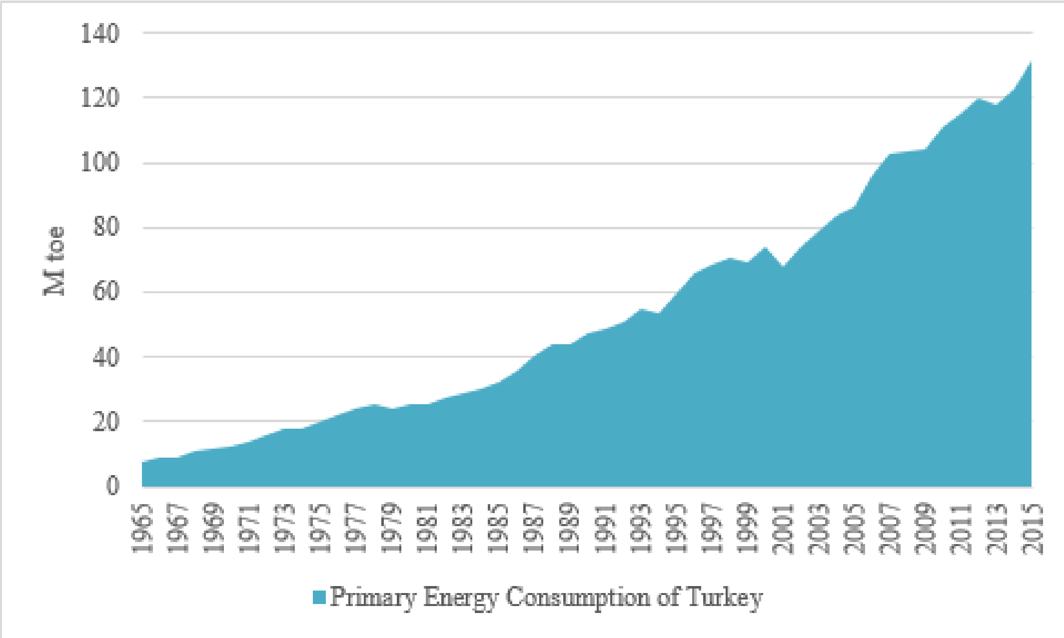


Figure 1.10: Primary energy consumption of Turkey between years 1965 and 2015 (M toe) [4]

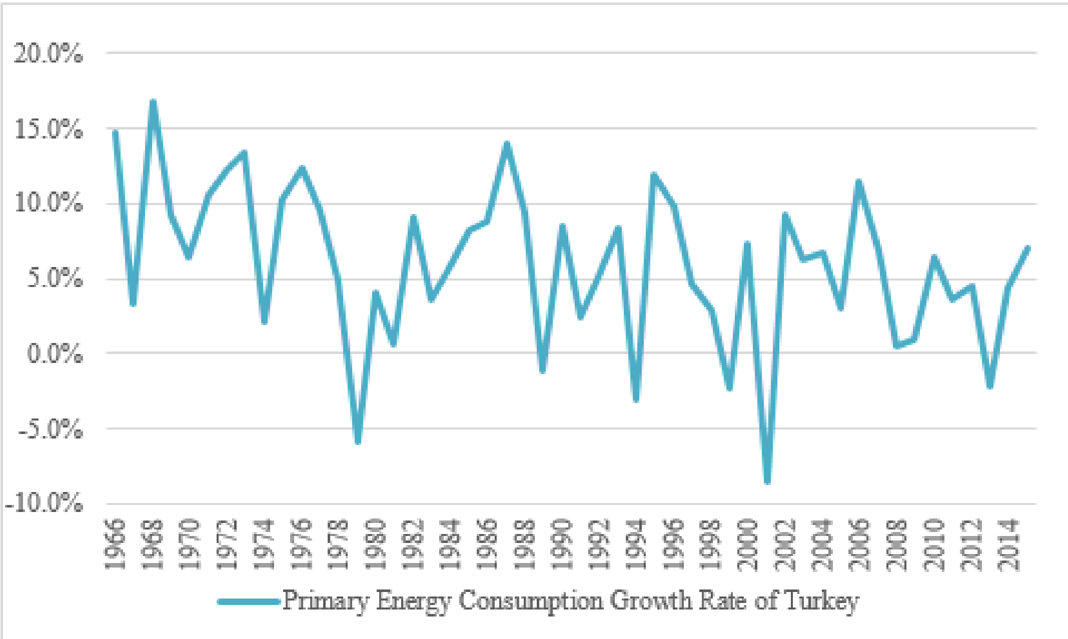


Figure 1.11: Primary energy consumption growth rate of Turkey between years 1966 and 2015 (%) [4]

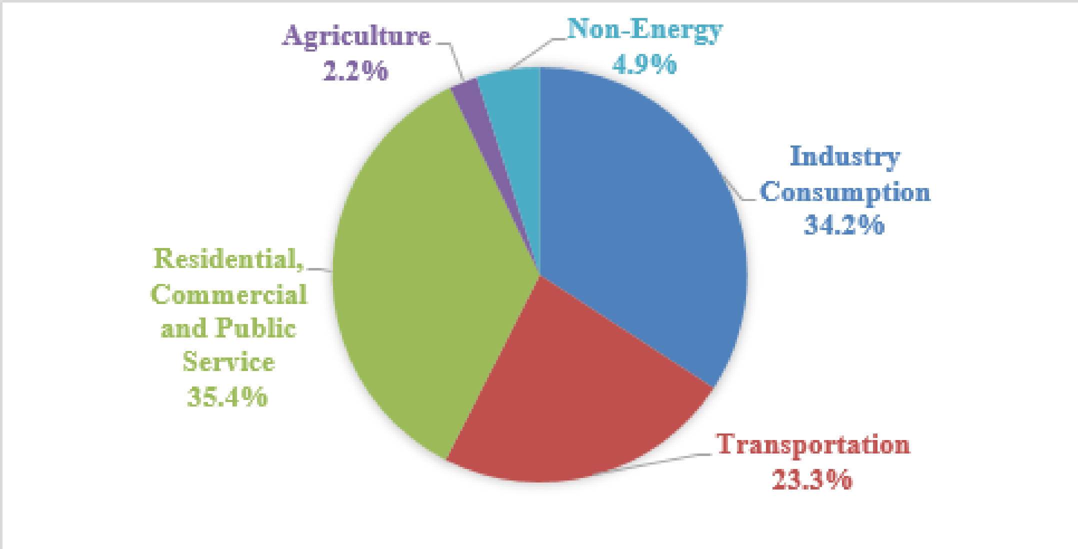


Figure 1.12: Final energy consumption rates by sectors in 2012 (%)

With the increasing use of natural gas in industry sector and urbanization, natural gas share in total primary consumption increased from 5% in 1990's and took the dominant place in 2008. Turkey mainly imports natural gas from Russia, Iran, Azerbaijan, Algeria and Nigeria. Since coal is mostly used in power generation, industry and heating Turkey has significant amount of coal consumption. As local resources, there are medium level lignite reserves and limited level of anthracite. Turkey has about 3.2% of the total global reserves of lignite and sub-bituminous coal [13]. In order to decrease dependence on coal import, field studies are in progress to finding new lignite resources. Yet, large share of coal consumption depends on imports. Petroleum is used mainly in transportation sector and it was persisted as dominant source for years but left its place to natural gas recently. Crude oil is mainly imported from Iraq, Russia and Iran [14]. According to calculations based on energy balance table of Turkey in 2012, primary energy import dependency rate was 73%. Domestic production rate of total coal as a share of 120 m toe of primary energy supply is 43%, lignite was a domestic resource and hard coal was imported with rate of 95%. Oil and natural gas import rates were 92% and 99%, respectively. Domestic and imported resources can be found in Table 1.1. Since most of energy supplied externally, there is significant amount of import cost of primary energy procurement. Total energy import cost of Turkey in 2012 was around $ 60 billion and cost of other years can be found in Figure 1.13.

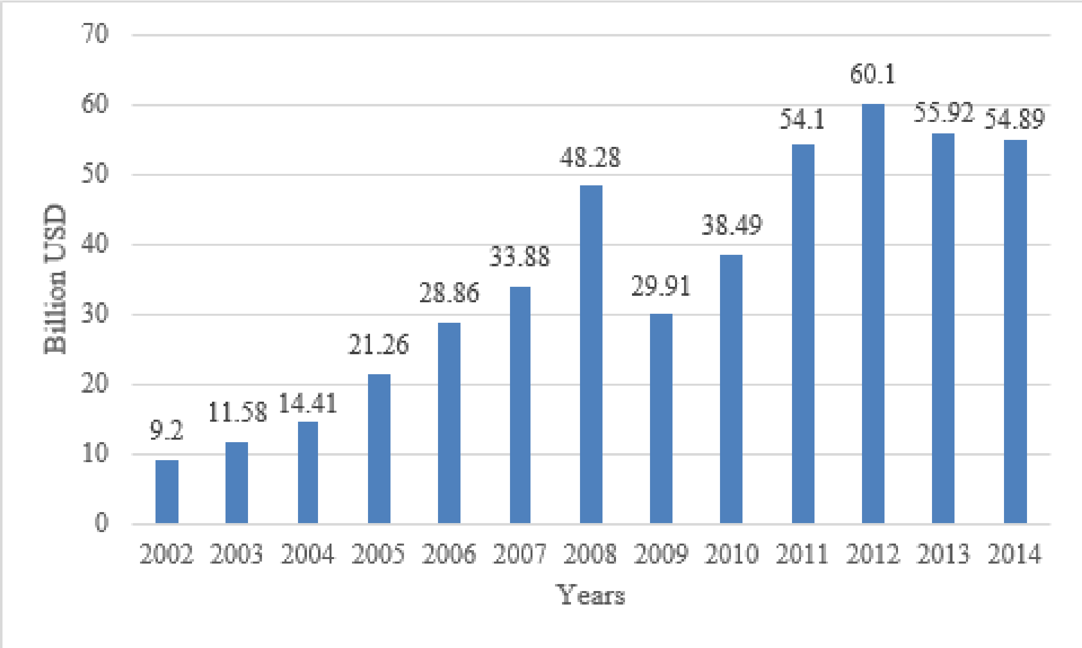


Figure 1.13: Primary energy import cost of Turkey between years 2001-2014 (Billion USD) [14]

Due to high import cost of primary energy resources, share of local resources such as renewable resources should be increased and national resource exploration activities should be continued for energy security concerns. In 2012, 12 Mtoe energy supplied by renewable resources with highest share of 42% of hydro power, 29% of wood, animal and vegetable waste and 18% of geothermal energy, 6% of solar power and 4% of wind power.

Balance of energy supply and demand in 2012 is shown in Table 1.1. Shares of primary energy resources in domestic production, import and export and detailed sectoral consumption are indicated. Also, key energy sector indicators with GDP and population of Turkey in 2012 are shown in Table 1.2.

Table 1.1: Energy Balance Table of Turkey in 2012 (k toe) [15]

Energy Resources																		
Energy Supply/ ——— Demand Balance	**Hard Coal**	**Lignite**	**Asphal tite**	**Coke**	**Petro coke**	**Wood**	**Waste**	**Total Solid Fuel**	**Oil**	**Natu ral Gas**	**Hydro power**	**Geo ther- mal**	**Biofuel**	**Wind**	**Electri city**	**Geo ther- mal Heat**	**Solar**	**Total**
Domestic Production (+)	1,095	15,355	567			2,350	1,115	20,483	2,440	533	4,976	773	23	504		1,463	768	31,964
Import (+)	19,237			253	2,936			22,426	37,856	37,910					501			98,693
Export (-)	5							5	6,103	504					254			6,866
Bunkers (-)									3,453									3,453
Stock Changes (+/-)	-12	78	-96	22	-136			-144	-98	-565								-808
Statistical Diff. (+/-)									563									563
Primary Energy Supply	**20,316**	**15,433**	**471**	**275**	**2,800**	**2,350**	**1,115**	**42,761**	**31,205**	**37,373**	**4,976**	**773**	**23**	**504**	**247**	**1,463**	**768**	**120,093**
Conversion Sector	**-11,018**	**-10,066**	**-219**	**2,743**	**0**	**-5**	**-60**	**-18,626**	**-3,744**	**-20,105**	**-4,976**	**-773**	**0**	**-504**	**16,418**	**1,225**	**0**	**-31,086**
Electricity Plants	-6,922	-10,023	-219			-5	-60	-17,229	-753	-19,049	-4,976	-773		-504	20,597	1,225		-21,463
Coking Plants	-4,085			2,743				-1,342										-1,342
Petrochemical Feedstock									-1,771									-1,771
Petroleum Refinery									-1,018	-1,042					-99			-2,158
Own Use and Loses	-11	-43						-55	-202	-14					-4,080			-4,351
Final Energy Consumption	**9,297**	**5,367**	**252**	**3,018**	**2,800**	**2,345**	**1,055**	**24,134**	**27,461**	**17,268**	**0**	**0**	**23**	**0**	**16,665**	2,688	**768**	**89,007**
Sectors Total	**9,297**	**5,367**	**252**	**3,018**	**2,800**	**2,345**	**1,055**	**24,133**	**27,461**	**17,268**	**0**	**0**	**23**	**0**	**16,665**	2,688	**768**	**89,007**
Industry Consumption	**2,574**	**2,327**	**144**	**3,018**	**2,800**	**0**	**0**	**10,863**	**1,920**	**8,122**	**0**	**0**	**0**	**0**	**8,013**	**1,225**	**268**	**30,411**
Food and Tobacco	55	11		2				68	16	440					503			1,028
Sugar	2	24		33				59	32	202					41			335
Textile and Leather	46	88						134	39	513					1,248			1,934
Paper, Pulp and Printing	3	59						62	44	123					148			377
Ceramic	53	144			24			221	176	610					93			1,100
Glass & Glass Products									34	253					83			371
Chemical & Petrochemical	83			22				105	232	709					292			1,338
Fertilizer									6	655					27			688
Cement	1,452	1,362		2	2,157			4,973	14	139					600			5,726
Iron and Steel	510			2,911				3,421	48	832					1,761	126		6,189
Non-Ferrous Metals	5	55		8				68	11	462					207			748
Motor Vehicle Industry		1						1	10	129					70			210
Other Industry	365	582	144	40	619			1,750	1,257	3,055					2,938	1,100	268	10,368
Transport	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**20,359**	**299**	**0**	**0**	**23**	**0**	**73**	0	**0**	**20,753**
Rail								0	143						23			166
Domestic Navigation								0	528						0			528
Domestic Aviation								0	1,258						0			1,258
Pipeline Transportation								0		239					21			260
Road								0	18,429	60			23		28			18,540
Other Sectors	**6,724**	**3,040**	**108**	**0**	**0**	**2,195**	**211**	**12,277**	**1,787**	**8,848**	**0**	**0**	**0**	**0**	**8,579**	1,463	**500**	**33,453**
Res., Com. & Public Serv.	6,662	3,040	108			2,195	211	12,215	804	8,833					8,076	1,081	500	31,509
Agriculture	62							62	983	14					503	382		1,944
Non-Energy						**150**	**844**	**994**	**3,396**									**4,390**

Table 1.2: Key indicators of Turkey in 2012 [16]

Population (millions)	74.9
GDP (billion 2010 USD)	812.21
GDP PPP (billion 2010 USD)	1298.56
Energy Production (Mtoe)	30.72
Net imports (Mtoe)	90.15
TPES (Total Primary Energy Supply) (Mtoe)	118.22
Electricity Consumption (TWh)	206.71
CO2 Emissions (Mt of CO2)	302.67
Electricity Consumption/ Population (MWh/capita)	2.76

Since the essential energy resources of Turkey are fossil fuels, greenhouse gas emission amount is a conspicuous subject. Increase in carbon dioxide emission can be seen in Figure 1.14. Energy related greenhouse gas emission is more than any other sector with the share of 72.5%, industrial processes follows them with 13.4%, agriculture sector accounted for 10.6% and waste with 3.5% in 2014. Increase rates compared to 1990 level can be found in Table 1.3 [17].

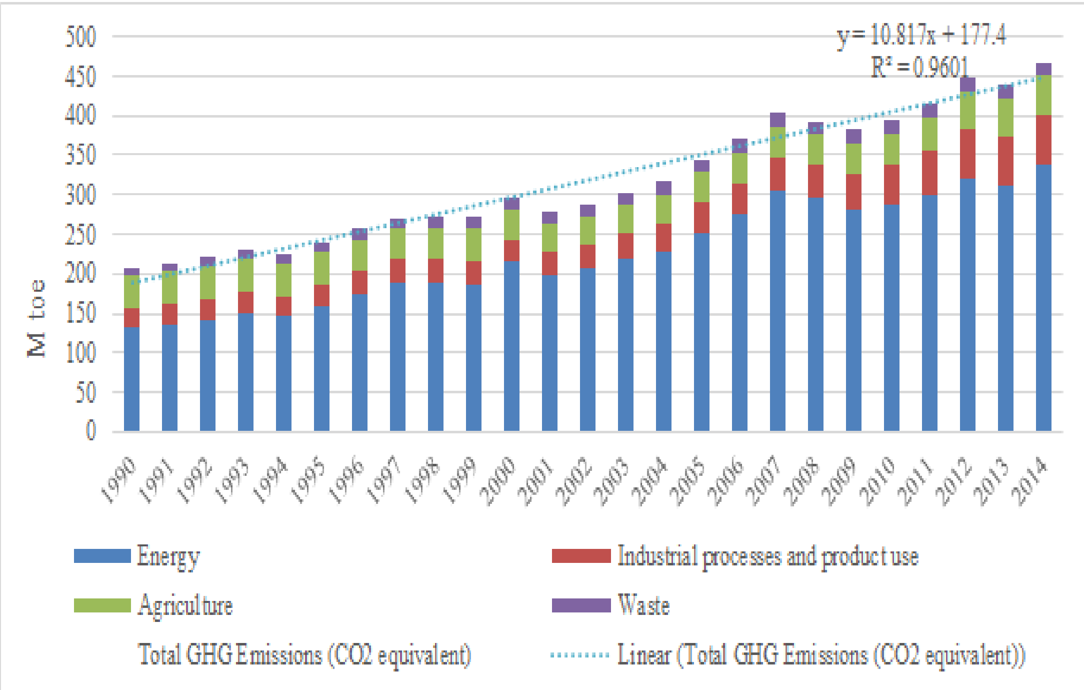


Figure 1.14: Greenhouse Gas Emissions of Turkey between years 1990-2014 (million tonnes carbon dioxide equivalent) [17]

Table 1.3: Greenhouse gas emissions by sectors (CO_2 equivalent) in Turkey from 1990 to 2014 [17]

Year	Energy	Industrial processes and product use	Agriculture	Waste	Total GHG Emissions (CO2 equivalent)	Change in GHG compared to 1990 (%)
1990	132.5	23.1	41.2	10.9	**207.8**	-
1995	160.1	27.0	39.8	12.2	**239.0**	15.0
2000	214.4	28.4	39.6	14.4	**296.8**	42.9
2005	252.7	37.8	37.9	16.9	**345.2**	66.2
2010	286.0	51.8	39.3	18.1	**395.3**	90.2
2011	298.2	58.2	41.1	18.4	**415.9**	100.2
2012	321.3	62.4	45.8	18.0	**447.5**	115.4
2013	310.0	63.2	49.3	16.2	**438.8**	111.2
2014	339.1	62.8	49.5	16.1	**467.6**	125.0

Electricity (power) demand of Turkey increased by 52% in last 10 years and has reached to 265 TWh in 2015. Detailed gross demand and production amounts are illustrated in Figure 1.15. Growth rate in electricity demand was 8.4% in 2010, 9.4% in 2011, 5.2% in 2012 and 3.3% in 2015. Average growth rate of 10 years is about 5.2%. Growth rate of gross demand, generation, import and export of electricity can be found in Table 1.4. In years of economic crisis electricity consumption decreased or stayed constant. However it is expected to see an average growth rate of 7.5% in 10 years after 2012 [18].

Installed power capacity has reached 73,000 MW in 2015, and it was 57,000 MW in 2012 of which 61.4% consisted of thermal, 34.4% consisted of hydro and followed by wind with 4% and 0.3% with geothermal. In 2015, thermal production capacity decreased to 57.3% due to increase in hydro to 35.4%, wind to 6.2%, geothermal to 0.9% and unlicensed solar to 0.3%. Annual development of installed capacity by sources is shown in Figure 1.16 and comparison between 2012 and 2015 can be found in Table 1.5.

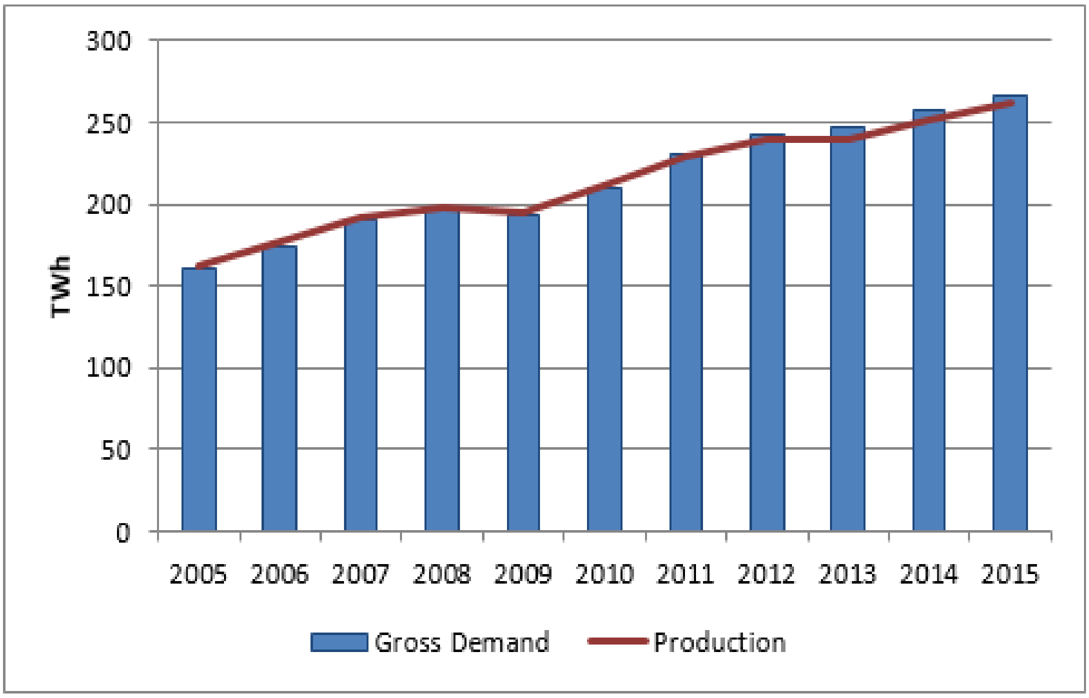


Figure 1.15: Annual development of gross electricity generation and gross demand between 2005 and 2015 (TWh) [19]

Table 1.4: Generation, import, export and demand of electricity (TWh) and growth in gross demand (%) [19]

Year	**Production**	**Import**	**Export**	**Gross Demand**	**Growth in Gross Demand**
2005	161.9562	0.6359	1.7981	160.794	
2006	176.2998	0.5732	2.2357	174.6373	8.6%
2007	191.5581	0.8643	2.4222	190.0002	8.8%
2008	198.418	0.7894	1.1222	198.0852	4.3%
2009	194.8129	0.812	1.5458	194.0791	-2%
2010	211.2077	1.1438	1.9176	210.434	8.4%
2011	229.3951	4.5558	3.6446	230.3063	9.4%
2012	239.4968	5.8267	2.9536	242.3699	5.2%
2013	240.154	7.4294	1.2267	246.3566	1.6%
2014	251.9628	7.9533	2.696	257.2201	4.4%
2015	261.7833	7.1355	3.1945	265.7244	3.3%

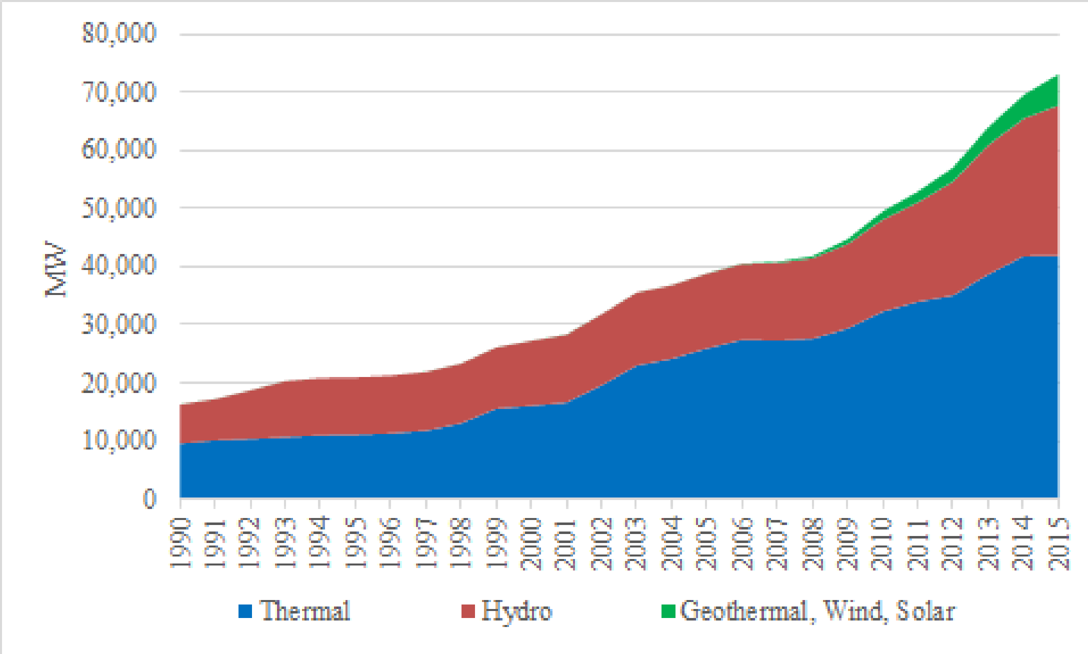


Figure 1.16: Annual development of installed capacity by sources between 1990 and 2015 (MW) [19]

Table 1.5: Installed capacity of Turkey by sources in 2012 and 2015 (MW) [19]

		2012	***2015***
Single Fuel Fired	Hard Coal	4,382.5	6,825.2
	Lignite	8,193.3	8,696.5
	Liquid Fuels	1,285.5	522.7
	Natural Gas	14,116.4	18,527.6
	Renewable and Waste	168.8	370.1
	TOTAL	*28,146.5*	*34,942.0*
Multi Fuel Fired	Solid+Liquid	598.5	582.7
	Liquid+N.Gas	6,282.2	6,378.3
	TOTAL	*6,880.7*	*6,961.0*
Thermal		35,027.2	41,903.0
Hydro		19,609.4	25,867.8
Geothermal		162.2	623.9
Wind		2,260.6	4,503.2
Solar			248.8
TOTAL		**57,059.4**	**73,146.7**

Electricity generation from renewable resources geothermal, wind and solar increased 100% from 153.4 GWh in 2005 to 15271 GWh in 2015. Electricity generation mix by primary energy resources from 2006 and 2015 is represented in Figure 1.17. Detailed generation rates of electricity production in years 2012 and 2015 can be found in Figure 1.18 and 1.19. Natural gas as the dominant fuel accounted for 43.63% of total power generation in 2012. Other primary energy resources was coal (28.39%), hydro (24.16%), geothermal and wind (2.82%), liquid fuels (0.68%) and renewable, waste (0.3%).

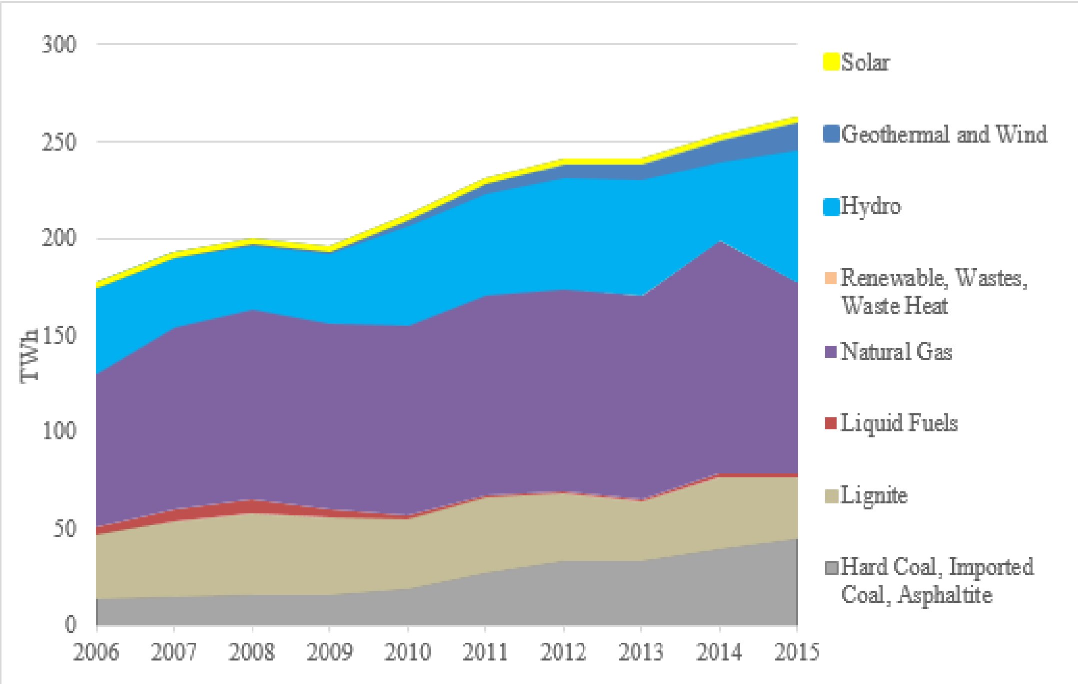


Figure 1.17: Electricity generation by primary energy resources between 2006 and 2015 (TWh) [19]

In order to use domestic resources and reduce energy dependence Turkey aims to increase share of renewable energy sources in national energy mix and coupled with reduction in greenhouse gas emissions. Additionally, it is planned to add two nuclear power plants located in Mersin/Akkuyu in south coast of Turkey and Sinop in north coast of Turkey into operation by 2023. And construction of a third one is planned during the same period. Approximately, 80 billion kWh of electricity output expected per year from plants in Akkuyu and Sinop [20].

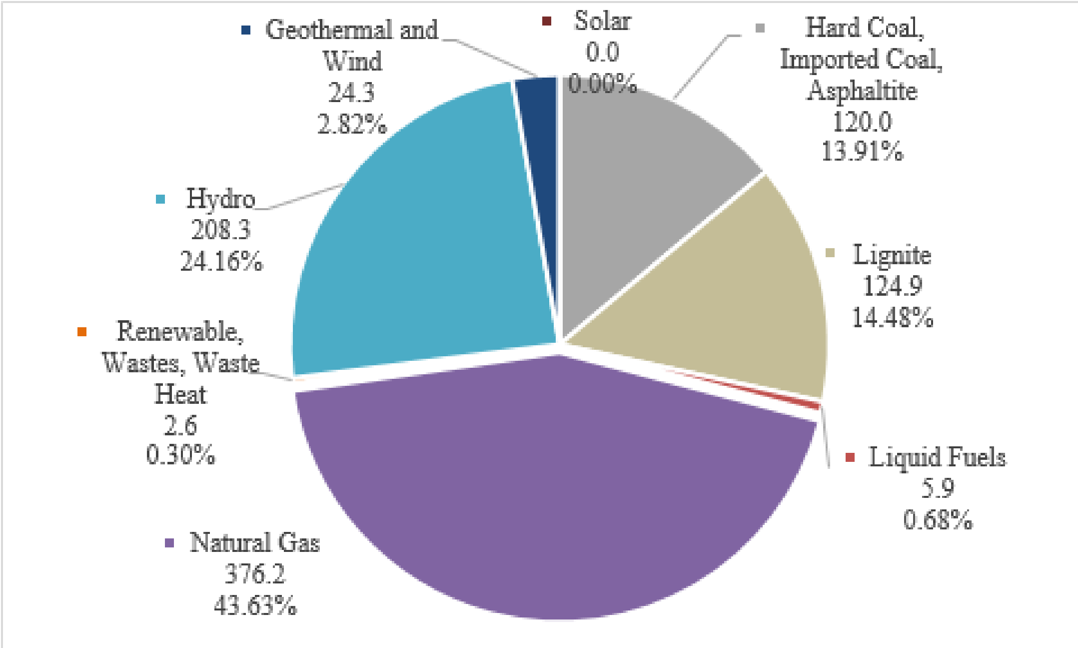


Figure 1.18: Electricity generation by primary energy resources in 2012 (PJ) [19]

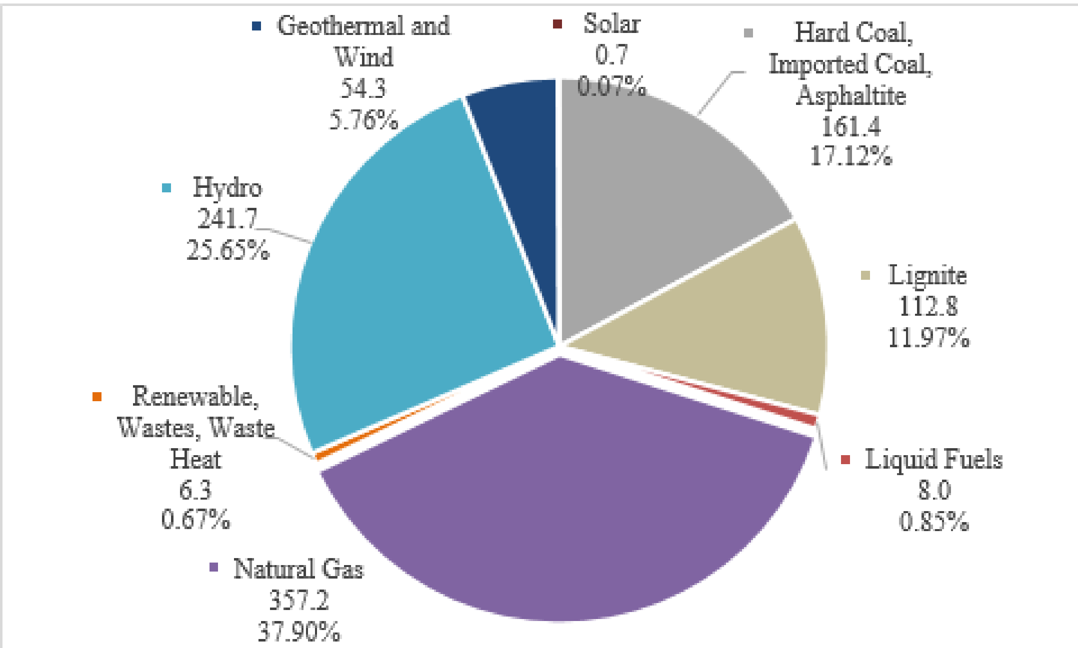


Figure 1.19: Electricity generation by primary energy resources in 2015 (PJ) [19]

This study introduces a long-term, bottom-up energy supply and demand model that can be used for policy analysis of Turkish energy system focused on the electricity generation sector. For this purpose, TIMES model generator is deployed to modeling a base electricity sector and analysis of different policy scenarios focusing the renewable energy incentives by government and impacts on carbon dioxide emissions are elaborated.

This thesis is organized as follows. In Chapter 2, a literature review on top-down and bottom-up energy modeling systems is provided. Methodology of TIMES modeling environment is presented in Chapter 3, including the mathematical model. Technological characterization of supply, conversion and demand technologies and details of TIMES model of Turkish electricity sector are represented in Chapter 4. Developed base and alternative scenarios, and their assumptions are defined in Chapter 5 and results are compared. Concluding remarks of the study are stated in Chapter 6.

Chapter 2

Literature Review

Energy models investigating energy supply and demand are used by decision makers and also they are important indicators on controversial subjects such as greenhouse gas emission limits, nuclear energy, the share of renewables and energy security [21]. To analyze the relationships between energy systems and economy, there are two main modeling approaches exists: top-down and bottom-up models. The term "top" stands for aggregate and "bottom" stands for disaggregated models [22]. Top-down models represent macroeconomic approach, and bottom-up models represent system from engineering approach [23]. In top-down models production functions are used on the other hand bottom-up models use detailed technological representations. Both approaches have some advantages and disadvantages because of the way they are representing the energy system. In addition to following details on top-down and bottom-up approaches, the hybrid approach is explicated.

2.1 Top-down Models

Top-down models are established based on macroeconomic theory, and econometric techniques and parameters are generated according to historical data on consumption, prices, incomes and factor costs to the final demand of goods and services and supply from main sectors[22]. Top-down models assess the system with aggregate economic variables and describe the whole economy. In macroeconomic approach energy represented as a production factor [23]. These models are conducted with economic growth, inter-industrial structural change, demographic development, and price trends and aim maximum consumer welfare and have feedback loops among welfare, employment and economic growth in an equilibrated market [21].

As an input-output model, Energy EcoNomy Environmental Damage Model (ENDAM) is a 10-sector model. Since the energy and energy users are significant in this model, coal, oil extraction, oil processing, electricity and gas sectors utilized. And as non-energy sectors agriculture and forestry, construction, manufacturing, transport and services added. UK input-output tables obtained as interindustry data. To detailed analysis of emissions which is related to economic activity, sulfur dioxide, nitrogen oxides and carbon dioxide gasses included. The model explores sectoral interrelationships and energy-environmental issues and also examines energy-environmental policies [24].

ENERPLAN which was developed by Tokyo Energy Analysis Group provides both macroeconomic and energy sector models. It is a simulation model which use historical data for the variables to conduct an econometric analysis with an assumed econometric model to determine model coefficients and then run the simulation [25].

Energy-Environment-Economy Model for Europe (E3ME) is a complex econometric, simulation model developed by Cambridge Economics to analyze long-term applications of energy-environment-economy policies. E3ME combines sectoral model estimated by econometric models with computable general equilibrium models that provide analysis of the long-run outcomes for the main economic indicators as a response to policy changes [26].

The Dynamic Integrated model of Climate and the Economy (DICE) and the Regional Integrated model of Climate and the Economy (RICE) model which is a more detailed version both are integrated assessment models. Their objective function expresses economic well-being associated with a path of consumption [27].

2.2 Bottom-up Models

The bottom-up models or systems engineering approach evaluate on a detailed representation of technological options and potentials for technical changes in the energy system. The connections represented as energy flows, a resources network and final users described in detail. Paths from extraction of resources to final use are introduced [23]. The technologies include technical and economic parameters, and changes are possible in these parameters. Bottom-up models represent demand as end-use demands such as lighting, cooling and heating instead of energy types [28]. In these models, sectoral outputs such as one PJ of residential heating service are produced by a mix of each technologies' outputs. Therefore, the production function of a sector is constructed implicitly, and their complexity depends on the reference energy system of each sector [29]. Bottom-up models aims to determine the best technologies by policies, policy effects, investment costs, and sectoral costs and surpluses, etc. [21].There are four kinds of bottom-up models: partial equilibrium models, simulation models, multi-agent models, and optimization models [21].

Optimization models aim to determine the optimal set of technology choices with minimized cost under certain constraints. Since the investment and operation cost data are required for optimization, these models use discrete energy conversion technologies. Optimization models neglect several market imperfections [21]. MARKAL and TIMES model are the most known energy optimization models developed by ETSAP. Moreover, there are other bottom-up optimization models explained below.

Energy Flow and Optimization Model-ENVironment (EFOM-ENV) is a linear programming model developed by Commission of European Communities, DGXII.

The model covers national energy system with a detailed description of technologies, yet there is no interaction between non-energy sectors. The model aims energy and environment policy analysis regarding emission reduction for a medium to long time period [30].

Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE-III) developed by Austrian International Institute for Applied System Analysis (IIASA) analyses future energy strategies with regard to available technologies, resources, energy service demands and emissions. It is a time-dependent linear programming model. There are three variables technology activity, annual new installations of technologies and resource extraction and the model aims to analyze environmental and investment policy with an objective function minimizes the sum of discounted costs. The model consists of a detailed description of end-users and energy technologies and has a reference energy system representing energy carriers and technologies [31]. The model characteristics are similar to MARKAL and TIMES.

As a bottom-up optimization model, Georgiou proposes a deterministic mixed integer linear programming model for the long-term energy planning of power systems in Greece. The problem is solved by CPLEX solver under parallel deterministic optimization option. The model is a least cost optimization model and covers electricity interconnections. It is applied for 2014-2024 period to discover new capacity investments, the fuel mix trend, share of renewable energy sources and achievement of country's targets, and investigate the benefits of interconnection of islands to the main continental power system. However, the model does not include the other sectors [32].

MARKAL is a model generator developed by Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA) and is used to identify least-coast energy systems. MARKAL (an acronym for MARKet ALlocation) is a dynamic linear optimization model which is widely used whole over the world. The model uses input projections of energy demands as final user demand

and resource costs. Other usage areas of MARKAL are as follows; cost-effective responses under emission restrictions, forward long-term energy balance analysis under different scenarios and determination of effects of regulations, taxes, and subsidies, greenhouse gas emission level projection, etc. [33].

TIMES (The Integrated MARKAL-EFOM System) model generator is the successor of MARKAL. The TIMES combines a technical engineering approach, and economic approach and it is a technology rich, bottom-up, linear optimization model [34]. Further details about TIMES model is given in Section 3.1.

Remme et al. [35] analyze strategies to reduce GHG emission on global level within the UK-Japan Low Carbon Society (LCS) project. They use TIMES model generator that covers years between 2000 and 2100 and divided the world into 15 regions. And they find out in the base scenario, without any abatement effort energy-related carbon dioxide emissions are about to double by 2050 compared to 2000 level. To this manner, they apply scenarios such that CO_2 price up to \$100/t in 2050 can reduce CO_2 emissions by 23% relative to 2000, and enforce to halve the CO_2 emission level by 2050 at the global level. Then, in a sensitivity analysis for 50% reduction scenario they analyze the role of nuclear power production which increased 1.6 times and CO_2 capture and storage. In the case of CCS is not available, renewable shares increase double.

Weilong et al. [36] focus on carbon capture and storage which is one of the low-carbon technologies in the power sector, under carbon emission reduction scenarios using China TIMES model. The model covers the 5-year intervals from 2010 to 2050. And they apply two mitigation scenarios for carbon intensity 35-40-40 and 40-40-45 which represent the percentage reductions for 10-year intervals between 2020 and 2050. As a result, due to low capacity factor and instability of renewable energy, CCS become competitive under carbon constraints. In the case of lower cost of renewable technologies, CCS influence is restricted, but the decline of CCS cost may expand CCS in the power system.

Pina et al. [37] use a model for investment decisions in electricity production that considers seasonal, daily and hourly supply and demand dynamics in Sao Miguel, Portugal for the 2005-2025 period. They use hourly time resolution to capture variations of renewable energy productions and demand dynamics by dividing a year as four seasons, three days per season (weekdays, Saturday, Sunday) and 24 hours per day. On the contrary to predecessors MARKAL and EFOM, TIMES is flexible enough to use such time-slices and different length of time periods. They have two policies such that, electricity production of 50% in 2013 and 75% in 2018 from renewable energy instead of imported fuels and increasing renewable energy penetration in primary energy up to 40% for all sectors. And they have the opportunity to elaborate penetration of renewables in a system, electric vehicles, energy storage systems or promoting energy efficiency in policies by using higher time resolutions. According to their results having lower time resolution leads to overestimations on renewable energy to install. And they conclude that to assess the real impact of a policy as its benefits and drawbacks it is crucial to use higher resolution energy system model.

Vaillancourt et al. [38] analyzed the role of nuclear energy as an improvement for greenhouse gas emission reduction in long-term climate scenarios by using World-TIMES model over 15 regions between the years 2000 and 2010. Around 1300 technologies which include various power plants and consumption processes used for energy representation. To respect the aim of the study, the database includes five types of nuclear power plants. In the base scenario, primary energy demand at a global level doubles from 2000 to the end of time horizon with the dominance of fossil fuel in energy generation and with the highest growth in nuclear energy share. Also, the base scenario CO_2 concentration level is 584 ppmv. Then, they designed two scenarios for the CO_2 concentration levels for 2100 as 450 ppmv and 550 ppmv as a restrictive policy. As a result of the CO_2 reduction, the marginal cost in 450 ppmv scenario is extremely higher than the other scenario. The share of the nuclear power in electricity production reach around 20% in base and reduction scenarios in 2050 and then gets 50%, 51%

and 68% in base, 550 ppmv and 450 ppmv scenarios in 2100. Besides, renewable resource share increases 102% and the fossil fuel decrease about 50% in 450 ppmv scenario compared to the base case.

The TIMES and MARKAL both technology explicit, multi-region, dynamic, partial equilibrium models. The equilibrium is reached via linear programming at the point maximizing the total surplus of consumers and suppliers. Although the basic concepts are same for both models, there are significant technical differences between two models.

Although length of time periods are fixed in MARKAL, TIMES allows flexible time periods. In TIMES, since all the input data are specified independent from definition of time periods, in the case of change it is easier to implement in TIMES than MARKAL. Time-slices were limited in MARKAL, but TIMES allows flexible time-slices grouped in seasonal (or monthly), weekly (weekend/weekday) and daily (day/night) for any commodity and these levels can be expanded. In TIMES, each process has the same variables such as activity or investment variables. Also, process parameters clearer such as multi-fuel process efficiency definition can be done by one process in TIMES. There are specific parameters such as lead time and capital cost for construction and dismantling of facilities. In the situation of new investments are made for a process, variables over defined vintage period v is used without any replicas of process representing a different vintage and new parameters for the vintage year is used. TIMES has more commodity-related variables than MARKAL such as total production and total consumption. While in MARKAL investments are paid at beginning of a time-period, in TIMES capital presented as progressive payment spread over economic life for large facilities. In TIMES also discount rates can be defined as a time-dependent discount, bur discount rates are constant in MARKAL [39].

Because of the advanced features, TIMES model is utilized in this study and since there is no significant study for Turkey which is modeling the entire energy system particularly in hourly time-slice basis and evaluating electricity system via TIMES model, this study aims to fill this gap in the literature.

2.3 Hybrid Models

Top-down modeling contains a high level of macroeconomic completeness through the feedback loops combined with microeconomic realism, and bottom-up modeling comprises a high degree of technological explicitness and a low degree of macroeconomic completeness [21]. There is no explicit representation of technologies in top-down models and aggregated data is used for predicting while bottom-up models have a detailed description of technologies and disaggregated data is used for exploring. Top-down models are based on observed market behavior and assume there are no discontinuities in historical trends, and bottom-up models are independent of observed market behavior. And top-down models internalize behavioral relationships while bottom-up models are assessing the cost of technological options [30]. To overcome the limitations of these models, hybrid energy system modeling combining macroeconomic models with bottom-up models for each energy and the conversion sector were developed [21].

Some general equilibrium models include an amount of fuel and technology disaggregation in power generation sector [29]. The MERGE model [40] is a fully integrated applied general equilibrium model. Each region is designed as independent price taking agent and supplies, and demands are in equilibrium by means of the prices of the internationally traded commodities such as oil, gas, coal, carbon emission rights and a numeraire good represents all items produced outside of the energy sector.

Also there are advanced bottom-up models containing some of the effects of entire economy on the energy system [29]. MARKAL-MACRO and TIMES-MACRO are combining the technological detail with a basic representation of macro economy [29]. MARKAL is a technology explicit model where MACRO is a succinct, single sector, optimal growth dynamic inter-temporal general equilibrium model maximizing national utility function [41]. In the merged model, partial equilibrium through optimization for meeting supply and demand with the neo-classical macro-economic approach is utilized [30]. MESSAGE-MACRO (Model for Energy Supply Strategy Alternatives and their General Environmental Impact-MACRO) [42], is a hybrid model that is linking an LP energy supply model MESSAGE with a non-linear macroeconomic model MACRO. MESSAGE generates prices related to the total and marginal costs of energy supply and MACRO supplies the quadratic demand functions and overall energy demand is adjusted. Then MESSAGE run with the adjusted demand and generates prices until prices and demands stabilize. SCREEN model [43] combines technological details of the electricity sector with a macroeconomic computable general equilibrium framework.

Chapter 3

Approach

In this study, TIMES modeling approach has used to modeling energy system and electricity sector of Turkey.

3.1 The TIMES Energy Modeling System

TIMES (an acronym for The Integrated MARKAL-EFOM System) is an economic model generator developed by Energy Technology Systems Analysis Programme (ETSAP) of the International Energy Agency (IEA). It is suitable for deployment of single or multi-region energy systems and applied for analysis of overall energy sector or a single sector. It has a technology-rich representation of energy dynamics over a multi-period time horizon. TIMES combines technical engineering approach and economic approach. TIMES bottom-up model generates least-cost energy system by linear programming according to user constraints.

TIMES is a model generator both for single and multi-regional energy systems and also the system can define entire energy sector or only one sector such as electricity. Prediction of primary energy supply and potentials, existing stocks of equipment, parameters of available future technologies, and end-use energy service demand such as residential heating, car road travel are given to model as inputs to generate reference scenario. Then, TIMES model balances supply and demand at a minimum global cost which is at a maximum total economic surplus by decisions of equipment investment over the planning horizon. TIMES is a vertically integrated model because it considers the analysis of alternative generation technologies on the economics of energy supply and environmental conditions on generation equipment type and fuel decisions. In each time period, the quantities and prices of commodities are in equilibrium [29].

3.2 Reference Energy System

Reference Energy System (RES) is an interconnected network diagram that represents various entities such as production, transformation, consumption processes. TIMES models built on three types of entities to construct RES: technologies (processes), commodities and commodity flows.

Technologies or processes are the representation of physical devices that transform commodities to others. For instance, mining or import processes, refineries that energy-processing plants, conversion plants that produce electricity, end-use demands such as vehicles. Commodities consist of energy carriers which are carriers that contain energy to be transformed into other forms such as electricity, demand for energy services such as residential and transportation, materials, monetary flows, environmental indicators such as GHG. A commodity is produced or consumed by a processes. Commodity flows are the links connecting process and commodities and represent an input or an output of a process. For example, electricity produced by a gas fired power plant at a particular period, time-slice in a region is a commodity flow.

In Figure 3.1, a small example of RES for a single energy service demand which is home space heating. Energy carriers gas, electricity, and oil are used by three space heating technologies. These energy carriers are produced by other technologies gas plant, gas,coal and oil fired power plants and an oil refinery, respectively. The primary energy resources used in plants and refinery, either extracted or imported. After a commodity enters a process, its name is changed [29].

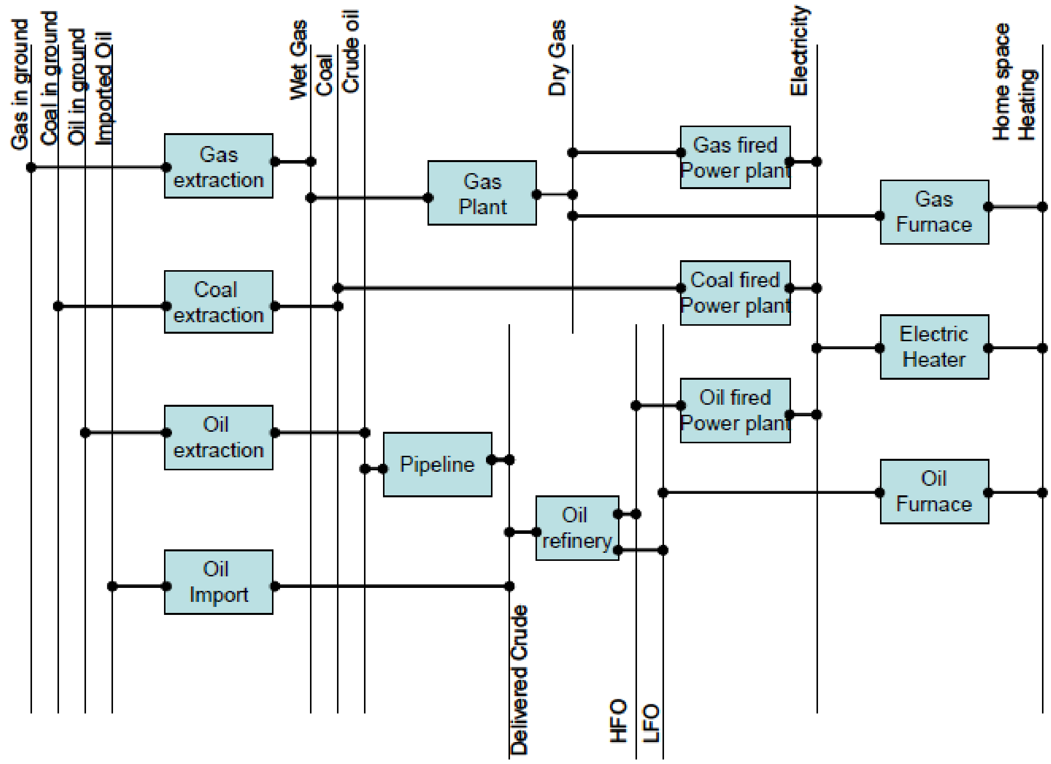


Figure 3.1: Partial view of a Reference Energy System [29]

3.3 The Mathematical Formulation of the TIMES Model

A simplified formulation of TIMES linear program is expressed as in TIMES documentation of Loulou et. al. [29].

3.3.1 Indexes

Index r indicates region, t stands for time period, v is used for vintage year of an investment. If there is no vintage, then v=t. Index p is process (technology), c is commodity and s is time-slice.

3.3.2 Decision Variables

The decision variables which are unknowns represents the choices of the model as results. All of the variables are prefixed with "VAR_"

VAR_NCAP(r,v,p): New capacity investment for process p, in period v and region r. Units of this variable depends on technology. Typical units are PJ/year for most energy technologies, GW for electricity conversion technologies (1 GW=31.536 PJ/year) etc.

VAR_CAP(r,t,p): Total installed capacity of process p in region r and period t. This variables only defined for bounds or constraints but no other equation.

VAR_ACT(r,v,t,p,s): Activity level of a process p, in region r and period t (optionally with vintage v and time-slice s) Typical unit is PJ for all energy technologies.

VAR_FLO(r,v,t,p,c,s): The quantity of commodity c consumed or produced by process p, in region r and period t. Vintage v and time-slice s can be used as options. Typical unit is PJ for all energy technologies.

VAR_IRE(r,v,t,p,c,s,exp) and *VAR_IRE(r,v,t,p,c,s,imp):* Quantity of commodity c (PJ/year) exported or purchased imported by region r through process p in period t. Time-slice s can also be used. IRE stands for inter-regional exchange.

VAR_COMNET(r,t,c,s): The net amount of commodity at period t, time-slice s. This parameter is represents the difference between produced and imported amount minus consumed and exported amount [44].

Also, there are other commodity, flow, objective function related variables used for reporting or limitations.Some variables are not present in this study. More detailed information about other variables can be seen in related TIMES documentation [29].

3.3.3 Objective Function

Objective function of TIMES minimizes the total system cost by taking negative of the consumer surplus. The cost is calculated for each year of the horizon and then annualized. Elements of the total cost are as follows:

- *Capital cost* of investing into processes and dismantling processes at the end of life,
- Annual fixed and variable *Operation and maintenance costs* and other annual costs ,
- Exogenous *import* and domestic resource *production* cost,
- Exogenous *export* revenues,
- *Delivery costs* of commodities consumed by processes attached to commodity flows,
- *Taxes and subsidies* related to commodity flow and activities of process and investments,
- *Revenues from recuperation of commodities* accrued when dismantling of a process release commodities,
- *Damage costs* due to emissions of certain pollutants if defined ,
- *Salvage value* of processes and embedded commodities at the end of the planning horizon,
- *Welfare loss* of reduced end-use demands

Because of the lead-time *(ILED)* of construction of large processes, the investment payments are allocated to several years. TIMES allow investments to be made progressively instead of in one lump amount. Another case for investments is if the process life of an investment is not long enough to cover the period that investment decision is taken, then the investment is repeated during this period. At the end of some processes, there may be dismantling capital costs incurred later than investment period t. The capital cost is allocated to an economic life *(ELIFE)* instead of technical life *(TLIFE)* of the process and annualized at a different discount rate.

To aggregate all costs, the capital costs accrued as annual payments computed for each year, and salvage value assigned to the year at the end of the horizon for active investments as a lump sum revenue. Other annual costs included to the annualized capital cost payments minus salvage value to compute *ANNCOST*. Then, a total net present value of annual costs for each region is calculated and discounted to the reference year with introduced general discount rate *d*. The aggregated total system cost which constructs the following objective function of TIMES to be minimized in equilibrium computation.

$$NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} (1 + d_{r,y})^{REFYR-y} \times ANNCOST(r, y) \tag{3.1}$$

where,

NPV	: Net present value of the total cost for all regions
ANNCOST(r,y)	: Total annual cost in region r and year y
d	: General discount rate
REFYR	: Reference year for discounting
YEARS	: Set of years including all years in the horizon and the years before initial period and after end of horizon
R	: Set of regions

3.3.4 Constraints

In order to minimize total discounted cost a large number of constraints must be satisfied.

3.3.4.1 Capacity Transfer Constraint

The investment decision for a technology increases the installed capacity of this technology until the end of its technical life. Technologies with expired lifetime removed from that capacity. For a time period t total available capacity for a technology p is calculated by considering all new investments and those which are made before that period and have remaining lifetime.

$$VAR\_CAPT(r,t,p) = \sum_{t-t'<LIFE(r,t',p)} VAR\_NCAP(r,t',p) + RESID(r,t,p) \tag{3.2}$$

where,

$VAR\_CAPT(r,t,p)$	: Total available capacity of tech. p in region r in period t
$LIFE(r,t',p)$	: Technical lifetime of technology p in region r in period t
VAR_NCAP(r,t',p)	: The amount of new investment of a technology p in region r in period t
RESID(r,t,p)	: Residual capacity of technology p still available in region r in period t

3.3.4.2 Definition of Process activity variables

To link technology related activity variables to commodity related flow variables, a constraint is introduced to compute overall activity variable. First, the group of commodities that defines the activity of the process is identified. Then, the modeler chooses one of consumed or produced commodities by this simple process to define activity level. For processes with multiple commodities as input and output, primary commodity group (pcg) is chosen as the activity defining group and then the modeler identifies which commodity group (inputs or outputs) defines activity for this process.

$$VAR\_ACT(r,v,t,p,s) = \sum_{c \in pcg} VAR\_FLO(r,v,t,p,c,s)/ACTFLO(r,vp,c) \tag{3.3}$$

where,

$VAR\_ACT(r,v,t,p,s)$	: Activity level of technology p with vintage year v in region r in period t for time-slice s
$VAR\_FLO(r,v,t,p,c,s)$	: Flow level of a commodity c in technology p with vintage year v in region r in period t for time-slice s
ACTFLO(r,v p,c)	: Activity conversion factor from activity of a technology p with vintage year v to the flow of commodity c in region r

3.3.4.3 Use of capacity

TIMES model decides the capacity usage with respect to availability factor in addition to investment decisions. It should be noted that the model may decide not to use all of the available capacity but modeler can force to use capacity with full potential. This constraint assures that activity of each technology can not exceed its maximum available capacity in a certain period and time-slice.

$$\begin{aligned} VAR\_ACT(r,v,t,p,s) \leq or = & AF(r,v,t,p,s) * PRC\_CAPACT(r,p) \\ & * FR(r,s) * VAR\_CAP(r,v,t,p) \end{aligned} \tag{3.4}$$

where,

$VAR\_ACT(r, v, t, p, s)$	:	Activity level of technology p with vintage year v in region r in period t for time-slice s
$AF(r, v, t, p, s)$	:	Availability factor of technology p with vintage year v in region r in period t for time-slice s
$PRC\_CAPACT(r, p)$	:	Conversion factor between units of capacity and activity of a technology p in region r
$FR(r, s)$	:	Parameter of fractional duration of time-slice s
$VAR\_CAP(r, v, t, p)$	:	Capacity of technology p with vintage year v in region r in period t

3.3.4.4 Commodity balance equation

For each time period, sum of domestic production and imports to a region must be balanced with the consumed and exported amount for each commodity in each time-slice defined by the user. For example, natural gas consumed in power plants and in residential usage, and exported to other regions must not surpass the amount of natural gas extracted, transformed and imported from other regions. This constraint represents an equality for materials and inequality for energy carriers, emissions, and demands by allowing surplus production. A simple version of commodity balance constraint is provided in Equation 3.5.

$$
\begin{aligned}
&[(\sum_{p,c \in TOP_{r,p,c,out}} VAR\_FLO(r,v,t,p,c,s) \\
&+ VAR\_SOUT(r,v,t,p,c,s) * STG\_EFF(r,v,p)) \\
&+ \sum_{p,c \in RPC\_IRE_{r,p,c,imp}} VAR\_IRE(r,t,p,c,s,imp) \geqslant or = \\
&+ \sum_{p} Release(r,t,p,c) * VAR\_NCAP(r,t,p,c)] * COM\_IE(r,t,c,s) \\
&[\sum_{p,c \in TOP_{r,p,c,in}} VAR\_FLO(r,v,t,p,c,s) + VAR\_SIN(r,v,t,p,c,s) \\
&+ \sum_{p,c \in RPC\_IRE_{r,p,c,exp}} VAR\_IRE(r,t,p,c,s,exp) \\
&+ \sum_{p} Sink(r,t,p,c) * VAR\_NCAP(r,t,p,c) + FR(c,s) * VAR\_DEM(c,t)]
\end{aligned}
\tag{3.5}
$$

where,

$VAR\_SOUT/SIN(r,v,t,p,c,s)$	: Storage output/input flow of technology p with vintage year v in region r for time-slices s in period t
$TOP(r,p,c,in/out)$	: Input/output flow of commodity c into/from technology p in region r
$RPC\_IRE(r,p,c,imp/exp)$	: Import/export flow into/from region r of commodity c via technology p
$STG\_EFF(r,v,p)$	: Efficiency of storage technology p with vintage year v in region r
$COM\_IE(r,t,c,s)$	: Infrastructure efficiency of commodity c in region r inperiod t for time-slice s
$Release(r,t,p,c)$	: The amount of comm.c necessary per unit of new capacity of tech. p dismantled in region r in period t
$Sink(r,t,p,c)$	: The quantity of commodity c required per unit of new capacity of technology p in region r in period t
$FR(s)$	: Fraction of the year covered by time-slice s

3.3.4.5 Defining flow relationships in a process

Output commodities of a process can not be independent of its input commodities. In order to ensure the relationship between multiple input and output flows of a technology, this constraint equalizes ratio of outputs to input flows to a constant. For single input/output processes, this constraint defines basic efficiency of the process.

$$\begin{aligned} &\sum_{c\in cg2} VAR\_FLO(r,v,t,p,c,s) \\ &= FLO\_FUNC(r,v,cg1,cg2,s) \\ &* \sum_{c\in cg1} COEFF(r,v,p,cg1,c,cg2,s) * VAR\_FLO(r,v,t,p,c,s) \end{aligned} \tag{3.6}$$

where,

$cg1$	: Input commodity group
$cg2$	: Output commodity group
$FLO\_FUNC(r,v,cg1,cg2,s)$	: Efficiency ratio of technology p with vintage year v in region r which consumes cg1 and produces cg2
$COEFF(r,v,p,cg1,c,cg2,s)$	: Considers the harmonization of different time-slice resolution of flow variables

3.3.4.6 Limiting flow shares in flexible processes

Constraints mentioned before, are regulating the input/output flows on commodity groups level, but are allowing processes to be flexible by not limiting commodity shares. To restrain this flexibility lower and upper bounds can be defined by assigning FLO_SHAR coefficients to the commodities in Equation 3.7. For example, the flow of commodity1 can be at most 50% of total output. Additionally, losses of input should be considering as efficiency in production processes.

$$VAR\_FLO(c) \leqslant, \geqslant, = FLO\_SHAR(c) * \sum_{c' \in cg} VAR\_FLO(c') \tag{3.7}$$

3.3.4.7 Peaking reserve constraint (For time-sliced commodities)

Since demand fluctuates over time-slices, this constraint imposes that capacity of all processes producing related commodities at each time period and each region must be more than average demand in the peak time-slice by a particular percentage indicated as COM_PKRSV.

$$\begin{aligned}
&[\sum_{pproducingc=pcg} PRC_CAPACT(r,p) * Peak(r,v,p,c,s) \\
&* FR(s) * VAR_CAP(r,v,t,p) * VAR_ACTFLO(r,v,p,c)] \\
&+ \sum_{pproducingc \neq pcg} NCAP_PKCNT(r,v,p,c,s) * VAR_FLO(r,v,t,p,c,s) \\
&+ VAR_IRE(r,t,p,c,s,i) \geqslant \\
&[1 + COM_PKRSV(r,t,c,s)] \\
&* \sum_{(pconsumingc)} VAR_FLO(r,v,t,p,c,s) + VAR_IRE(r,t,p,c,s,e)
\end{aligned} \tag{3.8}$$

where,

$NCAP\_PKCNT(r,v,p,c,s)$	: Fraction of technology p's capacity in a region r for period t and commodity c which is either electricity or heat that is allowed to contribute to the peak load in time-slice s (for processes which are predicted to available during peak it is 1, for others such as wind turbine it is less than 1
$COM\_PKRSV(r,t,c,s)$	: Peak reserve coefficient for a commodity c in period t for time-slice s in region r

3.3.4.8 Constraints on commodities

In the TIMES modeling framework, variables of commodities such as total quantity produced can be limited. It is possible to apply cumulative bounds on commodities for multiple periods especially for emissions. Also, tax or penalty can be applied to produced commodities.

3.3.4.9 User constraints

In addition to the standard TIMES constraints mentioned before, the modeler can apply user-defined constraints (UC's) over TIMES variables to processes and commodities. For example, forcing a particular percentage of electricity generation must be supplied by renewable energy resources or investment in a new technology can be limited by a defined ratio to others for a specific time period.

Chapter 4

Technological Characterisation of Supply, Conversion and Demand Technologies

As mentioned in Chapter 1, with rapidly growing energy demand, the electricity sector is the key component of the energy system in Turkey due to high dependence on use in all sectors. Therefore, significant investments are being made in electricity generation sector, and capacity is increasing gradually. Total installed capacity of primary energy resources and significant changes are shown in Figure 4.1. Although hydro had the biggest share in installed capacity (34%), and the natural gas had 25%, in 2012, natural gas was the dominant fuel with the share of 43.63% of total power generations. Other primary energy resources were coal (28.39%), hydro (24.16%), geothermal and the wind (2.82%), liquid fuels (0.68%) and renewable, waste (0.3%) used in power generations. Compared to 2014, shares of hydro, fuels, wind, geothermal and biogas had increased in 2015 while natural gas and coal shares were decreasing [19].

4.1 Properties of the TIMES Model

In this study, a detailed and comprehensive TIMES model used to analyze Turkish electricity sector with the aim of balancing supply and demand of national energy needs at minimum cost. This model is developed within the "Development of Boğaziçi University Energy Modelling System (BUEMS) and Study of Greenhouse

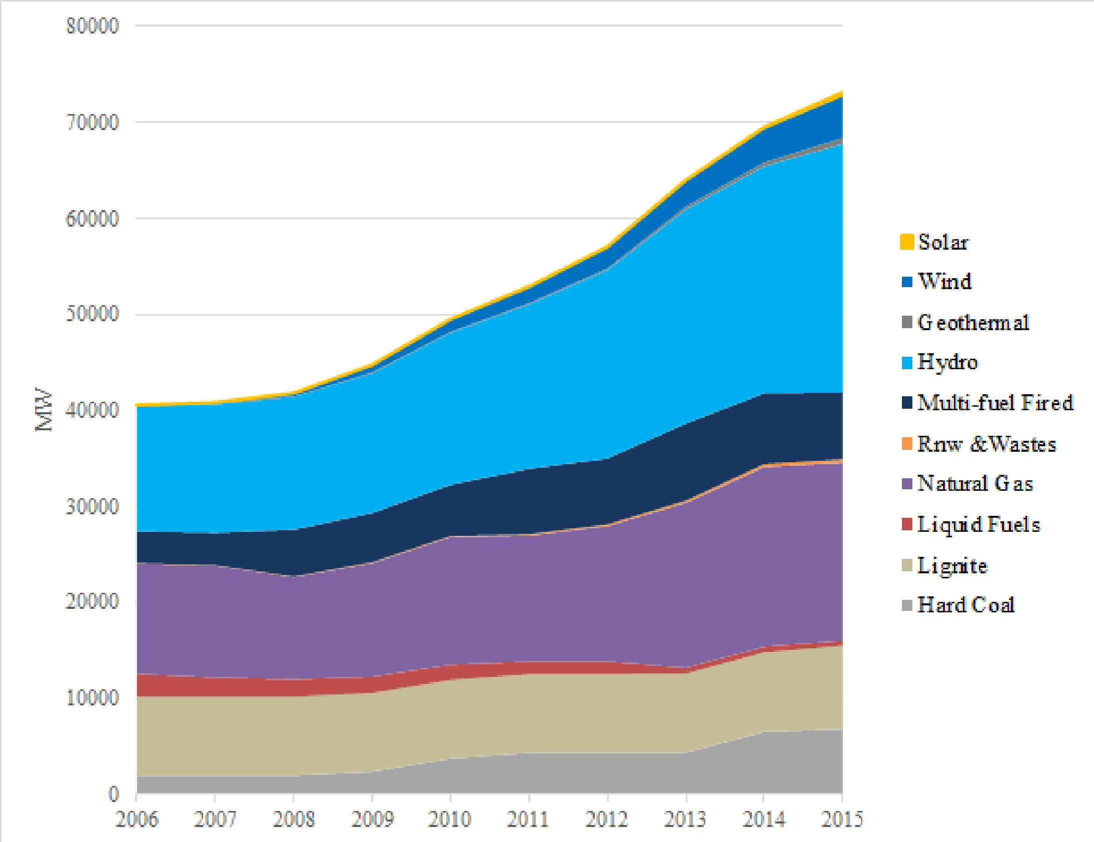


Figure 4.1: Installed capacity between years 2006-2015 (MW) [19]

Gas Emission Reduction Effects on Turkey and Scenario Analysis" project of The Scientific and Technological Research Council of Turkey (TÜBİTAK). This thesis study specialized on electricity generation sector. Other sectors are developed by using publicly available data within this project.

TIMES model consists of primary energy resources, conversion technologies, energy carriers, production technologies, end-use technologies and demand sectors. The energy system starts with the supply of primary energy resources such as coal, natural gas, etc. Then, primary energy resources converted into energy carriers like electricity and heat in conversion technologies such as power plants. These energy carriers finally consumed in end-use technologies such as vehicles according to demands. Main demand categories represented as agricultural, industrial, residential and transportation sectors.

Energy flows between primary energy resources, energy production and conversion technologies and end-use demand devices are represented in a reference energy system for a time horizon of 2012-2050 in a single region. The time periods between milestone years are unequal, and time-slices are set at seasonal, daily and hourly levels to introduce demand characteristics and operations of technologies to be included in price and demand dynamics of the model. Turkish hourly electricity load data for years between 2007 and 2014 was analyzed and from average load, a demand pattern determined as in Table 4.1 as percentages of total load. The patterns quite differs among seasons for weekdays and also there is a daily variation in load of weekend days for each season as they illustrated in Figure 4.3 and Figure 4.4. Based on the average electricity load curve 4 seasonal, 3 daily and 24 hourly (at total 288) time-slices are adopted. December, January, and February are considered as winter months, March, April, and May are described as spring months, June, July, and August are defined as summer months and finally September, October and November are specified as fall months. Weekdays includes days Monday through Friday. The structure of time-slices and basic time horizon representation are illustrated in Figure 4.2. Each timeslice consist of abbreviations for season, day, and hour. WI,SP,SU, and FA are abbreviations for winter, spring, summer and fall. WK, WE1, and WE2 are abbrevations for weekday, saturday and sunday. Each H is representing an hour of a day. Since an hour equal to 1/288 of a year in this structure, in order to equalize the sum of time-slices (G_YRFR) up to 1, there are minor differences between time-slices as shown in Table 4.2. The sum of total elements in matrix is 1. The 288 time-slices defined in the name of day/night time-slice level.

In the model, 2012 US million dollars ($USm 2012) is used as the currency unit. System-wide discount rate is determined as 5% to discount the total system cost.

Data entry and result evaluation of developed TIMES model procured through the ANSWER interface for preparing data to be transferred into GAMS (The General Algebraic Modeling System) solution environment as a bridge between ANSWER and the solver. To reduce the runtime that increased after definition

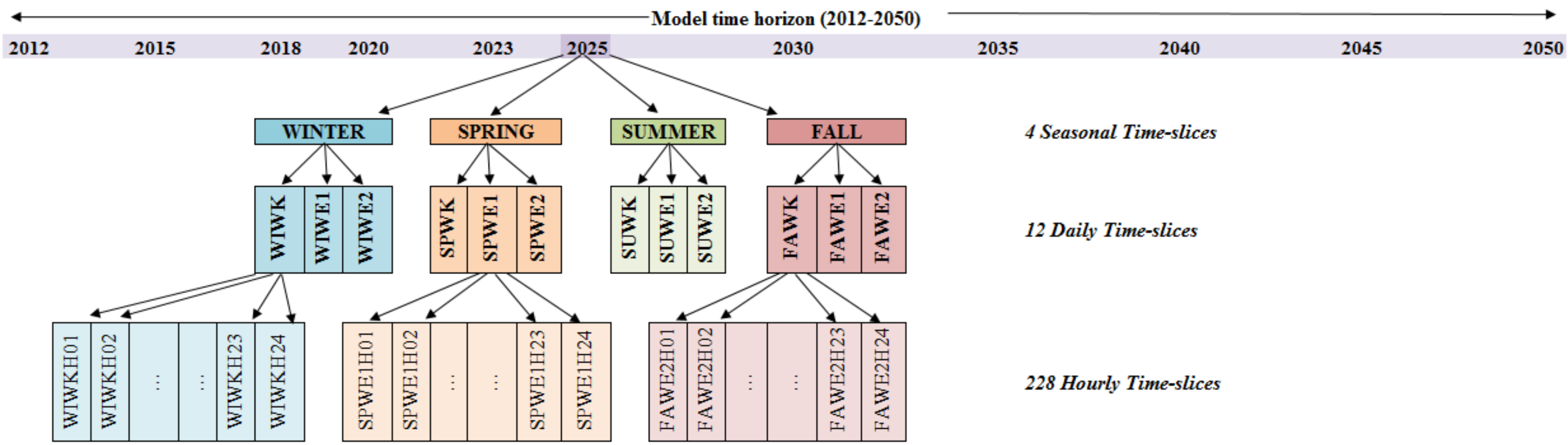


Figure 4.2: Time-slices of TIMES model

Table 4.1: Electricity load of each time-slice as a fraction of the total average demand of years between 2007 and 2014 [45]

	WEEKDAY				SATURDAY				SUNDAY			
Hour	Fall	Spring	Summer	Winter	Fall	Spring	Summer	Winter	Fall	Spring	Summer	Winter
1	0.0067	0.0067	0.0075	0.0070	0.0014	0.0014	0.0015	0.0014	0.0013	0.0013	0.0015	0.0014
2	0.0063	0.0063	0.0071	0.0065	0.0013	0.0013	0.0015	0.0013	0.0012	0.0012	0.0014	0.0013
3	0.0061	0.0061	0.0069	0.0062	0.0012	0.0012	0.0014	0.0013	0.0012	0.0012	0.0013	0.0012
4	0.0060	0.0060	0.0067	0.0061	0.0012	0.0012	0.0014	0.0012	0.0012	0.0011	0.0013	0.0012
5	0.0060	0.0059	0.0066	0.0061	0.0012	0.0012	0.0013	0.0012	0.0011	0.0011	0.0013	0.0011
6	0.0060	0.0059	0.0064	0.0062	0.0012	0.0012	0.0013	0.0012	0.0011	0.0011	0.0012	0.0011
7	0.0060	0.0059	0.0063	0.0064	0.0012	0.0012	0.0013	0.0012	0.0011	0.0011	0.0012	0.0011
8	0.0064	0.0064	0.0068	0.0067	0.0012	0.0012	0.0013	0.0013	0.0011	0.0011	0.0012	0.0011
9	0.0073	0.0074	0.0079	0.0077	0.0014	0.0014	0.0015	0.0014	0.0012	0.0011	0.0013	0.0012
10	0.0079	0.0081	0.0088	0.0084	0.0015	0.0015	0.0017	0.0016	0.0012	0.0012	0.0014	0.0013
11	0.0081	0.0083	0.0091	0.0087	0.0016	0.0016	0.0017	0.0016	0.0013	0.0013	0.0015	0.0013
12	0.0083	0.0083	0.0093	0.0087	0.0016	0.0016	0.0018	0.0017	0.0014	0.0013	0.0015	0.0014
13	0.0080	0.0080	0.0091	0.0083	0.0015	0.0016	0.0017	0.0016	0.0013	0.0013	0.0015	0.0014
14	0.0080	0.0080	0.0092	0.0085	0.0015	0.0016	0.0017	0.0016	0.0013	0.0013	0.0015	0.0014
15	0.0081	0.0081	0.0094	0.0085	0.0015	0.0015	0.0017	0.0016	0.0013	0.0013	0.0015	0.0014
16	0.0081	0.0080	0.0093	0.0085	0.0015	0.0015	0.0017	0.0016	0.0013	0.0013	0.0015	0.0014
17	0.0081	0.0079	0.0091	0.0087	0.0015	0.0015	0.0017	0.0016	0.0014	0.0013	0.0015	0.0014
18	0.0081	0.0078	0.0088	0.0089	0.0015	0.0014	0.0016	0.0016	0.0014	0.0013	0.0014	0.0015
19	0.0081	0.0078	0.0084	0.0087	0.0015	0.0015	0.0016	0.0016	0.0014	0.0013	0.0014	0.0015
20	0.0080	0.0079	0.0082	0.0085	0.0015	0.0015	0.0016	0.0016	0.0015	0.0014	0.0015	0.0015
21	0.0079	0.0080	0.0085	0.0082	0.0015	0.0015	0.0016	0.0015	0.0014	0.0015	0.0015	0.0015
22	0.0077	0.0079	0.0086	0.0080	0.0015	0.0015	0.0016	0.0015	0.0014	0.0014	0.0016	0.0015
23	0.0077	0.0078	0.0085	0.0081	0.0015	0.0015	0.0016	0.0015	0.0014	0.0014	0.0016	0.0015
24	0.0073	0.0075	0.0082	0.0077	0.0014	0.0014	0.0016	0.0015	0.0013	0.0014	0.0015	0.0014

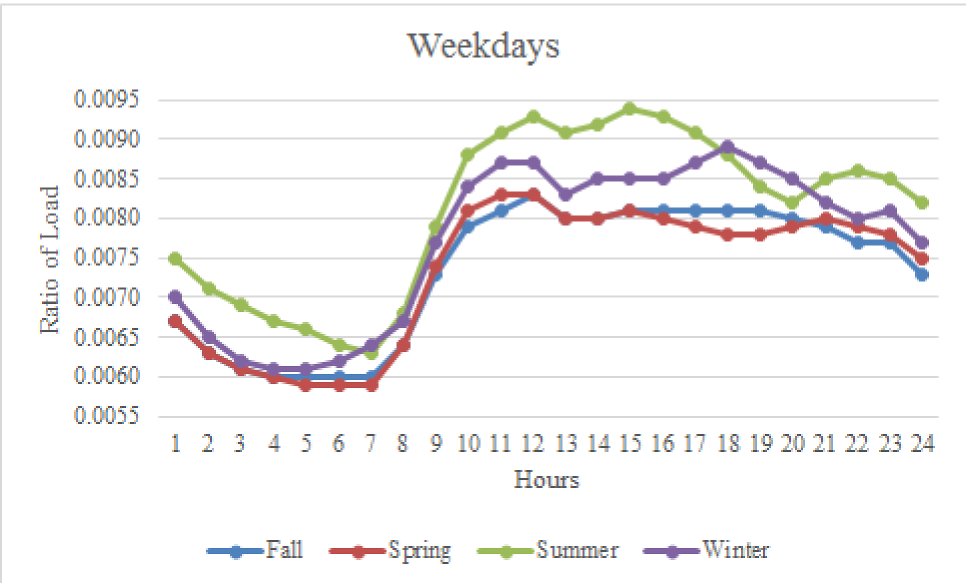


Figure 4.3: Comparison of electricity load pattern of the weekdays based on seasonal variances average of the years between 2007 and 2014 [45]

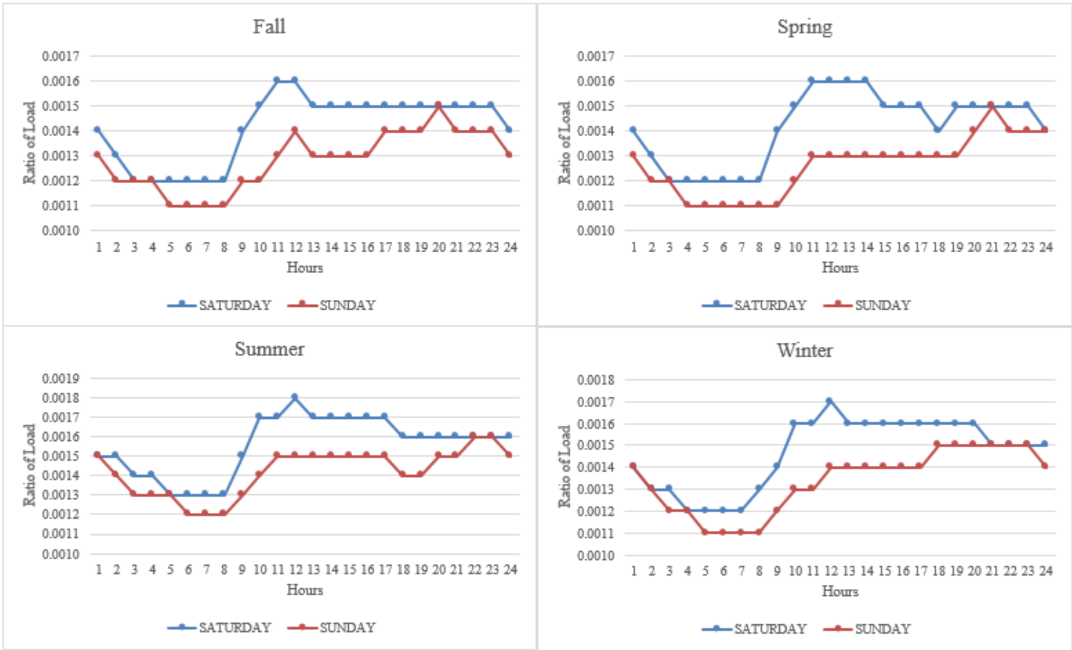


Figure 4.4: Comparison of electricity load pattern of the weekend days based on seasonal variances average of the years between 2007 and 2014 [45]

Table 4.2: Duration of each time-slice as a fraction of a year

G_YRFR	Fall			Spring			Summer			Winter		
Hour	**Weekday**	**Saturday**	**Sunday**	**Weekday**	**Saturday**	**Sunday**	**Weekday**	**Saturday**	**Sunday**	**Weekday**	**Saturday**	**Sunday**
1	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0073	0.0015	0.0015
2	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0073	0.0015	0.0015
3	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0073	0.0015	0.0015
4	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0073	0.0015	0.0015
5	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
6	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
7	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
8	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
9	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
10	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
11	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
12	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
13	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
14	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
15	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
16	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
17	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
18	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
19	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
20	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
21	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
22	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
23	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
24	0.0074	0.0015	0.0015	0.0075	0.0015	0.0015	0.0075	0.0015	0.0015	0.0073	0.0015	0.0015
Daily	0.1776	0.0360	0.0360	0.1796	0.0360	0.0360	0.1796	0.0360	0.0360	0.1752	0.0360	0.0360
Seasonal	0.2496			0.2516			0.2516			0.2472		

of 288 time-slices for some of the commodities and processes, the interior point method has been deployed within CPLEX solver which is efficient for solving larger scale problems.

An example of reference energy system in ANSWER interface is shown in Figure 4.5 for the the ELCT commodity related to power plants and transmission line.

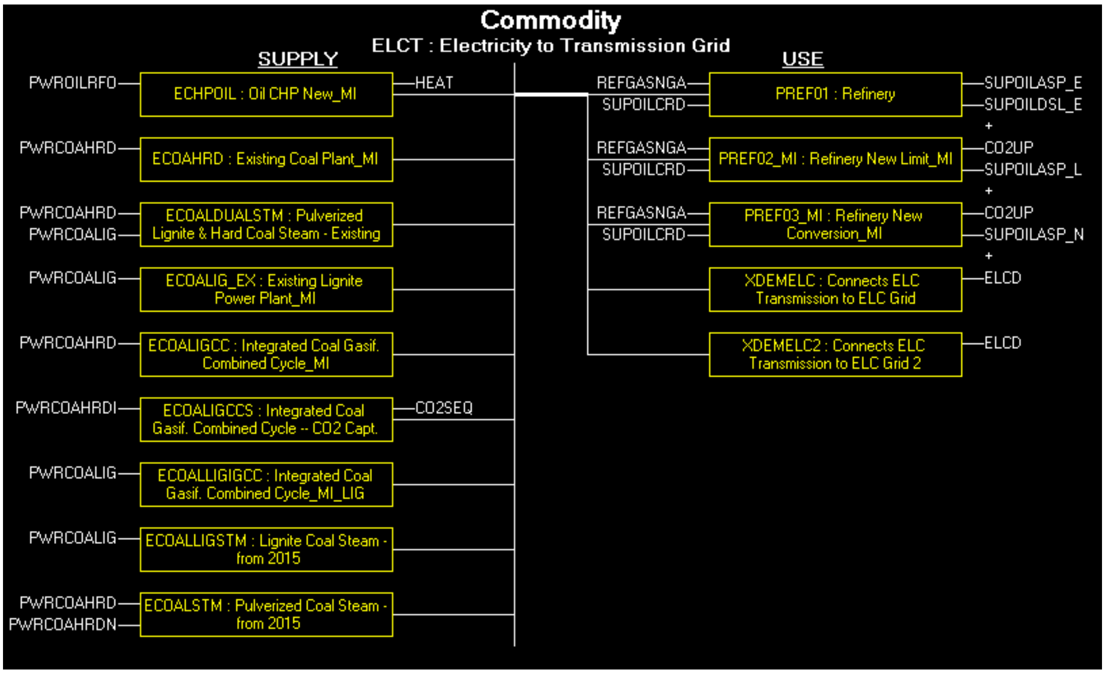


Figure 4.5: A partial view from the Reference Energy System in ANSWER interface for the commodity ELCT related to power plants

In this chapter, mentioned resources, technologies and related data are indicated. Data are acquired from public and private organizations including TEIAS, TURKSTAT, EUAS, EPDK, MENR, etc. Data on technological parameters were taken from EPA U.S. MARKAL 2013 database [46].

4.2 Demands

Demand used in the model is projected with the population, economic and demographic indicators within the project and they are inelastic. But the secondary commodities like electricity are elastic.

As shown in Table 4.1, electricity consumption is not distributed homogeneously. The electricity is consumed by agricultural, industrial, residential, commercial and service, and transportation sectors in the model. And as mentioned in Table 4.3, demand was distributed over these sectors with the share of 3%, 48.1%, 48.5%, and 0.4% respectively in 2012. In 2015, residential consumption was 4127 ktoe and commercial and service consumption was 5205 ktoe. Since the residential consumption takes very large share, some elements of residential consumption distributions rearranged and represented with 288 time-slices in the model.

Table 4.3: Sectoral electricity consumption rates [15]

	2012		**2015**	
Consumption Sector	**ktoe**	**share**	**ktoe**	**share**
Industrial	8,013.0	48.1%	8878.382	47.5%
Residential, Commercial and Public Srv.	8,075.7	48.5%	9332	49.9%
Transportation	72.8	0.4%	17	0.1%
Agriculture	503.1	3.0%	461	2.5%
Total final consumption	16,664.6		18688.37	

4.2.1 Residential Space Heating

In respect to represent residential space heating in hourly time-slice (288) the following operations were followed. All residential space heating processes and demand are defined in day/night time-slices.

In Turkey, half of the electricity was consumed by 10 provinces, İstanbul, İzmir, Kocaeli, Ankara, Bursa, Antalya, Adana, Şanlurfa, Hatay and Gaziantep in 2014 [47]. To obtain an average temperature value for Turkey, three provinces that have high electricity consumption were chosen according to their climatic characteristic. Average temperature of İstanbul, İzmir, and Ankara were summarized for each year between 2007 and 2014 as in Table 4.4. The mean of average value of each year was calculated as in Table 4.5. Then, 2007 was determined as the year with lowest mean absolute deviation. From 2007 calculations, İstanbul which has the lowest mean absolute deviation was chosen as identifier province with the data of 2007. After the determination, hourly temperature data are summarized for defined time-slices of the model as in Table 4.6.

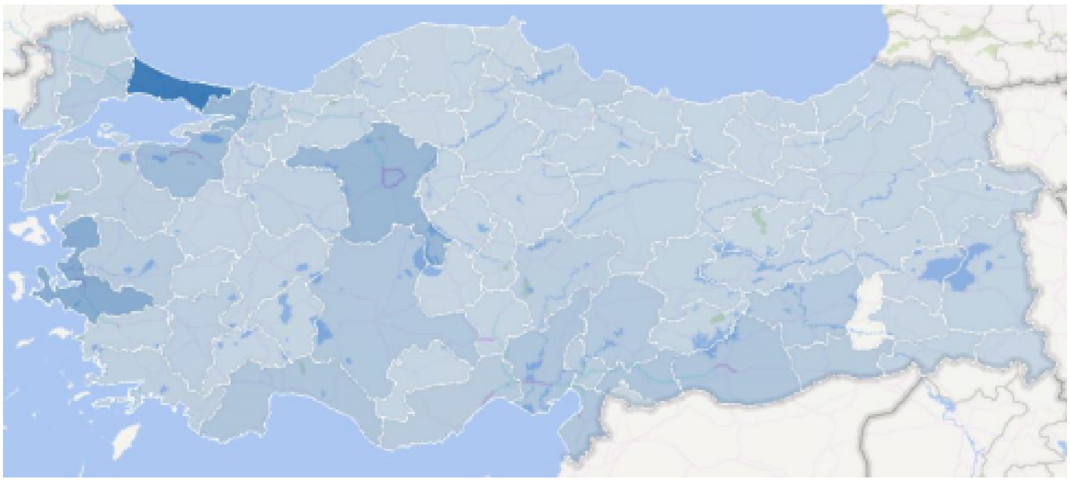


Figure 4.6: Electricity consumption by provinces [47]

Table 4.4: Average seasonal temperature value for three provinces in 2007 (°C)

	FALL			SPRING			SUMMER			WINTER		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
İstanbul	16.55	17.23	16.46	13.62	13.15	14.38	26.06	25.23	25.85	7.98	6.77	6.92
Ankara	11.86	12.62	11.85	9.58	10.08	10.08	22.77	22.38	22.69	0.19	1.00	-0.54
İzmir	17.65	18.77	17.77	15.30	15.46	15.92	27.89	27.46	27.54	7.69	8.23	7.00
avg	**15.35**	**16.21**	**15.36**	**12.83**	**12.90**	**13.46**	**25.58**	**25.03**	**25.36**	**5.29**	**5.33**	**4.46**

Table 4.5: Mean of average seasonal temperatures for years 2007-2014 (°C)

avg. Temp.	FALL			SPRING			SUMMER			WINTER		
	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday	Weekday	Saturday	Sunday
2007	15.35	16.21	15.36	12.83	12.90	13.46	25.58	25.03	25.36	5.29	5.33	4.46
2008	15.84	15.59	15.67	13.52	13.40	13.82	24.78	24.38	24.12	3.42	3.19	3.31
2009	15.48	16.23	15.56	11.95	12.23	11.74	23.93	23.82	23.69	6.30	6.03	6.42
2010	16.84	16.05	16.21	12.94	13.31	13.72	25.01	25.13	25.23	6.82	7.64	7.44
2011	13.93	14.46	13.92	11.05	11.31	11.31	23.69	23.59	23.56	5.36	4.88	5.36
2012	17.30	17.67	17.97	12.39	12.21	12.36	25.36	25.72	25.62	2.70	4.15	4.45
2013	15.04	14.00	14.67	13.89	13.33	13.92	24.34	24.19	24.05	5.04	5.17	5.54
2014	15.89	15.59	14.56	13.54	12.81	12.79	24.36	24.18	23.57	7.37	7.58	7.22
avg	**15.71**	**15.72**	**15.49**	**12.76**	**12.69**	**12.89**	**24.63**	**24.50**	**24.40**	**5.29**	**5.50**	**5.52**

Eurostat defines heating degree days as *HDD*= $(18° - T_m)*d$ if T_m is lower than or equal to 15° (heating treshold) , and *HDD=0* if T_m is greater than 15° , where T_m is the daily average temperature and d is days [48]. The differences between 18 ° and hourly average temperature are noted in a table if average hourly data

Table 4.6: Hourly average temperature values of İstanbul in 2007 (°C)

	FALL			SPRING			SUMMER			WINTER		
	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY
1	15.8	17.0	15.5	11.9	11.8	12.5	24.4	23.2	24.0	7.5	7.0	6.8
2	15.3	16.1	15.3	11.6	11.3	12.2	23.9	22.5	23.5	7.1	6.8	6.5
3	14.9	15.7	15.3	11.3	10.9	11.8	23.4	22.1	23.2	7.0	6.6	6.1
4	14.6	15.5	15.1	11.1	10.7	11.7	23.1	21.8	22.6	7.1	6.4	5.7
5	14.4	15.6	15.0	10.8	10.3	11.8	22.9	21.7	22.3	6.9	6.1	5.5
6	14.4	15.5	15.1	10.8	10.2	11.7	22.8	21.7	22.3	6.9	6.3	5.7
7	14.5	15.7	14.9	11.0	10.5	11.8	23.1	22.1	22.7	6.9	6.2	5.8
8	15.1	16.0	15.3	11.9	11.5	12.6	24.1	23.2	23.7	7.0	6.2	6.0
9	16.3	17.2	16.1	13.0	12.6	13.6	25.4	24.4	25.1	7.5	6.7	6.5
10	17.1	18.1	16.9	13.7	13.7	14.3	26.0	25.0	25.7	8.2	7.2	7.4
11	17.8	18.5	17.5	14.6	14.5	15.3	26.8	26.4	26.7	8.7	7.7	7.9
12	18.2	19.0	18.1	15.2	14.8	15.9	27.5	26.8	27.1	9.0	8.2	8.3
13	18.7	19.5	18.3	15.7	15.2	16.6	28.1	27.7	27.5	9.2	8.3	8.7
14	18.9	19.7	18.5	16.1	15.5	17.0	28.5	28.2	27.8	9.4	8.6	8.9
15	19.1	20.0	18.3	16.5	16.0	17.6	29.2	28.6	28.8	9.4	8.6	9.1
16	19.1	19.7	18.2	16.5	16.3	17.4	29.3	28.7	29.5	9.1	8.4	8.8
17	18.8	19.3	18.1	16.2	16.2	16.9	29.1	28.7	29.1	8.6	8.0	8.3
18	18.3	18.5	17.8	15.8	15.6	15.7	29.0	28.3	28.6	8.3	7.6	7.8
19	17.6	17.6	17.2	15.1	15.3	14.7	28.3	27.4	28.1	8.1	7.1	7.3
20	17.2	16.8	17.2	14.2	14.5	13.7	27.3	26.3	27.2	8.0	6.9	7.2
21	16.9	16.6	17.0	13.6	13.9	12.8	26.3	25.4	26.2	7.8	7.0	7.2
22	16.8	16.1	16.7	13.3	13.7	12.4	25.7	25.1	25.6	7.8	7.0	6.9
23	16.4	16.0	16.7	12.8	13.1	12.0	25.1	24.6	24.9	7.7	7.0	7.1
24	16.1	15.7	16.7	12.6	13.0	11.7	24.6	24.2	24.8	7.6	6.9	6.9
days	65	13	13	66	13	13	66	13	13	64	13	13

lower than or equal to 15 °. Then, these heating degrees weighted according to number of days that seasons have, and finally implemented into the model as the residential space heating demand distribution as in Figure 4.7. There is no space heating demand in summer, fall daytime, and spring afternoon.

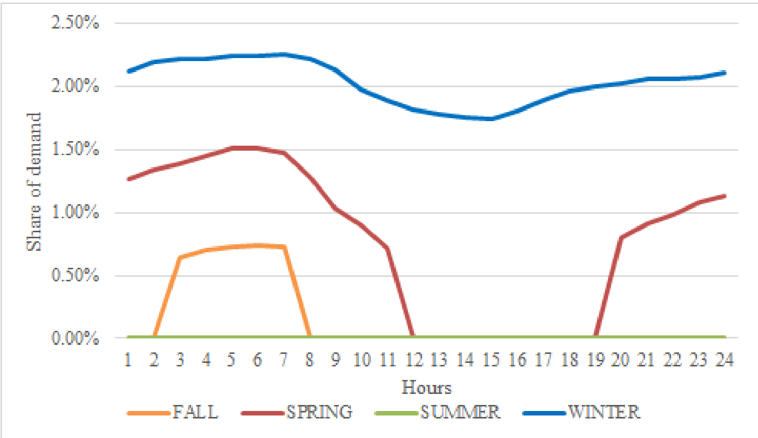


Figure 4.7: Model residential space heating load distribution as a fraction of annual demand based on heating degree hours specification

4.2.2 Residential Space Cooling

To represent residential space cooling in hourly time-slice (288) the following operations were followed. All residential space cooling processes and demand are defined in day/night time-slices.

Cooling degree days are defined as $CDD = (T_m - 22^{\circ}) * d$ if T_m is greater than 22° (cooling treshold), and $CDD=0$ if T_m is lower than or equal to 22°, where T_m is the mean temperature and d is days [48]. Since the baseline for cooling is 22°, differences between hourly average temperature and 22° are noted in a table if average hourly data greater than 22°. Then, these cooling degrees weighted according to number of days that seasons have and finally implemented into the model as the residential space heating demand distribution as in Table 4.7. In table, data colors are column based. Minor deviations in weekend days are ignored.

Table 4.7: Model residential space cooling load distribution as a fraction of annual demand based on cooling degree hours specification

	FALL			SPRING			SUMMER			WINTER		
	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY
1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0185	0.0018	0.0030	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0145	0.0009	0.0022	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0110	0.0002	0.0018	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0089	0.0000	0.0010	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0070	0.0000	0.0005	0.0000	0.0000	0.0000
6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0063	0.0000	0.0005	0.0000	0.0000	0.0000
7	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0088	0.0002	0.0010	0.0000	0.0000	0.0000
8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0164	0.0018	0.0025	0.0000	0.0000	0.0000
9	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0268	0.0038	0.0048	0.0000	0.0000	0.0000
10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0310	0.0047	0.0057	0.0000	0.0000	0.0000
11	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0370	0.0068	0.0070	0.0000	0.0000	0.0000
12	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0430	0.0075	0.0078	0.0000	0.0000	0.0000
13	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0475	0.0087	0.0085	0.0000	0.0000	0.0000
14	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0508	0.0095	0.0090	0.0000	0.0000	0.0000
15	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0555	0.0100	0.0105	0.0000	0.0000	0.0000
16	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0568	0.0105	0.0115	0.0000	0.0000	0.0000
17	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0550	0.0103	0.0109	0.0000	0.0000	0.0000
18	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0547	0.0098	0.0100	0.0000	0.0000	0.0000
19	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0489	0.0083	0.0094	0.0000	0.0000	0.0000
20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0410	0.0067	0.0079	0.0000	0.0000	0.0000
21	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0330	0.0053	0.0064	0.0000	0.0000	0.0000
22	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0285	0.0048	0.0055	0.0000	0.0000	0.0000
23	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0240	0.0040	0.0044	0.0000	0.0000	0.0000
24	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0200	0.0034	0.0043	0.0000	0.0000	0.0000

4.2.3 Residential Water Heating

The residential water heating demand is represented in hourly time-slices (288) with reference of residential and services sector water heating demand of the Swiss TIMES energy system model (STEM) [49]. All residential water heating processes and demand are defined in day/night time-slices as shown in Table 4.8.

Table 4.8: Model residential water heating load distribution as a fraction of annual demand

	FALL			SPRING			SUMMER			WINTER		
	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY
1	0.0030	0.0005	0.0005	0.0030	0.0005	0.0005	0.0010	0.0002	0.0002	0.0050	0.0008	0.0008
2	0.0032	0.0005	0.0005	0.0032	0.0005	0.0005	0.0010	0.0002	0.0002	0.0055	0.0010	0.0010
3	0.0033	0.0006	0.0006	0.0033	0.0006	0.0006	0.0013	0.0003	0.0003	0.0055	0.0010	0.0010
4	0.0038	0.0006	0.0006	0.0038	0.0006	0.0006	0.0015	0.0003	0.0003	0.0060	0.0013	0.0013
5	0.0060	0.0010	0.0010	0.0060	0.0010	0.0010	0.0025	0.0003	0.0003	0.0095	0.0020	0.0020
6	0.0100	0.0020	0.0020	0.0100	0.0020	0.0020	0.0048	0.0010	0.0010	0.0160	0.0033	0.0033
7	0.0130	0.0025	0.0025	0.0130	0.0025	0.0025	0.0070	0.0015	0.0015	0.0190	0.0035	0.0035
8	0.0135	0.0025	0.0025	0.0135	0.0025	0.0025	0.0105	0.0020	0.0020	0.0165	0.0030	0.0030
9	0.0110	0.0021	0.0021	0.0110	0.0021	0.0021	0.0085	0.0018	0.0018	0.0135	0.0025	0.0025
10	0.0085	0.0016	0.0016	0.0085	0.0016	0.0016	0.0055	0.0013	0.0013	0.0115	0.0021	0.0021
11	0.0080	0.0015	0.0015	0.0080	0.0015	0.0015	0.0045	0.0010	0.0010	0.0115	0.0020	0.0020
12	0.0078	0.0016	0.0016	0.0078	0.0016	0.0016	0.0045	0.0010	0.0010	0.0115	0.0023	0.0023
13	0.0072	0.0015	0.0015	0.0072	0.0015	0.0015	0.0038	0.0010	0.0010	0.0110	0.0020	0.0020
14	0.0068	0.0013	0.0013	0.0068	0.0013	0.0013	0.0035	0.0010	0.0010	0.0100	0.0018	0.0018
15	0.0068	0.0013	0.0013	0.0068	0.0013	0.0013	0.0035	0.0010	0.0010	0.0100	0.0018	0.0018
16	0.0068	0.0015	0.0015	0.0068	0.0015	0.0015	0.0035	0.0010	0.0010	0.0105	0.0020	0.0020
17	0.0073	0.0016	0.0016	0.0073	0.0016	0.0016	0.0045	0.0013	0.0013	0.0100	0.0020	0.0020
18	0.0073	0.0016	0.0016	0.0073	0.0016	0.0016	0.0045	0.0010	0.0010	0.0100	0.0023	0.0023
19	0.0098	0.0021	0.0021	0.0098	0.0021	0.0021	0.0035	0.0010	0.0010	0.0160	0.0033	0.0033
20	0.0095	0.0021	0.0021	0.0095	0.0021	0.0021	0.0060	0.0015	0.0015	0.0130	0.0028	0.0028
21	0.0093	0.0020	0.0020	0.0093	0.0020	0.0020	0.0085	0.0020	0.0020	0.0100	0.0020	0.0020
22	0.0070	0.0016	0.0016	0.0070	0.0016	0.0016	0.0045	0.0013	0.0013	0.0095	0.0023	0.0023
23	0.0055	0.0011	0.0011	0.0055	0.0011	0.0011	0.0040	0.0010	0.0010	0.0070	0.0013	0.0013
24	0.0033	0.0005	0.0005	0.0032	0.0005	0.0005	0.0015	0.0003	0.0003	0.0050	0.0008	0.0008

4.2.4 Residential Lighting

The residential lighting demand is represented in hourly time-slices (288) with reference of daily lighting power observed in a sample house of a family who live in a city center, have two kids and both parents are working [50]. In that study, daily demand of a family observed for energy saving. From that observations, hourly lighting patten is deduced as in Figure 4.8 and divided into hours according to seasonal sunrise and sunset hours of Turkey. Sunrise and sunset hours [51] are determined as 07:00 for winter and fall, 06:00 for spring and summer, and 17:00 for winter, 18:00 for fall, 19:00 for spring and 20:00 for summer. Weekly and seasonal lighting demand variances ignored. Hourly lighting demand pattern in Table 4.9 implemented into the model. All residential lighting process and demand are defined in day/night time-slices.

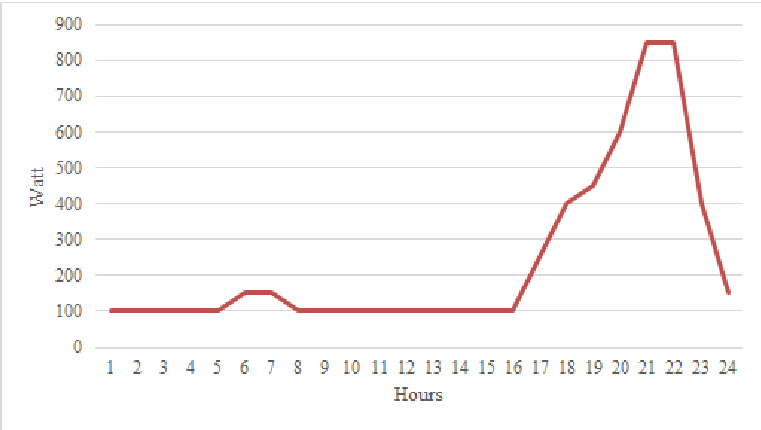


Figure 4.8: Deduced pattern of lighting demand of a family in a weekday [50]

Table 4.9: Model residential lighting load distribution as a fraction of annual demand

	WEEKDAY				SATURDAY				SUNDAY			
	Fall	Spring	Summer	Winter	Fall	Spring	Summer	Winter	Fall	Spring	Summer	Winter
1	0.0034	0.0034	0.0034	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
2	0.0034	0.0034	0.0034	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
3	0.0034	0.0034	0.0034	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
4	0.0034	0.0034	0.0034	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
5	0.0034	0.0034	0.0034	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
6	0.0051	0.0051	0.0051	0.0051	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010
7	0.0051	0.0042	0.0034	0.0051	0.0010	0.0008	0.0007	0.0010	0.0010	0.0008	0.0007	0.0010
8	0.0034	0.0033	0.0033	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
9	0.0034	0.0033	0.0033	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
10	0.0034	0.0033	0.0033	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
11	0.0034	0.0033	0.0032	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
12	0.0034	0.0033	0.0032	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
13	0.0034	0.0033	0.0032	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
14	0.0034	0.0033	0.0032	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
15	0.0034	0.0033	0.0032	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
16	0.0034	0.0033	0.0032	0.0034	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
17	0.0034	0.0033	0.0033	0.0085	0.0007	0.0007	0.0007	0.0017	0.0007	0.0007	0.0007	0.0017
18	0.0135	0.0033	0.0033	0.0135	0.0027	0.0007	0.0007	0.0027	0.0027	0.0007	0.0007	0.0027
19	0.0152	0.0152	0.0033	0.0152	0.0030	0.0030	0.0007	0.0030	0.0030	0.0030	0.0007	0.0030
20	0.0203	0.0203	0.0203	0.0203	0.0041	0.0041	0.0041	0.0041	0.0041	0.0041	0.0041	0.0041
21	0.0287	0.0287	0.0287	0.0287	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057
22	0.0287	0.0287	0.0287	0.0287	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057
23	0.0135	0.0135	0.0135	0.0135	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027
24	0.0051	0.0051	0.0051	0.0051	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010

4.2.5 Residential Refrigerator

The residential refrigerator demand is represented in hourly time-slices (288) with reference of a study of Barker et al. [52] that collected power data from a real home for 82 days. They presented hourly load of several appliances and indicated the on-off period varies with environmental conditions and it is not regular. Hourly consumption of refrigerator obtained from the graph that they presented and applied to all seasons equally as in Table 4.10.

Table 4.10: Model residential refrigerator load distribution as a fraction of annual demand

	FALL			*SPRING*			*SUMMER*			*WINTER*		
	WEEKDAY	*SATURDAY*	*SUNDAY*	*WEEKDAY*	*SATURDAY*	*SUNDAY*	*WEEKDAY*	*SATURDAY*	*SUNDAY*	*WEEKDAY*	*SATURDAY*	*SUNDAY*
1	0.0056	0.0011	0.0011	0.0056	0.0011	0.0011	0.0056	0.0011	0.0011	0.0056	0.0011	0.0011
2	0.0052	0.0011	0.0011	0.0052	0.0011	0.0011	0.0052	0.0011	0.0011	0.0052	0.0011	0.0011
3	0.0052	0.0011	0.0011	0.0052	0.0011	0.0011	0.0052	0.0011	0.0011	0.0052	0.0011	0.0011
4	0.0050	0.0010	0.0010	0.0050	0.0010	0.0010	0.0050	0.0010	0.0010	0.0050	0.0010	0.0010
5	0.0037	0.0007	0.0007	0.0037	0.0007	0.0007	0.0037	0.0007	0.0007	0.0037	0.0007	0.0007
6	0.0058	0.0011	0.0011	0.0058	0.0011	0.0011	0.0058	0.0011	0.0011	0.0058	0.0011	0.0011
7	0.0052	0.0010	0.0010	0.0052	0.0010	0.0010	0.0052	0.0010	0.0010	0.0052	0.0010	0.0010
8	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015	0.0074	0.0015	0.0015
9	0.0078	0.0016	0.0016	0.0078	0.0016	0.0016	0.0078	0.0016	0.0016	0.0078	0.0016	0.0016
10	0.0114	0.0023	0.0023	0.0114	0.0023	0.0023	0.0114	0.0023	0.0023	0.0114	0.0023	0.0023
11	0.0107	0.0021	0.0021	0.0107	0.0021	0.0021	0.0107	0.0021	0.0021	0.0107	0.0021	0.0021
12	0.0082	0.0016	0.0016	0.0082	0.0016	0.0016	0.0082	0.0016	0.0016	0.0082	0.0016	0.0016
13	0.0072	0.0014	0.0014	0.0072	0.0014	0.0014	0.0072	0.0014	0.0014	0.0072	0.0014	0.0014
14	0.0050	0.0010	0.0010	0.0050	0.0010	0.0010	0.0050	0.0010	0.0010	0.0050	0.0010	0.0010
15	0.0085	0.0017	0.0017	0.0085	0.0017	0.0017	0.0085	0.0017	0.0017	0.0085	0.0017	0.0017
16	0.0096	0.0019	0.0019	0.0096	0.0019	0.0019	0.0096	0.0019	0.0019	0.0096	0.0019	0.0019
17	0.0146	0.0029	0.0029	0.0146	0.0029	0.0029	0.0146	0.0029	0.0029	0.0146	0.0029	0.0029
18	0.0110	0.0022	0.0022	0.0110	0.0022	0.0022	0.0110	0.0022	0.0022	0.0110	0.0022	0.0022
19	0.0102	0.0020	0.0020	0.0102	0.0020	0.0020	0.0102	0.0020	0.0020	0.0102	0.0020	0.0020
20	0.0071	0.0014	0.0014	0.0071	0.0014	0.0014	0.0071	0.0014	0.0014	0.0071	0.0014	0.0014
21	0.0093	0.0019	0.0019	0.0093	0.0019	0.0019	0.0093	0.0019	0.0019	0.0093	0.0019	0.0019
22	0.0054	0.0011	0.0011	0.0054	0.0011	0.0011	0.0054	0.0011	0.0011	0.0054	0.0011	0.0011
23	0.0058	0.0012	0.0012	0.0058	0.0012	0.0012	0.0058	0.0012	0.0012	0.0058	0.0012	0.0012
24	0.0038	0.0008	0.0008	0.0038	0.0008	0.0008	0.0038	0.0008	0.0008	0.0038	0.0008	0.0008

4.2.6 Residential Appliances

The other residential appliances demand that consume electricity is represented in hourly time-slices (288) based on hourly electricity load distribution as shown in Table 4.1 since it was not possible to determine the distribution due to lack of data.

4.3 Primary Resources and Related Technologies

4.3.1 Natural Gas

As mentioned before, natural gas has a great importance in Turkish electricity sector since it has the highest share in power generation. Power generation shares and installed capacity of natural gas power plants are illustrated in Figure 4.9. Total installed capacity of multi-fuel fired power plants are listed in Table 4.11.

In 2012, 40.7 m^3 natural gas was used in Turkey with the increase of 5% from previous year and rated as all-time highest amount. Although the natural gas has the biggest consumption rate as 43.63% in power generation, it is not a domestic fuel in Turkey and 99% of the total supply was imported. In 2012, natural gas was imported from Russia with the share of 54%, from Iran with the share of 19%, 10% from Algeria, 8% from Azerbaijan, 3% from Nigeria and 6% from spot market as LNG [53]. Imported natural gas amounts can be found in Table 4.12.

Since the amount of imported natural gas depends on pipeline capacity, import from countries is modeled separately for Russia, Iran and Azerbaijan according to pipeline capacities and purchasing agreements and also LNG transformation capacities considered for LNG terminals. The purchasing agreements are included into the model as flow lower bounds for import as listed in Table 4.13.

In 2012, 50.8% of natural gas sold in the country was used in power generation, 23.8% used in residential buildings and 23.9% used in the industry. The remaining 1.5% share was exported [53].

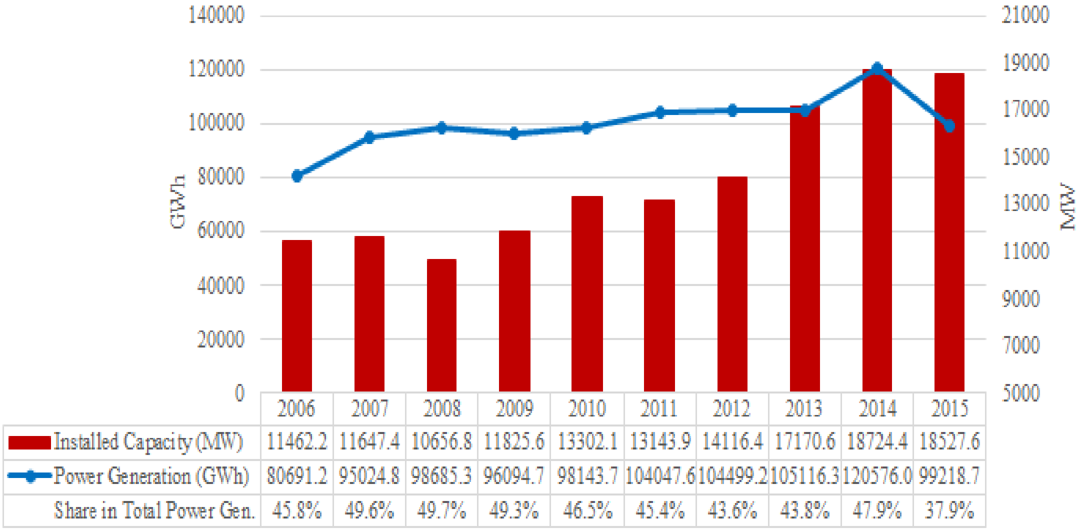


Figure 4.9: Development of installed capacity (MW) and power generation (GWh) for natural gas [19]

Table 4.11: Total installed capacity of natural gas power plants (MW) [19]
*Solid+N.Gas and Solid+N.Gas+Liquid fired power plants included

Years	Natural Gas	Solid+Liquid*	Liquid+ Natural Gas	TOTAL
2006	11462.2	471.0	2852.4	14785.6
2007	11647.4	471.0	2913.0	15031.4
2008	10656.8	471.0	4398.0	15525.8
2009	11825.6	415.7	4721.9	16963.2
2010	13302.1	452.7	4872.9	18627.7
2011	13143.9	477.6	6333.2	19954.7
2012	14116.4	598.5	6282.2	20997.1
2013	17170.6	612.3	7408.1	25191.0
2014	18724.4	585.8	6783.6	26093.9
2015	18527.6	582.7	6378.3	25488.6

Table 4.12: Imported natural gas (million Sm^3) [54]

Year	Russia	Iran	Azerbaijan	Algeria	Nigeria	Spot LNG	Total
2005	17524	4248	0	3786	1013	0	26571
2006	19316	5594	0	4132	11	79	30221
2007	22762	6054	1258	4205	1396	167	35842
2008	23159	4113	458	4148	1017	333	3735
2009	19473	5252	496	4487	903	781	35856
2010	17576	7765	4521	3906	1189	3079	38036
2011	25406	819	3806	4156	1248	1069	43874
2012	26491	8215	3354	4076	1322	2464	45922
2013	26212	873	4245	3917	1274	892	45269
2014	26975	8932	6074	4179	1414	1689	49262
2015	26783	7826	6169	3916	124	2493	48427

Table 4.13: Purchasing agreements for natural gas [55]

Contract	**Amount (plato value-billion Cm^3/yr)**	**Contract Date**	**Period (years)**	**Flow Start Date**
Russia (Western Line)	6	14.02.1986	25	1987
Algeria (LNG)	4	14.04.1988	20	1994
Nigeria (LNG)	1.2	9.11.1995	22	1999
Iran	10	8.08.1996	25	2001
Russia (Blue Stream)	16	15.12.1997	25	2003
Russia (Western Line)	(8-4 disposed)	18.02.1998	23	1998
Turkmenistan	16	21.05.1999	30	-
Azerbaijan	6.6	12.03.2001	15	2007

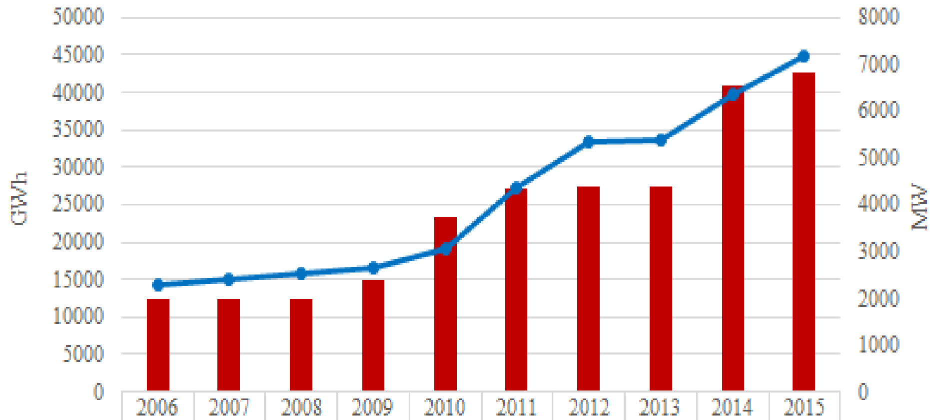
Natural gas technologies have very high availability rates. There are gas turbine combined cycle (existing and new), advanced turbine combined cycle, combined cycle with CO_2 capture, combined heat and power (existing and new), combustion turbine, advanced combustion turbine technologies defined in the model. Existing technologies are already in use, for others an investment decision is required.

In the model, the combined cycle with CO_2 capture technology has the highest investment cost among others yet investment of other CC technologies are cheaper than combined heat and power plants. And the lowest investment cost belongs to advanced combustion turbine technology. The other combustion turbine technologies have higher investment cost than CC technologies. The CHP technologies have highest activity costs and combustion turbine technologies follow them and combined-cycle turbine technologies have the lowest activity cost and also they are more efficient than other technologies. The lowest electrical energy efficiency rate belongs to CHP technologies.

All natural gas technologies have day/night time-slice level resolution which covers 288 time-slices.

4.3.2 Coal

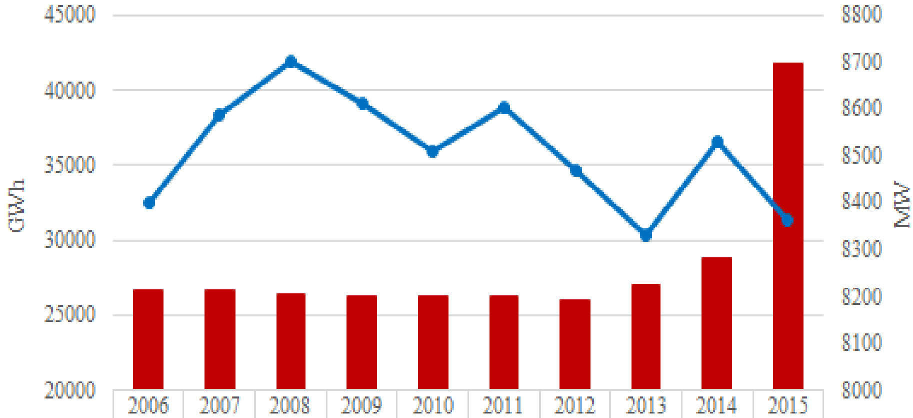
Since lignite is a low-grade coal and has high ash and humidity rate, generally used in thermal power plants. Anthracite is a high-calorie coal. Lignite is a domestic energy resource and has the 1.6% of global lignite reserves. 46% of the lignite reserves are located in Afşin-Elbistan and hard coal reserves located at Zonguldak. 95% of the total hard coal supply was imported in 2012. Turkey aims to increase domestic resources share and invest into these technologies in future plans. In that respect, installed capacity of lignite increased 5% in 2015 after its stable pattern for a while. Representation of the change in installed capacity and shares in the power generation of hard coal and lignite can be found in Figure 4.10 and Figure 4.11.



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Installed Capacity (MW)	1986.0	1986.0	1986.0	2391.0	3751.0	4351.0	4382.5	4382.5	6532.6	6825.2
Power Generation (GWh)	14216.6	15136.2	15857.5	16595.6	19104.3	27347.5	33324.2	33524.0	39647.3	44829.9
Share in Total Power Gen.	8.1%	7.9%	8.0%	8.5%	9.0%	11.9%	13.9%	14.0%	15.7%	17.1%

Figure 4.10: Development of installed capacity (MW) and power generation (GWh) for hard coal, imported coal, asphaltite [19]

There are various coal based technologies in the mode such as coal CHP (existing and new), lignite CHP (existing and new), existing coal plant, existing pulverized lignite and hard coal steam, integrated coal gasification combined cycle and integrated coal gasification combined cycle with CO_2 capture, integrated lignite gasification combined cycle, lignite coal steam and pulverized coal steam technologies. Existing coal technologies are adjusted such that they reflect the base year consumption, production and efficiency figures.



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Installed Capacity (MW)	8210.8	8211.4	8205.0	8199.3	8199.3	8199.3	8193.3	8223.2	8281.3	8696.5
Power Generation (GWh)	32432.9	38294.7	41858.1	39089.5	35942.1	38870.4	34688.9	30262.0	36615.4	31335.7
Share in Total Power Gen.	18.4%	20.0%	21.1%	20.1%	17.0%	16.9%	14.5%	12.6%	14.5%	12.0%

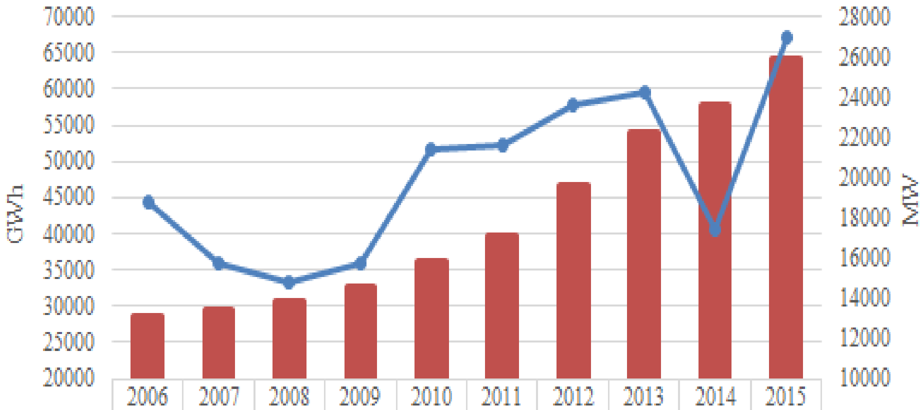
Figure 4.11: Development of installed capacity (MW) and power generation (GWh) for lignite [19]

4.3.3 Hydro

Hydro is one of the most significant and domestic primary energy resource in Turkey with the share of 25.6% of power generation in 2015 and also takes the highest share of renewable resources. Installed capacity and power generation are presented in Figure 4.12.

Gross hydroelectric potential calculated with the assumption of all flows are utilized with the 100% efficiency, is called theoretical hydroelectricity potential and computed as 433 billion kWh/year for Turkey. Since this assumption is not realistic, the maximum amount can be utilized with available technologies which are called the technically assessable potential is 216 billion kWh/year. On the other hand, technical assessable potential and economic potential differs as well. Total of hydro power plants in service, under construction and the plants that have not started construction defines the economic potential and it was calculated is 164 billion kWh/year [56].

Hydro technologies are represented with two power plants and are defined in day/night time-slice level in the model.



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Installed Capacity (MW)	13062.7	13394.9	13828.7	14553.3	15831.2	17137.1	19609.4	22289.0	23643.2	25867.8
Power Generation (GWh)	44244.2	35850.8	33269.8	35958.4	51795.5	52338.6	57865.0	59420.5	40644.7	67145.8
Share in Total Power Gen.	25.1%	18.7%	16.8%	18.5%	24.5%	22.8%	24.2%	24.7%	16.1%	25.6%

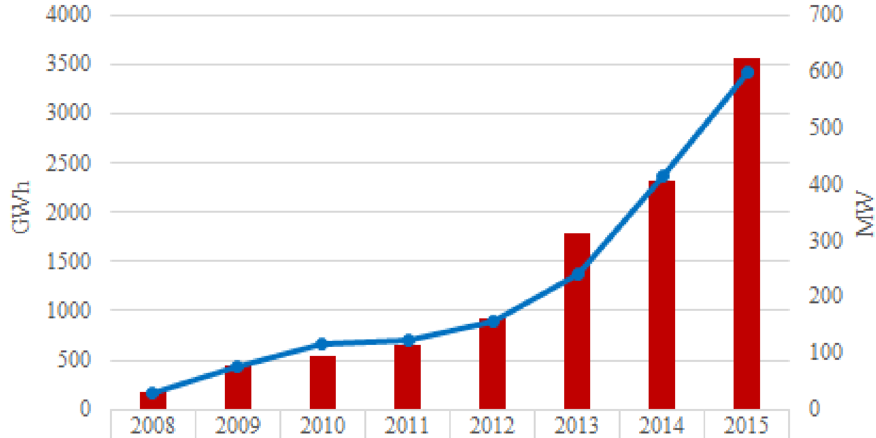
Figure 4.12: Development of installed capacity (MW) and power generation (GWh) for hydro [19]

4.3.4 Geothermal Energy

Geothermal energy is clean since it is emitting very low CO_2, NO_x and SO_x gases and a renewable energy type [57]. Since Turkey is located on Alps-Himalayas belt it has a large potential for geothermal energy which is indicated as 2000 MW for electricity generation. It is targeted to have 600 MW installed capacity for power generation by 2019 [58].

Installed capacity was stable between 1984 and 2002 as 17.5 MW than it has dropped to 15 MW level for the period of 2003-2005. Recently, the capacity and share in power generation are significantly increasing. Installed capacity in 2015 accounted for 3.8 times of 2012 value and 1.3% of power generation supplied by geothermal energy. Further representation can be seen in Figure 4.13.

There are three geothermal technologies for the power sector in the model: existing geothermal power plants, binary cycle and flashed steam and enhanced geothermal system that is available after 2025.



	2008	2009	2010	2011	2012	2013	2014	2015
Installed Capacity (MW)	29.8	77.2	94.2	114.2	162.2	310.8	404.9	623.9
Power Generation (GWh)	161.9	436.1	668.6	695.2	900.1	1364.0	2364.1	3424.0
Share in Total Power Gen.	0.1%	0.2%	0.3%	0.3%	0.4%	0.6%	0.9%	1.3%

Figure 4.13: Development of installed capacity (MW) and power generation (GWh) for geothermal [19],[15]

4.3.5 Wind

The wind is an important renewable energy resource which is stated as speed and direction parameters. The investment costs for wind technologies are very high, and capacity factors are low. Although these disadvantages, there are also several advantages following. The wind is a clean and reliable energy source, and there is no case to be stock out or facing price increases. It has low maintenance and repair cost, and installation and operation are comparatively simple and can start operation within a short time. Considering high import dependency to energy resources, it is a totally domestic resource. The categorization of electricity generation from wind depends on average wind speed and height of hub. A speed of 6.5m/s is a medium level, 7.5 m/s is considered as good and above 8.5 m/s are the very good category of wind. It is accepted that wind plants with 5 MW capacity can be installed at 50 meters height with wind speed more than 7.5 m/s. According to Potential Wind Energy Map (REPA), the wind energy potential is 48,000 MW and 1.3% of the surface of Turkey is convenient for wind plants [59].

Wind plants has first been in service by 1998 with installed capacity of 8.7 MW and increased to 18.9 MW by 2004. The installed capacity was 2,260 MW in 2012

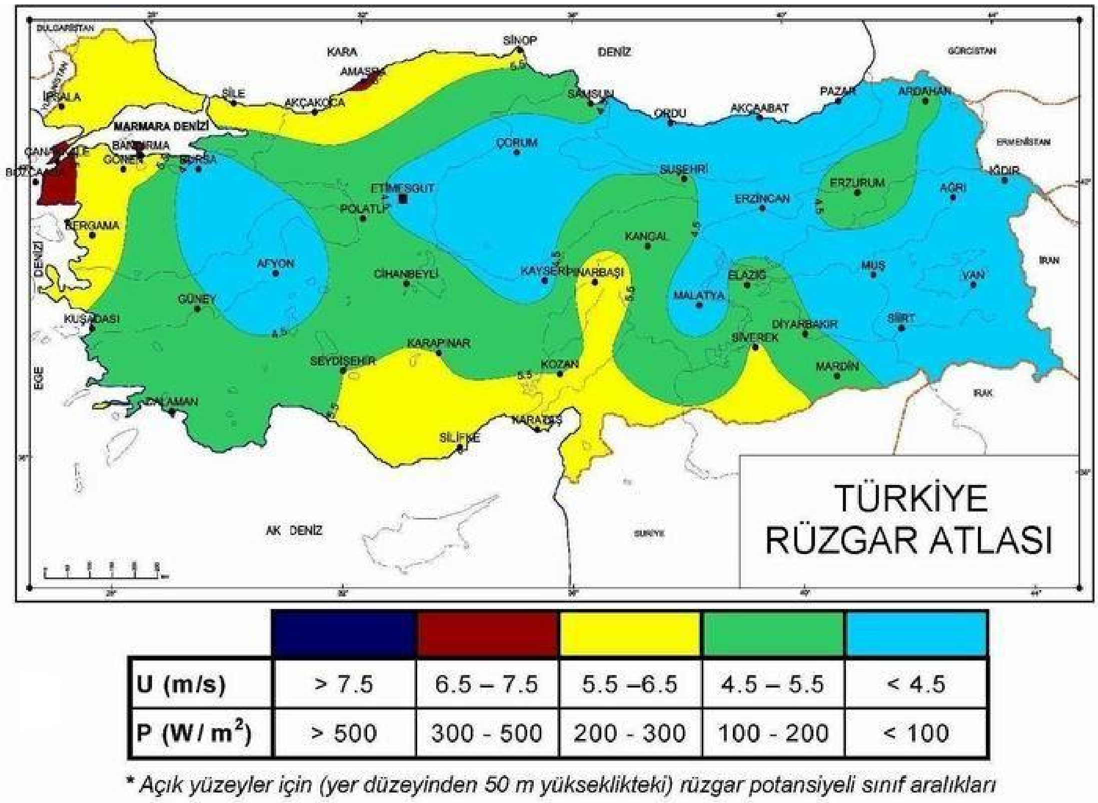
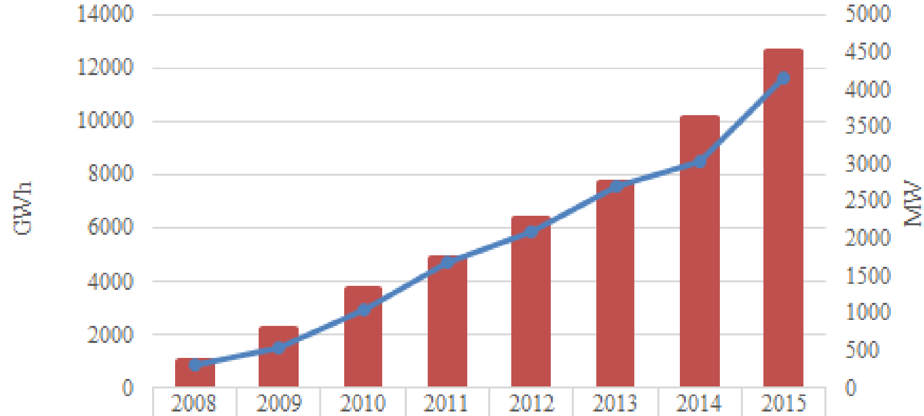


Figure 4.14: Wind speed map of Turkey [60]

and it has doubled in 2015 and reached to 4.5% of power generation. Detailed representation of installed capacity and power generation is shown in Figure 4.15.



	2008	2009	2010	2011	2012	2013	2014	2015
Installed Capacity (MW)	363.7	791.6	1320.2	1728.7	2260.6	2759.7	3629.7	4503.2
Power Generation (GWh)	847.0	1495.0	2916.0	4723.0	5860.0	7557.0	8520.0	11653.0
Share in Total Power Gen.	0.4%	0.8%	1.4%	2.1%	2.4%	3.1%	3.4%	4.5%

Figure 4.15: Development of installed capacity (MW) and power generation (GWh) for wind [19],[15]

There are onshore wind technologies with 8 m/s, 7.5 m/s, 7m/s, 6.5 m/s, 6 m/s, and 5.5 m/s and 5 m/s which are differs from each other with different availability factors, the technologies in higher wind speed locations have higher availability factor.

In order to generate a detailed supply of the wind in TIMES model, the map of wind speed in Figure 4.14 is investigated. Since the blue and green areas are not convenient for wind plants, a reference city is selected from the yellow area for a better representation of hourly wind speed. Since the installed power plants in 2012 are mostly located in İzmir, daily average wind speed of İzmir is analyzed between the years 2007 and 2014 and summarized for seasons. Then, the year 2008 which has the lowest mean absolute deviation was determined as a reference year to evaluate hourly wind speed data. After deciding to investigate İzmir 2008 data, hourly data was grouped into seasons for 24 hours and normalized. Hourly change in wind speed over seasons are summarized in Table 4.14. Then, the estimated wind distribution for weekday and weekends is implemented into the model as the availability of wind supply for each particular time-slice.

In these analyses, historical data of weatherunderground [61] has been utilized.

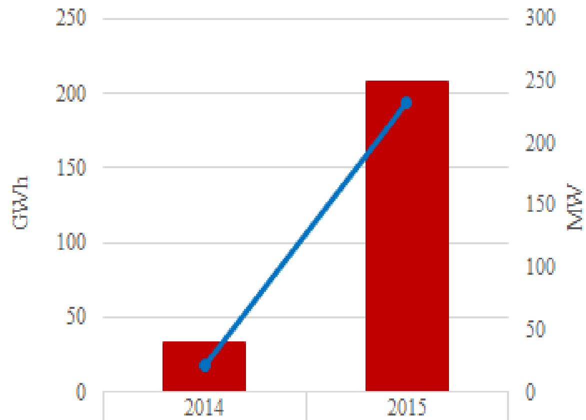
Table 4.14: Energy density distribution of wind for İzmir in 2008

	FALL	*SPRING*	*SUMMER*	*WINTER*
1	0.0065	0.0062	0.0100	0.0076
2	0.0067	0.0055	0.0096	0.0080
3	0.0067	0.0055	0.0096	0.0076
4	0.0063	0.0055	0.0096	0.0072
5	0.0058	0.0055	0.0096	0.0072
6	0.0060	0.0055	0.0096	0.0072
7	0.0060	0.0060	0.0096	0.0077
8	0.0062	0.0062	0.0112	0.0077
9	0.0070	0.0077	0.0132	0.0077
10	0.0087	0.0093	0.0145	0.0090
11	0.0104	0.0104	0.0153	0.0104
12	0.0115	0.0111	0.0161	0.0109
13	0.0122	0.0115	0.0171	0.0119
14	0.0131	0.0124	0.0179	0.0127
15	0.0140	0.0128	0.0183	0.0127
16	0.0144	0.0134	0.0188	0.0127
17	0.0143	0.0137	0.0196	0.0120
18	0.0136	0.0132	0.0196	0.0110
19	0.0118	0.0117	0.0196	0.0100
20	0.0103	0.0103	0.0176	0.0094
21	0.0096	0.0090	0.0152	0.0088
22	0.0088	0.0080	0.0136	0.0085
23	0.0078	0.0070	0.0116	0.0078
24	0.0070	0.0070	0.0106	0.0078

4.3.6 Solar

Solar energy is one of the clean energy types, and Turkey has a high solar energy potential because of its geographical location. Daily insolation rate is 7.5 hours/day and total insolation time is 2,737 hours and total solar energy is 1,527 kWh/m^2-year for Turkey.

In 2012, solar energy consumed in industrial and residential sectors accounted for 768 ktoe (32 PJ) [15] generated from solar collectors established in 18,640,000 m^2. Yet, there was no installed solar capacity for electricity generation. Installed capacity was 40.2 MW in 2014 and increased to 248.8 MW in 2015. The share of solar energy in electricity generation sector can be found in Figure 4.16.



	2014	2015
Installed Capacity (MW)	40.2	248.8
Power Generation (GWh)	17.4	194.1
Share in Total Power Gen.	0.01%	0.07%

Figure 4.16: Development of installed capacity (MW) and power generation (GWh) for solar [19],[15]

From the solar energy map (SEM-GEPA) in Figure 4.17, it is noticed that there are two solar regions: so-called blue region and orange region. To obtain appropriate daily solar data from both regions, regions separated by the median value of insolation time (hour/year) based on provinces level. The total solar potential of Turkey, 3,182 PJ/year, divided into the two regions with the ratio of areas. Then, the provinces that have a radiation value (KWh/m^2-year) near the average value of the region are taken as identifier provinces. The average hourly solar irradiance [62] of Giresun for the blue region and Tunceli for orange region summarized for seasons. Then, normalized solar pattern equally divided into hourly time-slices and implemented into the mode as illustrated in Figure 4.18 and Figure 4.19.

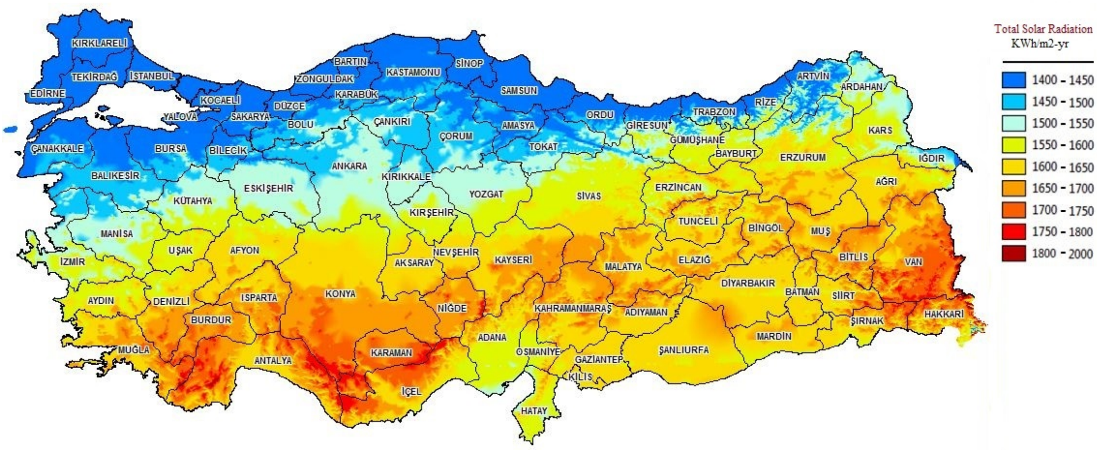


Figure 4.17: Solar energy map of Turkey [63]

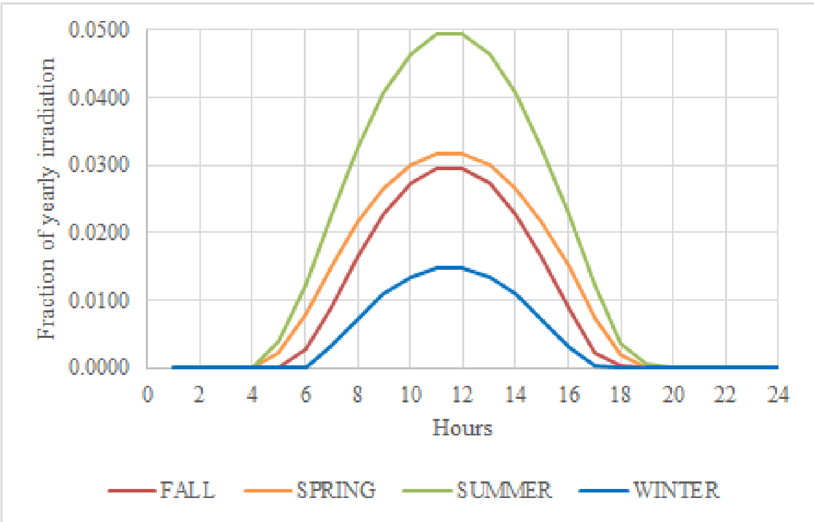


Figure 4.18: Hourly solar energy pattern of orange region

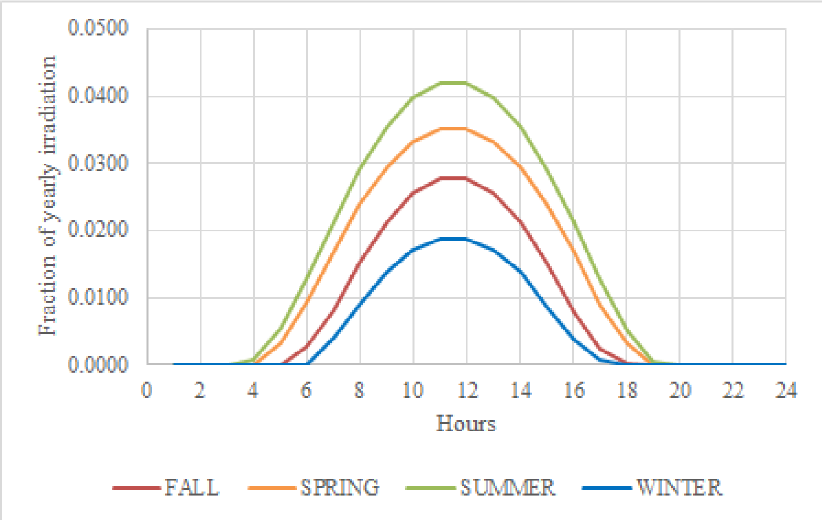
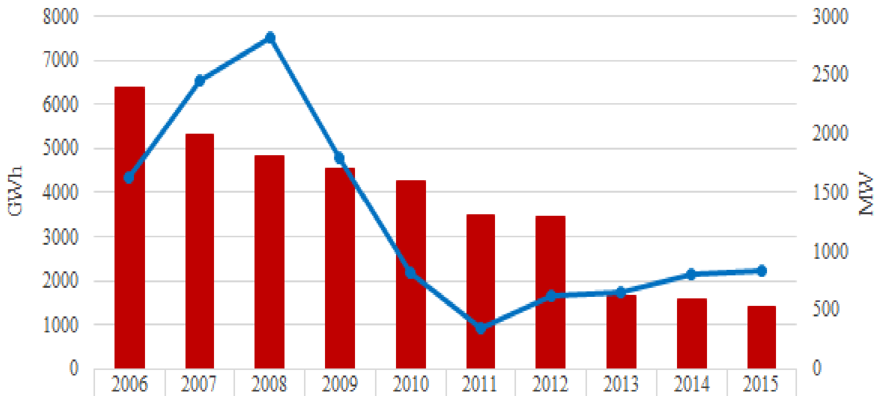


Figure 4.19: Hourly solar energy pattern of blue region

In the model, obtained solar energy supply from blue and orange regions consumed in electricity generation and residential water heating. There are one solar photo-voltaic and one solar thermal technology for electricity generation. Photo-voltaic technologies generated electricity directly from sunlight and required minimal maintenance. On the other hand, solar thermal concentrating solar power technologies obtain heat from solar energy and transform the heat into electricity. Investment cost for PVs is lower than thermal technologies and PVs have lower operating cost.

4.3.7 Liquid Fuels

Oil products used in various energy sectors such as transportation, agriculture and industry and fuel oil, diesel oil, LPG and naphtha are named as liquid fuels and used in power generation sector. Share of liquid fuels in electricity sector can be found in Figure 4.20. There are three type of liquid fuel technologies in the model, oil CHP, diesel power plant and RFO power plant.



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Installed Capacity (MW)	2396.5	2000.2	1818.6	1699.1	1593.3	1300.4	1285.5	616.3	594.9	522.7
Power Generation (GWh)	4,340.4	6,526.8	7,518.5	4,803.5	2,180.0	903.6	1,638.7	1,738.8	2,145.3	2,223.9
Share in Total Power Gen.	2.5%	3.4%	3.8%	2.5%	1.0%	0.4%	0.7%	0.7%	0.9%	0.8%

Figure 4.20: Development of installed capacity (MW) and power generation (GWh) for liquid fuels [19],[15]

4.3.8 Nuclear Power

In nuclear power plants, the nuclear energy released after fission and converted into heat then this heat converted into kinetic energy and finally electricity. There is no installed nuclear power plant in Turkey. Russia and Turkey have an agreement on cooperation for construction and operation of the first nuclear power plant in Mersin/Akkuyu. This nuclear power plant is planned to start up power generation by 2019 and it will have 4 units having a total capacity of 4,800 MW. Additionally, Turkey has signed an agreement with Japan for the planned second nuclear power plant construction in Sinop [64]. Approximately, 80 billion kWh electricity output will be generated per year from these two plants. By 2023, the two power plants are planned to be started up and the construction of a third nuclear power plant are to be started [20].

In the model, the nuclear power plant technology is closed for capacity investments until 2020 and set free in 2023-2050 period.

Chapter 5

Reference and Alternative Scenarios and Results

The TIMES model is run under several scenarios and the obtained results are compared. In all scenarios planning horizon of 2012 and 2050 is used and 2012 is the calibration year in the model. In the light of real data, electricity supply and demand, generation mix are calibrated to 2012. Since obtaining hourly historical data is not possible, annual data are considered in calibration. The defined time-slices and expansion of power generation sector are included in all scenarios. In this chapter, results are presented between 2012 and 2035 in order to the avoid end of horizon effect to the results.

5.1 Reference Scenario

The reference scenario is defined without any policy constraints and it reflects business as usual (BAU) and also called base scenario. The results of reference scenario and national energy forecasts or real data may not match because the reference scenario generates optimized results with a least cost solution [34]. There is no policy/regulation or restriction applied to this scenario and it is assumed this situation will last until the end of the modeling horizon.

As a result of the calibration, electricity generation values by sources and total generation are parallel to the real power generation value in 2012 and 2015, as shown in Table 5.1 and Table 5.2.

Table 5.1: The share of electricity generation by sources in base scenario and comparison with the real data of 2012

	2012-Real		2012-Model	
	Generation (PJ)	Share	Generation (PJ)	Share
Coal	119.97	13.91%	105.62	12.27%
Lignite	124.88	14.48%	138.69	16.11%
Liquid	5.90	0.68%	5.80	0.67%
Natural Gas	376.20	43.63%	376.46	43.73%
Hydro	208.31	24.16%	208.00	24.16%
Geothermal	3.24	0.38%	3.25	0.38%
Wind	21.10	2.45%	21.30	2.47%
Waste+Others	2.59	0.30%	1.81	0.21%
Gross Production	**862.19**		**860.936**	

Table 5.2: The share of electricity generation by sources in base scenario and comparison with the real data of 2015

	2015- Real		2015-Model	
	Generation (PJ)	Share	Generation (PJ)	Share
Coal	150.06	16.05%	147.00	15.70%
Lignite	112.15	11.99%	119.55	12.77%
Liquid	11.37	1.22%	9.50	1.01%
Natural Gas	353.50	37.80%	353.33	37.73%
Hydro	240.85	25.76%	240.00	25.63%
Geothermal	12.31	1.32%	12.00	1.28%
Wind	41.60	4.4%	42	4.49%
Renewable+Waste	13.24	1.42%	13.00	1.39%
Nuclear	0.00	0.00%	0.00	0.00%
Gross Production	**935.07**		**936.38**	

Looking at the big picture, gross power generation is expected to reach 1484 PJ by 72% (623 PJ) increase in 2023 and to grow 2,575 PJ by 199% (1713 PJ) increase in 2035 to meet the increasing demand of end-use sectors. As the main primary energy resource with the 43.7% share in 2012, natural gas share in production mix decrease to 21.4% and hard coal takes its place in 2023 with the share of 47.3%.

Renewables share (including hydro) in 2012 is accounted for 27% and dropped to 22% due to the decrease in the share of hydro to 19% although the generation amount is increased to 282 PJ. Hydro share is dropped to 11% by 2035. The biggest share of renewables after hydro belongs to the wind yet its share is decreasing in the following periods just as all the renewable energy shares are decreased.

The change in power generation amounts by primary energy sources are represented in Table 5.3 and their shares are illustrated in Figure 5.1.

Table 5.3: The electricity production mix for 2012-2035 in base scenario (PJ)

	2012	2015	2018	2020	2023	2025	2030	2035
Coal	105.6	147.0	172.0	192.0	701.2	802.4	1302.6	1697.3
Lignite	138.7	119.6	157.9	147.8	132.7	122.8	98.1	73.4
Liquid	5.8	9.5	5.0	4.5	4.1	3.3	2.5	1.7
Natural Gas	376.5	353.3	380.2	513.9	317.5	431.8	350.6	426.3
Hydro	208.0	240.0	282.7	282.7	282.7	282.7	282.4	282.2
Geothermal	3.3	12.0	8.2	8.2	8.2	8.3	8.3	8.5
Wind	21.3	42.0	28.9	30.1	30.1	30.1	94.5	78.2
Solar	0.2	7.3	7.3	7.3	7.3	7.2	7.2	7.2
Waste	1.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Production	**860.9**	**936.4**	**1042.1**	**1186.4**	**1483.8**	**1688.6**	**2146.1**	**2574.6**

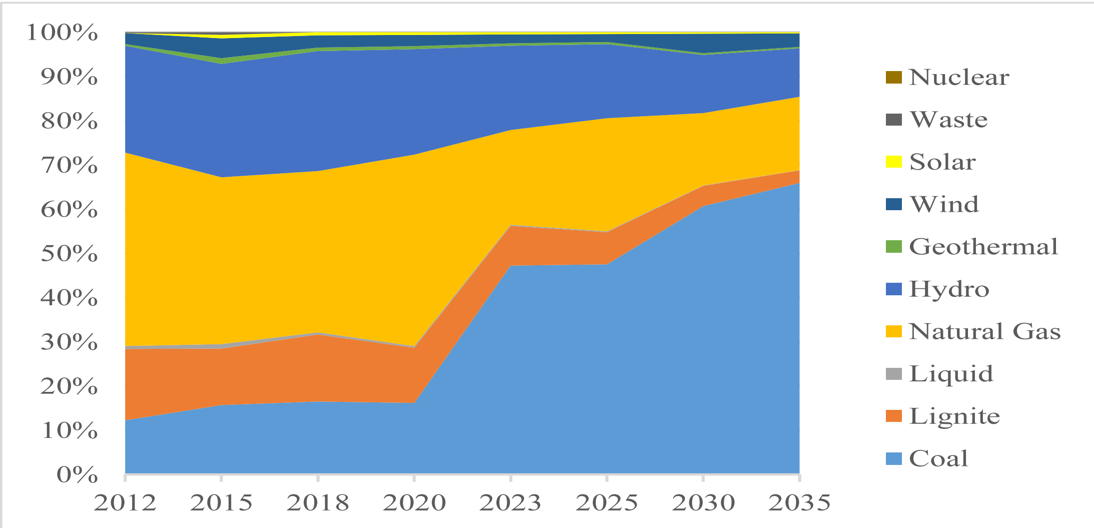


Figure 5.1: The electricity production mix share for 2012-2035 in base scenario

As a consequence of hourly time-slice resolution of the model, results also indicate hourly electricity generation by various technologies and consumption amounts as shown in Table 5.4 and Table 5.5.

Table 5.4: Example of change in total electricity generation (PJ) by a natural gas power plant in hourly time-slices in winter weekdays in 2035

Timeslice	Generation	Timeslice	Generation	Timeslice	Generation	Timeslice	Generation
WIWKH01	0.43	WIWKH07	0.83	WIWKH13	1.36	WIWKH19	1.36
WIWKH02	0.51	WIWKH08	1.36	WIWKH14	0.54	WIWKH20	1.36
WIWKH03	0.48	WIWKH09	1.36	WIWKH15	1.36	WIWKH21	1.36
WIWKH04	0.38	WIWKH10	1.36	WIWKH16	1.36	WIWKH22	1.36
WIWKH05	0.15	WIWKH11	1.36	WIWKH17	1.36	WIWKH23	1.36
WIWKH06	0.99	WIWKH12	1.36	WIWKH18	1.36	WIWKH24	1.36

Table 5.5: Example of change in total electricity consumption (PJ) by hourly time-slices in winter and summer weekdays in 2035

Time-slice	Consumption	Time-slice	Consumption	Time-slice	Consumption	Time-slice	Consumption
WIWKH01	17.8	WIWKH13	18.5	SUWKH01	10.4	SUWKH13	13.0
WIWKH02	17.8	WIWKH14	17.9	SUWKH02	10.4	SUWKH14	12.7
WIWKH03	17.8	WIWKH15	18.5	SUWKH03	10.4	SUWKH15	13.9
WIWKH04	17.7	WIWKH16	19.0	SUWKH04	10.5	SUWKH16	14.2
WIWKH05	17.5	WIWKH17	21.0	SUWKH05	10.6	SUWKH17	15.3
WIWKH06	18.2	WIWKH18	20.7	SUWKH06	10.6	SUWKH18	14.3
WIWKH07	18.1	WIWKH19	20.7	SUWKH07	10.6	SUWKH19	13.6
WIWKH08	18.5	WIWKH20	20.4	SUWKH08	10.6	SUWKH20	13.6
WIWKH09	18.5	WIWKH21	21.1	SUWKH09	10.9	SUWKH21	14.6
WIWKH10	20.1	WIWKH22	20.5	SUWKH10	13.4	SUWKH22	13.5
WIWKH11	19.6	WIWKH23	19.6	SUWKH11	13.5	SUWKH23	12.4
WIWKH12	18.7	WIWKH24	18.5	SUWKH12	13.1	SUWKH24	11.1

Distribution of the fuel consumption used to generate electricity shown in Table 5.6 and Figure 5.2 which is parallel to the production mix and dominated by hard coal in 2035. To meet demand, model chose to import high amount of coal instead of lignite since the domestic lignite resources are not enough. Detailed consumption shares of coal and lignite are also can be found in Figure 5.3 and Figure 5.4.

Table 5.6: Fuel consumption to electricity generation (PJ) in base scenario

	2012	2015	2018	2020	2023	2025	2030	2035
Coal	303.1	420.0	491.4	548.6	1868.9	2135.6	3478.5	4480.4
Lignite	401.8	341.9	451.4	422.3	379.3	350.8	280.2	209.7
Natural Gas	832.0	800.1	902.8	1211.0	789.0	981.8	789.0	912.0
Enriched Uranium (4.5%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	32.5	120.0	81.9	81.9	82.2	82.8	83.4	84.6
Municipal Solid Waste	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel	10.4	11.3	0.0	0.0	0.0	0.0	0.0	0.0
Residual fuel oil	14.0	28.0	19.8	17.8	16.5	13.2	9.9	6.6
Biomass	0.0	28.5	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	208.0	240.0	282.7	282.7	282.7	282.7	282.4	282.2
Solar	0.4	20.8	20.7	20.7	20.6	20.6	20.5	20.4
Wind	21.3	42.0	28.9	30.1	30.1	30.1	94.4	78.2
TOTAL	**1831.9**	**2052.6**	**2279.7**	**2615.2**	**3469.4**	**3897.7**	**5038.4**	**6074.1**

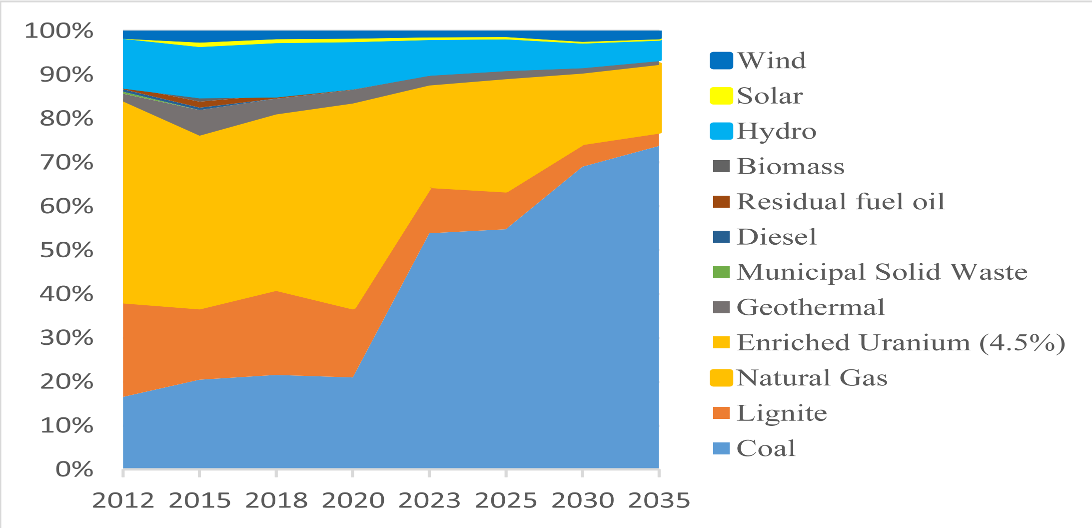


Figure 5.2: Fuel consumption shares of electricity generation in base scenario

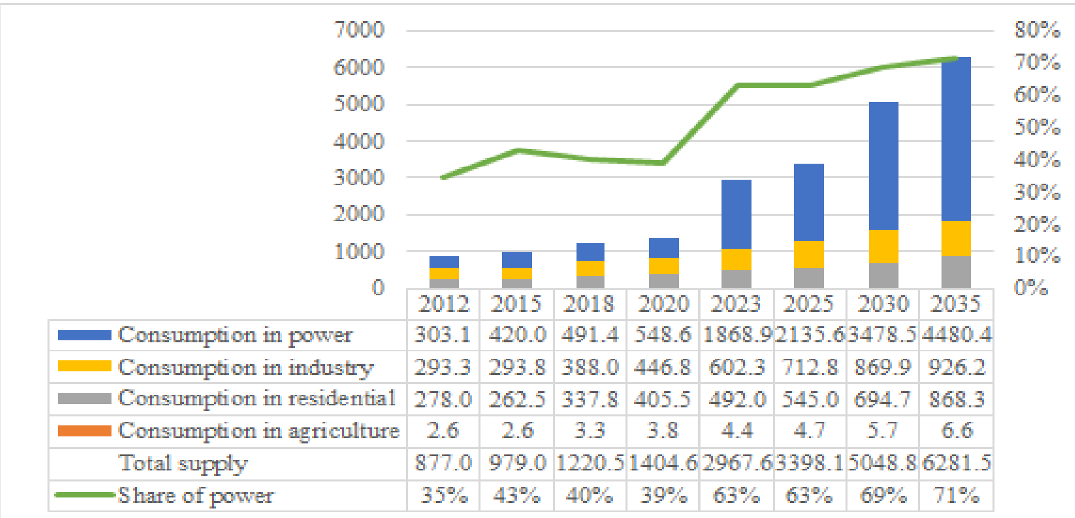
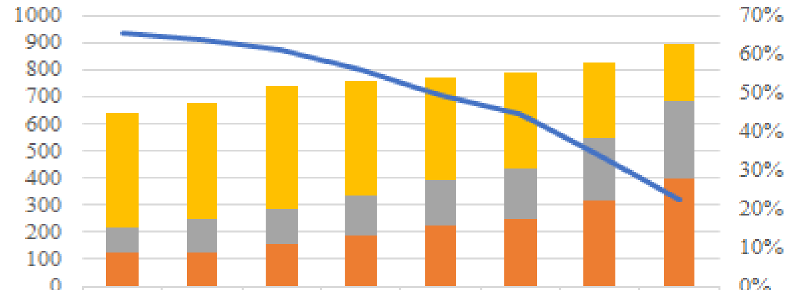
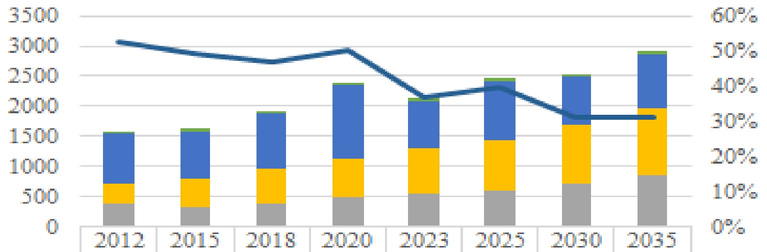


Figure 5.3: Hard coal supply and consumption by sources (PJ) in base scenario



	2012	2015	2018	2020	2023	2025	2030	2035
Consumption in power	419.0	431.6	451.4	422.3	379.3	350.8	280.2	209.7
Consumption in industry	93.6	124.5	132.8	150.2	166.8	188.4	229.8	289.6
Consumption in residential	126.0	122.7	154.0	184.9	224.5	248.6	316.7	396.1
Total supply	638.6	678.7	738.1	757.5	770.6	787.8	826.8	930.5
Share of power	66%	64%	61%	56%	49%	45%	34%	23%

Figure 5.4: Lignite supply and consumption by sources (PJ) in base scenario



	2012	2015	2018	2020	2023	2025	2030	2035
Consumption in refinery	38.8	42.5	42.9	46.7	52.3	59.1	53.4	39.6
Consumption in power	832.0	800.1	902.8	1211.0	789.0	981.8	789.0	912.0
Consumption in industry	341.3	465.8	586.5	661.0	764.6	837.5	984.8	1115.7
Consumption in residential	369.0	319.6	389.2	479.2	539.5	585.6	710.0	844.3
Consumption in agriculture	0.6	0.7	0.8	0.9	0.1	1.2	1.5	1.7
Total supply	1581.7	1628.5	1922.2	2398.8	2145.4	2465.2	2538.7	2913.3
Share of power	53%	49%	47%	50%	37%	40%	31%	31%

Figure 5.5: Natural gas supply and consumption by sources (PJ) in base scenario

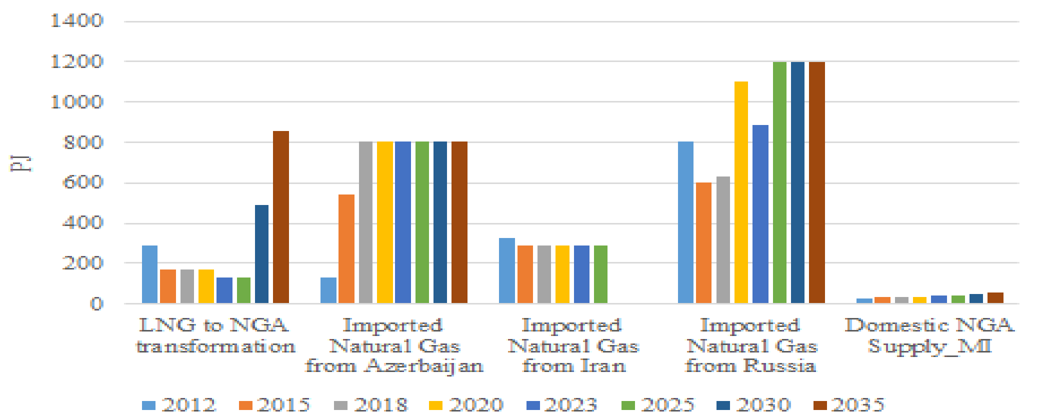


Figure 5.6: Natural gas supply by sources (PJ) in base scenario

Natural gas is consumed by power sector with around 50% share by 2023 and then decreased and consumption of natural gas is dominated by industry. After power residential natural gas consumption has a significant amount as illustrated in Figure 5.5. As mentioned before natural gas is supplied from four external and domestic sources with respect to the pipeline capacities, import prices and purchasing agreements. As a result of base scenario, natural gas import distributed as in Figure 5.6 and import capacity from Azerbaijan is fulfilled due to lower import prices and then, import from Russia preferred because of comparatively lower prices and than fulfilled. Domestic production is also gradually increased in the base scenario results.

Annual and seasonal electricity prices are calculated as the weighted average of marginal values of commodity balance constraint by time-slice proportion. Prices differs from each other in hourly basis as shown in Table 5.7. The average electricity prices are summarized for seasons and annual as $/Mwh in Figure 5.8. In general, electricity price is higher in winter season due to the high electricity consumption.

Table 5.7: Example of electricity price ($/MWh) by hourly time-slices in base scenario in 2035

Timeslice	Elc. Price	Timeslice	Elc. Price	Timeslice	Elc. Price	Timeslice	Elc. Price
FAWE1H01	63.00	FAWE1H07	63.00	FAWE1H13	102.64	FAWE1H19	102.64
FAWE1H02	63.00	FAWE1H08	63.00	FAWE1H14	63.26	FAWE1H20	102.64
FAWE1H03	63.00	FAWE1H09	63.00	FAWE1H15	102.64	FAWE1H21	102.64
FAWE1H04	40.65	FAWE1H10	102.64	FAWE1H16	102.64	FAWE1H22	102.64
FAWE1H05	24.34	FAWE1H11	102.64	FAWE1H17	102.64	FAWE1H23	102.64
FAWE1H06	63.00	FAWE1H12	102.64	FAWE1H18	102.64	FAWE1H24	63.00

Table 5.8: Average seasonal electricity price in base scenario ($/MWh)

$/Mwh	2018	2020	2023	2025	2030	2035
Annual	96.1	118.8	95.4	119.7	103.0	113.1
Fall	96.1	98.2	93.3	108.8	83.0	89.5
Spring	96.1	98.2	97.5	108.8	91.3	91.1
Summer	96.1	98.2	93.3	108.8	83.0	89.5
Winter	96.1	181.4	97.5	153.0	155.4	183.1

Electricity consumption by sectors is shown in Figure 5.7. Although industrial, residential and agricultural consumption have an increasing trend, transportation has no significant place in electricity consumption. Residential consumption is illustrated in Figure 5.8, and it is observed that the largest consumption share belongs to residential heating demand. That is the reason of the detailed representation of residential demand in the model with daily time-slice parameters.

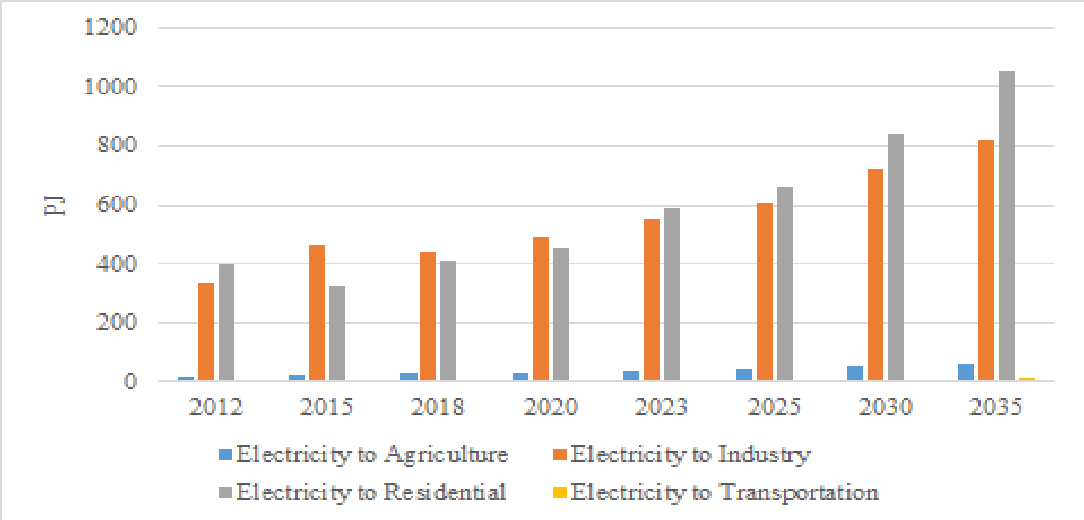


Figure 5.7: Electricity consumption by sectors (PJ) in base scenario

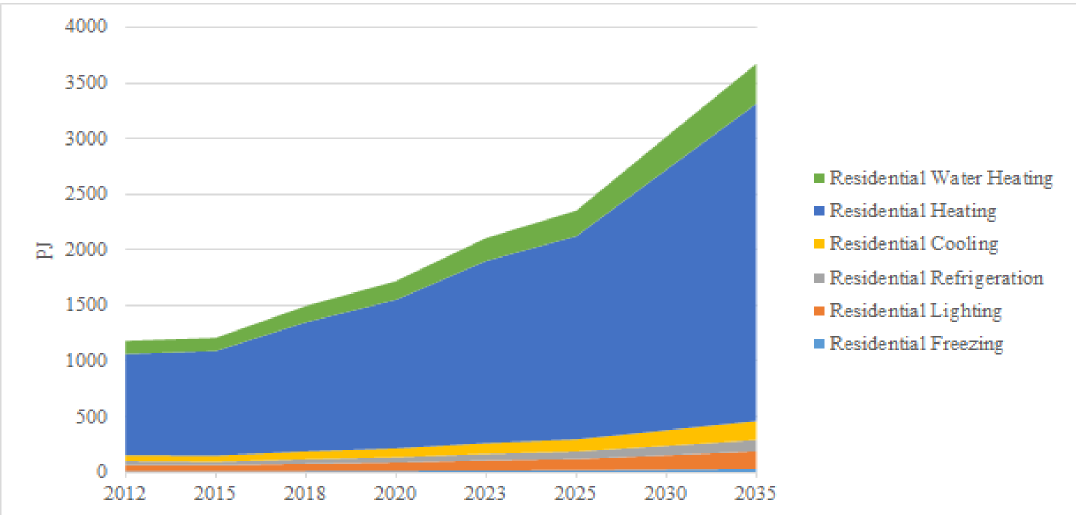


Figure 5.8: Residential sector demand distribution (PJ) in base scenario

In Table 5.9, real 2012 electricity load data summarized and colored as column based to compare model results. The electricity demand pattern of model in 2012 and 2015 based on hourly time-slices obtained as in the Table 5.10 and Table 5.11. Note that, only the residential sector has an hourly demand resolution and the demand of industrial, transportation and agricultural sectors have annual time-slices in the model. With a more detailed demand distribution of other sectors, the obtained demand distributions from base scenario can become more similar to the real electricity load distribution that shown in Figure 4.1. Besides, since the model is under various calibration constraints in the base year 2012, demand pattern is not distributed smoothly yet in 2015 it is more similar to the real demand pattern.

Table 5.9: Hourly total electricity demand pattern of 2012 based on real data

	2012 Real											
	FALL			*SPRING*			*SUMMER*			*WINTER*		
	WEEKDAY	*SATURDAY*	*SUNDAY*	*WEEKDAY*	*SATURDAY*	*SUNDAY*	*WEEKDAY*	*SATURDAY*	*SUNDAY*	*WEEKDAY*	*SATURDAY*	*SUNDAY*
1	0.0067	0.0014	0.0013	0.0067	0.0014	0.0013	0.0075	0.0015	0.0015	0.0070	0.0014	0.0014
2	0.0063	0.0013	0.0012	0.0063	0.0013	0.0012	0.0071	0.0015	0.0014	0.0065	0.0013	0.0013
3	0.0061	0.0012	0.0012	0.0061	0.0012	0.0012	0.0069	0.0014	0.0013	0.0062	0.0013	0.0012
4	0.0060	0.0012	0.0012	0.0059	0.0012	0.0011	0.0067	0.0014	0.0013	0.0061	0.0012	0.0012
5	0.0060	0.0012	0.0011	0.0059	0.0012	0.0011	0.0066	0.0013	0.0013	0.0061	0.0012	0.0011
6	0.0060	0.0012	0.0011	0.0059	0.0012	0.0011	0.0064	0.0013	0.0012	0.0062	0.0012	0.0011
7	0.0060	0.0012	0.0011	0.0059	0.0012	0.0011	0.0063	0.0013	0.0012	0.0064	0.0012	0.0011
8	0.0063	0.0012	0.0011	0.0064	0.0012	0.0011	0.0068	0.0013	0.0012	0.0067	0.0013	0.0011
9	0.0073	0.0014	0.0012	0.0074	0.0014	0.0011	0.0079	0.0015	0.0013	0.0077	0.0014	0.0012
10	0.0079	0.0015	0.0012	0.0081	0.0015	0.0012	0.0088	0.0017	0.0014	0.0084	0.0016	0.0013
11	0.0081	0.0016	0.0013	0.0083	0.0016	0.0013	0.0091	0.0017	0.0015	0.0087	0.0016	0.0013
12	0.0082	0.0016	0.0014	0.0083	0.0016	0.0013	0.0093	0.0018	0.0015	0.0087	0.0017	0.0014
13	0.0079	0.0015	0.0013	0.0079	0.0016	0.0013	0.0091	0.0017	0.0015	0.0083	0.0016	0.0014
14	0.0080	0.0015	0.0013	0.0080	0.0016	0.0013	0.0092	0.0017	0.0015	0.0085	0.0016	0.0014
15	0.0081	0.0015	0.0013	0.0081	0.0015	0.0013	0.0094	0.0017	0.0015	0.0085	0.0016	0.0014
16	0.0081	0.0015	0.0013	0.0080	0.0015	0.0013	0.0093	0.0017	0.0015	0.0085	0.0016	0.0014
17	0.0081	0.0015	0.0014	0.0079	0.0015	0.0013	0.0091	0.0017	0.0015	0.0087	0.0016	0.0014
18	0.0081	0.0015	0.0014	0.0078	0.0014	0.0013	0.0088	0.0016	0.0014	0.0089	0.0016	0.0015
19	0.0081	0.0015	0.0014	0.0077	0.0015	0.0013	0.0084	0.0016	0.0014	0.0087	0.0016	0.0015
20	0.0080	0.0015	0.0015	0.0078	0.0015	0.0014	0.0082	0.0016	0.0015	0.0084	0.0016	0.0015
21	0.0079	0.0015	0.0014	0.0080	0.0015	0.0015	0.0085	0.0016	0.0015	0.0082	0.0015	0.0015
22	0.0077	0.0015	0.0014	0.0079	0.0015	0.0014	0.0086	0.0016	0.0016	0.0080	0.0015	0.0015
23	0.0077	0.0015	0.0014	0.0078	0.0015	0.0014	0.0085	0.0016	0.0016	0.0081	0.0015	0.0015
24	0.0073	0.0014	0.0013	0.0075	0.0014	0.0014	0.0082	0.0016	0.0015	0.0077	0.0015	0.0014

Table 5.10: Hourly total electricity demand pattern of 2012 in base scenario

	2012 Model											
	FALL			SPRING			SUMMER			WINTER		
	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY
1	0.0052	0.0020	0.0020	0.0058	0.0015	0.0020	0.0051	0.0018	0.0015	0.0069	0.0016	0.0018
2	0.0049	0.0010	0.0010	0.0062	0.0012	0.0013	0.0052	0.0011	0.0020	0.0079	0.0020	0.0014
3	0.0051	0.0020	0.0020	0.0059	0.0015	0.0012	0.0050	0.0020	0.0010	0.0089	0.0015	0.0020
4	0.0052	0.0011	0.0013	0.0058	0.0019	0.0020	0.0047	0.0011	0.0018	0.0067	0.0016	0.0020
5	0.0053	0.0020	0.0011	0.0057	0.0012	0.0011	0.0051	0.0019	0.0012	0.0064	0.0020	0.0013
6	0.0055	0.0010	0.0020	0.0062	0.0014	0.0020	0.0050	0.0011	0.0010	0.0073	0.0017	0.0014
7	0.0053	0.0013	0.0011	0.0070	0.0018	0.0019	0.0049	0.0012	0.0019	0.0067	0.0015	0.0020
8	0.0049	0.0020	0.0015	0.0069	0.0013	0.0012	0.0051	0.0018	0.0011	0.0071	0.0020	0.0017
9	0.0055	0.0010	0.0020	0.0059	0.0018	0.0013	0.0057	0.0011	0.0019	0.0075	0.0016	0.0014
10	0.0097	0.0020	0.0012	0.0075	0.0014	0.0018	0.0068	0.0014	0.0014	0.0097	0.0020	0.0020
11	0.0061	0.0020	0.0020	0.0091	0.0019	0.0019	0.0072	0.0016	0.0018	0.0079	0.0016	0.0020
12	0.0067	0.0012	0.0014	0.0060	0.0015	0.0020	0.0068	0.0020	0.0014	0.0076	0.0020	0.0015
13	0.0058	0.0020	0.0018	0.0058	0.0012	0.0019	0.0098	0.0015	0.0020	0.0089	0.0018	0.0020
14	0.0055	0.0012	0.0013	0.0055	0.0020	0.0014	0.0067	0.0020	0.0015	0.0073	0.0015	0.0014
15	0.0062	0.0020	0.0014	0.0059	0.0014	0.0020	0.0090	0.0015	0.0014	0.0076	0.0020	0.0017
16	0.0097	0.0012	0.0020	0.0060	0.0013	0.0020	0.0076	0.0014	0.0019	0.0085	0.0016	0.0018
17	0.0098	0.0020	0.0016	0.0097	0.0015	0.0018	0.0083	0.0015	0.0019	0.0088	0.0020	0.0020
18	0.0068	0.0015	0.0020	0.0062	0.0020	0.0018	0.0073	0.0018	0.0020	0.0087	0.0020	0.0018
19	0.0067	0.0015	0.0014	0.0098	0.0015	0.0019	0.0071	0.0019	0.0014	0.0087	0.0021	0.0020
20	0.0076	0.0020	0.0020	0.0080	0.0018	0.0017	0.0081	0.0018	0.0017	0.0086	0.0019	0.0018
21	0.0083	0.0020	0.0020	0.0091	0.0019	0.0019	0.0090	0.0019	0.0019	0.0103	0.0021	0.0021
22	0.0079	0.0016	0.0016	0.0088	0.0019	0.0019	0.0084	0.0019	0.0017	0.0098	0.0020	0.0020
23	0.0076	0.0018	0.0020	0.0070	0.0020	0.0018	0.0077	0.0013	0.0018	0.0081	0.0020	0.0020
24	0.0059	0.0014	0.0011	0.0066	0.0012	0.0016	0.0059	0.0020	0.0018	0.0084	0.0020	0.0017

Table 5.11: Hourly electricity demand pattern of 2015 by all sectors in base scenario

	2015 Model											
	FALL			SPRING			SUMMER			WINTER		
	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY	WEEKDAY	SATURDAY	SUNDAY
1	0.0054	0.0011	0.0011	0.0070	0.0014	0.0014	0.0057	0.0011	0.0011	0.0082	0.0017	0.0017
2	0.0053	0.0011	0.0011	0.0070	0.0014	0.0014	0.0056	0.0011	0.0011	0.0083	0.0017	0.0017
3	0.0061	0.0011	0.0011	0.0071	0.0015	0.0014	0.0055	0.0011	0.0011	0.0083	0.0017	0.0017
4	0.0062	0.0011	0.0011	0.0071	0.0015	0.0014	0.0054	0.0011	0.0011	0.0082	0.0017	0.0017
5	0.0061	0.0011	0.0010	0.0071	0.0014	0.0014	0.0053	0.0010	0.0010	0.0082	0.0017	0.0017
6	0.0064	0.0011	0.0011	0.0074	0.0015	0.0014	0.0055	0.0011	0.0011	0.0084	0.0017	0.0018
7	0.0063	0.0011	0.0012	0.0072	0.0015	0.0014	0.0054	0.0010	0.0011	0.0084	0.0017	0.0017
8	0.0056	0.0011	0.0011	0.0072	0.0015	0.0014	0.0059	0.0011	0.0011	0.0086	0.0018	0.0018
9	0.0057	0.0012	0.0011	0.0071	0.0014	0.0014	0.0062	0.0012	0.0012	0.0086	0.0018	0.0018
10	0.0070	0.0014	0.0014	0.0082	0.0016	0.0016	0.0076	0.0015	0.0015	0.0096	0.0020	0.0020
11	0.0069	0.0014	0.0014	0.0079	0.0016	0.0014	0.0077	0.0015	0.0015	0.0095	0.0019	0.0019
12	0.0067	0.0013	0.0013	0.0067	0.0015	0.0013	0.0076	0.0015	0.0015	0.0091	0.0019	0.0018
13	0.0066	0.0013	0.0013	0.0066	0.0013	0.0013	0.0076	0.0015	0.0015	0.0089	0.0018	0.0018
14	0.0063	0.0013	0.0013	0.0064	0.0013	0.0013	0.0074	0.0015	0.0014	0.0087	0.0018	0.0018
15	0.0067	0.0013	0.0013	0.0068	0.0013	0.0013	0.0079	0.0015	0.0015	0.0091	0.0019	0.0018
16	0.0068	0.0014	0.0013	0.0069	0.0014	0.0013	0.0080	0.0016	0.0016	0.0092	0.0019	0.0019
17	0.0073	0.0015	0.0015	0.0073	0.0015	0.0014	0.0085	0.0017	0.0017	0.0100	0.0020	0.0020
18	0.0072	0.0015	0.0014	0.0070	0.0014	0.0014	0.0081	0.0016	0.0016	0.0099	0.0020	0.0020
19	0.0072	0.0014	0.0014	0.0072	0.0014	0.0016	0.0078	0.0015	0.0015	0.0099	0.0020	0.0020
20	0.0070	0.0014	0.0014	0.0081	0.0016	0.0016	0.0078	0.0015	0.0015	0.0097	0.0020	0.0020
21	0.0075	0.0015	0.0015	0.0087	0.0017	0.0018	0.0081	0.0016	0.0016	0.0102	0.0021	0.0021
22	0.0071	0.0014	0.0014	0.0084	0.0017	0.0017	0.0076	0.0015	0.0015	0.0098	0.0020	0.0020
23	0.0067	0.0013	0.0013	0.0081	0.0016	0.0016	0.0071	0.0014	0.0014	0.0094	0.0019	0.0019
24	0.0062	0.0012	0.0012	0.0077	0.0015	0.0016	0.0065	0.0013	0.0013	0.0090	0.0018	0.0018

In base scenario, the total CO_2 emission is 349 Mton in 2012 and is almost doubled in 2023 and expected to reach 1,076 Mton which is three times of 2012 value in 2035. The highest share of the total CO_2 emission arises from the electricity sector. In 2012, power generation sector covers the 36.5% of total CO_2 emission with 128 Mton CO_2 and increased to 46% as 494 Mton CO_2 in 2035. The main reason for the high emission amounts is the electricity generation sector are based on fossil fuels in base scenario. The second highest emission is derived from industrial sector with the share of 21.6% in 2012 and it increased to 23.4% in 2020 which is the maximum share of industrial sector through the years due to a slow increasing rate of electricity sector emissions between 2015 and 2020. Transportation sector covers the 19% of total emissions in 2012 and its increasing share starts decreasing after 2023 and accounts for 12.3% in 2035. Residential sector also has the 18.3% share in 2012 and 16.8% in 2035. Refineries have a range of 2 to 5% share which reaches the maximum share in 2018 and then decreasing. The share of agriculture is around 1% in the time horizon. Total CO_2 emission through years and CO_2 emissions of all sectors can be found in Table 5.12.

Table 5.12: Emissions of sectors and total CO_2 emission (kt) of the base scenario

FIT_S	2012	2015	2018	2020	2023	2025	2030	2035
Total Carbon dioxide Emissions	349,456	383,766	444,065	495,573	630,019	705,453	892,464	1,035,350
CO2 from Agriculture	3,255	3,594	4,544	5,142	5,961	6,522	8,028	9,444
CO2 from Industry	75,324	86,415	104,555	119,992	148,400	168,692	207,704	237,859
CO2 from Electricity Sector	127,507	138,269	145,098	155,150	226,504	257,807	368,073	453,522
CO2 from Refineries	12,795	14,011	23,390	25,497	28,532	31,011	29,143	21,599
CO2 from the Residential Sector	63,889	58,934	74,865	89,354	106,093	116,764	146,540	180,501
CO2 from Transportation Sector	66,686	76,163	91,614	100,437	114,529	124,657	132,977	132,425

In TIMES model investment decisions are made based on to reach minimum annualized total cost, and the system cost consists of annual investment cost, fixed operation and management cost, flow cost (including import and export prices), activity cost and flow taxes and subsidies. There is no subsidy or tax in the base scenario. Total cost is expected to be doubled by 2023. Investment costs constitute about 67% of total costs in 2023.

5.2 Policy Scenarios

Two related scenario groups applied into the model and results are compared in the following subsections.

5.2.1 Government Incentive Scenarios

The renewable energy law no:5346 on utilization of renewable energy sources for the purposes of generating electrical energy introduces incentives for domestic energy projects, providing feed-in-tariffs for electricity from renewable energy sources. The aims of this law are increasing the share of electricity generated from the renewable energy resources, reducing the import dependency on fuels and environment protection by producing clean energy [65]. The law became valid in 2005 and regulated with the decree no: 2013/5625 by the Council of Ministers. Feed-in tariff is applicable for ten years after the generation facility becomes operational by the end of 2020. This law provides investors a financial support as generated energy will be sold at the price that feed-in tariff indicates in Table 5.13.

Table 5.13: Feed-in tariffs for energy produced by generation facilities based on renewable energy resources, Law no: 5346 [65]

Type of Production Facility Based on Renewable Energy Resources	Prices Applicable (USD cent/kWh)
a. Hydroelectric production facility	7.3
b. Wind power based production facility	7.3
c. Geothermal power based production facility	10.5
d. Biomass based production facility (including landfill gas)	13.3
e. Solar power based production facility	13.3

The feed-in tariff scenarios and the assumptions are explained in the following subsections.

5.2.1.1 Solar Incentive Scenario

In the solar incentive scenario (FIT_S), feed-in tariff is applied just for solar technology investments. To insert the incentives into the model, the PV and thermal solar technologies are replicated with different start years. Briefly, new defined technologies are available for investment in 2015, 2018, 2020 and the years after 2023, respectively. The reason to do that, a solar technology invested in 2015, 2018 and 2020 gets a flow subsidy for 10 years with the rate of 13.3 USD cent/kWh, yet the others invested after 2020 does not. The technology invested in 2015 gets flow subsidy to 2025, but technology invested in 2018 gets flow subsidy to 2030 in the model because there is no milestone year of 2028 in the model. Again, the technology invested in 2020 gets flow subsidy to 2030. Under the assumptions of base scenario, solar incentive included to the model to examine how much solar energy technology investment will be done and how much carbon dioxide emission would decrease in response to the increasing renewable energy in production mix.

The main primary energy resource with the 43.7% share in 2012, natural gas share in production mix decrease to 21.6% and hard coal takes its place in 2023 with the share of 36.5%. Renewables share (including hydro) in 2012 is accounted for 27% and increased to 38.8% due to the increase in the share of solar to 13.4% in 2020. Hydro share is dropped to 11% by 2035. The biggest share in renewables after hydro belongs to the solar as 10.7% in 2020 and then decreasing in the following periods. Since the total electricity production does not change significantly, increasing share of solar energy compensated by a decrease in natural gas in 2018 and decrease in coal in 2023, in the production mix.

The detailed power generation by primary energy resources is represented in Table 5.14 and fuel shares are shown in Figure 5.9.

Table 5.14: The electricity production mix for 2012-2035 in FIT_S scenario (PJ)

	2012	2015	2018	2020	2023	2025	2030	2035
Coal	102.0	147.0	172.0	192.0	541.6	638.2	1158.9	1505.4
Lignite	142.3	119.5	157.9	147.8	132.7	122.8	98.1	73.4
Liquid	5.8	9.5	5.0	4.5	4.1	3.3	2.5	1.7
Natural Gas	376.5	353.3	325.6	381.5	319.6	439.5	348.1	469.4
Hydro	208.0	240.0	282.7	265.0	282.7	282.7	281.5	281.6
Geothermal	3.3	12.0	8.2	8.2	8.2	8.3	8.3	8.5
Wind	21.3	42.0	28.9	28.9	35.8	35.8	94.5	78.2
Solar	0.2	7.3	91.4	158.3	158.3	158.3	158.3	158.2
Waste	1.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Production	**860.9**	**936.4**	**1071.6**	**1186.1**	**1483.0**	**1688.9**	**2150.1**	**2576.4**

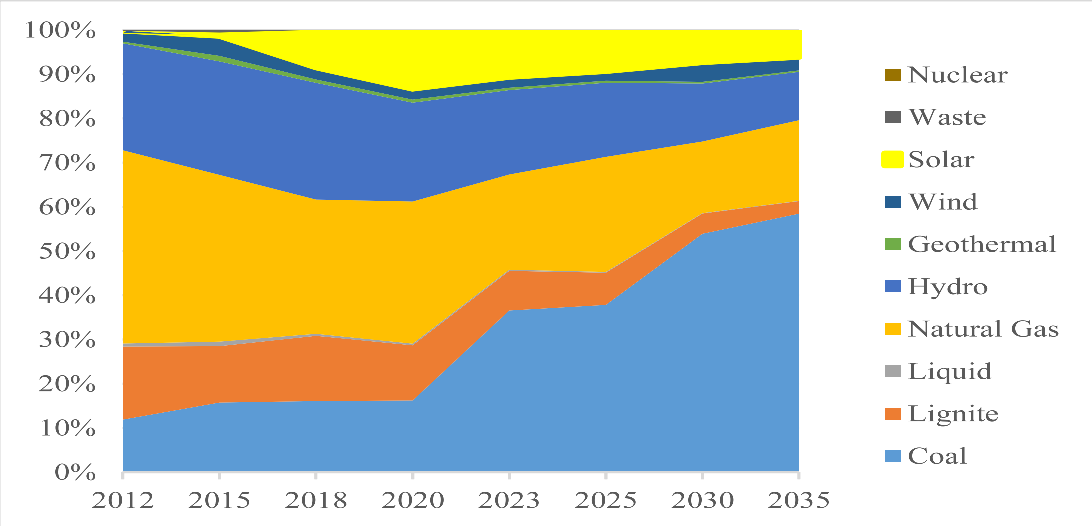
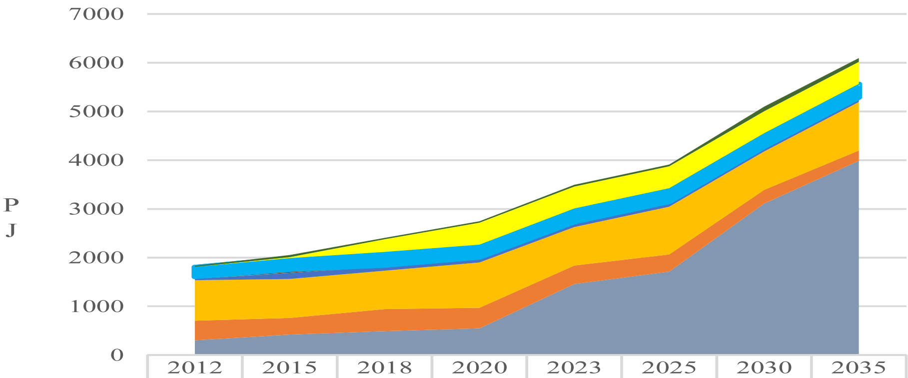


Figure 5.9: The electricity production mix share for 2012-2035 in FIT_S scenario

Annual average electricity prices are decreased by 34.8% in 2018 and 1.21% in 2023 comparing to the base scenario. Seasonal prices also decrease comparing to the base scenario except winter. In winter while prices are decreased by 33.3% in 2018 and 16.7% in 2020, between 2023 and 2030 increase in prices is observed with the rate of 34.9%, 10.6%, and 3.4%, respectively. That case can be expressed with capacity poorness caused by the increased share of solar energy which has a limited availability in winter, in production mix. Average electricity prices are summarized in Table 5.15.

Table 5.15: Average seasonal price of electricity in FIT_S scenario ($/MWh)

($/MWh)	2018	2020	2023	2025	2030	2035
Annual	62.67	109.56	94.21	119.03	102.77	112.99
Fall	62.51	96.09	81.75	101.74	81.01	88.82
Spring	64.08	98.20	82.39	104.13	89.27	92.91
Summer	60.03	93.41	81.75	101.74	81.01	88.82
Winter	64.08	151.16	131.49	169.25	160.64	182.44



	2012	2015	2018	2020	2023	2025	2030	2035
Wind	21.3	42.0	28.9	28.9	35.8	35.8	94.4	78.2
Solar	0.4	20.8	260.3	450.8	450.7	450.7	450.6	450.6
Hydro	208.0	240.0	282.7	265.0	282.7	282.7	281.5	281.6
Biomass	-	28.5	-	-	-	-	-	-
Residual fuel oil	14.0	28.0	19.8	17.8	16.5	13.2	9.9	6.6
Diesel	10.4	11.3	-	0.0	0.0	0.0	0.0	0.0
Municipal S.Waste	8.3	-	-	-	-	-	-	-
Geothermal	32.5	120.0	81.9	81.9	82.2	82.8	83.4	84.6
Enriched Uranium	-	-	-	-	-	-	-	-
Natural Gas	832.0	800.1	789.0	930.5	789.0	980.0	789.0	996.9
Lignite	401.8	341.9	451.4	422.3	379.3	350.8	280.2	209.7
Coal	303.1	420.0	491.4	548.6	1,458.7	1,713.7	3,109.0	3,987.7
TOTAL	1,831.9	2,052.6	2,405.4	2,745.8	3,494.9	3,909.8	5,098.2	6,095.9

Figure 5.10: Fuel consumption to electricity generation (PJ) in FIT_S scenario

The natural gas consumption for the electricity generation decreases about 113 PJ in 2018 and 281 PJ in 2020 in FIT_S scenario comparing to the base scenario. Additionally, coal consumption decreases by 410 PJ in 2023. Change in primary energy consumption for electricity generation is presented in Figure 5.10.

The carbon dioxide emissions in FIT_S scenario are affected by the decreasing share of fossil fuels and the increasing share of solar energy in electricity production mix. The total CO_2 emission is decreased by 1.4% in 2018 and 5.6% in 2023 comparing to the base scenario. The highest share of the total carbon dioxide emission arises from the electricity sector as in the base scenario. Yet, its emission decreases with 4.4% in 2018 and decreases from 264,651 kt to 226,504.1 kt with a 14.4% rate in 2023 comparing to the base scenario. The second highest emission is derived from industrial sector with the share of 21.6% in 2012 and it increased to 24.2% in 2020 which is the maximum share of industrial sector through the years. Emissions of industrial sector are slightly increased comparing to the base scenario. Transportation sector covers the 19% of total emissions in 2012 and its increasing share starts diminishing after 2018 and accounts for 12.8% in 2035. Refineries have a range of 2 to 5% share which reaches the maximum share in 2018 and then decreasing. The share of agriculture sector is around 1% in the time horizon. Total carbon dioxide emission through years and carbon dioxide emissions of all sectors can be found in Table 5.16.

Table 5.16: Emissions of sectors and total carbon dioxide emission (kt) of the FIT_S scenario

FIT_S	2012	2015	2018	2020	2023	2025	2030	2035
Total Carbon dioxide Emissions	349,456	383,766	444,065	495,573	630,019	705,453	892,464	1,035,350
CO2 from Agriculture	3,255	3,594	4,544	5,142	5,961	6,522	8,028	9,444
CO2 from Industry	75,324	86,415	104,555	119,992	148,400	168,692	207,704	237,859
CO2 from Electricity Sector	127,507	138,269	145,098	155,150	226,504	257,807	368,073	453,522
CO2 from Refineries	12,795	14,011	23,390	25,497	28,532	31,011	29,143	21,599
CO2 from the Residential Sector	63,889	58,934	74,865	89,354	106,093	116,764	146,540	180,501
CO2 from Transportation Sector	66,686	76,163	91,614	100,437	114,529	124,657	132,977	132,425

The total system cost with subsidies decreased less than the incentive amount in FIT_S scenario due to the increased investment, activity, flow, and fixed costs. Received subsidies substracted from total cost for related years in objective function between 2015 and 2030. But the total cost without subsidy substraction is increased by 0.04% to 0.05% comparing to the base scenario after 2018.

5.2.1.2 Wind Incentive Scenario

In the wind incentive scenario (FIT_W) feed-in tariff is applied just for wind technology investments. To insert the incentives into the model, all wind technologies are replicated with different start years. Briefly, new defined technologies are available for investment in 2015, 2018, 2020 and the years after 2023, respectively. The reason to do that, a wind technology invested in 2015, 2018 and 2020 gets a flow subsidy for 10 years with the rate of 7.3 USD cent/kWh, yet the others invested after 2020 does not. The technology invested in 2015 gets flow subsidy to 2025, but technology invested in 2018 gets flow subsidy to 2030 in the model because there is no milestone year of 2028 in the model. Again, the technology invested in 2020 gets flow subsidy to 2030. Under the assumptions of base scenario, wind incentive included to the model to examine how much wind energy technology investment will be done and how much carbon dioxide emission would decrease in response to the increasing renewable energy in production mix.

The main primary energy resource with the share of 43.7% share in 2012, natural gas share in production mix decrease to 30.6% in 2018 while it is 36.5% in the base scenario. This share replaced with the production from wind technologies and their shares increase 6% in the production mix and reach 9.9% in 2018 and 15% in 2020. Coal takes the first place in production mix in 2023 and remains as the dominant fuel by 2035 yet its share is 37.5% in FIT_W scenario while it is 47.3% in the base scenario. Wind share starts decreasing after 2023. Hydro has the highest share of renewables but decreases as 1% from the base scenario in 2018 and 2020 then reach the amount in the base scenario again.

The detailed power generation amounts by primary energy resources are summarized in Table 5.17 and fuel shares are shown in Figure 5.11.

	2012	2015	2018	2020	2023	2025	2030	2035
Coal	102.0	147.0	172.0	192.0	559.7	642.2	1211.9	1672.9
Lignite	142.3	119.6	157.9	147.8	132.7	122.8	98.1	73.4
Liquid	5.8	9.5	5.0	4.5	4.1	3.3	2.5	1.7
Natural Gas	376.5	353.3	325.6	394.6	317.5	443.9	354.6	364.5
Hydro	208.0	240.0	282.7	265.0	282.7	282.7	282.6	282.5
Geothermal	3.3	12.0	8.2	8.2	8.2	8.3	8.3	8.5
Wind	21.3	42.0	105.1	179.6	179.6	179.6	179.6	163.3
Solar	0.2	7.3	7.3	7.3	7.3	7.2	7.2	7.2
Waste	1.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Production	**860.9**	**936.4**	**1063.7**	**1198.9**	**1491.8**	**1690.1**	**2144.8**	**2574.0**

Table 5.17: The electricity production mix for 2012-2035 in FIT_W scenario (PJ)

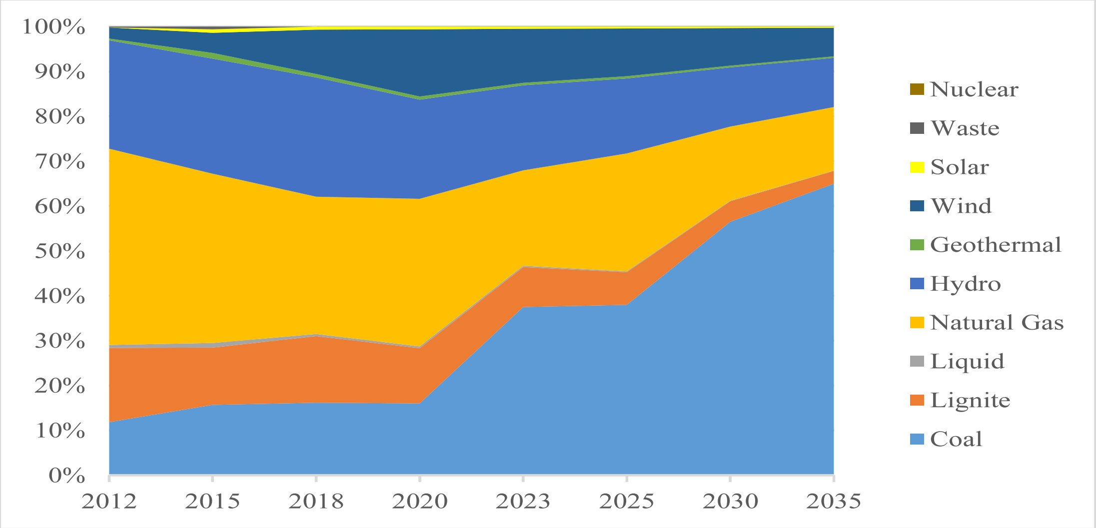


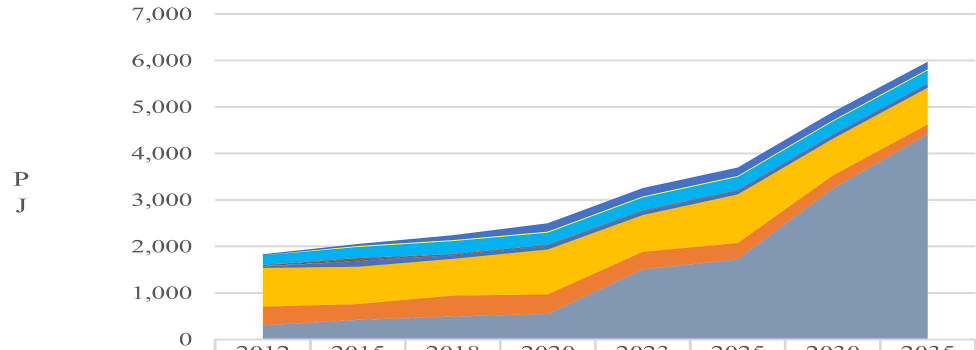
Figure 5.11: The electricity production mix share for 2012-2035 in FIT_W scenario

Annual electricity prices are decreased by 22.8% in 2018 and 17.3% in 2020 comparing to the base scenario. Then, there is no significant change after 2020. This is because of the wind share in electricity production mix is increased in 2018 and 2020 and subsidy received. Since the received subsidy is decreasing with the decrease in wind share in increasing electricity generation, the transition to the other technologies wipes off the decrease in prices. Since the wind technologies are available in winter there is no price increment observed in winter. Average electricity prices are summarized in Table 5.18.

Table 5.18: Average seasonal price of electricity in FIT_W scenario

$/Mwh	2018	2020	2023	2025	2030	2035
Annual	74.16	98.20	95.59	120.95	103.23	113.32
Fall	74.16	98.20	95.59	120.95	85.56	92.12
Spring	74.16	98.20	95.59	120.95	94.86	96.13
Summer	74.16	98.20	95.59	120.95	85.56	92.12
Winter	74.16	98.20	95.59	120.95	147.57	173.79

Natural gas consumption for electricity generation decreases about 113 PJ in 2018 and 249 PJ in 2020 in FIT_W scenario comparing to the base scenario. Additionally, coal consumption decreases by 364 PJ in 2023. Change in primary energy consumption for electricity generation can be found in Figure 5.12.



	2012	2015	2018	2020	2023	2025	2030	2035
Wind	21.3	42.0	105.1	179.6	179.6	179.6	179.6	163.3
Solar	0.4	20.8	20.7	20.7	20.6	20.6	20.5	20.4
Hydro	208.0	240.0	282.7	265.0	282.7	282.7	282.6	282.5
Biomass	-	28.5	-	-	-	-	-	-
Residual fuel oil	14.0	28.0	19.8	17.8	16.5	13.2	9.9	6.6
Diesel	10.4	11.3	-	-	-	-	0.0	0.0
Municipal S. Waste	8.3	-	-	-	-	-	-	-
Geothermal	32.5	120.0	81.9	81.9	82.2	82.8	83.4	84.6
Enriched Uranium	-	-	-	-	-	-	-	-
Natural Gas	832.0	800.1	789.0	962.5	789.0	1,043.8	789.0	789.0
Lignite	401.8	341.9	451.4	422.3	379.3	350.8	280.2	209.7
Coal	303.1	420.0	491.4	548.6	1,505.3	1,724.2	3,245.0	4,416.9
TOTAL	1,831.9	2,052.6	2,242.1	2,498.5	3,255.3	3,697.7	4,890.3	5,973.1

Figure 5.12: Fuel consumption to electricity generation (PJ) in FIT_W scenario

The carbon dioxide emissions in FIT_W scenario are affected by the decreasing share of fossil fuels and the increasing share of wind energy in electricity production mix. The total CO_2 emission is decreased by 1.3% in 2018 and 5.2% in 2023 comparing to the base scenario. The highest share of the total carbon dioxide emission arises from the electricity sector as in the base scenario. Yet, its emission decreases with 4.4% in 2018 and decreases from 264,651 kt to 230,839 kt with a 12.7% rate in 2023 comparing to the base scenario. The second highest emission is derived from industrial sector with the share of 21.6% in 2012 and it increased to 24.2% in 2020 which is the maximum share of industrial sector through the years. Emissions of industrial sector are slightly decreased comparing to the base scenario.Transportation sector covers the 19% of total emissions in 2012 and its increasing share starts diminishing after 2020 and accounts for 12.5% in 2035. Residential sector also has the 18.3% share in 2012 and 17% in 2035. Refineries have a range of 2 to 5% share which reaches the maximum share in 2018 and then decreasing. The share of agriculture sector is around 1% in the time horizon. Total carbon dioxide emission through years and carbon dioxide emissions of all sectors can be found in Table 5.19.

Table 5.19: Emissions of sectors and total carbon dioxide emission (kt) of the FIT_W scenario

FIT_W	2012	2015	2018	2020	2023	2025	2030	2035
Total Carbon dioxide Emissions	349,456	383,766	444,507	494,820	633,160	709,831	903,821	1,062,694
CO2 from Agriculture	3,255	3,594	4,544	5,142	5,961	6,522	8,028	9,444
CO2 from Industry	75,324	86,415	105,025	119,908	147,835	168,386	206,417	237,382
CO2 from Electricity Sector	127,507	138,269	145,098	157,013	230,839	262,491	380,718	481,343
CO2 from Refineries	12,795	14,011	23,390	25,490	28,524	31,011	29,143	21,599
CO2 from the Residential Sector	63,889	58,934	74,837	86,829	105,471	116,764	146,539	180,501
CO2 from Transportation Sector	66,686	76,163	91,614	100,437	114,529	124,657	132,977	132,425

The total system cost with subsidies decreased less than the incentive amount in FIT_W scenario due to the increased investment, activity, flow, and fixed costs. Received subsidies substracted from total cost for related years in objective function between 2018 and 2030. Subsidy amount is doubled in 2020 then start decreasing. But the total cost without extraction of subsidy increased by 0.05% to 0.08% comparing to the base scenario between 2018 and 2025.

5.2.1.3 Solar and Wind Incentive Scenario

In the solar and wind incentive scenario (FIT_WS), feed-in tariff is applied both for the solar and the wind technology investments. The same implementation mentioned before is exercising. Under the assumptions of base scenario, solar and wind incentives included to the model to examine how much solar and wind energy technology investment will be done and how much carbon dioxide emission would decrease in response to the increasing renewable energy in production mix.

Total electricity production increased 4.4% in 2018 and 6.6% in 2020. The natural gas which has the 43.7% share in 2012 in production mix, decreases to 29.9% in 2018 while it is 36.5% in the base scenario and then decreases to 24.6% in 2020. The coal takes its dominant place in 2023 increasing to 26.9% which is comprising the generation 301 PJ less than the base scenario. The share of hydro drops to 21% in 2020 while it is 23.8% in the base scenario. The highest share in renewables after hydro belongs to the solar energy which increases to 14.2% in 2020 and the wind follows with a share of 12.6% in 2020, as expected. Then both of the wind and the solar shares start decreasing and while their production amount remains stable. In 2018, the production of solar and wind get balanced with the decrease of natural gas and a small proportion of lignite and also cause a 46 PJ increase in total production yet the production from both technologies does not reach the same amounts which they account in single feed in tariffs (FIT_S and FIT_W) in the FIT_WS scenario.

The detailed power generation by primary energy resources is represented in Table 5.20 and fuel shares are shown in Figure 5.13.

Table 5.20: The electricity production mix for 2012-2035 in FIT_WS scenario (PJ)

	2012	2015	2018	2020	2023	2025	2030	2035
Coal	105.6	147.0	172.0	192.0	399.7	509.9	1063.7	1494.0
Lignite	138.7	119.5	148.6	144.6	132.7	122.8	98.1	73.4
Liquid	5.8	9.5	5.0	4.5	4.1	3.3	2.5	1.7
Natural Gas	376.5	353.3	325.6	311.3	317.5	422.3	352.1	394.5
Hydro	208.0	240.0	282.7	265.0	282.7	282.7	282.1	281.5
Geothermal	3.3	12.0	8.2	8.2	8.2	8.3	8.3	8.5
Wind	21.3	42.0	62.4	179.6	179.6	179.6	179.6	163.3
Solar	0.2	7.3	83.6	159.7	159.7	159.7	159.7	159.7
Waste	1.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Production	**860.9**	**936.4**	**1088.0**	**1265.0**	**1484.3**	**1688.5**	**2146.1**	**2576.4**

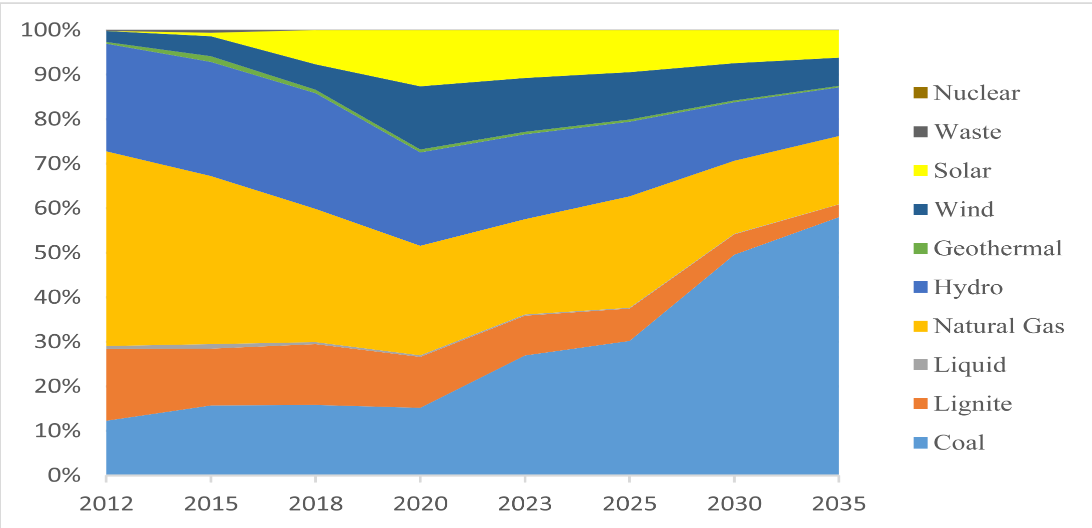
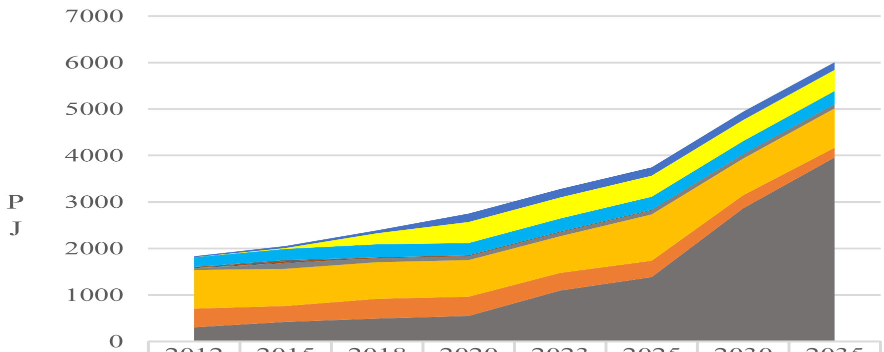


Figure 5.13: The electricity production mix for 2012-2035 in FIT_WS scenario (PJ)

Annual electricity prices are decreased by 41% in 2018 and 50% in 2020 comparing to the base scenario. Then, the prices reach the base scenario prices after 2020. This is because of the wind and solar shares in electricity production mix is increased in 2018 and 2020 and subsidy received. Since the received subsidy is decreasing with the decrease in wind and solar share in increasing electricity generation, the transition to the other technologies wipes off the decrease in prices. Average electricity prices are summarized in Table 5.21.

Table 5.21: Average seasonal price of electricity in FIT_WS scenario

$/MWh	2018	2020	2023	2025	2030	2035
Annual	56.90	59.83	95.45	120.14	103.35	113.29
Fall	57.05	59.21	94.17	112.86	86.80	91.85
Spring	57.05	61.22	96.76	112.86	88.19	95.36
Summer	56.46	57.68	94.12	112.86	86.80	91.85
Winter	57.05	61.22	96.76	142.31	152.33	175.02



	2012	2015	2018	2020	2023	2025	2030	2035
Wind	21.3	42.0	62.4	179.6	179.6	179.6	179.6	163.3
Solar	0.4	20.8	238.0	454.8	454.8	454.8	454.7	454.7
Hydro	208.0	240.0	282.7	265.0	282.7	282.7	282.2	281.5
Biomass	0.0	28.5	0.0	0.0	0.0	0.0	0.0	0.0
Residual fuel oil	14.0	28.0	19.8	17.8	16.5	13.2	9.9	6.6
Diesel	10.4	11.3	0.0	0.0	0.0	0.0	0.0	0.0
Municipal S. Waste	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal	32.5	120.0	81.9	81.9	82.2	82.8	83.4	84.6
Enriched Uranium	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	832.0	800.1	789.0	789.0	789.0	998.6	789.0	849.3
Lignite	401.8	341.9	424.9	413.3	379.3	350.8	280.2	209.7
Coal	303.1	420.0	491.4	548.6	1094.2	1383.8	2863.9	3957.1
TOTAL	1831.9	2052.6	2390.2	2750.1	3278.3	3746.4	4943.0	6006.8

Figure 5.14: Fuel consumption to electricity generation (PJ) in FIT_WS scenario

The carbon dioxide emissions in FIT_WS scenario are affected by the decreasing share of fossil fuels and the increasing share of solar and wind energy in electricity production mix. The total CO_2 emission is decreased by 2.3% in 2018 and 10.8% in 2023 comparing to the base scenario. The highest share of the total carbon dioxide emission arises from the electricity sector as in the base scenario. Yet, its emission decreases with 6.4% in 2018 and decreases from 264,651 kt to 192,600 kt in 2023 comparing to the base scenario. The second highest emission is derived from industrial sector with the share of 21.6% in 2012 and it increased to 24.9% in 2025 which is the maximum share of industrial sector through the years. Emissions of industrial sector are slightly decreased comparing to the base scenario. Transportation sector covers the 19% of total emissions in 2012 and its increasing share starts diminishing after 2020 and accounts for 12.9% in 2035. Residential sector also has the 18.3% share in 2012 and 17.6% in 2035. Refineries have a range of 2 to 5% share which reaches the maximum share in 2018 and 2020 and then decreasing. The share of agriculture sector is around 1% in the time horizon. Total carbon dioxide emission through years and carbon dioxide emissions of all sectors can be found in Table 5.22.

Table 5.22: Emissions of sectors and total carbon dioxide emission (kt) of the FIT_WS scenario

FIT_WS	2012	2015	2018	2020	2023	2025	2030	2035
Total Carbon dioxide Emissions	349,456	383,766	440,142	481,032	595,553	675,642	868,808	1,023,752
CO2 from Agriculture	3,255	3,594	4,544	5,142	5,961	6,522	8,028	9,444
CO2 from Industry	75,324	86,415	103,707	118,379	147,845	168,475	206,840	237,691
CO2 from Electricity Sector	127,507	138,269	142,051	145,878	192,600	228,213	345,281	442,092
CO2 from Refineries	12,795	14,011	23,390	25,490	28,524	31,011	29,143	21,599
CO2 from the Residential Sector	63,889	58,934	74,837	85,705	106,093	116,764	146,539	180,501
CO2 from Transportation Sector	66,686	76,163	91,614	100,437	114,529	124,657	132,977	132,425

The total system cost with subsidies decreased less than the incentive amount in FIT_W scenario due to the increased investment, activity, flow, and fixed costs. Received subsidies substracted from total cost for related years in objective function between 2015 and 2030. But the total cost without substraction of subsidy increased by 0.06% to 0.14% comparing to the base scenario after 2018.

Total incentive amount of FIT_WS scenario is not equal to the sum of incentive amount of FIT_S and FIT_W scenarios. Instead, the incentive of FIT_WS scenario is 31% less than the total incentive of the two scenarios in 2018 since the production does not reach the same amounts in single feed-in tariffs. Then, the incentive of FIT_WS scenario is 0.6% more than the sum of the two scenarios between 2020-2030. Therefore, application of both wind and solar incentive policies is not powerful as the total of them.

5.2.2 Emission Limitation Scenarios

Emission limitation scenarios enables the analyses of technology investments and resource consumptions are differs when an emission restriction enforced over electricity sector emissions and total emission values obtained from the subsidy scenarios without and subsidy on renewables. The emission limitation scenarios and the assumptions are explained in the following sections.

5.2.2.1 Electricity Sector Emission Limitation Scenario

In the electricity sector emission limitation scenario (CO2PWR_WSUP), the electricity sector emission amount is limited with the total carbon dioxide amount generated in the FIT_WS scenario but without any subsidy application. It is interesting how the model behaves in order to satisfy this limitation and change the choices of investment and generation.

The electricity consumption decrease 2% in 2018 comparing to the base scenario and for other years decrease in generation varies between 0.1% and 0.9%. The main primary energy resource is natural gas in CO2PWR_WSUP scenario until 2030 when coal reach 47.8% share. In 2018, lignite and natural gas generation amounts decrease by around 20 PJ and geothermal increases by 20 PJ and therefore the total generation decreases by 20 PJ. In 2020, generation from lignite decreases as 80 PJ and 50 PJ increase in solar which accounts for 5% of total generation and increase in geothermal and natural gas compensate the decrease. In 2023, even the coal has the highest share, generation from coal decrease 440 PJ and increase of natural gas about 283 PJ and increasing production of 20 PJ from geothermal, 74 PJ from wind and 52 PJ from solar balance the total generation yet the total generation decreases by 9.5 PJ comparing to the base scenario. Share of hydro,liquid and waste remain same as the base scenario.

The detailed power generation by primary energy resources is presented in Table 5.23 and fuel shares can be found in Figure 5.15. It can be concluded that, share of solar, wind and geothermal increase in production mix and in the middle run share of natural gas increases and coal decreases significantly in order to satisfy electricity sector carbon dioxide emission limit.

Table 5.23: The electricity production mix for 2012-2035 in CO2PWR_WSUP scenario (PJ)

	2012	2015	2018	2020	2023	2025	2030	2035
Coal	105.6	147.0	172.0	192.0	261.4	400.5	1016.8	1444.3
Lignite	138.7	119.6	136.8	67.6	132.7	122.8	98.1	73.4
Liquid	5.8	9.5	5.0	4.5	4.1	3.3	2.5	1.7
Natural Gas	376.5	353.3	357.7	520.1	601.2	671.7	457.3	505.0
Hydro	208.0	240.0	282.7	282.7	282.7	282.7	282.7	282.7
Geothermal	3.3	12.0	28.5	28.5	29.1	29.1	29.3	29.4
Wind	21.3	42.0	30.1	30.1	103.6	103.6	179.6	163.3
Solar	0.2	7.3	7.3	59.6	59.6	59.6	59.6	59.5
Waste	1.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Production	**860.9**	**936.4**	**1020.1**	**1185.1**	**1474.3**	**1673.3**	**2125.8**	**2559.4**

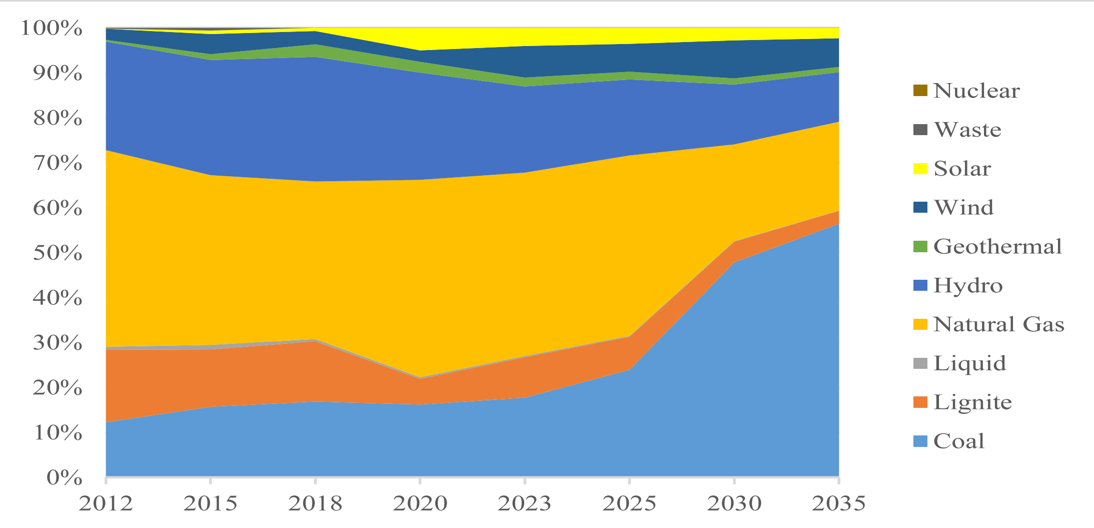
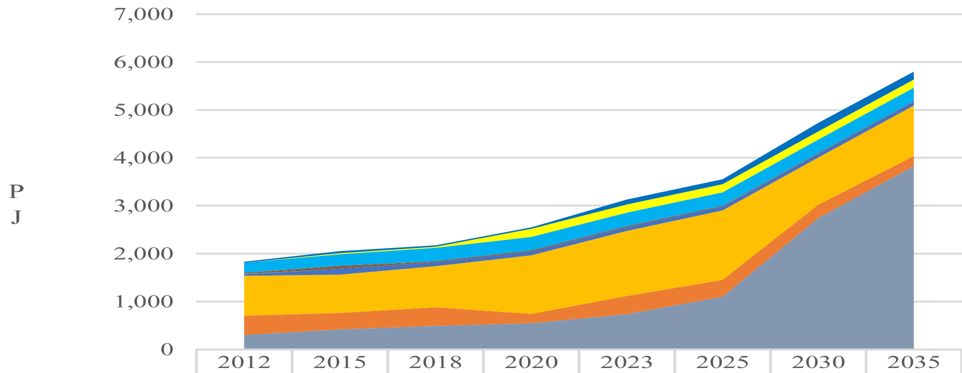


Figure 5.15: The electricity production mix for 2012-2035 in CO2PWR_WSUP scenario (PJ)

Average annual electricity prices are increased in CO2PWR_WSUP scenario comparing to the base scenario. In 2018, the annual price is increased by 13.9% and the highest increase in prices is noted as 54.5% in 2023 which is the year that generation from coal is lower and generation from geothermal, solar and wind are higher than the base scenario. Also in contrast to the feed-in tariff scenarios, the emission reduction cost is not subsidized in the CO2_SUP scenario, therefore the increase in costs reflected to the end user by increased electricity prices. Average electricity prices are summarized in Table 5.24.

Table 5.24: Average seasonal price of electricity in CO2PWR_WSUP scenario ($/MWh)

S/MWh	2018	2020	2023	2025	2030	2035
Annual	109.44	122.14	147.35	158.30	141.87	123.47
Fall	109.44	121.87	142.43	151.57	125.25	103.30
Spring	109.44	121.87	142.43	151.57	130.64	108.53
Summer	109.44	121.87	142.43	151.57	125.25	103.30
Winter	109.44	122.96	162.33	178.78	187.01	179.56



	2012	2015	2018	2020	2023	2025	2030	2035
Wind	21.3	42.0	30.1	30.1	103.6	103.6	179.6	163.3
Solar	0.4	20.8	20.7	169.8	169.7	169.7	169.6	169.5
Hydro	208.0	240.0	282.7	282.7	282.7	282.7	282.7	282.7
Biomass	-	28.5	-	-	-	-	-	-
Residual fuel oil	14.0	28.0	19.8	17.8	16.5	13.2	9.9	6.6
Diesel	10.4	11.3	-	-	-	-	0.0	0.0
Municipal S. Waste	8.3	-	-	-	-	-	-	-
Geothermal	32.5	120.0	81.9	81.9	82.8	82.8	83.4	84.6
Enriched Uranium	-	-	-	-	-	-	-	-
Natural Gas	832.0	800.1	856.1	1,224.0	1,357.2	1,448.2	982.9	1,054.5
Lignite	401.8	341.9	391.0	193.4	379.3	350.8	280.2	209.7
Coal	303.1	420.0	491.4	548.6	738.6	1,102.5	2,742.6	3,828.7
TOTAL	1,831.9	2,052.6	2,173.8	2,548.3	3,130.4	3,553.5	4,731.0	5,799.7

Figure 5.16: Fuel consumption to electricity generation (PJ) in CO2PWR_WSUP scenario

For electricity generation, the natural gas consumption decreases about 47 PJ in 2018 and increases 568 PJ in 2023, 466 PJ in 2025, 194 PJ in 2030 and 143 PJ in 2035 in CO2PWR_WSUP scenario comparing to the base scenario. Additionally, coal consumption decreases by 1130 PJ in 2023, 1033 PJ in 2025, 736 PJ in 2030 and 652 PJ in 2035. Lignite consumption decreases 60 PJ and 229 PJ in 2018 and 2020. Change in primary energy consumption for electricity generation can be found in Figure 5.16.

The power generation sector emissions are limited by the power generation emission amount of the FIT_WS scenario in CO2PWR_WSUP. Total carbon dioxide emission is 1.6% less than the base scenario in 2018 while it is 2.3% for FIT_WS scenario in 2018. The highest decrease in total CO_2 emission is observed in 2023 with a rate of 10.7% Generally, total carbon dioxide emissions are less than the base scenario emissions but more than the FIT_WS scenario emissions.The highest share of the total carbon dioxide emission arises from the electricity sector as in the base scenario. Yet, its emission decreases with 6.4% in 2018 and decreases from 264,651 kt to 192,600 kt in 2023 comparing to the base scenario. The second highest emission is derived from industrial sector with the share of 21.6% in 2012 and it increased to 25% in 2023 which is the maximum share of industrial sector through the years. Emissions of industrial sector are slightly increased comparing to the base scenario. Transportation sector covers the 19% of total emissions in 2012 and its increasing share starts diminishing after 2020 and accounts for 12.9% in 2035. Residential sector also has the 18.3% share in 2012 and 17.6% in 2035. Refineries have a range of 2 to 5% share which reaches the maximum share in 2018 and then decreasing. The share of agriculture sector is around 1% in the time horizon. Total carbon dioxide emission through years and carbon dioxide emissions of all sectors can be found in Table 5.25.

Total system cost of the CO2PWR_WSUP scenario increases 0.1% in 2018 comparing to the base scenario. Then, the increase rate 0.04%, 0.04%, 0.05%, 0.03% and 0.02% in 2020, 2023, 2025, 2030, and 2035, respectively. Comparing to the cost of FIT_WS scenario without substraction of incentive, total cost of CO2PWR_WSUP scenario decreased by 0.05% in 2018, 0.1% in 2020, 0.06% in 2023 and decreased less.

Table 5.25: Emissions of sectors and total carbon dioxide emission (kt) of the CO2PWR_WSUP scenario

CO2PWR_WSUP	2012	2015	2018	2020	2023	2025	2030	2035
Total Carbon dioxide Emissions	349,456	383,766	442,929	486,142	596,170	676,674	869,095	1,023,389
CO2 from Agriculture	3,255	3,594	4,544	5,142	5,961	6,522	8,028	9,444
CO2 from Industry	75,324	86,415	105,025	119,908	148,436	169,507	207,128	237,328
CO2 from Electricity Sector	127,507	138,269	142,051	145,878	192,600	228,213	345,281	442,092
CO2 from Refineries	12,795	14,011	23,388	25,490	28,524	31,011	29,143	21,599
CO2 from the Residential Sector	63,889	58,934	76,307	89,286	106,120	116,764	146,539	180,501
CO2 from Transportation Sector	66,686	76,163	91,614	100,437	114,529	124,657	132,977	132,425

5.2.2.2 Total Emission Limitation Scenario

In the total emission limitation scenario (CO2_WSUP), the total emission amount is limited with the total carbon dioxide amount generated in the FIT_WS scenario but without any subsidy application. It is interesting how the model behaves in order to satisfy this limitation and change the choices of investment and generation.

The electricity consumption decreases 2% in 2018 comparing to the base scenario and for other years decrease in generation varies between 0.1% and 0.9%. The main primary energy resource is natural gas in CO2_WSUP scenario until 2030 when coal reaches 47.8% share. In 2018, lignite and natural gas generation amount decrease by around 27 and 18 PJ and geothermal and wind increase by 20 and 4 PJ and therefore the total generation decreases by 20 PJ. In 2020, generation from lignite decreases as 98 PJ and 54 PJ increase in solar which accounts for 5% of total generation and increase in geothermal and natural gas compensate the decrease. In 2023, even the coal has the highest share, generation from coal decreases 440 PJ and increase of natural gas about 279 PJ and increasing production of 20 PJ from geothermal, 74 PJ from wind and 54 PJ from solar balance the total generation yet the total generation decreases by 9.5 PJ comparing to the base scenario. The share of hydro, liquid and waste remain same as the base scenario.

The detailed power generation by primary energy resources is presented in Table 5.26 and fuel shares can be found in Figure 5.17. It can be concluded that, share of solar, wind and geothermal increase in production mix and in the middle run the share of natural gas increases and coal decreases significantly in order to satisfy carbon dioxide emission limit.

Table 5.26: The electricity production mix for 2012-2035 in CO2_WSUP scenario (PJ)

	2012	**2015**	**2018**	**2020**	**2023**	**2025**	**2030**	**2035**
Coal	105.6	147.0	172.0	192.0	263.7	398.8	1018.0	1461.2
Lignite	138.7	119.6	130.2	50.3	132.7	122.8	98.1	73.4
Liquid	5.8	9.5	5.0	4.5	4.1	3.3	2.5	1.7
Natural Gas	376.5	353.3	362.6	539.0	596.7	679.3	458.5	492.3
Hydro	208.0	240.0	282.7	282.7	282.7	282.7	282.7	282.7
Geothermal	3.3	12.0	28.5	28.8	29.1	29.1	29.3	29.4
Wind	21.3	42.0	33.5	33.5	104.2	104.2	179.6	163.3
Solar	0.2	7.3	7.3	61.1	61.1	61.1	61.1	61.0
Waste	1.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Production	**860.9**	**936.4**	**1021.8**	**1191.8**	**1474.3**	**1681.3**	**2129.8**	**2565.1**

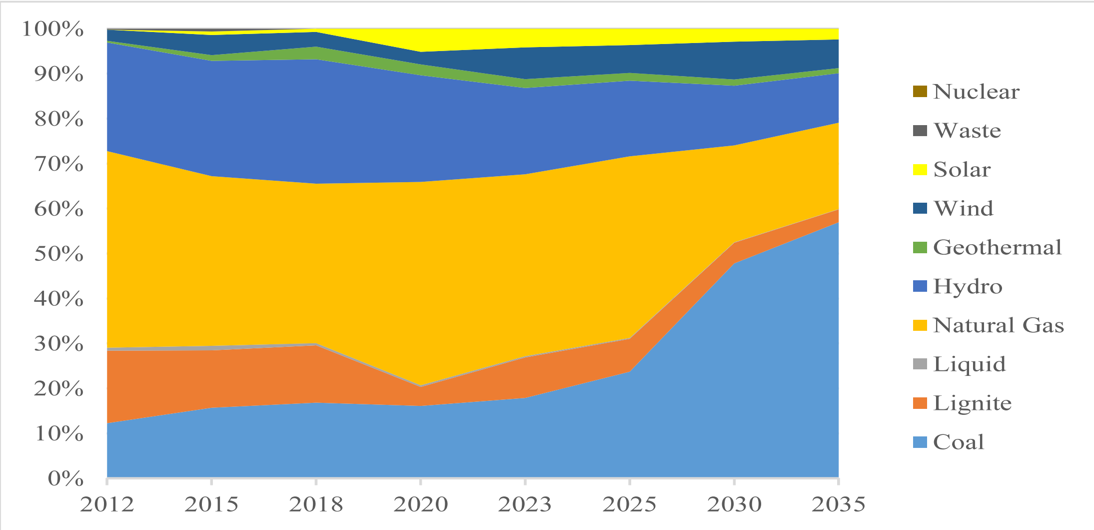
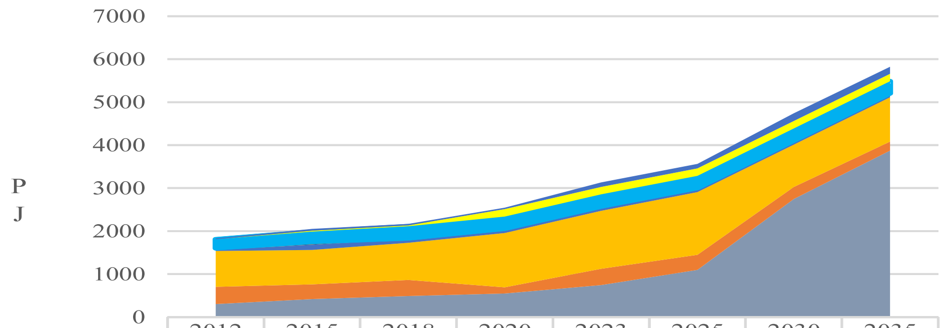


Figure 5.17: The electricity production mix for 2012-2035 in CO2_WSUP scenario (PJ)

Average annual electricity prices are increased in CO2_WSUP scenario comparing to the base scenario. In 2018, the annual price is increased by 20.5% and the highest increase in prices is noted in 2023 as 55.3% which is the year that generation from coal is lower and generation from geothermal, solar and wind are higher than the base scenario. Also in contrast to the feed-in tariff scenarios, the emission reduction cost is not subsidized in the CO2_SUP scenario, therefore the increase in costs reflected to the end user by increased electricity prices. Average electricity prices are summarized in Table 5.27.

Table 5.27: Price of electricity by seasonal timeslices in CO2_WSUP scenario

$/MWh	2018	2020	2023	2025	2030	2035
Annual	115.83	126.57	148.14	167.70	140.43	122.03
Fall	115.83	121.87	145.34	161.01	123.42	101.67
Spring	115.83	121.87	145.34	161.01	129.56	106.65
Summer	115.83	121.87	145.34	161.01	123.42	101.67
Winter	115.83	140.89	156.66	188.08	185.97	178.97



	2012	2015	2018	2020	2023	2025	2030	2035
Wind	21.3	42.0	33.5	33.5	104.2	104.2	179.6	163.3
Solar	0.4	20.8	20.7	174.0	174.0	174.0	173.9	173.8
Hydro	208.0	240.0	282.7	282.7	282.7	282.7	282.7	282.7
Biomass	-	28.5	-	-	-	-	-	-
Residual fuel oil	14.0	28.0	19.8	17.8	16.5	13.2	9.9	6.6
Diesel	10.4	11.3	-	-	-	-	0.0	0.0
Municipal S. Waste	8.3	-	-	-	-	-	-	-
Geothermal	32.5	120.0	81.9	81.9	82.8	82.8	83.4	84.6
Enriched Uranium	-	-	-	-	-	-	-	-
Natural Gas	832.0	800.1	866.3	1,263.3	1,348.7	1,458.0	985.2	1,031.0
Lignite	401.8	341.9	372.1	143.8	379.3	350.8	280.2	209.7
Coal	303.1	420.0	491.4	548.6	744.6	1,098.0	2,745.9	3,872.0
TOTAL	1,831.9	2,052.6	2,168.5	2,545.7	3,132.8	3,563.7	4,740.9	5,823.8

Figure 5.18: Fuel consumption to electricity generation (PJ) in CO2_WSUP scenario

For electricity generation, the natural gas consumption decreases about 37 PJ in 2018 and increases 560 PJ in 2023, 476 PJ in 2025, 196 PJ in 2030 and 119 PJ in 2035 in CO2_WSUP scenario comparing to the base scenario. Additionally, coal consumption decreases by 1124 PJ in 2023, 1038 PJ in 2025, 733 PJ in 2030 and 608 PJ in 2035. Lignite consumption decreases 80 PJ and 279 PJ in 2018 and 2020. Change in primary energy consumption for electricity generation can be found in Figure 5.18.

The total carbon dioxide emissions are limited by the total emission of the FIT_WS scenario in the CO2_WSUP scenario. The highest decrease in total CO_2 emission is observed in 2023 with a rate of 10.8% as in FIT_WS scenario. The highest share of the total carbon dioxide emission arises from the electricity sector as in the base scenario. Yet, its emission decreases with 7.4% in 2018 and decreases from 264,651 kt to 192,666 kt with a rate of 27.2% in 2023 comparing to the base scenario. Generally, electricity sector carbon dioxide emissions are less than the base scenario emissions for whole time horizon but more than FIT_WS electricity sector emissions from 2023. The second highest emission is derived from industrial sector with the share of 21.6% in 2012 and it increased to 24.9% in 2025 which is the maximum share of industrial sector through the years. Emissions of industrial sector are slightly decreased comparing to the base scenario. Transportation sector covers the 19% of total emissions in 2012 and its increasing share starts diminishing after 2020 and accounts for 12.9% in 2035. Residential sector also has the 18.3% share in 2012 and 17.6% in 2035. Refineries have a range of 2 to 5% share which reaches the maximum share in 2018 and then decreasing. The share of agriculture sector is around 1% in the time horizon.Total carbon dioxide emission through years and carbon dioxide emissions of all sectors can be found in Table 5.28

In CO2_WSUP optimization scenario, marginal carbon dioxide reduction costs are shown in Table 5.29. These values can be considered as a carbon tax in that scenario since the maximum carbon dioxide emissions are limited in this scenario.

Table 5.28: Emissions of sectors and total carbon dioxide emission (kt) of the CO2_WSUP scenario

CO2_WSUP	2012	2015	2018	2020	2023	2025	2030	2035
Total Carbon dioxide Emissions	349,456	383,766	440,142	481,032	595,553	675,642	868,808	1,023,752
CO2 from Agriculture	3,255	3,594	4,544	5,142	5,961	6,522	8,028	9,444
CO2 from Industry	75,324	86,856	104,579	119,391	147,764	168,323	206,407	235,032
CO2 from Electricity Sector	127,507	138,269	140,475	142,459	192,666	228,361	345,723	444,753
CO2 from Refineries	12,795	14,011	23,387	25,521	28,521	31,015	29,134	21,597
CO2 from the Residential Sector	63,889	58,493	75,542	88,081	106,112	116,764	146,539	180,501
CO2 from Transportation Sector	66,686	76,163	91,614	100,437	114,529	124,657	132,977	132,425

Table 5.29: Carbon dioxide emission reduction cost in CO2_WSUP scenario (2012 USD m/ton)

(2012 US$/Ton)	2018	2020	2023	2025	2030	2035
Marginal CO2 Reduction Cost	41.7	44.1	48	42.6	32.5	7.5

Total system cost of the CO2_WSUP scenario increases 0.02% in 2018 comparing to the base scenario. Then, the increase rate 0.05%, 0.04%, 0.05%, 0.03% and 0.01% in 2020, 2023, 2025, 2030, and 2035, respectively. Comparing to the cost of FIT_WS scenario without extraction of incentive, the total cost of CO2_WSUP scenario decreased by 0.05% in 2018, 0.1% in 2020, 0.06% in 2023 and then decreasing.

5.3 Discussion of Scenarios

For all scenarios, natural gas remains the dominant fuel for electricity generation in the short run. In FIT_W, FIT_S, and FIT_WS scenarios natural gas shares decrease in 2018 and 2020 than remain close to the shares in the base scenario but in emission restriction scenarios an significant increase is observed after 2023. Coal shares are lower than the base scenario in all policy and optimization scenarios yet for all FIT scenarios and the base scenario, coal becomes dominant fuel in 2023. But since the natural gas shares are very high in CO2PWR_WSUP and CO2_WSUP scenarios, coal become dominant fuel after 2030. The most remarkable decrease in coal shares observed in these two restriction scenarios. Solar share remarkably increases to above 10% in FIT_S and FIT_WS scenarios and reach to 5% in other scenarios except the FIT_W scenario which has the same solar share as base scenario. Wind share increases above 14% in FIT_W and FIT_WS scenarios but remains the same as the base scenario in FIT_S and barely increase to above 8% in emission restriction scenarios. Production mix of base, feed-in tariff and emission, and emission restriction scenarios are presented in Table 5.30.

Total system costs across all the policy and optimization scenarios increase as can be found in Table 5.31. Note that, government incentives are not included in the cost analysis. The highest cost is observed in FIT_WS scenario which increases both the wind and the solar technologies for production subsidy. Since the emission amounts limited by the emission level of FIT_WS scenario in CO2PWR_WSUP and CO2_WSUP scenarios model to applies the minimum cost investment decisions to reach that emission limit. Therefore increasing cost in these two emission restriction scenarios is lower than the incentive scenario FIT_WS. In addition to that, the incentives also has a negative effect to government while decreasing the electricity prices for end-users. As a conclusion, to reach a particular emission limit, applying emission restrictions/tax policy to the system is cheaper instead of introducing incentives.

Table 5.30: Shares of primary energy resources for electricity generation for each milestone year across all scenarios (%)

BASE	2012	2015	2018	2020	2023	2025	2030	2035
Coal	12.27%	15.70%	16.50%	16.18%	47.25%	47.52%	60.70%	65.92%
Lignite	16.11%	12.77%	15.15%	12.45%	8.94%	7.27%	4.57%	2.85%
Liquid	0.67%	1.01%	0.48%	0.38%	0.28%	0.20%	0.12%	0.06%
Natural Gas	43.73%	37.73%	36.48%	43.32%	21.40%	25.57%	16.33%	16.56%
Hydro	24.16%	25.63%	27.13%	23.83%	19.05%	16.74%	13.16%	10.96%
Geothermal	0.38%	1.28%	0.79%	0.69%	0.55%	0.49%	0.39%	0.33%
Wind	2.47%	4.49%	2.77%	2.54%	2.03%	1.78%	4.40%	3.04%
Solar	0.02%	0.78%	0.70%	0.61%	0.49%	0.43%	0.34%	0.28%
Waste	0.19%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gross Production (PJ)	**860.9**	**936.4**	**1042.1**	**1186.4**	**1483.8**	**1688.6**	**2146.1**	**2574.6**

FIT_WS	2012	2015	2018	2020	2023	2025	2030	2035
Coal	12.27%	15.70%	15.81%	15.18%	26.93%	30.20%	49.56%	57.99%
Lignite	16.11%	12.77%	13.66%	11.43%	8.94%	7.27%	4.57%	2.85%
Liquid	0.67%	1.01%	0.46%	0.35%	0.28%	0.20%	0.12%	0.06%
Natural Gas	43.73%	37.73%	29.92%	24.61%	21.39%	25.01%	16.41%	15.31%
Hydro	24.16%	25.63%	25.98%	20.95%	19.05%	16.74%	13.15%	10.92%
Geothermal	0.38%	1.28%	0.75%	0.65%	0.55%	0.49%	0.39%	0.33%
Wind	2.47%	4.49%	5.74%	14.20%	12.10%	10.64%	8.37%	6.34%
Solar	0.02%	0.78%	7.68%	12.63%	10.76%	9.46%	7.44%	6.20%
Waste	0.19%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gross Production (PJ)	**860.9**	**936.4**	**1088.1**	**1265.0**	**1484.3**	**1688.5**	**2146.1**	**2576.4**

FIT_S	2012	2015	2018	2020	2023	2025	2030	2035
Coal	11.85%	15.70%	16.05%	16.19%	36.52%	37.79%	53.90%	58.43%
Lignite	16.53%	12.77%	14.73%	12.46%	8.95%	7.27%	4.56%	2.85%
Liquid	0.67%	1.01%	0.46%	0.38%	0.28%	0.20%	0.12%	0.06%
Natural Gas	43.73%	37.73%	30.38%	32.16%	21.55%	26.03%	16.19%	18.22%
Hydro	24.16%	25.63%	26.38%	22.35%	19.06%	16.74%	13.09%	10.93%
Geothermal	0.38%	1.28%	0.76%	0.69%	0.55%	0.49%	0.39%	0.33%
Wind	2.47%	4.49%	2.70%	2.44%	2.41%	2.12%	4.39%	3.03%
Solar	0.02%	0.78%	8.53%	13.35%	10.67%	9.37%	7.36%	6.14%
Waste	0.19%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gross Production (PJ)	**860.9**	**936.4**	**1071.6**	**1186.2**	**1483.1**	**1688.9**	**2150.1**	**2576.3**

CO2PWR_WSUP	2012	2015	2018	2020	2023	2025	2030	2035
Coal	12.27%	15.70%	16.86%	16.20%	17.73%	23.94%	47.83%	56.43%
Lignite	16.11%	12.77%	13.41%	5.71%	9.00%	7.34%	4.61%	2.87%
Liquid	0.67%	1.01%	0.49%	0.38%	0.28%	0.20%	0.12%	0.06%
Natural Gas	43.73%	37.73%	35.07%	43.89%	40.78%	40.14%	21.51%	19.73%
Hydro	24.16%	25.63%	27.71%	23.85%	19.18%	16.90%	13.30%	11.05%
Geothermal	0.38%	1.28%	2.79%	2.40%	1.97%	1.74%	1.38%	1.15%
Wind	2.47%	4.49%	2.95%	2.54%	7.03%	6.19%	8.45%	6.38%
Solar	0.02%	0.78%	0.71%	5.03%	4.04%	3.56%	2.80%	2.33%
Waste	0.19%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gross Production (PJ)	**860.9**	**936.4**	**1020.1**	**1185.1**	**1474.3**	**1673.3**	**2125.8**	**2559.4**

FIT_W	2012	2015	2018	2020	2023	2025	2030	2035
Coal	12.27%	15.70%	16.17%	16.01%	37.52%	38.00%	56.50%	65.00%
Lignite	16.11%	12.77%	14.84%	12.32%	8.90%	7.26%	4.57%	2.85%
Liquid	0.67%	1.01%	0.47%	0.37%	0.28%	0.20%	0.12%	0.06%
Natural Gas	43.73%	37.73%	30.61%	32.91%	21.28%	26.27%	16.53%	14.16%
Hydro	24.16%	25.63%	26.58%	22.11%	18.95%	16.73%	13.18%	10.98%
Geothermal	0.38%	1.28%	0.77%	0.68%	0.55%	0.49%	0.39%	0.33%
Wind	2.47%	4.49%	9.88%	14.98%	12.04%	10.63%	8.37%	6.35%
Solar	0.02%	0.78%	0.68%	0.61%	0.49%	0.43%	0.34%	0.28%
Waste	0.19%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gross Production (PJ)	**860.9**	**936.4**	**1063.7**	**1124.4**	**1417.3**	**1615.5**	**2070.3**	**2499.4**

CO2_WSUP	2012	2015	2018	2020	2023	2025	2030	2035
Coal	12.27%	15.70%	16.83%	16.11%	17.89%	23.72%	47.80%	56.97%
Lignite	16.11%	12.77%	12.74%	4.22%	9.00%	7.30%	4.60%	2.86%
Liquid	0.67%	1.01%	0.48%	0.37%	0.28%	0.20%	0.12%	0.06%
Natural Gas	43.73%	37.73%	35.49%	45.22%	40.47%	40.41%	21.53%	19.19%
Hydro	24.16%	25.63%	27.67%	23.72%	19.18%	16.81%	13.27%	11.02%
Geothermal	0.38%	1.28%	2.79%	2.41%	1.97%	1.73%	1.38%	1.15%
Wind	2.47%	4.49%	3.28%	2.81%	7.07%	6.20%	8.43%	6.37%
Solar	0.02%	0.78%	0.71%	5.13%	4.14%	3.63%	2.87%	2.38%
Waste	0.19%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gross Production (PJ)	**860.9**	**937.0**	**1024.0**	**1188.5**	**1474.3**	**1681.3**	**2129.8**	**2565.5**

Table 5.31: Total system cost (2012 USD m) and % changes across all scenarios (2012 USD m)

Total System Cost	2018	2020	2023	2025	2030	2035
BASE	1,887,402	2,157,143	2,557,000	2,836,250	3,907,391	4,886,706
FIT_S	1,888,169	2,158,299	2,558,303	2,837,699	3,909,090	4,888,445
FIT_W	1,888,366	2,158,887	2,558,727	2,837,693	3,907,791	4,886,917
FIT_WS	1,888,568	2,160,240	2,559,761	2,838,726	3,909,444	4,888,624
CO2_WSUP	1,887,693	2,158,121	2,558,144	2,837,754	3,908,478	4,887,380
CO2PWR_WSUP	1,887,634	2,157,956	2,558,147	2,837,772	3,908,497	4,887,457

System Cost Changes	2018	2020	2023	2025	2030	2035
FIT_S	0.04%	0.05%	0.05%	0.05%	0.04%	0.04%
FIT_W	0.05%	0.08%	0.07%	0.05%	0.01%	0.00%
FIT_WS	0.06%	0.14%	0.11%	0.09%	0.05%	0.04%
CO2_WSUP	0.02%	0.05%	0.04%	0.05%	0.03%	0.01%
CO2PWR_WSUP	0.01%	0.04%	0.04%	0.05%	0.03%	0.02%

Table 5.32: Total carbon dioxide reduction (ton) and unit carbon dioxide reduction cost (2012 USD m/ton) across all scenarios

CO2 Reduction-Ton	2018	2020	2023	2025	2030	2035
FIT_S	6,224,600	16,387,000	37,602,000	39,209,500	33,648,600	40,634,000
FIT_W	5,782,700	17,139,700	34,461,500	34,831,600	22,292,000	13,290,000
FIT_WS	10,147,800	30,927,800	72,068,400	69,020,800	57,305,300	52,232,000
CO2_WSUP	10,147,800	30,927,800	72,068,400	69,020,800	57,305,300	52,232,000
CO2PWR_WSUP	7,360,900	25,818,000	71,450,700	67,988,700	57,017,700	52,595,000

Unit CO2 Reduction Cost	2018	2020	2023	2025	2030	2035
FIT_S	123	71	35	37	51	43
FIT_W	167	102	50	41	18	16
FIT_WS	115	100	38	36	36	37
CO2_WSUP	29	32	16	22	19	13
CO2PWR_WSUP	32	31	16	22	19	14

Since the share of renewables increases in power generation in all scenarios, carbon dioxide emission reduction is observed as can be found in Table 5.32. The highest carbon dioxide emission reduction is occurs in the FIT_WS scenario because of the highest renewables share and in the CO2_WSUP scenario because the emission limit of this scenario is set to same emission level. The unit emission reduction costs are calculated as 2012 USD m cost increase per carbon dioxide ton reduction comparing to the base scenario in Table 5.32. The emission reduction costs are lower in the emission restriction optimization scenarios comparing to incentive scenarios and calculated as 16 2012USDm/ton.

Chapter 6

Conclusion

The main objective of this thesis is to analyze the aggregated energy supply-demand balance and carbon dioxide emissions of Turkey specific to the electricity sector by TIMES energy system modeling and also generating results that represent how the system responds to any actions that implemented as a policy. As a contribution, the supply and demand side elaborated with an hourly resolution to provide a more precise evaluation of electricity sector.

In this study energy flows are represented with a network including primary energy resources, energy conversion technologies and end-use demand technologies for a time period of 2012-2050. The database consists of residential, industrial, transportation and agricultural and power sectors. For a better analysis of policy impacts, each sector has various technologies and demand parameters.

In this study model results compared with 5 different scenarios under two scenario categories. First, feed-in tariff applications for solar, wind and both technologies and in second category electricity sector emissions and total emissions are restricted by the amounts of solar and wind feed-in tariff scenario. As analyzed in the previous chapter, in the economic optimization scenarios the emission restriction has an impact of carbon dioxide tax. It can be concluded that for emission abatement limiting the emission is more effective than introducing incentives. Since the wind and the solar incentive scenario has the highest system cost (without extraction of subsidy) across all scenarios, even though the total carbon dioxide restriction scenario has the same emission levels, emission abatement is less costly with defining an upper limit for carbon dioxide emissions.

In this study, hydro-power is not modeled with an hourly resolution yet the availability of hydro power plants could be adjusted for different seasons according to precipitation as a future work. Also micro hydro power plants are not represented into the database even though these technologies are very popular within the energy community despite the fact that lack of data it was not possible to include them in the analysis. Also no storage option has been considered within the database. However, as a storage technology high inefficiency involving hydro pump storage can make such kind of investment very expensive due to 70-85% pumping efficiency [66] and approximate 60% turbine efficiency the overall efficiency rate is almost 46% ignoring the evaporation effect. Distributed generated is not taken into this study however the same technology involved into centralized photo voltaic technology is also the main component of the distributed generated (e.g.solar). Since such kind of a technology option in database won't be better than centralized photo voltaic generation in terms of cost, distributed generated will not be preferred by the model over the centralized photo voltaic technologies. In that sense, model results will not be effected by the lack of distributed generated technologies.

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Curriculum Vitae

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