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Türkiye Enerji Sektöründe Dönüşüm
Önemli Aşamalar ve Zorluklar

Temmuz 2015

DÜNYA BANKASI
IBRD • IDA

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ESMAP
Energy Sector Management Assistance Program

Report No: ACS14951

Transformation in Türkiye's Energy Sector

Key milestones and challenges

July 2015

DÜNYA BANKASI
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Energy and Mining Global Practice

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H Street NW
Washington DC 20433
Telephone: 202-473-1000
Internet: www.worldbank.org

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Abbreviations

All amounts expressed in dollars are in US dollars unless otherwise stated.

AKP	Justice and Development Party
OFM	automatic pricing mechanism billion
bcm	cubic meters
YI	Build-Operate
BOT	Build-Operate-Transfer
BOTAS	Balancing Power Market of Petroleum Pipeline
DGP	Transportation Joint Stock Company
HEAR	Balancing and Reconciliation Regulation
KCGT	combined cycle gas turbine (power plant)
CNG	compressed natural gas
CPS	country cooperation strategy
RK	Competition Authority
GÖP	Day Ahead Market
GÖPM	Day Ahead Scheduling Mechanism electricity
EDAS	distribution company
DSI	General Directorate of State Hydraulic
EBT	Works Electronic Bulletin Table
EBRD	European Bank for Reconstruction and
EC	Development European Commission
HOUSE	energy efficiency
EIA	environmental impact assessment
EIE/EIEI	General Directorate of Electrical Works Research Administration
EPC	Electricity Market Law No. 4628 dated 2001 (“new EML” No. 6446 dated 2013)
EPDY	Electricity Market Distribution Regulation Energy Market
Energy Market Regulatory Authority	Regulatory Authority European Network of Transmission
ENTSO-E	System Operators for Electricity Energy Market Operating
EPİAŞ	Company (“new PMUM”) Energy Sector Management
ESMAP	Assistance Programme European Union
EU	
EUAS	Electricity Production Corporation General
EIGM	Directorate of Energy Affairs General
DIAB	Directorate of Foreign Relations and EU gross
GDP	domestic product
GenCo	manufacturing company
GWh	gigawatt-hour
HEPP	hydroelectric power plant
UFC	international financial institution initial
IPO	public offering
IPP-(BEÜ)	independent energy
LNG	producer liquefied natural
LPG	gas liquefied petroleum
LY	gas Licensing Regulation
mcm	million cubic meters
ETKB	Ministry of Energy and Natural Resources
KB	Ministry of Development
MoEU	Ministry of Environment and Urbanization Ministry of
OSIB	Forestry and Water Affairs megavolt ampere (one
MVA	million volt ampere) megawatt
MW	
MW	megawatt electricity

MWh	megawatt-hour
DG	natural gas
DGPK	Natural Gas Market Law
SID	Network Operation Regulations
NGS	nuclear power plant
OECD	Organisation for Economic Co-operation and Development
I-B	operation and maintenance
OIB	Privatization Administration
PMUM	Market Financial Reconciliation Center (electricity market operator within TEİAŞ)
PV	photovoltaic
PPP	public-private partnerships
ÖSK	Private sector participation
EAT	renewable energy
YEKA	Renewable Energy Law River type
RoR	hydroelectric power plant special
Special Consumption Tax	consumption tax
SDIF	Savings Deposit Insurance Fund small
SME	and medium-sized enterprises public
SCARCE	economic enterprises
DPT	State Planning Organization (restructured as the Ministry of Development after 2011)
STS	Standard Transportation
TAEK	Agreement Turkish Atomic Energy
TANAP	Agency Trans Anatolian Pipeline
TAP	Trans Adriatic Pipeline
TORETOSAF	Türkiye Average Electricity Wholesale Price Temporary
G-SENSE	Balancing and Reconciliation Regulation Türkiye Electricity
TEAS	Production and Transmission Joint Stock Company Türkiye
TEDAS	Electricity Distribution Joint Stock Company Türkiye Electricity
TEIAS	Transmission Joint Stock Company
ONLY	Turkish Electricity Authority
TETAS	Turkish Electricity Trading and Contracting Joint Stock Company
TL	Turkish Lira
tpe	ton oil equivalent
IHD	Transfer of operating rights
UTE	third party access
TP	Turkish Petroleum Corporation thermal
TS	power plant
HEAT	transmission system operator
TWh	terawatt-hour
TSKB	Turkish Industrial Development Bank
THREE	European Electricity Transmission Coordination Organization (became ENTSO-E after July
AOGM	2009) weighted average gas cost
RES	wind farm
YEGM	General Directorate of Renewable Energy (ETKB)
YEKDEM	Renewable Energy Resources Support Mechanism

ExecutiveSummary

Executive Summary

Turkey's energy reform has succeeded in ensuring the energy security required for a fast-growing economy with rapidly increasing energy needs through a variety of interconnected measures. These measures include legislative amendments regarding electricity, gas, renewable energy and energy efficiency; the establishment of a regulatory authority for the energy sector; energy pricing reform; the establishment of a functioning electricity market; the widespread availability of natural gas; the restructuring of state-owned energy enterprises; and widespread private sector participation through privatization and new investments. These measures have resulted in (a) the creation of an electricity market with more than 800 participants; (b) over 31,000 megawatts (MW) of market-based, private sector electricity generation capacity being put into operation between 2001 and 2014; (c) the entire electricity distribution system being taken over by private investors between 2008 and 2013; and (d) thanks to the regulatory framework for renewable energy and the development of the electricity market, an additional 16,000 MW of generation capacity based on renewable sources was provided in the period 2001-2014.

Turkey first opened its energy sector to the private sector in 1984 as part of the transition to a general market economy. However, simply removing the state monopoly was not enough. In the absence of a solid legal and regulatory framework and a functioning energy market, only limited progress could be made. In response to expectations of power shortages, legal changes were made in 1994 and 1997 to provide state guarantees to attract private sector investment in electricity generation. A capacity of 8,550 MW was contracted under long-term power purchase agreements that provided a Treasury guarantee for the payments of the public company. While these agreements provided temporary relief, they did not provide a long-term solution in terms of energy security.

With the aim of becoming a member of the European Union (EU), Turkey, taking into account the electricity and gas directives and energy reforms adopted by the EU in 1996, decided to form a working group to review existing options and prepare a new roadmap. These preparatory studies enabled Türkiye to take action at the right time. Türkiye's energy market reforms were initiated in 2001 as part of the government's response to a deep economic crisis; as is often the case with fundamental reforms, this crisis provided the pressure, determination and momentum needed to implement the reform proposals. Economic growth, which had slowed towards the end of the century, slowed towards the end of the century and then collapsed completely when Turkey was dragged into a deep economic and financial crisis in 2000-2001. Comprehensive reforms were initiated with the support of the International Monetary Fund and the World Bank. The government took very strong measures in some sectors, most notably the banking sector. The energy sector is among these sectors: the Electricity Market Law and the Natural Gas Market Law were adopted in 2001. Both laws were ambitious and comprehensive. These two laws provided for the restructuring of the sector, established electricity and gas markets, ensured market openness, introduced provisions such as the formation of electricity suppliers (i.e. trading companies) and the implementation of bilateral contracts, ensuring open access to networks and the establishment of the Energy Market Regulatory Authority (EPDK).

These laws, enacted in 2001, provided the necessary legal basis. Later, systematic and gradual efforts were made to establish the necessary regulatory framework, restructure public electricity companies and establish a central electricity trading platform (PMUM). Although the initial reactions of private sector investors were encouraging, these responses were ultimately insufficient to ensure security of electricity supply, as retail tariffs remained below cost-covering levels until 2007. In 2008, a new cost-based price

The introduction of the tariff mechanism and a series of tariff adjustments introduced in 2008-09 made the electricity sector financially sustainable, supported large investments in market-based generation and enabled the government to launch the hitherto overdue distribution privatisation programme.

Past successes can guide the way forward, but they do not guarantee future success. Türkiye's economy continues to grow. Demand for energy, especially electricity, continues to rise. For Türkiye's growth and development, and for the well-being of its citizens, the energy sector must address the challenges of securing electricity and gas supplies. Despite significant achievements to date, reforms in the energy sector will need to continue if Turkey is to continue securing electricity and gas supplies without having to resort to the large-scale—and long-term unsustainable—state support mechanisms of the 1990s.

The development of the electricity market continues under the new Electricity Market Law, enacted in 2013, which foresees the establishment of a new Electricity Market Operating Company (EPİAŞ). The company will be a joint venture of the electricity transmission system operator TEİAŞ (30 percent capital share), Borsa İstanbul (30 percent) and electricity and gas market participants (40 percent). After EPİAŞ takes over the electricity market operating functions from TEİAŞ, it will also open up to the gas market. In parallel, Borsa İstanbul will develop a financial risk management platform for market participants.

Despite significant progress made by Türkiye in expanding gas supply and privatizing the gas distribution sector, the development of the gas market has lagged far behind the electricity market and the security of gas supply is at risk. During the cold winter months, gas demand exceeds supply, leading to supply shortages. BOTAŞ, with the support of the government, recently signed a contract with Azerbaijan for additional gas supply, which is expected to be delivered by 2018. As existing contracts expire, new contracts/sources and spot liquefied natural gas (LNG) as an emergency measure[1]More measures will be needed, including imports. A comprehensive set of measures are needed to secure supply in the medium and long term. The amendment to the Natural Gas Law enacted in 2001 in the near future will be an important step in terms of unbundling the national gas company BOTAŞ, further liberalizing imports and establishing an effective gas trading platform. In addition, the establishment of a pricing mechanism that reflects costs and the removal of cross-subsidies will facilitate competition. If Turkey wants to ensure security of gas supply, increase private sector participation in gas imports and realize its claim to be a regional energy hub, these measures must be implemented.

Most energy consumers in Türkiye have become more accepting of high energy prices as an inevitable cost of development. However, this acceptance does not mean that all household consumers can comfortably pay their energy bills. Targeted social support and energy efficiency programs for low-income consumers can be considered as an integral part of the overall electricity and gas market liberalization process. The possibility of social support in the form of direct cash payments to consumers (without affecting energy prices) was envisaged in the laws enacted in 2001, but this has not been implemented.

This review presents for the government's consideration a set of integrated measures to continue the development of electricity and gas markets and reassure market participants that liberalisation is continuing and that governance and transparency in public institutions and energy SOEs will be improved:

- Amendments to the Natural Gas Market Law may be put into effect.
- Taking advantage of the decline in gas import prices, the government could allow BOTAŞ to make cost-reflective and transparent wholesale gas price adjustments.

- It will take some time to develop a social security mechanism for low-income consumers (even if it is included in one of the existing subsidy mechanisms financed from the budget), but the government may announce that it has decided to create such a mechanism.
- The development process of EPİAŞ can be accelerated so that EPİAŞ can become fully operational in 2015.
- The Ministry of Energy, BOTAŞ and TEİAŞ may disclose to market participants the mechanisms for managing gas supply shortages and electricity shortages in the winter of 2015-16 before these mechanisms are implemented and required to be used.
- The government may announce that it has decided to register the shares of TEİAŞ, certain parts of BOTAŞ (after unbundling), EÜAŞ, TETAŞ and TP on the stock exchange for the purpose of an IPO program to be held on Borsa Istanbul.

Energy market participants and consumers/citizens want improved governance and increased transparency in the energy sector:

- Modernizing governance in energy SOEs and listing key energy enterprises on the stock exchange are important policy priorities. The Decree Law No. 233 on State Economic Enterprises, the Court of Accounts Law, the Public Procurement Law, and a series of controls implemented by the Ministry of Energy, the Ministry of Development and the Treasury undermine management autonomy. Despite being established as companies, BOTAŞ, EÜAŞ, TEİAŞ and TETAŞ still face significant challenges in transforming into modern, autonomous and professionally run state economic enterprises.
- Energy market participants want increased transparency in regulatory processes (EPDK), market transactions (PMUM/EPİAŞ), trading activities of EÜAŞ and TETAŞ, and electricity and gas transmission system operations in areas such as balancing, load dispatch, congestion management and supply disruption (TEİAŞ and BOTAŞ).
- The sheer number of applications can sometimes clog up the environmental impact assessment and project approval processes. Project owners have complained about the complexity of the procedures, delays and lack of transparency. Environmentalists and citizens have expressed concerns about the inconsistent application of environmental permitting and licensing procedures and the inadequacy of public reporting of decisions. Greater transparency is needed in the processes of making and justifying decisions, whether approval or rejection.

Gaining public support for energy reforms – and the investments they aim to attract – is fundamentally simpler than attracting private sector investment, but in practice it can be just as difficult. Public support requires constant, relentless and unwavering sharing of information, education, consultation, participation and *transparency* requires; otherwise, continued public support will be undermined.

Overview

Overview

BTürkiye’s energy reforms, implemented through a variety of interconnected measures, have provided energy security for a rapidly growing economy with rapidly increasing energy needs. These measures include legislative arrangements for electricity, gas, renewable energy and energy efficiency; the establishment of a regulatory authority for the energy sector; energy pricing reform; the establishment of a functioning electricity market; the widespread availability of natural gas; the restructuring of state-owned energy enterprises; and widespread private sector participation through privatization and new investments. As a result of these measures, (a) an electricity market with more than 800 participants has been established; (b) over 31,000 megawatts (MW) of market-based, private sector electricity generation capacity was put into operation between 2001 and 2014; and (c) the entire electricity distribution system was taken over by investors between 2008 and 2013.

The “secret” of Türkiye’s success lies in a three-way cooperation and risk sharing between successive governments, public institutions and state-owned energy companies, and Turkish investors and their mostly Turkish financiers. This cooperation developed slowly and intensified “step by step,” as is often said in discussions of energy reforms in Türkiye. The reform process began in the 1980s, when the energy sector was opened to private sector initiatives, and accelerated after the adoption of the electricity and gas market laws in 2001, which initiated the liberalization of Türkiye’s energy markets—and continues today.

The legal and regulatory framework and the sector and market structures have evolved step by step over time. Energy prices have been adjusted at a pace that was considered acceptable to consumers. A succession of governments, public institutions and state-owned energy companies, investors and financiers were ready to create and make this framework and structures work. The parties were prepared to take political, operational and financial risks and were able to do so. This risk sharing has made Türkiye’s energy reform possible. This reform success is not easily replicable; in fact, it is very difficult to replicate. Other countries will have to chart their own paths, but they can learn from Türkiye’s experience, both in terms of past steps and current reform challenges.

The aim of this review, which examines the stages Türkiye has gone through and the challenges ahead, is (a) to inform future energy reforms for reformers who want to learn and benefit from Türkiye's experiences and (b) to contribute to the dialogue on future energy reforms in Türkiye.

Türkiye’s achievements in developing and implementing market-oriented energy reforms and selected key reform challenges for the upcoming period will be summarized in this overview section and will be fully presented in the main report text. In terms of the reform process, the main focus areas will be the electricity and natural gas sectors, with energy pricing and subsidies in the oil sector also being addressed. The report covers the period starting in 2001, when the electricity and natural gas market laws were enacted, and briefly covers the period from 1984, when the energy sector was opened to private sector investment, to 2001, when the new energy market laws were enacted, in order to present important stages and highlight the main lessons to be learned.

In terms of future challenges, the report discusses the ongoing and incomplete liberalisation process in the electricity and gas markets, as well as the government support required, including improving governance in the energy sector.

The first part of this overview will present the milestones of Türkiye's energy transition, including legislative and regulatory achievements, pricing developments, sector restructuring, sector and market structure, electricity market development, inclusion of natural gas in Türkiye's energy supply mix, the roles played by Turkish investors and their financiers, development of renewable energy, nuclear power, political leadership issues, as well as support provided for reforms, pricing and subsidies.

The second part of this overview will present key challenges facing Türkiye's energy sector as a contribution to the ongoing reform dialogue in Türkiye. These challenges include reforming the natural gas market, further developing the electricity market, and governance issues in the energy sector. Environmental and social issues and issues are also discussed in the relevant sections.

2.1 Overview Part 1: Energy Reform Milestones

International experience shows that implementing comprehensive reforms often takes a long time and requires long-term commitment. Turkey is no exception. As explained in Section II, although reforms began in the 1980s, they are still ongoing today and there are significant challenges that remain.

Türkiye's energy reforms can be divided into two separate phases:

- Phase 1: Opening up the sector to the private sector in the 1980s and 1990s; and
- Phase 2: Market-based reforms implemented from 2001 onwards.

In both stages, energy security – securing energy supply to support economic growth and the welfare of citizens – was the main domestic driver of the reform. With one exception: macro and fiscal issues. The issue of maintaining the budget and external balances became a growing concern in the late 1990s and eventually became the main driver of market-based reforms that began in 2001, when a deep economic crisis and a temporary decline in energy demand were experienced. The approach of attracting private sector investment under market conditions, especially in order to provide electricity production without the state entering into long-term power purchase agreements (PPAs) and large-scale state guarantees – was adopted as the main tool to ensure energy security without endangering macro and fiscal balances. Energy security concerns pushed and forced the government to accelerate reforms from 2008 onwards.

Turkey is a candidate country for European Union (EU) membership. Accession negotiations began in October 2005. Turkey sees the accession process as a fundamental “modernization process” for itself. EU membership and the goals of energy cooperation and integration with Europe have been effective external drivers for energy reform. The design of market-based reforms that Türkiye initiated in 2001 was inspired by the EU’s electricity and natural gas directives adopted in 1996, as well as reforms in Europe, including the restructuring and privatization of the electricity sector in England and Wales and the development of the Nordic electricity market. Since Türkiye’s vision of becoming an energy hub would benefit both Turkey and the EU, market integration would be in the interest of both parties.

2.1.1Stage 1: Opening the Market to the Private Sector in the 1980s and 1990s

2.1.1.1 Economic Liberalization Aiming at Market Economy

Turkey opened its energy sector to the private sector as part of its transition to a market economy. Turkey, emerging from a severe economic crisis in the late 1970s, a military coup in 1980, and political turmoil in the early 1980s, entered a new era in 1983. The country began a transition from a state-controlled industrialization based on import substitution, where state ownership and control were heavily dominant, to a free market economy in terms of both domestic markets and international trade. This broad economic policy transformation was also reflected in the electricity sector with the enactment of the law in 1984 on the authorization of organizations other than the Turkish Electricity Authority (TEK) to generate, transmit, distribute, and trade electricity under the Build-Operate-Transfer (BOT), Transfer of Operating Rights (TOOR), and autoproducer models. Experiences and results related to the use of these three models are discussed below.

2.1.1.2 Restructuring the Energy Sector

TEK, which was first established in 1970 as an integrated institution for electricity generation, transmission and rural electrification, became a de facto monopoly in 1982 with the acquisition of municipal distribution activities by TEK. However, a law enacted in 1984 ended TEK's monopoly and TEK was structured as a public economic enterprise. The restructuring in the electricity sector continued in 1993 with the division of TEK into the Turkish Electricity Generation and Transmission Corporation (TEAŞ) and the Turkish Electricity Distribution Corporation (TEDAŞ). TEAŞ and TEDAŞ were tasked with purchasing electricity from the BOT and İHD companies connected to the transmission and distribution networks and from autoproducers.

The Turkish Petroleum Corporation (TP - previously TPAO) was established in 1954 as the national oil company of Türkiye for the purpose of exploration, extraction, production, refining and marketing of hydrocarbon resources. However, after a series of restructuring and privatization measures, TP has focused its activities mainly on the production side (exploration, drilling, well completion and production); however, it also operates Türkiye's only natural gas storage facility. One of the several companies in Türkiye's oil and gas sector, the Petroleum Pipeline Corporation (BOTAŞ), was also born from TP. TP established BOTAŞ in 1974 to transport crude oil via pipelines. After Türkiye signed its first agreement with the Soviet Union in 1986 to import natural gas, BOTAŞ expanded its scope of activities to include natural gas transportation and trade, thus becoming a trading company and de facto Türkiye's national gas company. Contrary to the liberalization and restructuring in the electricity sector, BOTAŞ gained monopoly rights regarding the import, distribution, sale and pricing of natural gas - with a government decree issued in 1990.

2.1.1.3 Private Sector Participation in the Electricity Sector (PSP)

Four models have been used for ÖSK: transfer of operating rights (TORR), build-operate-transfer (BOT), build-operate (BO) and autoproducer.

Experiences of the IHD Model

HRA model It envisages the transfer of operating rights of public assets (in this case, the generation and distribution assets of TEK, TEAŞ and TEDAŞ) to private sector management, provided that the necessary investments are made by the private sector during the term of the TOE contract. Of the many attempts made in the 1980s and 1990s to use the TOE model to attract private sector companies to the electricity sector, most were ultimately unsuccessful due to fundamental legal problems in transferring public assets to private sector management, the absence of state guarantees before 1994 (for generation) and regulatory uncertainties (for distribution and generation).

Efforts to transfer distribution and generation assets in the 1990s initially suffered the same fate. The Ministry of Energy and Natural Resources (ETKB) held public tenders to transfer most of Türkiye’s 78 electricity distribution regions to private sector management and signed contracts for 11 regions. However, objections to the legal basis of these contracts were filed with the Council of State, Türkiye’s highest administrative court. The court annulled most of the 11 contracts and only two contracts were implemented.

ETKB also held tenders to transfer 16 power plants to the private sector and signed contracts for six of them with the approval of the Council of Ministers. However, here too, objections were made regarding the legal basis and all but one of the contracts were annulled by the Council of State.

Although the HRA efforts in the 1980s and 1990s were largely unsuccessful due to the lack of a solid legal basis, the experience gained enabled Türkiye to make the necessary legal changes to create a solid legal basis that would enable it to successfully use the HRA model in its 2008–13 electricity distribution privatization program.

Autoproducer Model Experiences

Autoproducer model It envisages industrial companies to own and operate power plants primarily for their own electricity needs. Although there were autoproducer plants in Türkiye before 1984, they were mostly used in state-owned sugar factories and cogeneration plants.[2] facilities and were governed by special regulations. The law enacted in 1984 and the subsequent regulations enacted between 1994 and 1999, which allowed companies to jointly establish power plants, triggered widespread investment in autoproducer plants. By 2001, approximately 2,300 MW of generation capacity had been established. Although not foreseen in 1984 when the law was enacted, these plants played an important role in the development of Türkiye's electricity market two decades later.

Experiences with BOT and BOT Models

BOT model It consists of three stages:

1. Financing and construction of an asset – in this case, electricity generating plants – by a private company;
2. Operating the power plant and selling the electricity it produces to a public institution under a long-term contract – in this case, selling the electricity to TEK and TEAŞ under power purchase agreements; and
3. Transfer of the asset to the State at the end of the contract period.

Since the 1984 law was seen as providing an insufficient legal basis for the implementation of the BOT model, a specific law was enacted in 1994 regarding the implementation of the BOT model. In addition to eliminating the legal uncertainties regarding the BOT model, the 1994 law provided for the provision of a state guarantee by the Treasury for payments under TEAŞ's electricity purchase contracts.

The BOT law, enacted in 1994, attracted significant interest from foreign and domestic investors. Investors submitted more than 200 project proposals that, if built, would triple Türkiye's production capacity. The Ministry of Energy and Natural Resources (ETKB) and TEAŞ were unprepared to handle this unexpected flood of unsolicited project proposals. As a result, 24 BOT contracts (with a total production capacity of 2,450 MW) were negotiated and signed, but most of the proposals were never implemented.

BI Model:

Instead of reviewing and comparing hundreds of unsolicited bids, the government decided to focus on priority projects of its own choosing and to select investors for these projects through competitive bidding in order to obtain more reasonable prices and terms. In order to reduce legal uncertainties and thus increase the financing of the projects, a modified version of the BOT model was implemented in which the condition of transferring the power plants to TEAŞ at the end of the contract period was removed. Five contracts with a total generation capacity of 6,100 MW were signed under this model, called Build-Operate (BO).

2.1.1.4 Change of Direction

A total of approximately 8,550 MW of generation capacity was contracted and constructed under the BOT and BO schemes. All contracts included a "take or pay" clause. TEAŞ's purchasing obligations were supported by state guarantees provided by the Treasury. The BOT/BO model, implemented with competitive selection and Treasury guarantees, could have been used beyond the five competitively tendered projects and possibly secured additional generation capacity. Instead of relying on more guarantees, however, Turkey adopted a market-based approach to attract private sector investment. This process change was brought about and made possible by several reasons:

- The Treasury and the State Planning Organization (SPO; after 2001 the Ministry of Development) had become increasingly reluctant to provide Treasury guarantees for BOT and BO projects, considering the contingent liabilities;
- Allegations of irregularities and irregularities have been raised in the BOT contracting process. The shift from negotiated BOT contracts based on unsolicited bids to competitively awarded BOT contracts for priority projects has helped alleviate these concerns but has not eliminated allegations of past BOT contracting.
- As economic growth began to slow in the late 1990s, electricity demand growth also slowed down and supply/demand balances began to ease with the projected production of the BOT and BO power plants already under contract. The argument that Treasury guarantees should be provided to ensure supply security lost its meaning and was replaced by the medium-term, expensive take-or-pay approach.[3]had taken the risk of excess supply due to its obligation.

- The first electricity directive published by the EU in 1996 and electricity reforms in Europe pushed the government to adopt market-based approaches. A working group was formed to review existing options and prepare a new roadmap, bringing together officials from the Ministry, TEAŞ, TEDAŞ, DPT and the Treasury. These preparatory efforts enabled Türkiye to take action at the right time.

2.1.2 Phase 2: Market-Based Reforms Since 2001

As is often the case with fundamental reforms, a crisis provided the impetus for the implementation of planned energy reforms. In this case, the crisis was exceptionally deep and left Türkiye with no choice but to implement exceptionally strong measures. The following section presents the achievements and lessons learned from the competitive electricity and gas market model that Türkiye has implemented since 2001. The discussion focuses on the electricity sector; progress in the gas sector has been more limited and is therefore discussed in more detail in Section 2.2, which focuses on the challenges of energy reform.

The 2000–01 Crisis

Turkey is known for its economic cycles marked by booms and busts. During the 1990s, GDP growth varied between 9.3% and -5.5% (decline). With the slowdown that began in the late 1990s, growth fell to 7.5% in 1997 and 2.5% in 1998. Along with the slowdown in Türkiye, the financial crises in East Asia and Russia reduced foreign investors' confidence in Türkiye and reduced capital flows. Meanwhile, a major earthquake hit Türkiye in 1999. Inflation rose and the economy contracted by 3.6%. A disinflation and macroeconomic stabilization program supported by the IMF stand-by agreement was launched in 1999, but concerns about the health of the banking sector persisted and grew. Financial crises erupted in November 2000 and, after a brief recession, in February 2001. Following this, a second and much larger IMF-supported program was launched.

As a result, Türkiye's Savings Deposit Insurance Fund (SDIF) took over 18 banks in a program of mergers, closures, and recapitalizations that totaled more than 30 percent of Türkiye's GDP. The resources needed by SDIF were transferred from the budget through bonds. The cost was considerable—Türkiye's public debt doubled—but growth resumed as market confidence was restored. There was a remarkable recovery: after a 5.7 percent contraction in 2001, GDP grew by 6.2 percent in 2002 and by an annual average of more than 6 percent through 2007. The banking sector, which emerged from the restructuring that followed the 2000–01 crisis, provided much of the debt financing to investors responding to the government's crisis-response to the energy sector.

Electricity and Natural Gas Market Laws of 2001

In 2001, the government launched comprehensive reforms in some sectors, especially the banking sector, as discussed above, and took quite strong measures. The energy sector did not lag behind the banking sector: the Electricity Market Law (EPK) and the Natural Gas Market Law (DGPK) were enacted in 2001. Disputes between public authorities, allegations of corruption and lawsuits filed in courts regarding some of the previously concluded contracts[4] helped build public support for reform, including the passage of these laws in parliament. Both laws were ambitious and comprehensive. They provided sectoral restructuring, established electricity and gas markets, ensured market openness, introduced provisions such as electricity suppliers (trading companies), bilateral contracts, open access to grids and the establishment of the Energy Market Regulatory Authority (EMRA).

2.1.2.1 Electricity Market Development

This section summarizes the main features of the development of Türkiye's electricity market, which are described in detail in the main report.

The ultimate goal was to create a competitive market environment that could attract private sector investments and increase efficiency through competition. This required significant changes in the administrative and regulatory framework, the restructuring and unbundling of state-owned companies, significant changes in trade regulations, the creation of a competitive market where multiple buyers and sellers could interact, and the establishment of an open access regime for non-discriminatory access to the transmission and distribution networks. It also required some transitional arrangements and a sequencing of steps to be taken to move from a single-buyer monopolist model to wholesale competition and ultimately to full retail competition (which would occur when all consumers are free, i.e. have the freedom to choose their electricity suppliers).

2.1.2.2 Legal, Regulatory and Institutional Framework

The EML issued in 2001 provided the legal basis. Within the scope of the EML, EPDK was established as the regulator of the electricity market and shortly thereafter, it was renamed as the Energy Market Regulatory Authority as its area of responsibility was expanded to include natural gas, liquefied petroleum gas (LPG) and petroleum markets. EPDK prepared secondary legislation on licensing, tariffs for regulated activities, transmission and distribution network rules, market opening, market rules and procedures, and balancing and reconciliation. In line with the development of the market, improvements were made through amendments and revisions in both the EML and EPDK regulations, and new regulations were issued as necessary.

EMRA fulfills and exercises its duties and powers arising from the relevant laws through the Energy Market Regulatory Board, which is the representative and decision-making body of the Authority. The Board consists of nine members, including the EMRA President, and each member is appointed by the Council of Ministers for a six-year term. In order to ensure the operational autonomy of EMRA, the law stipulates that Board members cannot be dismissed before the end of their terms of office. The law also provides for EMRA's financial autonomy by stipulating that it will finance its activities through fees collected from the energy sector. While there are increasing concerns about EMRA's autonomy and government interference in its tariff-setting authority, the market regulation and supervision authority has largely been transferred from the government to an independent regulator.

Türkiye adopted a new Electricity Strategy in March 2004.[5] The strategy's objectives also included the privatization of electricity distribution by the end of 2006. Since the EML did not include targeted measures for the development of renewable energy and energy efficiency, separate laws were enacted for Renewable Energy and Energy Efficiency in 2005 and 2007, respectively.

2.1.2.3 Restructuring of Public Electricity Companies

In 2001, in line with the principle of unbundling market activities, the Turkish Electricity Generation and Transmission Corporation (TEAŞ) was divided into three separate divisions:

- Turkish Electricity Transmission Corporation (TEİAŞ) was established for electricity transmission, system operation and market operation activities;
- Electricity Production Corporation (EÜAŞ) was established for electricity production activities; and
- The Turkish Electricity Trading and Contracting Corporation (TETAŞ) was established for electricity wholesale activities – including the management of long-term ESAs (with the companies BOT, BO and HRA) inherited from the previous regime.

In addition, in order to implement distribution privatization in line with the Electricity Strategy published in 2004, TEDAŞ was restructured as a parent company and 20 regional subsidiaries in the 2004-06 period.

2.1.2.4 Transitional Period Measures

- As an interim measure, the contracts entered into in 2006 between (a) TETAŞ and EÜAŞ as wholesale electricity suppliers and (b) TEDAŞ subsidiaries and buyers (covering 85 percent of their retail supplies)[6](transitional period agreements) were made. This measure was abolished in 2012.

- In order to implement the uniform national retail tariff policy for non-eligible consumers, a price equalization mechanism (i.e. inter-regional cross-subsidy) was introduced to balance cost differences among distribution regions.
- Fifteen BOT model project proposals were converted into market-based projects and licensed by EMRA, providing approximately 1,300 MW of capacity for the emerging electricity market.

2.1.2.5 Separation of Functions

Türkiye's legal and regulatory framework distinguishes between competitive market activities and regulated activities. Transmission and distribution activities are regulated by the Energy Market Regulatory Authority. Non-eligible consumers[7]Apart from retail sales and TETAŞ's wholesale activities, competitive market activities such as production and supply are not regulated. The following unbundling measures can be highlighted:

- *Decomposition of the transmission:*With the establishment of TEİAŞ, the operation of the transmission network and electricity system was separated from the supply activity.
- *Decomposition of the distribution:*The separation of distribution from supply was carried out in two stages. Until the end of 2012, distribution and retail activities were carried out by the same regional distribution company under separate accounts (“account separation”). Each regional distribution company had two licenses: a distribution license for the operation of the distribution system in its region and a retail license for the supply of electricity to non-eligible consumers in its region. Following the recommendation of the Competition Authority, as stated in the amendments made to the Energy Market Regulatory Authority in 2008 and in the Strategy Document published in 2009, these activities had to be legally separated. By the end of 2012, distribution companies were legally separated into distribution and “assigned supply” companies.[8]
    - Since January 2013, distribution companies have been operating and maintaining the distribution network, carrying out the necessary network investments, and providing electricity distribution and connection services to all system users, including free consumers who are connected and/or will be connected to the distribution system, without discrimination.
    - Since January 2013, incumbent supply companies can sell electricity and/or capacity to both non-eligible consumers within their jurisdiction and to eligible consumers nationwide. These companies also serve as suppliers of last resort for consumers in their jurisdiction.
    - Although distribution companies cannot engage in any other market activity, owners or shareholders of generation/supply companies can (and often do) own distribution companies and retail supply companies. There is no restriction on incumbent supply companies. This raises potential concerns regarding the implementation of the open access regime (see next section) and should be carefully monitored by the EMRA and the Competition Authority.

2.1.2.6 Provisions Regarding Open Access to Transmission and Distribution Networks

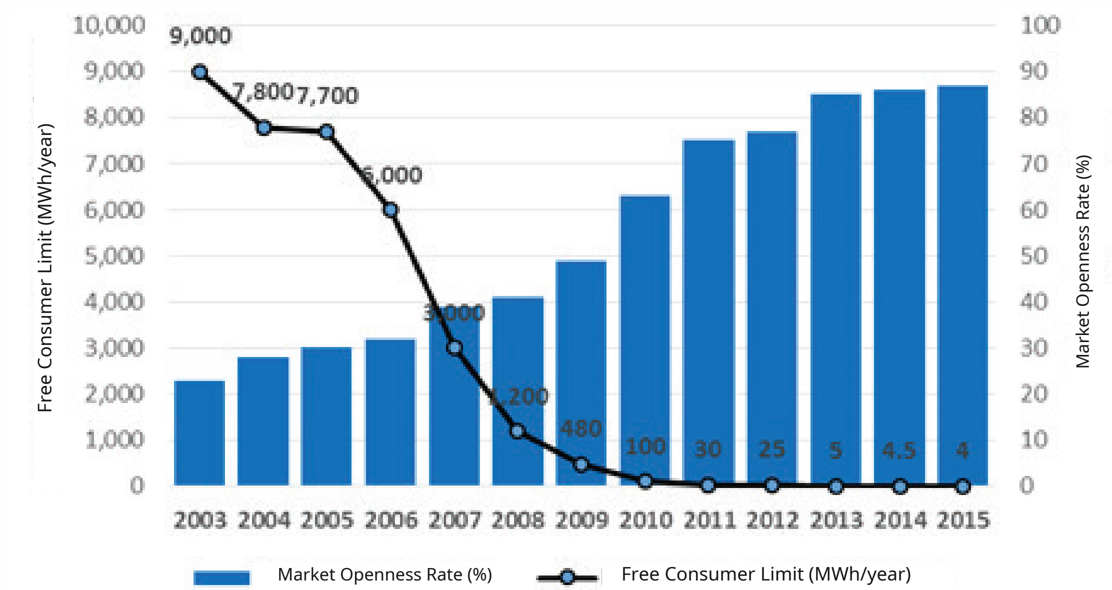
Unbundling of network activities is a precondition for open access to networks and has been achieved as described above. In addition, an effective third party access (TPA) regime requires a set of rules, procedures and pricing regulations for non-discriminatory access to networks and use of the system by third parties. These are introduced by the EML and secondary legislation. EMRA monitors the activities of network operators and the functioning of the market to ensure the implementation of these provisions. TEIAS and distribution companies are obliged to provide non-discriminatory access to networks in accordance with TPA rules covering: (a) connection to networks and (b) use of transmission and distribution networks, which are regulated by standard connection and system use agreements. In addition, connection and system use prices are regulated through connection charges and transmission/distribution tariffs.

As a result, generating companies and other suppliers can access eligible consumers, and eligible consumers can access potential suppliers – all made possible by market design and trading regulations that create a competitive, market-based mechanism for determining who has the right to use the grid to access customers.

2.1.2.7 Free Consumers and Market Opening

The electricity market was opened in 2003, when large consumers were able to freely choose their electricity suppliers. In 2003, the consumption limit applied to become a free consumer was 9 GWh per year; this limit was gradually reduced to 4 MWh as of January 2015, as shown in Figure 1. During the same period, the theoretical market openness rate (a measure of market liberalization) reached 85%.

Figure 1. Electricity Market Openness Rate, 2003–15

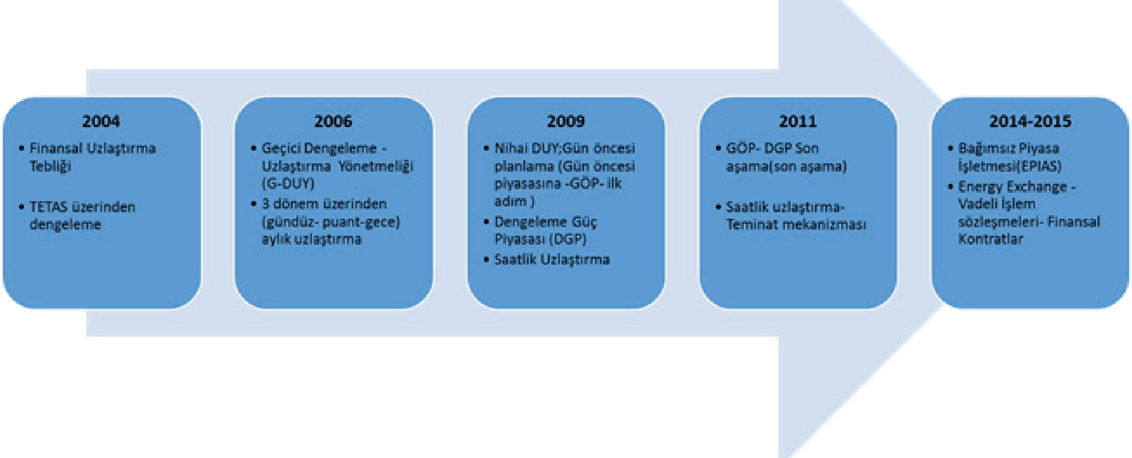


Until 2010, the number of free consumers exercising their right to choose their suppliers remained at very low levels. The number of these consumers has increased significantly since 2010, reaching approximately one million. The suppliers of free consumers are mostly manufacturing companies and wholesale companies (trading companies).

2.1.2.8 Central Balancing, Settlement and Trading Arrangements

Establishing an electricity exchange (i.e. a centralized platform for electricity trading) is a complex and multi-year endeavor. The steps taken are shown in Figure 2 and discussed below.

Figure 2. Development of the Electricity Market



Türkiye's March 2004 Electricity Strategy envisaged the ambitious development of Türkiye's electricity exchange in two stages: (a) an interim balancing and settlement mechanism by January 2005, and (b) a modern day-ahead market with hourly prices by July 2006. The time required was anticipated to be overly optimistic – the first step was completed in 2006 and the second in 2011 – but the results were impressive from the outset. The Market Financial Reconciliation Center (PMUM) was established within TEİAŞ to manage the balancing and settlement mechanism. Even after the Day-Ahead Market was established in 2011, Türkiye's electricity exchange continued to be called PMUM. The development of the electricity market will continue with the separation of PMUM from TEİAŞ in 2015 and its becoming an independent Electricity Markets Operation Corporation (EPİAŞ).

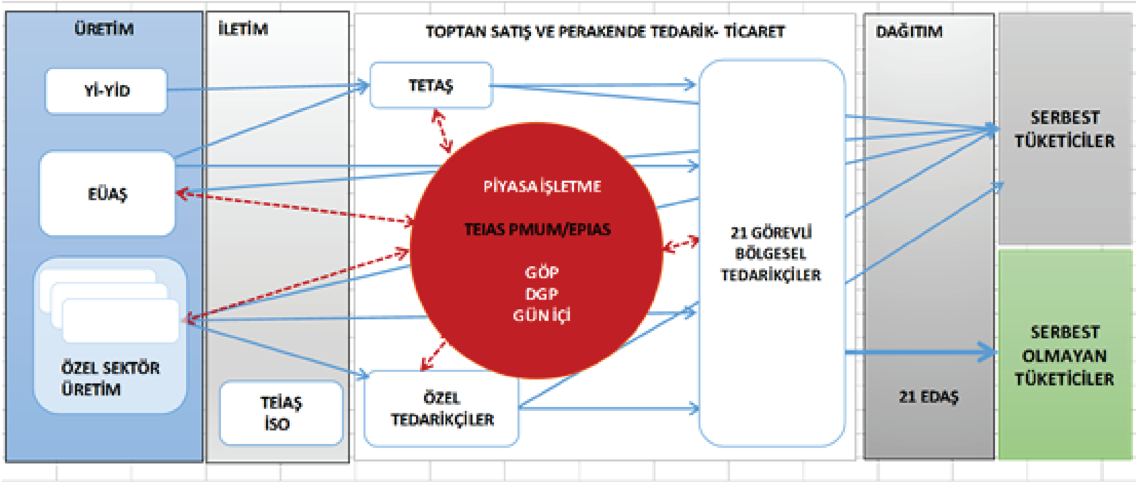
The purpose of the temporary balancing and settlement mechanism was to assist the transmission system operator, TEİAŞ, in its task of balancing electricity supply and demand in real time. It did this through a mechanism that allowed TEİAŞ to prepare an indicative generation schedule one day in advance of actual load dispatch. In the absence of a comprehensive IT system (the development of the IT system had only just begun), generation companies submitted their proposed schedules and prices to PMUM twice a month. TEİAŞ prepared daily demand forecasts; and PMUM prepared daily schedules for power plants (and ensured that TEİAŞ announced them).

Prices in PMUM were not regulated, but instead reflected demand and supply. PMUM provided an attractive centralized market for private generators, including those who own projects based on renewable energy sources. Wholesale prices in PMUM quickly exceeded $55/MWh in the "support mechanism" for renewable energy,[9] hydroelectric project activities accelerated and wind project activities took off. However, the continuation of regulated tariffs at low levels created a disincentive for free consumers to abandon regulated tariffs, and they remained as non-free consumers (many consumers who had become free consumers returned). Instead of trying to make bilateral contracts with free consumers, generation companies sold the electricity they produced on PMUM. Autoproducers (industrial facilities that initially established electricity generation facilities for their own electricity needs) also took advantage of the same opportunity: they sold the electricity they produced on PMUM and purchased the electricity they needed from distribution companies at lower and state-controlled tariffs. As a result, PMUM, which was initially intended to play a much more limited role as a temporary balancing and settlement mechanism, rapidly developed into a liquid wholesale market.

2.1.2.9 Development of PMUM Trading Platforms

In the Electricity Strategy published in 2009, the main transition process steps and target dates for the separation of PMUM's energy trading and balancing markets were confirmed. In line with this strategy, (a) a temporary day-ahead planning market was implemented in 2009 and (b) modern day-ahead and balancing markets were launched by TEİAŞ in December 2011 in accordance with the EMRA regulations. A new intraday market designed by PMUM will soon be put into operation by the Electricity Market Operation Corporation (EPİAŞ), which will replace TEİAŞ. The intraday market is expected to be particularly useful for renewable energy generation facilities with irregular production – it is much easier for these facilities to forecast their production during the day than day-ahead forecasts and it is more appropriate for them to use the intraday market for better balancing. The resulting electricity market structure is shown in Figure 3.

Figure 3. Electricity Market Structure



2.1.2.10 Energy Markets Operations Joint Stock Company (EPİAŞ)

The operation of the organized wholesale electricity markets and the financial settlement of transactions in these markets will be transferred from TEİAŞ to the independent Energy Market Operation Corporation (EPİAŞ). TEİAŞ will continue to operate the balancing power market and the ancillary services market. The government signaled its intention to establish such a company in the Electricity Strategy published in 2009, and the new Electricity Market Law enacted in 2013 also foresaw the establishment of EPİAŞ.

EPİAŞ will be responsible for the operation of organized wholesale markets (such as day-ahead and intraday) for electricity and, in the future, gas, and will become a de facto energy exchange. The EPDK pioneered the work on the establishment of EPİAŞ. TEİAŞ has a 30 percent share in EPİAŞ, Borsa İstanbul has a 30 percent share, and the remaining 40 percent is shared among interested market participants. Financial trading and risk management tools will be developed and operated by Borsa İstanbul. Market participants welcomed the idea of an independent energy market operator, and 97 companies responded to EPİAŞ's invitation to become shareholders in EPİAŞ.

2.1.2.11 TETAŞ and Credit Value as the Administrator of State Guaranteed Electricity Purchase Contracts Sales to Non-Existent Electricity Distribution Companies

Another notable feature of Türkiye's electricity reform is the establishment of TETAŞ in the 1990s to manage the BOT/BO contracts and to act as a buyer of electricity produced by contractual and state-guaranteed BOT/BO plants, together with PMUM, the central market platform for market-based electricity. This dual structure was inevitable when the planned privatization of TEDAŞ's electricity distribution subsidiaries by the end of 2006 proved impracticable and was consequently delayed by several years. If the generation companies had only dealt with TEDAŞ distribution companies with low state-controlled tariffs and industrial companies as potential customers, market-based generation would not have developed as much as it did by selling to PMUM at that time. TETAŞ fulfilled its obligations to Türkiye's BOT/BO model generation companies and blended the electricity produced by the more expensive BOT/BO plants with the cheaper EÜAŞ electricity. TETAŞ supplied electricity to TEDAŞ distribution companies at a time when most of them were not financially sustainable or creditable due to low retail tariffs. TETAŞ continues to supply electricity to distribution companies (including energy purchased from PMUM), all of which are now privatized. TETAŞ also operates the price equalization mechanism that ensures the implementation of a uniform national retail tariff policy.

2.1.2.12Tariffs and Investments and Their Impact on Electricity Market Development

According to the Electricity Market Law;

- All regulated tariffs must reflect costs;
- The price of energy (excluding regulated end-user tariffs) is determined by the market under competitive conditions; and
- If some consumers need to be protected, subsidies are provided through the direct subsidy mechanism rather than through tariffs.

As discussed below, actual implementation of these principles was not always possible – particularly in the 2003–07 period. The government policy that directed EMRA to keep electricity retail tariffs constant between 2003 and 2007 undermined expectations for adequate generation investment and distribution privatization. The fact that retail electricity prices were kept constant despite significant increases in imported gas prices and generation costs since 2005 led to a serious deterioration in the financial sustainability of the sector. This had the effect of limiting the resources available for new public investments, discouraging private investors, and sending false signals to energy consumers about energy use and consumption. Security of supply has once again become a primary and growing concern.

Partial power outages in 2006 accelerated the implementation of a temporary balancing and settlement mechanism (which quickly evolved into an effective wholesale trading platform, as discussed below), but pricing decisions were again delayed. There was pressure on pricing. The government was faced with a choice between two options: (a) allowing EMRA to make significant tariff adjustments and (b) exposing the country to the risk of increased power outages—potentially leading to blackouts, economic slowdowns, and citizen protests. Given the perceived increased risk of power outages, a new cost-based energy pricing mechanism was approved in March 2008, and significant price adjustments were made in 2008–09, as discussed below.

Due to the low retail tariffs, TEDAŞ distribution companies were unable to make payments to their suppliers (EÜAŞ, PMUM, and TETAŞ) on time. This led to the accumulation of outstanding debts of PMUM to vendors (private sector generation companies, TETAŞ and EÜAŞ); to BOTAŞ, the BOT/BO companies of TETAŞ; and to BOTAŞ, the gas supplier of EÜAŞ. In order to prevent the private sector generation companies from backing out, PMUM decided to make payments first to the private sector generation companies and then to TETAŞ and EÜAŞ. The accumulated debts continued to increase until the tariff reform in 2008 and the implementation of the cost-based energy pricing mechanism (discussed below) and were then gradually paid off and the debts were completely settled in 2011.

Cost Based Energy Pricing Mechanism

Due to the rapidly increasing risk of power outages due to insufficient investments and high demand growth, the High Planning Council (a council chaired by the Prime Minister) approved a new cost-based energy pricing mechanism in March 2008. The mechanism, implemented by EMRA in July 2008, envisaged the adjustment of electricity prices on a quarterly basis through mandatory tariff applications (with justification) by companies and tariff adjustments by EMRA to cover increases in the costs of TKİ, TETAŞ, EÜAŞ, TEDAŞ and BOTAŞ (provided that they are reasonably justified), including the cost of electricity supplied from the wholesale market.

BOTAŞ was able to operate the mechanism for gas sales only until 2009 – a problem that still hinders the development of the natural gas market today, as discussed below. In electricity, EPDK implemented pricing from 2008, with the following impressive results:

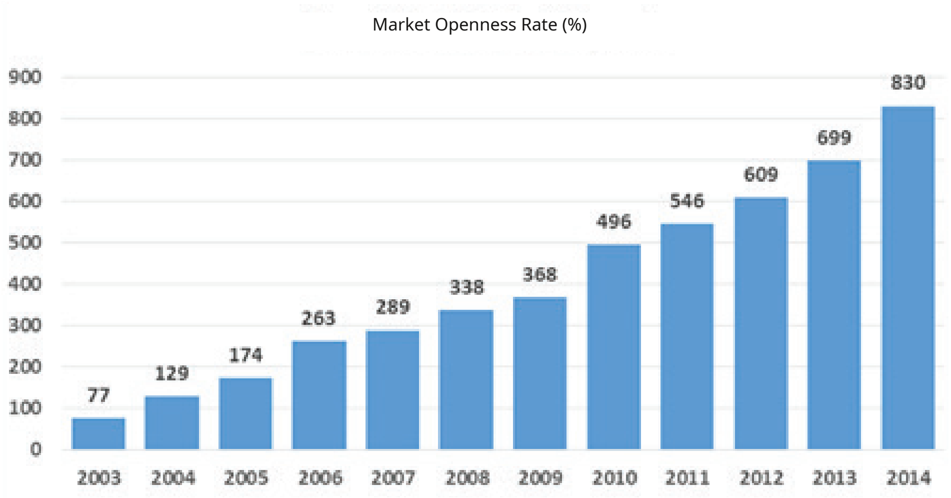
- A series of significant tariff adjustments totaling 60 percent by January 2009 brought tariffs to a level where costs were covered.

- Despite the tariff adjustments, collection rates began to improve, especially after the privatization of distribution.
- Financial recovery was achieved in the electricity sector with tariffs reflecting costs and improved bill collections.
- The financial recovery enabled TETAŞ and PMUM to pay current bills and clear accumulated debts to private sector generation companies by 2010.
- The remaining cross-debts and receivables between public sector companies were offset by a special legislation passed by the Turkish Grand National Assembly in February 2011.

2.1.2.13 Investor Response and Results

The response of the private sector to these legal and regulatory measures and to the development of the PMUM trading platform has been quite striking. Since 2008, approximately 31,000 MW of new generation capacity has been developed without state guarantees. The Day-Ahead Market operated by PMUM currently covers approximately 30 percent of Türkiye's electricity supply – and provides the price signal for electricity bought and sold outside PMUM through bilateral contracts. As discussed in the following section, the distribution privatization program has been initiated, implemented and completed. Finally, as seen in Figure 4, the number of market participants has gradually increased and now exceeds 830. These mostly consist of private generation companies and wholesale/retail companies.

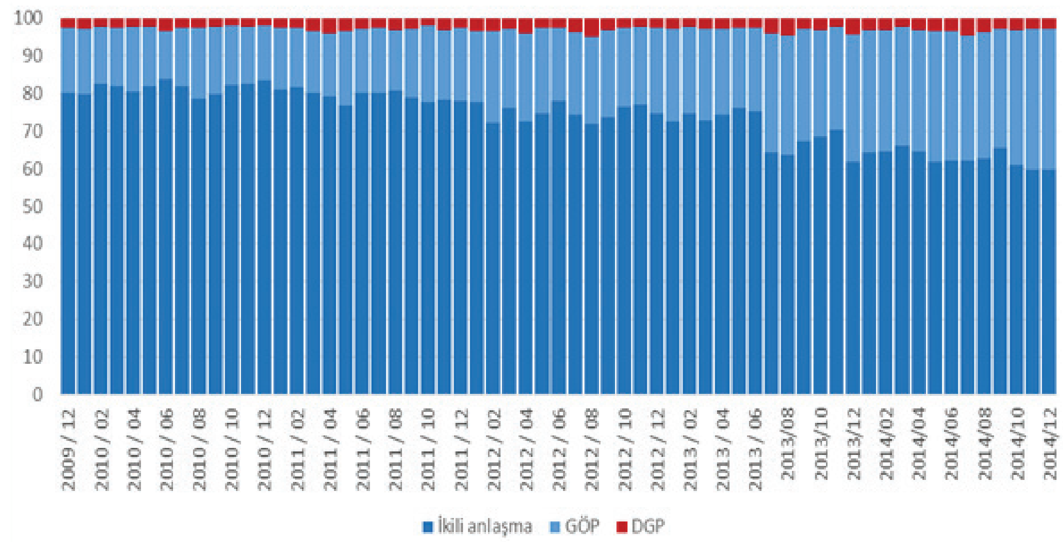
Figure 4. Increase in Electricity Market Participants, 2003–14



Source: TEIAS PMUM.

Approximately 70 percent of Türkiye's electricity is currently bought and sold through bilateral contracts. The remaining electricity is bought and sold primarily in the Day Ahead Market (DAM) and imbalances are resolved in the Balancing Power Market (BPM). Figure 5 shows the increase in the share of the day-ahead market in total electricity trading since the start of day-ahead trading.

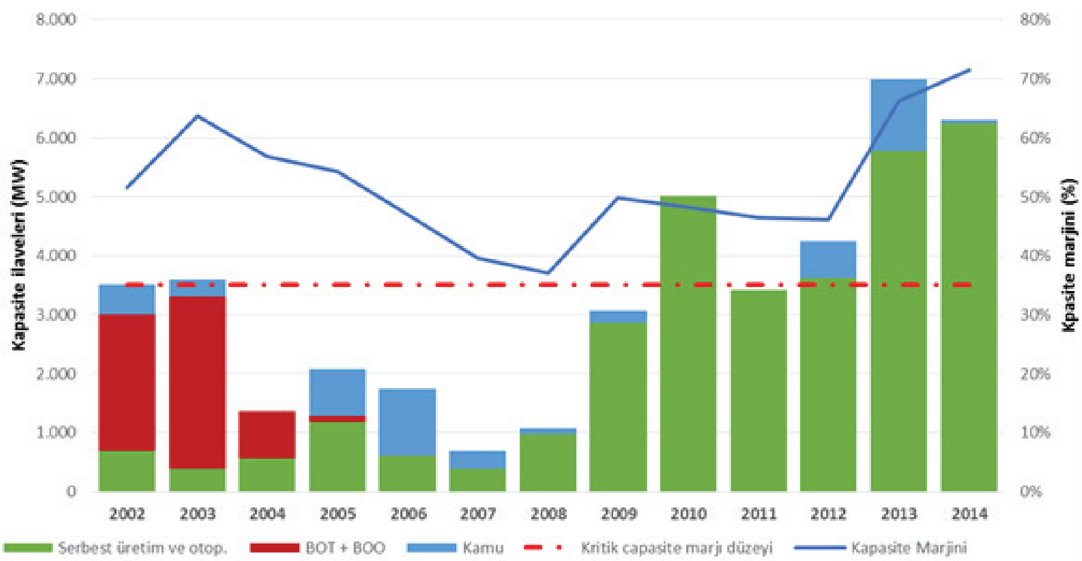
Figure 5. Increase in Trading in the Day-Ahead Market, 2009–14 (%)



Source: TEIAS PMUM.

Figure 6 shows the production capacity additions and capacity margins over the period 2002 to 2014. (*Capacity margin*It shows the percentage of total nominal production capacity above peak demand. It is an indicator of the supply/demand balance, but does not reflect the actual availability of production capacity.*reserve margin*(Not to be confused with.) For Turkey, past experience has shown that the capacity margin should not be lower than 35 percent due to the high share of hydroelectric capacity and low availability of EÜAŞ lignite power plants. (This is shown as the "critical capacity margin level" in the graph.)

Figure 6. Production Capacity Additions and Capacity Margins, 2002–2014



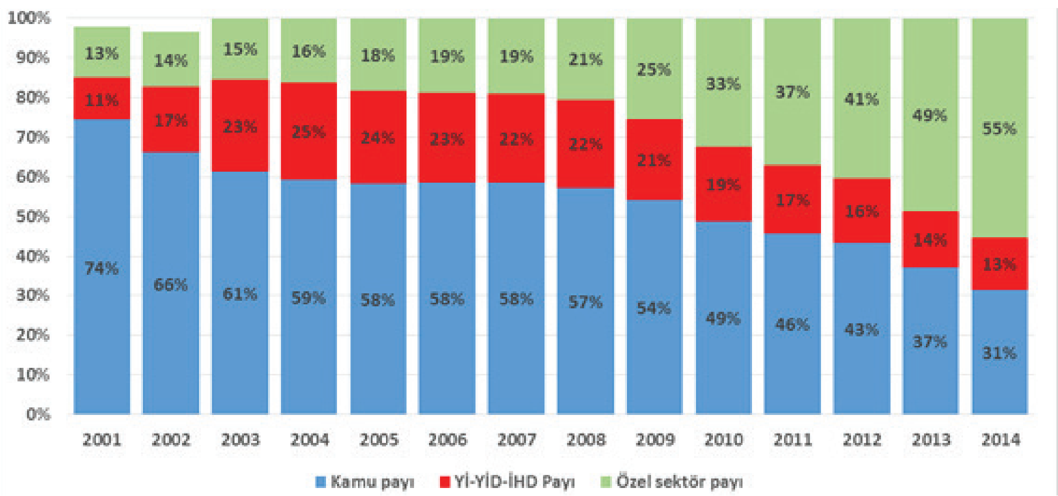
Source: EPDK-TEİAŞ

After the 2000-01 crisis, Turkey embarked on a determined reform path that delivered solid economic growth of over 6 percent per year from 2002 to 2007. Projections through 2007 showed that capacity margins would fall below the critical 35 percent level in 2009 and then continue to decline rapidly. Figure 5 shows that capacity margins have actually increased. This is because the global economic crisis of 2008 hit the Turkish economy as well. Growth slowed and GDP began to contract from the fourth quarter of 2008, bringing annual growth down to 1.1 percent for 2008 and -4.8 percent for 2009. The economy then rebounded, growing 9 percent in 2010. Since 2010, economic growth has stabilized at 3-4 percent per year, and electricity demand growth has fallen correspondingly – at 4-5 percent per year – well below the 6-7 percent annual average recorded in the previous decade. Investment in electricity generation has continued, with capacity additions peaking in 2013. Generation capacity margins have reached 70 percent. The market would have been oversupplied if the severe drought of 2014 had not hit hydropower production.

In the late 1990s and early 2000s, the risk and cost of excess capacity was borne by the public sector – directly by TEAŞ and TETAŞ and indirectly by the Treasury, which acts as the guarantor of the BOT/BO contracts. Now, the risk and cost of excess capacity are borne mainly by the private sector, as owners and financiers of market-based generation companies. Competition in the electricity market has increased. The most affected are older and less efficient natural gas power plants, which now have more difficulty in covering their production costs. Consolidation is expected in the market: some older plants have closed and others are expected to close. However, unlike in 2000–01, the banking sector is expected to be able to withstand the effects of financial difficulties that some of its customers will experience. The challenge for the government is to persuade investors and financiers to continue investing so that security of supply can be maintained after the current temporary excess capacity situation ends.

Figure 7 shows the transition from almost 100 percent public generation to market-based private generation, which currently accounts for the majority of electricity supply at 55 percent, in less than 14 years after the adoption of the EML in 2001. It should be noted that BO power plants, which constitute 10 percent of the total capacity, are also private sector investments and, unlike BOT power plants, will not be transferred to the public, so these power plants can also be added to the private sector's share.

Figure 7. Shares of Private Generation Companies in Total Installed Power, 2001–14 (%)



2.1.2.14 Privatization

Order of priority

The Strategy Document published in 2004 gave priority to the privatization of distribution. This "privatization of distribution first" approach aimed to create a reliable distribution sector that would give confidence to future investors about generation privatizations and new capacity additions. TEDAŞ was not in a position to provide this confidence. If the aim was to privatize generation before distribution, TEDAŞ would be the main customer of generation companies. It was considered that generation privatizations would not be successful because generation companies would not sign contracts with TEDAŞ without a state guarantee. There were no state guarantees and since having them would mean a return to the pre-2001 privatization method, which was contrary to the market-based competitive approach of the EML, it was not wanted anyway.

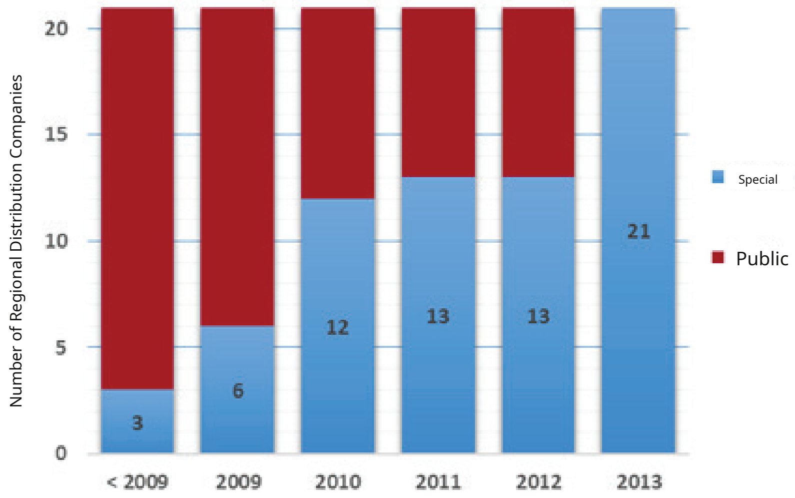
The second problem was the lack of reliable metering, billing, and balancing-settlement functions required for effective wholesale competition; such an environment would require time and investment. The third factor was the desire to reduce losses and theft through effective private sector management.

Distribution Customization

The privatization of distribution was adopted as the most appropriate solution to ensure the necessary investments, satisfactory bill collection performance and efficient distribution network operation in the long term and in a sustainable manner. The first privatization attempt in the 1990s was unsuccessful due to legal issues and uncertainties in the regulatory environment. By the time the second attempt was launched in 2008, these problems had been resolved: (a) the legal issues were resolved in consultation with the Council of State and a revised approach was adopted, where the HRA contract was signed with TEDAŞ and its subsidiaries and the shares of these subsidiaries were offered for sale through a competitive tender process conducted by the Privatization Administration (ÖİB); and (b) the uncertainties in the regulatory environment were eliminated through the Electricity Market Law and EPDK regulations.

The cost-based energy pricing mechanism helped build private sector confidence and the government initiated the implementation of the delayed electricity distribution privatization program. The PA structured the sales process in three stages – four in 2008, three in 2009 and eleven in 2010 – to determine the winning bidders for all 18 distribution companies covered by the program. However, seven of the tenders held in 2010 could not be finalized and were later cancelled and reopened in 2012-23. This time, all seven distribution companies were sold and the privatization program was completed in 2013. The total revenue from the privatization program, as shown in Figure 8, was approximately US$12.7 billion.

Figure 8. Development of Distribution Regions Privatization



Source: OIB

Production Customization

It was assumed that generation privatization could only be successful when there were commercial buyers (such as private distribution companies and wholesale companies) in the market who could contract for the output of the newly privatized generation companies and when there was a developed centralized electricity market. Therefore, generation privatization was initiated after certain progress had been made in distribution privatization and wholesale-retail trading mechanisms had been put in place.

In line with this strategy, the government decided to privatize all thermal power plants and some hydroelectric power plants of EÜAŞ. So far, 10 large thermal power plants (5,758 MW) have been tendered and transferred to new private sector owners, along with some small hydroelectric power plants. The government plans to gradually privatize the remaining plants.

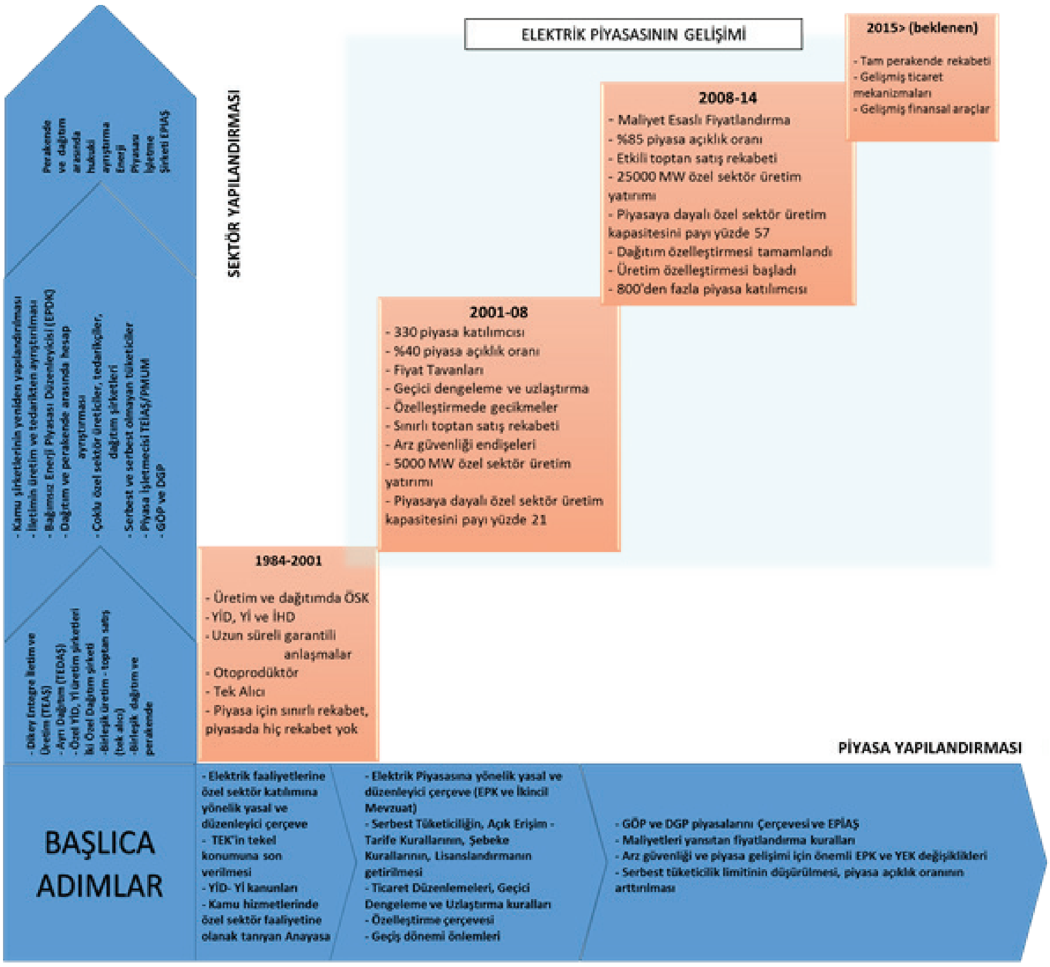
2.1.2.15 Success Factors and Emerging Challenges

As summarized in Figure 9, Turkey has largely achieved the targets it set in 2001. The development of Türkiye's electricity market and the successful completion of the distribution privatization programs at a time when domestic and international markets were experiencing crises and turmoil are based on several factors, including cooperation between different institutions. The government's commitment to the establishment of a free market, market-based investment, and privatization has been perceived by investors. The government has resolutely and repeatedly assured existing and prospective investors that there will be no return to the state guarantees of the 1990s and that generation investors and new owners of privatized electricity distribution companies will have the full support of the government.

The strong response of the private sector demonstrated the credibility of the government's resolve and the strength of the overall legal and regulatory framework. Türkiye's legal and regulatory framework facilitated private sector investment and privatization, and managers—the Ministry of Energy and Natural Resources and the Energy Market Regulatory Authority (EPDK) on the energy side and the Ministry of Finance, the PA, and privatization consultants on the privatization side—worked effectively together to implement the privatization program.

Finally, Türkiye's generally positive long-term growth prospects have helped attract and encourage investors. The Competition Authority's contribution to market design and implementation is also significant. Its recommendations for the separation of distribution and retail supply functions and its decisions on market share during privatization have helped increase the competitiveness of the electricity market.

Figure 9. Measures Regarding Türkiye's Sector and Market Structures and the Electricity Market Development



It is too early to assess the performance of the privatized distribution companies – detailed information is not yet available. Interviews with some private companies and industry associations suggest that several companies are struggling to meet, and may not be able to meet, EMRA's performance targets for system losses and/or bill collection. The cost-based tariff mechanism assumes that companies will continue to operate as long as they meet and exceed EMRA's performance targets. However, if companies fall short of these targets, their financial situation will come under increasing pressure. TEDAŞ's system has been divided into 20 companies to facilitate local companies' participation in the privatization process and to increase competition. These targets were met and competition was intense, including in the tenders for two companies in the southeast – Lake Van and Tigris – where loss and theft rates were unusually high. Interviews indicated that (a) EMRA's performance targets may be excessively stringent for some of the 20 companies offered for sale; and (b) some bidders were overly aggressive in calculating their bids and may have been overly optimistic in assessing their ability to combat loss and theft problems.

Although there is little that the government and EMRA can do about overly optimistic bid strategies of bidders in tenders, if objective assessments reveal that the targets are overly ambitious and/or based on unrealistic baseline information, EMRA may consider adjusting performance targets. Furthermore, in order to successfully implement practices aimed at increasing retail competition and expanding unlicensed production systems, EMRA should continuously and

Careful monitoring and coordination with the Competition Authority will be of vital importance.

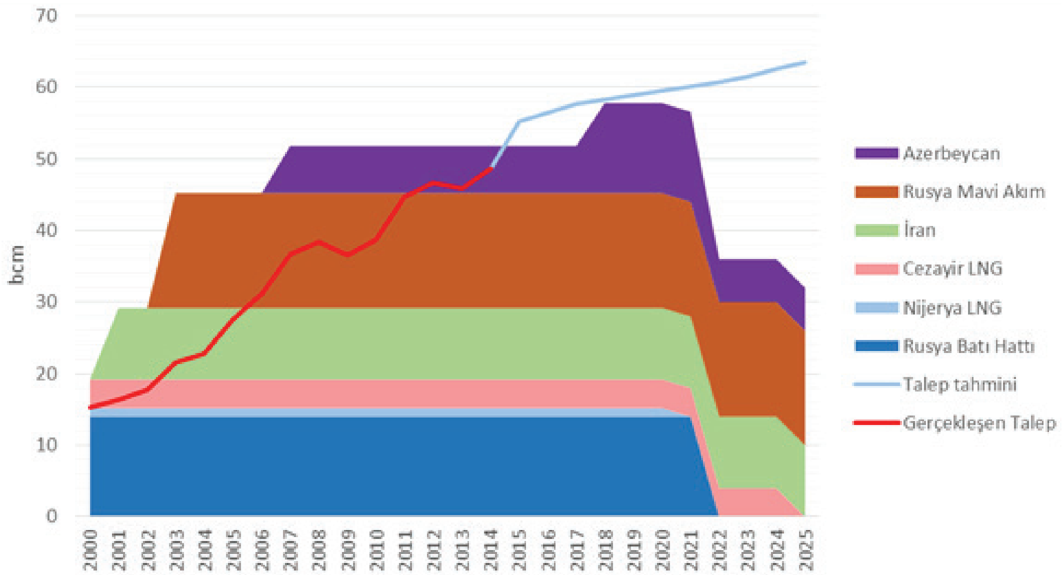
2.1.3 Gas Market Development

In contrast to the electricity sector, progress in the natural gas market has been relatively slow. The government has chosen to proceed cautiously with some key elements of the gas market reform envisaged in the Natural Gas Market Law enacted in 2001. In line with the principles of electricity sector restructuring, the Natural Gas Market Law also envisaged the restructuring of BOTAŞ and the separation of its commercial and infrastructure functions; however, this separation has not yet been achieved. The law formally abolished BOTAŞ's monopoly rights in natural gas imports, distribution, sales and pricing. BOTAŞ waived its monopoly rights in Türkiye's gas imports in a tender held in 2005, which released 4 billion cubic meters (bcm) of gas, and in 2012, 6 billion cubic meters of gas began to be imported by private sector companies. Despite the government's strong efforts, BOTAŞ is still the largest gas importer with almost 80 percent market share. The remaining 20 percent is shared by seven private sector companies.

The delay in unbundling BOTAŞ and BOTAŞ's failure to consistently apply the pricing mechanism have allowed the government to cushion the impact of gas price increases on the international market. These practices have allowed Türkiye to charge industrial enterprises the second lowest gas prices in Europe – only Romanian industrial enterprises have lower gas prices thanks to control over domestic gas producer prices. However, these practices cause significant distortions and undermine the development of a competitive gas market. The private sector has also expressed concerns about the conflict of interest posed by BOTAŞ's being both a major gas trading company and the owner and operator of the gas transmission system.

As seen in Figure 10, the current long-term gas purchase agreements are not sufficient to meet the projected demand growth. Large-scale additional gas imports, including spot LNG, will be needed. If these imports are not carried out by BOTAŞ, further liberalization of imports will be required, which will require the amendment of the Natural Gas Market Law. Due to insufficient gas storage capacity, gas supply cannot meet daily consumption during cold seasons. On the other hand, there are bottlenecks in BOTAŞ's gas network that restrict not only gas flow but also gas trading by future competitors. Until these problems are resolved, gas supply security will continue to be at risk.

Figure 10. Gas Import Contracts and Actual/Projected Gas Demand, 2000–25



Source: Prepared using BOTAŞ and EPDK data.

The 2001 law has been shown to be more effective in encouraging private sector participation in gas distribution in Türkiye. The EPDK has organized very successful and competitive license tenders for the construction of new urban distribution networks and the provision of distribution and retail supply services. Currently, gas service is available in 70 of Türkiye's 81 provinces, and all but one of these 70 provinces are provided by private companies. Competition for distribution licenses has been intense. Most of the companies that won EPDK's license tenders offered very low distribution fees for the first eight-year tariff period, and in some cases, no fees other than the initial connection fee were charged. EPDK is currently working on the tariffs to be applied for the second tariff period. In order to better reflect the cost of distribution services, distribution fees will inevitably need to be adjusted, as EPDK has done for electricity distribution.

2.1.4 Support for Renewable Energy

Although quite conservative in the European context, Türkiye’s support programmes have been effective in encouraging private sector investment in renewable energy. It is striking that Turkish companies invest in wind farms under a support programme that pays less than half the price paid to sell to the electricity market or to attract private sector companies under similar wind conditions in Bulgaria and Romania. The politically sensitive and legally controversial (and potentially costly) reversals that were subsequently seen in Bulgaria and Romania, which were aimed at excessive correction, have so far been avoided in Türkiye. However, there are concerns that solar support at $133/MWh could lead to large-scale expansion and become a financial burden for electricity consumers in the future, unless a ceiling is set for subsidised solar capacity. Given the ongoing decline in investment costs for solar installations, it may be possible to develop Türkiye’s rich solar potential in the medium term with support prices no higher than market prices.

2.1.4.1 Market-Based Incentive for Renewable Energy Investments

Turkish private sector companies were given the opportunity to invest in market-based hydroelectric power plant projects in 2004. Companies entered into hydroelectric power plant – and later other renewable energy – investments primarily because of the electricity market, where they expected to sell their production to large-scale consumers and trading companies at a profit at market prices. This contrasted with the approach taken in some other European countries, where governments encouraged private investment with attractive support programs offering prices well above the current wholesale prices in their electricity markets. There was initial hesitation among Turkish banks to finance renewable energy. However, the pioneering work of the Turkish Industrial Development Bank (TSKB) and the Turkish Development Bank (TKB) led the way for other banks, and later the large banks followed suit. As a second step in the effort to attract the private sector to renewable energy investments, the government prepared a Renewable Energy Law in 2005, which established a supportive security mechanism for renewable energy. The law stipulates that renewable energy producers will purchase the electricity they produce at a price of $55/MWh if they cannot sell it at a higher price in the market.

2.1.4.2 Holder Support Mechanism

The private sector was attracted to renewable energy investments based on the strength and promise of the electricity market, supported by a conservative floor price guarantee in the event of low market prices. The government, aware of much more generous support programs elsewhere, amended the Renewable Energy Law to provide more support in Türkiye. The Turkish Grand National Assembly approved an amendment law in December 2010, which provided for more support. The support provided in the law included (a) a feed-in tariff based on technology and (b) a support mechanism (a renewable energy pool) that provided for purchase guarantee arrangements. The approved feed-in tariff for hydro and wind ($73/

MWh) were similar to PMUM prices. The tariffs applied for geothermal ($105/MWh) and biomass and solar electricity ($133/MWh) were much higher than PMUM prices, but were below the prices expected by some investors, especially for solar. Instead, the new law introduced additional support through local content incentives. The government set these prices based on the expectation and assessment that the prices of renewable energy technologies would continue to fall, and therefore higher support prices should be avoided.

Türkiye's mechanism requires renewable energy producers to choose between benefiting from the support mechanism or selling the electricity they produce to the market in October of each year. Initially, in 2012 and 2013, investors overwhelmingly preferred the market option. For 2015, many investors preferred to switch to the support mechanism considering the current uncertainties; as a result, approximately half of the eligible renewable energy capacity entered the support mechanism, while the other half continued to sell to the market. The Electricity Market Law adopted in 2013 removed the licensing requirement for small generation facilities (less than 1 MW) based on renewable energy resources and imposed an obligation on the distribution companies in the regions where these facilities are located to purchase electricity from these facilities (since this is a national program, its reconciliation is carried out within the PMUM). It is expected that these special regulations for small-scale renewable energy production facilities will accelerate investments in solar energy in particular.

As a result of the development of the electricity market and the support mechanisms described above, approximately 16,000 MW of new generation capacity based on renewable energy sources was commissioned between 2002 and 2014.

2.1.4.3 Environmental and Social Dimensions of Renewable Energy Investments

Renewable energy enjoys broad support compared to thermal electricity generation. However, large-scale renewable energy investments, including small and medium-scale projects, inevitably have significant environmental and social impacts. Turkey is no exception. The large number of applicants has occasionally caused bottlenecks in the environmental impact assessment and project approval processes. Investors have complained about the complexity of procedures, delays and lack of transparency. Environmentalists and citizens have expressed concerns about the inconsistent application of environmental permitting and licensing procedures/guidelines and the lack of public disclosure of decisions.

In various parts of the country, renewable energy projects (especially hydropower plants) have caused public outrage mainly due to (a) the lack of adequate public consultation procedures during the licensing and decision-making stages of the projects and (b) the rushed expropriation procedures used in these projects. While public consultation may be mandatory during the EIA preparation phase depending on the size and environmental category of the projects, meaningful and accessible consultation with communities is often not carried out before, during and after project construction. As a result, people mainly resort to the courts for redress of their grievances. This is not an optimal process for public relations and managing social risks.

The assessment of cumulative impacts of renewable energy investments is particularly problematic. Environmental impact assessment and project approval processes focus on individual projects undertaken by different investors at different times rather than a series of projects on a river or a group of wind farms. The government has now adopted a river basin-scale planning approach. However, it will take 5–10 years to prepare integrated plans for all 25 river basins, and many additional hydropower plants will have been built by then. Solutions currently being implemented for wind farms built in Türkiye include an annual licensing cycle and competitive tenders for access to the grid by TEİAŞ. Time will tell whether and how these approaches will address these issues.

Investor associations emphasize that the entire sector has suffered from the mistakes of a few inexperienced investors. They agree that the damages suffered by those who suffered from these mistakes should be compensated, but they state that this should not be done by questioning the entire sector. All parties seem to agree that more and more transparent consultation is needed in the process and that decisions (whether approval or rejection) should be clearly justified. They also express the view that the lengthy review process should be shortened and rules and procedures should be standardized.

2.1.5 The Leading Role Played by Turkish Investors and Their Mostly Turkish Financiers

Türkiye's electricity reform program has attracted major investments from various foreign companies. Two of them – CEZ from the Czech Republic and E.ON from Germany (taking over from Verbund from Austria) – have joined the electricity distribution business in partnership with established domestic companies since the privatization program. In addition to CEZ and E.ON, six other foreign companies generate electricity in Türkiye: ACWA from Saudi Arabia, EdF Energies Nouvelles and ENGIE (formerly GdF Suez) from France, EnBW from Germany, OMV from Austria, and Statkraft from Norway. Most of these operate in partnership with established domestic companies, and all without long-term contracts with state guarantees. (India's Tata is also developing a hydroelectric power plant project in Georgia that will generate electricity for export to the Turkish market.)

Foreign banks providing project financing include BNP Paribas, BPCE, Deutsche Bank, Erste Group, MUFG, Raiffeisen, Société Génerale and Unicredit. The European Bank for Reconstruction and Development (EBRD), the European Investment Bank (EIB) and the International Finance Corporation (IFC) have also made significant financial commitments. While there is an impressive list of companies and banks, foreign investors and external financing have played a relatively small direct role in Türkiye's energy sector – particularly in the electricity sector, where there has been significant private sector investment –. On the other hand, foreign investment and external financing also support Türkiye's energy sector indirectly through Borsa Istanbul (Istanbul Stock Exchange) and local banks. Foreign companies are expected to increase their presence in the future through stakes in generation companies and possibly distribution companies.

Turkish investors and their mostly Turkish financiers have played a leading private sector role. The "secret" to Türkiye's success in energy reforms lies in the three-way cooperation and risk sharing between (a) successive governments, (b) public institutions and state-owned companies, and (c) Turkish investors and their mostly Turkish financiers. This cooperation accelerated after the adoption of the electricity and gas market laws in 2001, which initiated the liberalization of Türkiye's energy markets. Turkish investors took the risk of investing in electricity generation without a state guarantee, trusting in the strength and promise of the market at a time when the market existed only on paper with the Electricity Market Law enacted in 2001. They continued to invest year after year without waiting for the market to settle. The investors' desire for a centralized market is quite evident from the interest they showed in PMUM for sales since its establishment in 2006. –– However, from time to time, long-term contract requests come from financiers, if not from investors. Companies continue to trade electricity in PMUM in ever-increasing amounts. More than a hundred investors have applied to become shareholders in the new PMUM, namely the Electricity Market Operation Joint Stock Company (EPİAŞ).

The Renewable Energy Law enacted in 2005 has increased the interest of the private sector in renewable energy investments. The response of the private sector, mostly Turkish companies, has exceeded all expectations. The first wave of investments focused on hydroelectricity, then wind, and now solar energy investments are starting. The saying "If you don't have a 20 MW plant, you are nothing" reflects the excitement of Turkish investors. Not only experienced Turkish construction companies but also other Turkish companies with little or no previous experience in the energy sector have invested in medium-scale hydroelectric power plant projects and more recently in wind power plants, and will probably invest in solar power plants in the near future.

Following the extensive restructuring of the banking sector following the 2000-01 crisis, Turkey now has a banking sector that can provide large amounts of financing to Turkish investors. Turkish banks have provided a large portion of the debt financing to energy investors. While Turkish banks appear to be quite willing to take risks in the energy sector, they have wanted investors to assume the main risk. They have asked for capital requirements – which is normal – and have also preferred to provide corporate financing rather than project financing. Many Turkish companies new to the energy sector have been able to obtain some of the debt financing for energy projects due to their strong balance sheets. The use of capital markets through public offerings and bond issues has been limited and offers significant potential for financing a certain portion of future energy investment needs. Many companies, including large new entrants to the energy sector, are family-owned and may consider an IPO option. The government owns several energy companies that would be good candidates for IPOs. As long as electricity and gas markets are functioning and prices are allowed to be determined by the market, the availability of financing is not expected to be a constraint on energy investment.

2.1.6 Türkiye's Nuclear Program

Türkiye has a long history of interest in nuclear energy. The Atomic Energy Commission was established in 1956. The commission was restructured as the Turkish Atomic Energy Authority (TAEK) in 1982. The first feasibility report on a nuclear power plant was prepared in 1970. Subsequently, proposals and initiatives were made to initiate projects in 1973, 1976, 1980 and 1992. Nuclear energy was included in Türkiye's development plan in 1993 and a formal tender process for a 2,000 MW nuclear power plant was initiated in 1996. After a series of delays and postponements, this effort was abandoned in 2000 as the economic situation continued to deteriorate. With the recovery following the economic crisis, nuclear energy efforts were restarted in 2006.

2007In 2008, the Law on the Establishment and Operation of Nuclear Power Plants and the Sale of Energy (Law No. 5710) was enacted and in 2008, companies were asked to submit bids for the construction and operation of a nuclear power plant in Akkuyu (a small town on the Mediterranean coast) under the Build-Operate model. No treasury guarantee was provided, but TETAŞ was envisaged to be the buyer of the electricity produced. The only bid was submitted by a consortium led by Russia's state-owned nuclear energy company Atomstroyexport, and the tender was eventually cancelled. After several unsuccessful competitive tender attempts, the government decided to negotiate directly with the Russian government. Following intergovernmental negotiations, an intergovernmental agreement was signed between the Prime Minister of Turkey and the President of Russia in May 2010 for the construction of a 4,800 MW nuclear power plant (four units of 1,200 MW each) in Akkuyu. The agreement was ratified by the Turkish and Russian parliaments later that year.

These developments reactivated some suppliers who had not submitted bids in the initial tender process, and various bids were subsequently received. The government held meetings and negotiations with several groups and their governments. A second contract was subsequently signed in 2013 with a French-Japanese consortium for a 4,480 MW plant (four units of 1,120 MW each). The second plant will be built in Sinop on the Black Sea coast. The intergovernmental agreement was signed by the Turkish Grand National Assembly (TBMM) in April 2015. According to the intergovernmental agreement, the commissioning dates of the four units are as follows: unit one in 2023, unit two in 2024, unit three in 2027 and unit four in 2028. Additional contracts are expected to be awarded.

TETAŞ will purchase 70 percent of the output of the first and second units of the Akkuyu Nuclear Power Plant and 30 percent of the output of the third and fourth units at an average price of $123.5/MWh for a period of 15 years from the date of entry into commercial operation of each unit. The rest of the power plant output will be sold on the electricity market by the Akkuyu Company. The government will not initially acquire an equity stake in Akkuyu, either directly or through public companies. The Akkuyu Company will start with 100 percent Russian ownership, but it is reported that the Russians plan to reduce their ownership share to 51 percent. Therefore, Turkish companies (public and private) may become partners in the company in the later stages of construction and/or operation. 15

After a one-year operating period, by which time the debt portion of the plant financing will have been paid off, Akkuyu Company will pay 20 percent of its profits to the Turkish Government. TETAŞ will purchase 100 percent of the Sinop plant's output at an average price of $108.3/MWh (excluding fuel). Considering the capital participation of EÜAŞ and the fact that 100 percent of the Sinop plant's output will be purchased by TETAŞ, the visibility of public companies is higher in the Sinop plant than in the Akkuyu plant.

The electricity price of $123.5/MWh for the Akkuyu plant and $108.3/MWh (excluding fuel) for the Sinop plant will be well above the current market prices for base load electricity in the Turkish market. The UK Government[10]There is a widespread expectation that the Government will make arrangements to pass on these costs to electricity consumers in some way, on the same grounds that the Government has put forward that these arrangements will be beneficial in terms of security of supply, diversification and climate change. Whether for nuclear or renewable energy, guaranteed purchase arrangements inevitably reduce the size of the competitive market (i.e. the market in which private sector companies can compete).

The government's nuclear energy strategy envisages a number of nuclear energy projects. If the economy continues to grow at an average annual rate of 3–4 percent, electricity demand will continue to grow at an average annual rate of 4–5 percent. Although the growth rates are lower than in the previous decade, the system is now larger and will require continuous capacity additions. Türkiye's strategy envisages an increasingly diverse fuel mix for electricity generation: reducing the share of gas, increasing the share of renewables, fully utilizing remaining lignite resources, and introducing nuclear energy as a significant baseload source of electricity. Preparations for the first two nuclear power plant projects, planned to begin construction in the next few years, have encountered significant opposition from the local population and civil society. For the future implementation of its nuclear program, the government intends to: (a) provide greater information on the role of nuclear energy and the need for continued expansion of electricity production; (b) increase consultation on site selection; (c) increase transparency on waste management and contingency plans; and (d) consider separating the regulatory functions of TAEK and giving them to an independent nuclear regulatory authority. It is stated that a new Nuclear Energy Law and the new law prepared will cover the areas specified in articles (b), (c) and (d) above.

2.1.7 Political Developments and Favorable Environment for Energy Reform

Turkey experienced significant political change during the period covered by this study. The 1980s began with a military coup in September 1980. Governments that followed a short period of military rule were typically unstable and short-lived. Economic performance varied from year to year. Towards the end of the twentieth century, deficits increased and the economy slowed down. The twenty-first century began with a deep crisis in Türkiye. This seemingly never-ending political turbulence and upheaval created an unstable political environment in the 1980s and 1990s that was unsuitable for implementing energy reforms. The 2001 economic crisis ultimately provided an opportunity for energy reformers to put forward and secure approval of a rather ambitious legislative package for electricity and gas reform.

Unlike the 1980s and 1990s, Turkey had a stable government between 2002 and 2015. After the 2002 elections, the new government inherited an energy reform package initiated in 2001 and decided to continue to support and implement this reform package. However, the initial pace of reform implementation was slower than reformers had hoped. Oil prices were liberalized in 2005, but electricity pricing was clearly quite cautious: electricity prices were kept constant for five years between 2003 and 2007.

After being re-elected in the 2007 general elections, the government responded impressively to the newly emerging electricity supply security risk. From 2008 onwards, energy reforms gained momentum and yielded impressive results in the electricity sector, including the previously discussed renewable energy investments.

The government has acted more cautiously in gas sector reforms. Unlike the situation in the Electricity Market Law of 2001, the government has delayed the implementation of key measures in the Natural Gas Market Law of 2001, and BOTAŞ has failed to consistently implement the cost-based energy pricing mechanism enacted in 2008. As discussed earlier, gas sector reform is not yet complete.

Although the government has largely left "normal" energy contracts and investments to the private sector, it continues to play an active role in BOTAŞ's gas imports and nuclear energy investments/contracts. State guarantees are not provided, but the state places large and long-term liabilities on the public sector in a structure where BOTAŞ is the main gas buyer and TETAŞ will be the main buyer of electricity produced by these plants under the nuclear power plant contracts.

2.1.8 Energy Pricing and Subsidies

Price reform is a key element of successful energy reform when prices are below cost-recovery levels and the government's ability to provide subsidies is limited. This seemingly obvious fact is easy to state but difficult to translate into action, and price reform has proven difficult to implement in many countries. Although Turkey has made significant progress in energy price reform, challenges remain, particularly in the natural gas sector.

2.1.8.1 Oil

The oil price reform and liberalization was the first step taken and succeeded. This process lasted for decades. The liberalization process essentially started with the restructuring of TP in 1983. Then, price liberalization followed in 1989 with a law granting price setting rights to private companies. However, the initial impact was limited because public companies continued to dominate the sector and private companies had limited pricing freedom in reality.

In 1998, the government adopted an automatic pricing mechanism that sets price ceilings for petroleum products based on international prices.

The Petroleum Market Law enacted in 2003 assigned the EPDK to develop the electricity and gas markets, as well as the petroleum market, which it was tasked with developing in 2001. In accordance with the law enacted in 2003, petroleum prices were fully liberalized in 2005. The EPDK continued to monitor the functioning of the market and intervened in cases where it suspected price collusion. Gasoline and petroleum retail prices are at high levels due to high consumption taxes. Targeted tax exemptions were introduced for public transportation and agriculture.

2.1.8.2 Electricity and Natural Gas

Electricity and natural gas prices were managed by the government (through the Ministry of Energy) until the establishment of EMRA in 2001. However, although the authority to regulate prices was transferred to EMRA with the electricity and natural gas laws enacted in 2001, government influence still continues in practice. The cost-based energy pricing mechanism introduced in 2008 was designed to remove state control. This mechanism has been effective in electricity, where EMRA has been implementing the pricing mechanism since 2008 – with impressive results, as discussed above. BOTAŞ, on the other hand, has not been able to implement the mechanism consistently – a problem that still constrains the development of the natural gas market and indirectly affects the electricity market. The government effectively controls wholesale gas prices through BOTAŞ, leaving EMRA only the functions of regulating gas distribution and supply services.

2.1.8.3 Public Acceptance

Drivers in Türkiye are undoubtedly unhappy with the fact that the prices they pay at the pump for petrol and diesel are among the highest in Europe. However, adjustments to petrol, electricity and gas prices are being accepted by consumers.

Acceptance of high oil prices and the significant adjustments in electricity prices in 2008-09 was facilitated by Türkiye's economic growth performance since 2002 and the parallel relative increases in household incomes that eased the burden of price increases.

The government has at least 22 separate social support mechanisms. The only targeted energy subsidy in place is free coal distribution to low-income households at the municipal level. The government has not implemented targeted social support for the payment of electricity and gas bills by low-income consumers. Since households account for a small share of electricity consumption (about 20 percent) and an even smaller share of gas consumption (directly or through electricity), direct support to low-income households would be less costly than the subsidy currently applied on a general basis to the wholesale price of natural gas. The energy tariff in electricity prices applied to households is currently higher than the prices applied to non-residential electricity consumers. –This practice is a factor that will encourage consumers to switch suppliers when they become free consumers.

The government's main economic concern is not so much the impact of energy price increases on households as their impact on the economy through inflation and the competitiveness of Turkish industry. The assessment of economic policies seems to be that energy price adjustments can continue as long as they do not jeopardize economic growth and household income growth. Energy price adjustments are seen to be accepted as an inevitable cost of development. On the other hand, this acceptance does not mean that all households can comfortably pay their energy bills, so targeted social support and energy efficiency programs can be considered for low-income households.

2.1.9 Conclusion: Results of Türkiye's Energy Reforms

Energy reforms have provided the security of supply needed to meet the demand arising from Türkiye's rapidly growing economy and its rapidly growing population with rapidly increasing incomes.

The main lessons learned from Türkiye’s energy reforms are summarized in Table 1 at the end of this section. These lessons and Türkiye’s achievements have been discussed in previous sections, which outlined Türkiye’s transformation towards a competitive electricity and gas market model that it implemented in 2001. The discussion focuses primarily on the electricity sector; progress in the gas sector has been more limited and is discussed in more detail in Section 2.2, where energy reform challenges are discussed.

Energy security has been achieved through major investments. Since 2001, most of the investments have been made by private sector investors without state guarantees and based on the strengths of the electricity and gas markets. This has helped Türkiye's efforts to maintain fiscal and external balances.

Energy security has been achieved through diversification of Türkiye's primary energy mix through energy reforms:

- The transportation sector's dependence on petroleum products continues, but the use of oil in electricity generation has been almost eliminated and its use in industry has also been reduced;
- While natural gas use was almost zero in 1987, within 20 years it has become an important energy source, especially in electricity generation (it has a share of almost 50 percent);
- Private sector investments were attracted to complement the hydroelectric production capacity of EÜAŞ, and after the enactment of the Renewable Energy Law in 2005, the private sector became a pioneer in other renewable energy investments; and
- Another major step towards diversification has been taken with the signing of contracts for two major nuclear power projects to be commissioned in the next decade.

Energy reforms, which have largely led to market-based and cost-reflective energy prices, have supported more efficient use of energy and thus energy security. Increased energy efficiency has helped control demand growth and increase not only energy security but also Türkiye's overall competitiveness.

The “secret” to Türkiye’s success in implementing reforms is (a) successive governments, (b) public institutions and state-owned companies, and (c) Turkish investors and mostly Turkish financiers. lies in the three-way cooperation and risk sharing between the

Table 1. Key Lessons to be Learned from Türkiye’s Energy Reforms

Features of the Reformation	Application in Türkiye	Applicability in Other Countries
Legal framework	Electricity and Natural Gas Market Laws, Renewable Energy Law	The functioning of the legal system and an independent judiciary.
Regulatory framework	Energy Market Regulatory Authority	It requires independence and professionalism, government commitment and support, and competent professionals.
Central electricity market	PMUM, soon EPİAŞ	A large number of buyers and sellers are required. For small countries/systems this can be achieved through regional market solutions.
Launch of the market	Public companies and existing private companies engaged in manufacturing activities, including autoproducers in the industrial sector	Willingness of public companies to sell to the market. Availability of off-market or other private sector production capacity.
Addressing existing long-term contracts	TETAŞ in parallel with PMUM (contracts and market in parallel).	Availability and capacity of transitional vehicles.
Listing of reform steps	Before distribution privatization, initial generation investments, large generation investments parallel to distribution privatization; later stage generation privatization. Parallel to these, creation of central platforms; PMUM for market-based generation companies and TETAŞ for guaranteed independent energy producers.	The reliability of the government's commitment to implement reform legislation and strategy. The availability and capacity of transitional instruments.
Availability of new long-term contracts	There are no contracts longer than one year yet. Borsa Istanbul will offer financial instruments.	The market's ability to attract investors and financiers without long-term contracts
Wholesale market price	It is determined in PMUM based on supply and demand. In parallel with this, TETAŞ.	Willingness to accept market prices rather than price controls.
Mitigation against gaming/price manipulation by market participants	The state has and will continue to have a significant presence in the wholesale market through TETAŞ and EÜAŞ. EMRA and the Competition Authority can investigate allegations of manipulation.	The power of public institutions, market share of public production/ supply companies.
Retail market price	Cost-based pricing mechanism operated by EMRA as a temporary mechanism. Regulation of network services by EMRA on a permanent basis.	Willingness to accept cost recovery, including pass-through of wholesale prices.
Development of renewable energy	It is based on a functioning central electricity market; technology-specific feed-in tariffs provide additional convenience. The intraday market will facilitate large-scale renewable energy penetration.	A functioning wholesale market is required.
Customization of distribution	Legal and regulatory framework and institutions. Privatization Administration, Energy Market Regulatory Authority, Council of State.	Government commitment is needed, but so is a solid legal and regulatory framework and institutions
Work environment	Well-established local companies and prospective new entrants with high risk appetite. Foreign companies are present but the energy sector is not dependent on foreign participation.	The presence, size and risk appetite of local businesses.
Banking sector	Strong local banking sector (after radical banking sector reform). Foreign banks present but largely through local banks.	Existence, size and risk appetite of local banks.
Capital market	Borsa Istanbul (a large stock exchange), local and foreign investors.	Availability, size and risk appetite of investors.
Economic growth	Governments that manage the economy for sustainable growth and the well-being of citizens and to be successful in elections.	Political stability, the ability of governments to look beyond the immediate future and current problems.
Energy security for economic growth and citizen well-being	Rapid economic growth and increasing energy demand following a successful recovery from the 2001 economic crisis.	Is energy security at risk now/in the near future or in the medium/long term?
Financial balance	Determination to control contingent liabilities.	Financial condition. The ability of the state budget to carry contingent liabilities.
Current account balance	High energy import dependency. Need to control energy import bill to reduce current account deficits.	Having energy resources in the country. The share of energy in the country's import bill.
European Union	The accession goal provides an anchor for Türkiye's own modernization process.	The existence of effective external reform drivers.
Regional integration	The potential to become a regional energy terminal (especially for gas) to ensure greater energy security for Türkiye and contribute to energy security in the region and Europe.	Geographical and geopolitical feasibility of integration.
Public acceptance of energy price adjustments	Price adjustments were accepted as an inevitable part of economic growth and development. Electricity and gas price adjustments were preceded by increases in household incomes. No targeted social support for low-income consumers.	Expectations for growth and increases in the economy and household income. The availability of effective social support mechanisms for low-income consumers.

2.2 Overview Chapter 2: Challenges to Energy Reform

Past success can help guide the way forward, but it does not guarantee future success. The Turkish economy continues to grow. Demand for energy, especially electricity, continues to grow. The energy sector will need to overcome the challenges of providing the security of supply that is essential for Türkiye's growth and development and the well-being of its citizens. Some of the challenges facing the government now may be as challenging as they were in the past decade. Turkish investors and their mostly Turkish financiers have invested heavily and learned a lot, but their enthusiasm is not as great as it once was. Their risk-taking capacity has increased, and their risk understanding has improved. They expect the liberalization of the energy market to continue and for transparency and governance in the energy sector to improve and continue to improve.

The situation is more critical in the gas sector, where reform has lagged behind the electricity sector and supply security is at risk. However, considering that natural gas has the largest share in electricity production, problems in the gas sector will directly affect the electricity sector, even if there is currently excess supply. Governance problems in the EPDK, energy SEEs and the Ministry of Energy affect the entire energy sector.

Türkiye's economic growth rate for 2014 is projected at 2.9 percent. The World Bank estimates that the Turkish economy will continue to grow at an average annual rate of 3.0 to 3.5 percent in the 2015-17 period, but notes downside risks such as continued slow growth in Europe and geopolitical tensions. The decline in oil prices since mid-2014 and the ongoing decline in gas import prices could accelerate growth in 2015 and reduce the current account deficit and inflation.

On the other hand, concerns about the unpredictable business environment in Türkiye and the strength of key economic institutions act as a deterrent to domestic and foreign investors. These concerns include the business environment in the electricity and gas markets and the strength of key public institutions in the energy sector. Turkish energy investors and their mostly Turkish financiers, the irreplaceable third element of the three-way cooperation that explains the success of Türkiye's energy reforms, are concerned about the continued development of the energy market and the operational autonomy and transparency of the EMRA, energy SOEs and the Ministry of Energy. Despite the remarkable successes described in the first section of this overview, reforms in the energy sector will need to continue if Turkey is to continue to ensure security of electricity and gas supply without having to resort again to large-scale – and in the long term unsustainable – state support mechanisms.

This energy sector review highlights three broad energy reform challenges:

- Natural gas market reform,
- Further development of the electricity market, and
- Governance issues in the energy sector.

Each of these issues is addressed individually in the following sections.

2.2.1 Natural Gas Market Reform

After a short-term oversupply in the gas market – resulting from BOTAŞ's excess contracts – demand is once again catching up with contracted import quantities. Current gas demand, at around 47 billion cubic meters per year, has approached the total contracted supply of 52 billion cubic meters. Gas demand exceeds available supply during the cold winter months, leading to supply disruptions. With government support, BOTAŞ recently signed a contract with Azerbaijan to provide additional supply, which will add around 6 billion cubic meters of gas to Türkiye's contracted gas supply by 2018. Negotiations are ongoing with Russia on gas prices, new pipelines and additional gas purchases. LNG imports, including spot imports, will be needed to cover short-term deficits. Additional gas supply will need to be provided from new sources and new supply routes as existing contracts expire. In the privatization of gas distribution and gas usage

In contrast to the remarkable progress made in the expansion program, the development of the gas market has lagged far behind the development of the electricity market. A comprehensive set of measures is needed to ensure gas supply security in the medium and long term, starting with the amendment of the Natural Gas Market Law enacted in 2001, through steps such as the unbundling of the national gas company BOTAŞ and the consistent application of the cost-based energy pricing mechanism by BOTAŞ. These measures are needed to increase the share of the private sector in gas imports, to enable Türkiye to realize its ambition to become a regional energy hub and to maintain and improve gas supply security.

A package of measures covering five issues could further advance the development of the gas market:

1. Facilitating gas imports by the private sector;
2. Restructuring of BOTAŞ;
3. Cost-reflective and transparent wholesale gas pricing by BOTAŞ;
4. Establishing a central gas trading platform and ensuring that BOTAŞ gradually trades gas through this platform; and
5. Reducing network bottlenecks and increasing storage capacity.

2.2.1.1 Amendment of the Natural Gas Market Law

The government has submitted a bill to the Turkish Grand National Assembly to amend the Natural Gas Market Law. However, while the bill includes some of the five reform measures mentioned above, their formulation presents significant uncertainties:

- The draft amendment would eliminate gas import restrictions on companies other than BOTAŞ; these restrictions currently prohibit imports from countries with which BOTAŞ has signed gas purchase agreements. This amendment has long been sought by the private sector. However, (a) the draft amendment requires prospective importers to obtain approval from the Ministry of Energy (even LNG imports are not exempt from this requirement) and (b) BOTAŞ will be able to conclude new pipeline gas import contracts (with the approval of the Council of Ministers) in the event that gas supply security is compromised or for export purposes. These provisions may act as a deterrent to private sector initiatives, especially those companies that are not affiliated with gas producers in countries such as Russia and Azerbaijan, from which Türkiye has long imported.
- The amendment draft maintains the target of reducing BOTAŞ's share in gas imports to 20 percent, which was included in the law enacted in 2001. Although the year set for this target in the law enacted in 2001 was 2009, progress made until 2009 has remained marginal and BOTAŞ's share in the market is still around 80 percent. No deadline has been set for this target in the amendment draft.
- The draft amendment foresees the separation of gas transmission, storage and LNG activities from BOTAŞ and the establishment of two separate companies, one for the gas transmission network and operating activities, the other for gas storage and LNG terminals. The private sector has been waiting for such a restructuring for a long time. According to the amendment, this separation process will be completed within one year after the law comes into force.
- The amendment bill envisages expanding the scope of activities of the newly established Energy Market Operation Corporation (EPİAŞ) to include operating as a gas market operator in addition to electricity. As envisaged in the Electricity Market Law enacted in 2013, EPİAŞ is currently in the establishment phase. However, the amendment bill does not specify when the company’s scope of activities will be expanded to include the gas market.

Despite these observations, the proposed NGML amendments would constitute an important step towards the establishment of a competitive natural gas market.

2.2.1.2 BOTAS

BOTAŞ will continue to be the largest gas importer for the foreseeable future. As gas demand in Türkiye increases and BOTAŞ's current import contracts expire, BOTAŞ's market share will gradually decrease over time unless it signs new purchase contracts. Effectively unbundling BOTAŞ will help alleviate private sector concerns that BOTAŞ is strengthening its market position through its control of the grid. The private sector will closely monitor progress in the DGPK amendments, unbundling BOTAŞ, and establishing a gas trading platform for EPİAŞ (and the preparatory steps that EMRA and BOTAŞ will take before EPİAŞ covers the gas market) as signs of the government's intent and determination. In addition: To (a) help improve liquidity and (b) reduce both BOTAŞ's role in bilateral wholesale gas supply contracts and cross-subsidization opportunities, BOTAŞ could be obliged to trade an increasing share of its gas imports through the new EPİAŞ platform.

2.2.1.3 Wholesale Gas Pricing

Even if the 2001 law is amended as proposed and the measures described above are implemented, gas market reform will remain incomplete unless BOTAŞ implements cost-reflective and transparent wholesale gas pricing. An effective gas market that will create a fairer playing field for BOTAŞ and its competitors cannot be established without eliminating pricing distortions. The ongoing decline in gas import prices provides an opportunity to reform wholesale gas pricing without significantly increasing the prices BOTAŞ charged its customers in the market in 2015. Negotiations with Gazprom and the arbitration case with Iran regarding gas prices are ongoing. The government and BOTAŞ expect significant price reductions from both processes. LNG prices may fall even more than pipeline gas prices in 2015. The burden of potential price increases resulting from reductions in subsidies should be borne by users, not taxpayers, through prepaid oil import tax revenues. Targeted social support for low-income consumers could be considered.

2.2.1.4 Transmission System Bottlenecks and Gas Storage

Asking BOTAŞ and its successor gas transmission network company to eliminate grid bottlenecks would be the easiest part of the natural gas market reform. Market participants could be asked to provide feedback on grid investment plans and to submit proposals for the most urgently needed priority projects. BOTAŞ has demonstrated that it has the capacity to develop and implement gas transmission network projects. This capacity could be transferred to the gas transmission network company that will be established after unbundling. The new gas transmission network operator would also have an important opportunity to ensure gas market development by increasing the transparency of BOTAŞ's congestion management practices.

Not only to support the functioning of the gas market, but also to ensure supply security, gas storage capacity will need to be significantly increased. Türkiye's current gas storage capacity of 2.6 billion cubic meters is only about 5 percent of annual gas consumption. On the other hand, in other gas importing countries in Europe, storage capacities are about 20-30 percent of annual consumption. The construction of the Salt Lake gas storage project with a capacity of one billion cubic meters is ongoing and there is a large capacity for further storage capacity expansion. The draft law amending the Natural Gas Market Law foresees the separation of the gas transmission system, gas storage and LNG terminal activities from BOTAŞ and the establishment of two separate companies. The transfer of TP's existing gas storage facilities and ongoing storage investments to the newly established gas storage and LNG terminals company should be considered, as this will help create a stronger storage company from the outset.

2.2.1.5 Making Türkiye an Energy Center: Gas

Turkey has the vision and potential to become a regional hub in the field of gas.

Turkey has a nationwide gas transmission network connecting pipelines that bring gas imported from Russia, Azerbaijan and Iran to the country. Türkiye currently has two operational LNG terminals and suitable sites for additional terminals. Gas storage capacity is currently low, but a major storage project is under construction and there is great potential for further storage capacity expansion in the future. Turkey has the potential to further diversify its pipeline gas import sources with neighboring countries such as Iraq, Israel (via a subsea pipeline) and Turkmenistan. In addition, Europe is currently aiming to diversify its gas supply sources and routes through the "Southern Corridor"
– Turkey is positioned between Europe and potential gas resources in the Caspian and Middle East regions in this corridor. The first major investment within the scope of the Southern Corridor consists of a gas production project in Azerbaijan with an annual capacity of 16 billion cubic meters, the Trans-Anatolian Pipeline (TANAP) passing through Türkiye and the Trans-Adriatic Pipeline (TAP) gas transmission line projects passing through the western borders of Turkey and reaching Italy via Greece, Albania and the Adriatic Sea. BOTAŞ has signed a contract for 6 billion cubic meters per year and the remaining 10 billion cubic meters of gas per year will be transported to Italy via TANAP and TAP.

Once these pipelines are built, Turkey will have significant pipeline capacity beyond its own gas needs for the first time – a basic prerequisite for becoming a gas hub. It will also be possible to expand the TANAP and TAP pipelines to handle additional volumes. On the other hand, TAP will allow up to 80 percent reverse flow from the moment it enters operation.

Reform of the natural gas market is needed to realize the government's vision of making Türkiye an energy hub. As the experiences of the United States, the United Kingdom and continental Europe have shown, creating a functioning gas hub requires – beyond sufficient capacity for inflows, storage and outflows – a multitude of suppliers and multiple sources and routes of supply that are not under the control of a single market participant. Recent experiences in continental Europe have shown how gas hubs have helped new suppliers enter the European gas market, provided competition and brought market pressure to even the largest and most established European gas companies and their foreign gas suppliers.

2.2.2 Development of the Electricity Market

As discussed in the first section of this overview, Turkey has gradually established a well-functioning electricity market over the past decade. The legal, regulatory and institutional framework has attracted and enabled private sector investments in the market since 2001, with over 31,000 MW of which 25,000 MW have been made since 2008. The share of public companies in wholesale electricity supply (as producers or buyers under long-term power purchase agreements) has fallen below 50 percent. The central wholesale electricity market currently has over 800 market participants. The electricity market is competitive and has been oversupplied (indeed, Turkey would have been oversupplied in 2014 had it not been for a severe drought that led to a decline in hydropower production). However, market development efforts need to continue to persuade currently hesitant private sector investors to resume investment activities before it is too late, in order to avoid the risk of an electricity shortage before the end of the current decade.

A package of measures including general measures on four issues could further advance the development of the electricity market:

1. Natural gas market reform;
2. Establishment of EPİAŞ and development of financial trading and risk management tools;
3. Strengthening TEİAŞ operationally and financially; and
4. Transparency regarding EPDK decisions, TEİAŞ's congestion management, TETAŞ and EÜAŞ's market activities, and the government's operational and financial targets regarding TETAŞ and EÜAŞ.

2.2.2.1 Natural Gas Market

Given the important role of natural gas in the fuel mix of electricity generation, reform of the natural gas market is a key element of Türkiye's efforts to develop its electricity market. Prospective investors and financiers who will invest in new gas-fired power plant generation capacity want to increase predictability and transparency. Natural gas accounts for almost 50 percent of electricity generation. Gas-fired power plants play a decisive role in price formation in the electricity market. A well-functioning gas market will increase investor confidence in the electricity sector. It is expected that predictability and transparency will increase following the amendments to the Natural Gas Market Law and the establishment of a central gas trading platform by EPİAŞ.

2.2.2.2 EPİAŞ

The new Electricity Market Law enacted in 2013 foresaw the establishment of a new Energy Market Operation Corporation (EPİAŞ) to take over the electricity market operations of TEİAŞ. Market participants welcomed the goal of an independent energy market operator: 97 companies became shareholders of EPİAŞ upon the invitation of EPDK. EPİAŞ is expected to be an important step towards a more transparent market operation and the establishment of an effective energy exchange for both electricity and gas. The intraday market is expected to be implemented in 2015. The implementation of new methods such as market splitting and demand side participation will support more effective market operation. Financial trading and risk management tools will be developed and operated by Borsa İstanbul.

2.2.2.3 TEIAS

TEİAŞ, which is the backbone of the electricity system, is under increasing pressure to manage the demands of private generators and load changes. Over the past 10 years, TEİAŞ has faced a real challenge of expanding its transmission capacity in order to respond in a timely manner to new connection applications from hundreds of new generators, most of which are located in rural areas and have a total installed capacity exceeding 35,000 MW. Including those licensed but not yet constructed, TEİAŞ has been able to grant connection permits for a capacity of over 100,000 MW and is working to expand the grid according to the progress of the implementation of new generator projects.

The share of private sector generation is expected to continue to increase and the distribution side is fully privatized, which is increasingly challenging TEİAŞ between generation and distribution. The formation and increasing share of wind energy generation capacity and the newly emerging solar energy generation capacity pose significant integration and system operation problems for TEİAŞ. Unlike centrally located (large-scale) thermal power plants, which have longer construction times and thus provide TE-İAŞ with a longer time to respond to connection requests, wind and solar power generation plants are dispersed and have relatively short construction times. Wind and solar power plants with intermittent generation make reliable system operation much more complex and challenging.

Bottlenecks in TEİAŞ's transmission system can lead to curtailments, increase costs, and raise concerns about the use of market power by some generating companies. These problems are most striking when there is a shortage of gas supply, and can lead to forced use of gas power plants with lower efficiency due to constraints in the electricity transmission system and restrictions on gas supply to plants with the highest efficiency. TEİAŞ needs greater transparency in its grid congestion management.

The current institutional structure of TEİAŞ may not be sustainable in the medium and long term. There is a broad consensus on the limitations of TEİAŞ in the areas of finance, procurement, decision-making, transparency and personnel recruitment and retention. If progress is not expected in the general reform program in the area of governance of state economic enterprises, a solution to increase the operational capacity and financial strength of TEİAŞ may require the enactment of a special law that will provide TEİAŞ with sufficient autonomy.

2.2.2.4 Making Türkiye an Energy Center: Electricity

The Western and Northern European countries, from France to Finland, have integrated their electricity markets. This integration process is managed by a project called Price Copling of Regions (PCR) and regulated by a Multi-Regional Coupling (MRC) agreement. (PCR is a joint initiative of 7 European power central markets (exchanges) and aims to provide a common solution for price setting in day-ahead markets and the allocation of cross-border line capacities in electricity trading throughout Europe). Romania, Hungary, the Czech Republic and Slovakia have coupled their markets and are interested in joining the Western and Northern European market coupling. Bulgaria’s new market operator, the Independent Bulgarian Energy Exchange (IBEX), is interested in joining the European market coupling. Through the implementation of the PCR algorithm by EPİAŞ – and subject to sufficient interconnections with the European electricity system – Turkey will have the potential to participate in the emerging European electricity market. This is a significant opportunity for Türkiye.

Up to now, the integration has focused on interconnection and the work to be done for this purpose falls mainly under the responsibility of TEİAŞ (with the exception of the development of control systems for power generation plants) since synchronization with the European power system managed by the European Network of Transmission System Operators for Electricity (ENTSO-E) is required. Since this process has been completed and TEİAŞ has become an associate member of ENTSO-E, the existing interconnection can be put into full use. Further strengthening of the Turkey–ENTSO-E interconnection could help Türkiye to benefit more from trade opportunities with the European market. The transmission system limitations of the TEİAŞ system in the north-eastern part of the country restrict the use of Türkiye’s existing interconnection with Georgia. TEİAŞ’s system interconnections with other neighbouring countries are limited capacity connections, are in island operation mode or are not in operation. (The development of these connections and the exploitation of their potential and the increase in trade also depend on geopolitical developments.)

2.2.2.5 TETAŞ and EUAŞ

Reducing the public share of electricity production, which consists of electricity directly produced by EÜAŞ in its own power plants or indirectly purchased from TETAŞ's BOT/BO model production plants, will be beneficial for the development and liberalization of the electricity market. TETAŞ's contracts with BOT/BO production companies will gradually end between 2017 and 2021. These will be replaced by electricity purchases from nuclear power plant projects, which are expected to be commissioned with an average annual increase of 1,000 MW in the 2020s.

However, the majority of new generation capacity in Türkiye will continue to come from market-based private sector projects. In line with the government’s program to privatize thermal power plant generation capacity and small hydroelectric power plants – a total of approximately 16,000 MW of which is planned to be privatized, of which more than 4,000 MW has already been privatized – EÜAŞ’s generation will continue to decline. EÜAŞ will retain large hydroelectric power plants and is likely to be a partner in strategic public-private partnership (PPP) projects such as the Sinop Nuclear Power Plant Project and power plant projects aimed at utilizing domestic lignite resources. The government has used EÜAŞ, and particularly TETAŞ, as important instruments in supporting electricity sector reform and electricity market liberalization, and these companies will continue to be instruments that the government can use to intervene in the electricity market, including interventions against attempts at market player gaming/price manipulation. Greater transparency by the government regarding its operational and financial targets for TETAŞ and EÜAŞ would provide predictability and help alleviate market concerns about how the government intends to use TETAŞ and EÜAŞ in the coming years and beyond.

2.2.3 Governance in the Energy Sector

2.2.3.1 EMRA

EPDK was established in 2001 as an independent and administratively and financially autonomous public institution. EPDK carries out its duties and authorities arising from the law through the representative and decision-making body of the Institution.

It is implemented and exercised through the Energy Market Regulatory Authority. The Board consists of nine members, including the EPDK President, and each member is appointed by the Council of Ministers for a six-year term. In order to ensure the operational autonomy of the EPDK, the law stipulates that the Board members cannot be dismissed before the end of their terms. The law also provides for the financial autonomy of the EPDK from the government by stipulating that the EPDK will finance its activities through fees received from the energy sector. While these regulations are in line with international best practices, there are concerns that the appointments and the autonomy of the EPDK have been undermined in practice from time to time. The government can eliminate this problem by appointing generally accepted and market-trusted energy and finance sector professionals.

Although the regulated tariffs are determined by EPDK and a cost-based pricing mechanism is used to determine the prices to be applied by TETAŞ, EÜAŞ and distribution companies; the perception in the market is that energy pricing is actually determined by the government, not by EPDK. This perception is reinforced by the government's announcement of energy price adjustments or postponements in BOTAŞ's price adjustments despite its acknowledgement of financial difficulties.

The provision in the Electricity Market Law of 2013, which shifted responsibility for auditing the performance of electricity distribution companies from EMRA to the Ministry of Energy, contributed to concerns and perceptions that EMRA’s role was diminishing. Although audit reports will be sent to EMRA and EMRA is the final decision-making authority, this is an unusual regulation, especially considering that it was introduced ten years after EMRA was established.

The government's privatization program has transferred the entire distribution system to private companies. The distribution system includes both regions with previously low collection rates and regions with socioeconomic disadvantages. Even for two companies operating in regions with unusually high loss and theft rates - Van Lake Electricity Distribution Inc. and Dicle Electricity Distribution Inc. - several companies have submitted bids. It is not surprising that private distribution companies are experiencing great difficulties in these regions. The government is determined to make the privatization program a long-term success. During the privatization process, the government has resolutely and repeatedly assured investors that the new private sector owners of the privatized electricity distribution companies will have the full support of the government. The government has a legal responsibility to find sustainable solutions to problems that extend far beyond the electricity sector to areas such as law, order and socioeconomic development. However, undermining the ability of EMRA to regulate distribution companies cannot be part of this state support. If the government is concerned about EMRA's operational capacity, the expected measure should be to strengthen EMRA's authority and capacity rather than take these duties away from EMRA. The new audit unit established in the Ministry for the audit of distribution companies should be transferred to EPDK.

2.2.3.2 EPDK-Competition Authority Cooperation in Retail Competition

In order to increase retail competition, distribution companies should allow free consumers to switch to suppliers other than the incumbent supply companies (which belong to the same capital group as the distribution companies) without creating artificial difficulties. Similarly, in order to spread unlicensed production facilities, non-discriminatory third-party access to distribution networks is required. It is understood from the applications made by independent suppliers and consumers to the Competition Authority that there is a concern that some distribution companies abuse their market power to prevent switching and are reluctant to grant connection permits. Although retail and distribution activities are legally separated, there is no separation of ownership. Therefore, it is useful for the EMRA to carefully monitor the activities of incumbent retail companies and distribution companies in order to prevent such behaviors and to ensure strong coordination between the EMRA and the Competition Authority. In addition, It would be beneficial to ensure close cooperation between EMRA and consumer associations in order to raise awareness among consumers about the potential benefits of these transitions.

2.2.3.3 Subsidies for Low-Income Consumers

Most energy consumers in Türkiye have accepted energy price adjustments as an inevitable cost of economic development. However, this acceptance does not mean that all households can comfortably pay their energy bills. A recent impact assessment conducted across Turkey found that most households in Türkiye are able to pay their electricity bills despite price increases. However, it has been shown that household consumers without regular monthly income, rural households, and consumers whose livelihoods may depend on electricity use (such as farmers using electric water pumps for irrigation or small urban businesses) are vulnerable to increases in electricity prices. Social support and energy efficiency programs targeting low-income consumers will support the general liberalization process in the electricity and gas markets and may be considered in the context of the government's planned review of social assistance mechanisms.

Targeted social support and energy efficiency programs for low-income consumers can be considered as an integral part of the solution to the difficulties currently experienced by some privatized electricity distribution companies. Social support is not a substitute for flexible and innovative measures that companies will develop themselves. Some companies are reported to have tried practices such as forgiveness of past debts, fixed monthly payments, payment in installments, etc. However, there have also been reports of "wholesale" cuts to electricity services in some neighborhoods and villages, and the willingness of those who pay their bills in these areas to pay has decreased.

Targeted social support will also facilitate the transition to more "regular" tariffs in gas distribution in the upcoming period. In the highly competitive license tenders organized by EMRA for distribution licenses, most of the winning companies offered very low distribution fees for the first eight-year tariff period and in some cases did not charge any fees other than the connection fee charged at the beginning. EMRA is currently working on the tariffs for the second tariff period and inevitably the distribution fees will need to be increased in order to reflect the cost of the distribution service in these tariffs.

2.2.3.4 Transparency

Large-scale renewable energy investments, including small and medium-scale renewable energy projects, inevitably have significant environmental and social impacts. The large number of applicants has occasionally caused bottlenecks in the environmental impact assessment and project approval processes. Investors have complained about the complexity of the procedures, delays and lack of transparency. Environmentalists and citizens have expressed concerns about the inconsistent application of environmental permitting and licensing procedures/guidelines and the inadequacy of public reporting of decisions. There is a need for greater transparency in the process and clear justification of decisions (whether approval or rejection). In terms of nuclear energy, additional dimensions such as nuclear safety and waste disposal are areas where public demand for information has not been sufficiently met.

Türkiye's growing economy and growing population will continue to require more energy. Complex reforms and measures are needed to secure the investments expected from Turkish investors and their mostly Turkish financiers. Investors and financiers also want greater transparency in market operations (PMUM/EPIAŞ) and electricity and gas transmission system operations (TEİAŞ and BOTAŞ), including balancing, distribution, congestion management and supply disruptions. Gaining public support for reforms and the investments they aim to attract is simpler in principle, but equally difficult to achieve in practice. It requires constant, relentless and unwavering sharing of information, education, consultation, participation and transparency; otherwise, continued public support will be undermined. Improving statistical data collection and dissemination will help increase transparency and credibility with both market participants and the public.

2.2.3.5 Public Energy Enterprises

The role of state-owned enterprises (SOEs) in the energy sector has significantly decreased since 2001 and will continue to decrease as most investments are made by the private sector and the privatization program for EÜAŞ's thermal power plants is completed. However, despite their decreasing market share, the role of energy SOEs continues to be critical to the functioning of the electricity and gas markets. TEİAŞ, the operator of the electricity transmission system, and the soon-to-be-established gas transmission system operator and gas storage/LNG terminal company will form the backbone of the energy system. BOTAŞ will continue to be the largest importer and supplier of gas for the foreseeable future. EÜAŞ will continue to be the owner and operator of the country's largest hydroelectric power plants and thus a major player in the electricity market. The power purchase agreements signed in the 1990s will one by one expire, but the electricity trading company TETAŞ will continue to be a major buyer and seller of electricity due to its role in Türkiye's nuclear energy program. EÜAŞ will have a minority stake in at least one of the nuclear power plants and will sell significant amounts of electricity in the market together with TETAŞ.

Further modernization of the governance structure of energy SOEs and listing of key energy enterprises on the stock exchange are important policy priorities. Despite being established as companies, BO-TAŞ, EÜAŞ, TEİAŞ and TETAŞ still face significant challenges in transforming into modern, autonomous and professionally managed SOEs. The Decree Law No. 233 on State Economic Enterprises, the Court of Accounts Law, the Public Procurement Law and a series of controls implemented by the Ministry of Energy, the Ministry of Development and the Treasury undermine their management autonomy. According to the legislation, the boards of directors of energy SOEs consist of a CEO (General Manager), two Deputy General Managers (usually the most senior), two senior officials from the Ministry of Energy (usually Deputy Undersecretaries) and a member appointed by the Treasury. Investment proposals must be approved by the Board of Directors, the Ministry of Energy and the Ministry of Development. The government has the authority to approve even the grid investments of BOTAŞ and TE-İAŞ, despite being fully regulated by the Energy Market Regulatory Authority. Instead of commercial auditors, SOEs are audited by the Court of Accounts, an institution responsible for auditing the revenues, expenditures and assets of central and local government institutions on behalf of the Turkish Grand National Assembly (TBMM). SOEs are obliged to implement the Public Procurement Law instead of commercial procurement practices.

OECD's*Principles of Corporate Governance in Public Economic Enterprises*[11]It is a global benchmark for SOE governance reforms:

- Governments are required to develop and publish a public ownership policy that defines the purposes of public ownership, the role of the state in the corporate governance of SOEs, and how the state will implement the ownership policy.
- Governments should not interfere with the day-to-day management activities of SOEs. Instead, they should provide full support to SOEs to enable them to achieve their defined goals.*operational*They should grant autonomy and hold their boards and management accountable for their performance.

Naturally, energy SOEs will continue to conduct their activities in line with the government's energy policies and in accordance with the country's laws and regulations. Professionalization of the boards of directors and management of energy SOEs will help energy SOEs to have boards of directors and administrative structures that can manage and operate companies without the daily intervention of the government.

In recent years, there has been discussion of listing energy SOEs on Borsa Istanbul through public offerings. For example, this issue was raised by the Minister of Finance in an interview about the government's privatization and public offering plans in October 2014. There is the potential to implement an IPO program to support several main policy objectives. These include (a) improving governance in energy SOEs, as it is expected that new investors will want to professionalize the boards and management of energy SOEs; (b) supporting liberalization of the electricity and gas markets, directly improving the performance of SOEs and indirectly increasing general investor confidence; and (c) increasing revenues for the government – and more then increasing investment resources for each company depending on its investment needs and debt/equity position.

The IPO program could start with shares of TEİAŞ and the new gas transmission system company (after the expected separation of BOTAŞ). These could be followed by BOTAŞ, EÜAŞ and TETAŞ. The new gas storage/LNG terminal company may need some more time to make its operations and financial structure more attractive for an IPO. In the oil sector, TP is another important candidate for listing on the stock exchange. Secondary IPOs could then be carried out as part of a step-by-step ownership diversification and commercialization program.

In terms of listing public companies on the stock exchange, the Turkish Airlines reform provides an excellent local reference point: the state owns a significant share (49.12%) and the company is commercially managed outside the controls imposed by Decree Law No. 233, the Court of Accounts Law and the Public Procurement Law. In the energy sector, the Italian experience can provide a meaningful reference for Turkey: previously unthinkable, oil and gas company ENI, electricity producer and supplier Enel and transmission system operator Terna have been listed on local and international stock exchanges (with well-defined governance policies) and the Italian state has reduced its ownership share to well below 50%.

2.2.4 Next Steps in Energy Reform

Despite significant achievements since 2001, reforms in the energy sector will need to continue if Turkey is to continue to ensure electricity and gas supply security without having to resort again to large-scale – and in the long term unsustainable – state support mechanisms. This review of reform challenges concludes that a package of reform measures is needed to further develop the electricity and gas markets and improve the governance structures and functioning of the EMRA and key energy SOEs.

The government is updating the energy strategy it published in 2009. The strategy update is an excellent tool for the government to restate its energy vision with updated phases and timeframes, while also engaging existing market participants and prospective investors in the development and liberalization processes in Türkiye's electricity and gas markets.

Comprehensive reforms do not happen overnight, and market participants and financiers do not expect everything to happen overnight. However, to continue the development of electricity and gas markets and to reassure market participants that liberalization is ongoing, governance of public institutions and energy SOEs will be improved and transparency will be increased, "confidence-building measures" can be implemented in advance over the next 12 months. These measures could include:

- Amendments to the Natural Gas Market Law may be accepted.
- The government could take advantage of the decline in gas import prices to return BOTAŞ to the Cost-Based Pricing Mechanism and allow BOTAŞ to make wholesale natural gas price adjustments in a cost-reflective and transparent manner.
- Developing a social security mechanism for low-income energy consumers will take time (even if it is added to one of the existing subsidy mechanisms financed from the budget), but the government may announce that it has decided to create such a mechanism.
- The development process of EPİAŞ can be accelerated so that EPİAŞ can become fully operational in 2015.
- The Ministry of Energy, BOTAŞ and TEİAŞ may disclose to market participants the mechanisms for managing gas supply shortages and electricity shortages in the winter of 2015-16 before these mechanisms are implemented and required to be used.
- The government may announce that it has decided to register the shares of TEİAŞ, certain parts of BO-TAŞ (after unbundling), EÜAŞ, TETAŞ and TP on the stock exchange through an IPO program to be held on Borsa Istanbul.

Some of the challenges facing the government now may be as challenging as those faced over the past 14 years. Turkish investors and their mostly Turkish financiers have invested large amounts and learned a lot, but their enthusiasm is not as great as it once was. Their risk-taking capacity has increased, and so has their risk understanding. They are waiting for signs that the government intends to address the challenges. They also expect continued liberalization of the energy market and improved governance and transparency in the energy sector.

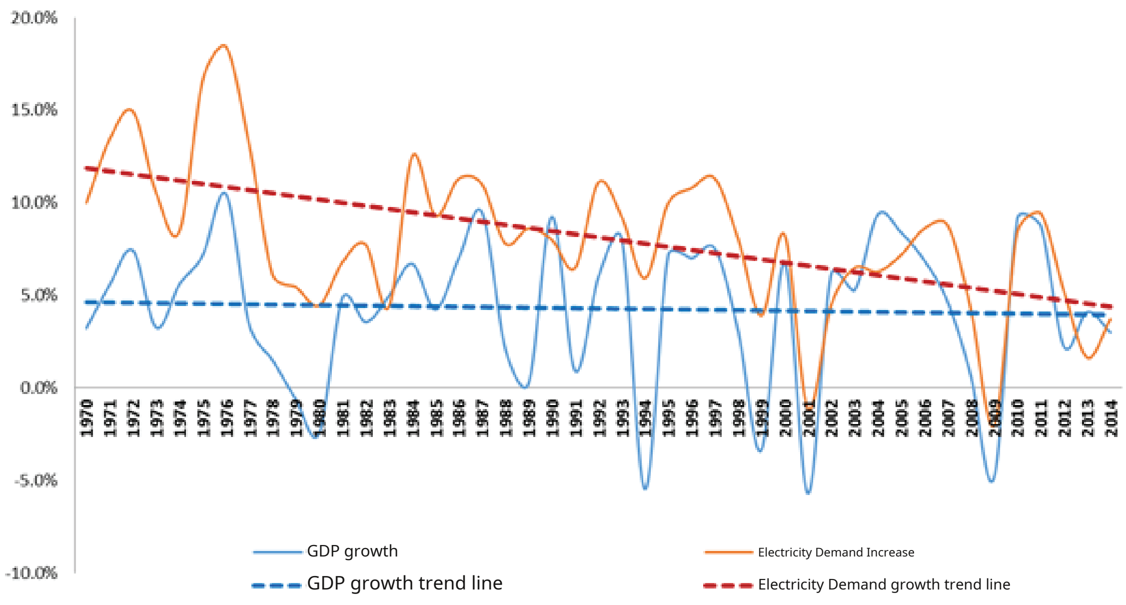
Main Report

Main Report

The Republic of Turkey is located between southeastern Europe and Asia and is surrounded by the Mediterranean, Aegean and Black Seas. Its neighboring countries are Azerbaijan, Bulgaria, Armenia, Georgia, Iraq, Iran Syria and Greece. The population of the country was 77,695,904 as of the end of 2014 and its total area is 780,580 km^2'is.[12]

The Turkish economy is described as an emerging market economy and is largely developed, making it one of the newly industrialized countries in the world. Despite numerous recessions and unstable growth performance, Türkiye's average GDP growth rate over the last 45 years is 4.3 percent. In parallel with the growing economy, Türkiye's electricity market is also one of the fastest growing in the world. As seen in Figure 11, the average monthly consumption increase since 1970 has been 8.3 percent.

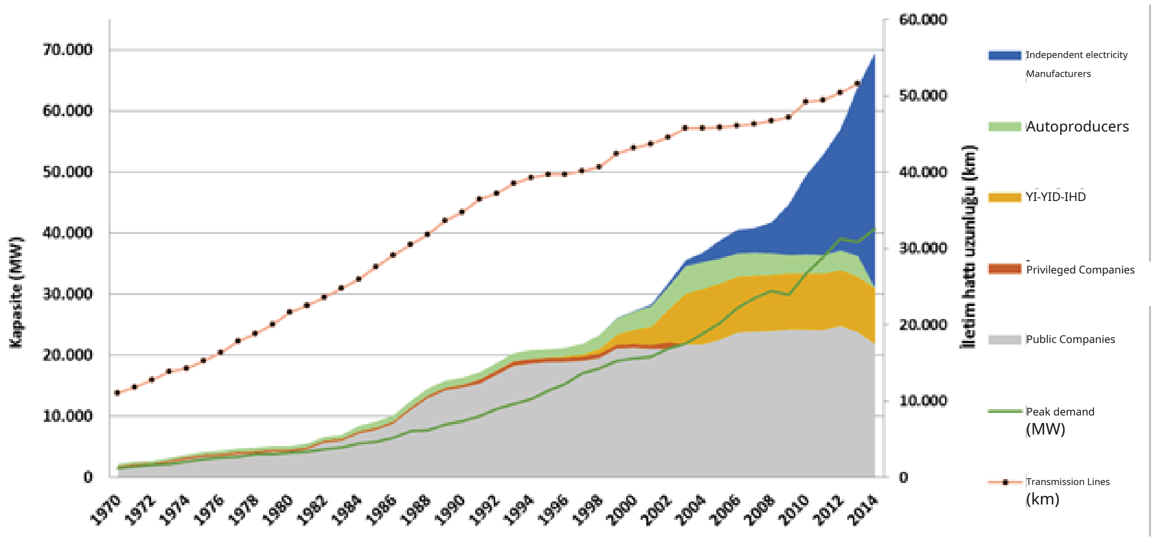
Figure 11. GDP and Electricity Demand Growth Rates, 1970 - 2014



Source: TÜİK and TEİAŞ.

In order to support Türkiye's economic growth and cope with the increasing demand for electricity, significant investments have been made in the generation, transmission and distribution sub-sectors of the electricity sector. In order to increase the generation capacity, different investment models have been implemented since the late 1960s. As a result, the ownership composition of the generation capacity has changed dramatically during the period in question. The evolution of the ownership of the generation capacity is shown in Figure 12.

Figure 12. Development of Peak Demand, Generation Capacity and Transmission Lines, 1970–2014



Source: TEİAŞ statistics.

Since 1970, Türkiye's electricity production has increased more than 30-fold, reaching 69,500 MW by the end of 2014. The segmented transmission system has been significantly improved, resulting in a nationwide interconnected transmission grid. The distribution system has also been expanded through ambitious urban and rural electrification programs, achieving the goal of "providing electricity to all citizens."

To understand the main drivers of the reforms that led to the opening of the electricity sector to the private sector, it is useful to summarize the situation in Türkiye in the early 1980s.

3.1Summary of the Electricity Sector Before 1984

3.1.1 Before the Turkish Electricity Authority: 1913–70

Although electricity production in Türkiye began in the early 1900s with a small 2 kW hydro turbine, the country's first commercial production facility was the coal-fired Silahtarağa power plant, which was commissioned in 1913. From that time until 1935, the electricity sector was almost entirely dominated by private enterprise. When the Republic of Turkey was founded in 1923, total installed power was 32 MW and per capita consumption was only 3.3 kWh. In 1935, a public development bank, Etibank and the Electrical Works Research Administration (EIE), were established and the electricity business was nationalized.

Until the 1970s, some public institutions – such as Etibank and İller Bankası (another public development bank), municipalities, EİE and the State Hydraulic Works (DSİ) – made investments that increased their generation, transmission and distribution capacities. The first public-private partnerships in the sector were established in the form of concession companies (Çukurova Elektrik A.Ş. and Kepez Elektrik A.Ş.).

Until the 1970s the system was fragmented. Except for some regional networks, transmission and distribution systems were not interconnected; rather, they were owned and operated by different public institutions, and all electrification programs were carried out by different public institutions. Municipalities and private companies with privileges had their own rights and responsibilities for electricity generation, transmission, distribution and sale. Although there were various public institutions involved in electricity generation, transmission and distribution, there was no central planning. Table 2 provides some indicators of the electricity sector as of 1970.

Table 2. Some Selected Indicators of Türkiye's Electricity Sector, 1970

1970	Public	Special							Total
		Prerogative Secret.	BOT	YI	IHD	Auto.	Special Free Elk. Prod.	Total Special	
Production Capacity (MW)	1,994	194	0	0	0	(360)*	0	194	**2,188**
Production Capacity Ownership (%)	91.1%	8.9%	0.0%	0.0%	0.0%	0.0%	0.0%	8.9%	
Transmission Lines (km)	11,000								
Number / capacity of Transmission Transformers (MVA)	No Information								
Rural Electrification (%)	6								

Source: TEİAŞ statistics.

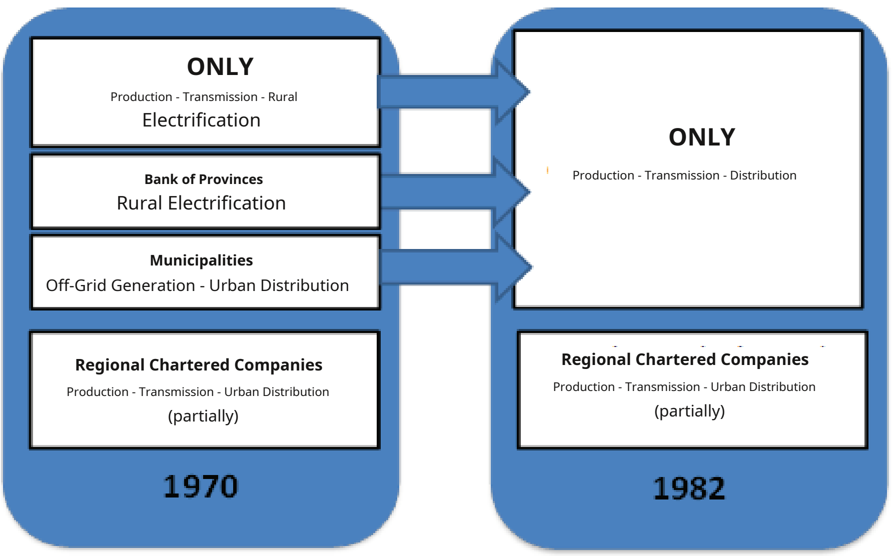
* It was mostly used in public sugar factories; therefore it was considered "public property".

3.1.2 TEK Period

The establishment of the vertically integrated Turkish Electricity Authority (TEK) in 1970 – and the consolidation of all electricity-related activities within this institution, except for the distribution systems owned and operated by municipalities and two regional private companies – was one of the important steps taken in the restructuring of the sector. The main priority was the electrification of Türkiye, and the main goal of TEK was to develop an interconnected and powerful transmission network along with the expansion of urban and rural electrification. The establishment of TEK was in line with the economic development policy favored at the time (development through a planned economy led by the state). The consolidation of the entire electricity sector was completed in 1982, when the urban electricity distribution activities were transferred from the municipalities to TEK. In fact, the initial intention was for the municipalities to carry out the distribution and retail activities. However, since the municipalities performed poorly and did not pay their electricity bills to TEK, it was eventually decided to transfer these facilities and service obligations to TEK. Private sector participation (PSP) was very limited and there were only two vertically integrated regional franchise companies and one franchised distribution company operating in a small region. These franchises were also partnered by public companies. The sector structure is summarized in Figure 13.

DSI and the General Directorate of Electrical Power Resources Research and Development Administration (EIE) were responsible for the development of hydroelectric capacity during the period in question.

Figure 13. Structure of the Electricity Sector Before 1984



In the late 1970s, Turkey entered an economic recession. GDP growth fell sharply and the economy contracted in 1979 and 1980. The global energy crisis due to rising oil prices was one of the reasons for this decline. Approximately 30 percent of the country's installed power capacity was dependent on oil imports, and restrictions on imports led to power outages and curtailments during 1978-1980.

In summary, the period 1970–1984 can be characterized by the following features:

- Consolidation of sector activities within a strong state monopoly;
- Centrally planned public investments in generation and transmission, and distribution investments carried out in line with an electrification programme; and
- Difficulties stemming from economic problems that constrained investment and even operation and maintenance budgets (especially lack of supply after 1977).

3.2 Electricity Sector Reform

Having emerged from a severe economic crisis in the late 1970s, a military coup in 1980, and political turmoil in the late 1980s, Turkey entered a new era in 1983. The country began a transition from an industrialization based on state-controlled import substitution, in which state ownership and control were largely dominant, to a free market economy in terms of both domestic markets and international trade.

The electricity sector was also affected by these developments and Turkey began to implement a transformation program in the electricity sector. The need for financing for the electricity sector and the desire to increase economic efficiency led the private sector to aim to participate in the electricity supply in Türkiye. Private sector participation is aimed not only to provide financing but also to have market-oriented skills, the latest technologies and to ensure a generally faster implementation compared to public sector management.

The transformation and restructuring process began in the first half of the 1980s with the opening of the operational components of the electricity market – generation, transmission and distribution – to the private sector. This process can be divided into two distinct phases:

- First phase: 1984–2001.
- Second phase: The period that started after the Electricity Market Law was adopted in 2001. This phase can be divided into two periods: 2001-2007 and 2008 to the present. In this second period, reform implementation gained momentum with the development of new energy pricing mechanisms and wholesale market mechanisms.

3.2.1 Phase One: 1984–2001

The first phase, between 1984 and 2001, featured legal and structural changes that (a) eliminated the state monopoly in electricity generation and distribution and (b) enabled private sector participation in the electricity sector. Table 3 shows the main electricity sector indicators at the beginning of this phase.

Table 3. Some Selected Indicators of the Turkish Electricity Sector, 1984

1984	Public	Special						
		Prerogative Secret.	BOT	YI	IHD	Auto.	Independent Elk. Prod.	Total Special
Production Capacity (MW)	7,190	324	0	0	0	948	0	1,272
Production Capacity Ownership (%)	85.0%	3.8%	0.0%	0.0%	0.0%	11.2%	0.0%	15.0%
Transmission Lines (km)	25,975							
Number / capacity of Transmission Transformers (MVA)	682 / 17,206							
Rural Electrification (%)	65							

Source: TEİAŞ statistics

In December 1984, Law No. 3096 was adopted to ensure private sector participation in the electricity sector. This Law**build-operate-transfer (BOT), transfer of operating rights (TRO) and autoproducer**It ended TEK's monopoly position in production by introducing private sector production investment models such as. In the same year, TEK's legal status was changed and it was turned into a public economic enterprise.

The first stage also consisted of intermediate stages. Due to the current uncertainties, the unsatisfactory progress of the BOT model and the increasing tightness of the supply/demand balance, a specific law (Law No. 3996) was enacted in 1994 regarding the implementation of the BOT model. Later, in 1997, in order to increase private sector production investments,**Build-Operate (BO) model**has been put into practice.

In addition, public companies were restructured and the sector structure was changed during this period. Details regarding the implementation of private sector participation models and restructuring are discussed in the following sections.

3.2.1.1 Sector Structure in the Period 1984–2001

The period between 1984 and 1993 can be described as a period of "TEK plus private sector participation". As seen in Figure 14, in 1993 TEK was restructured and two separate public companies were established: TEAŞ (Turkish Electricity Generation and Transmission Inc.) and TEDAŞ (Turkish Electricity Distribution Inc.). This was an important step towards the unbundling and corporatization of public enterprises. The separation of distribution and retail activities from generation and transmission activities and the establishment of new public companies were attempts to increase the efficiency of the public sector and ensure private sector participation; therefore, they can be considered as the first steps towards privatization.

Figure 14. Restructuring of TEK

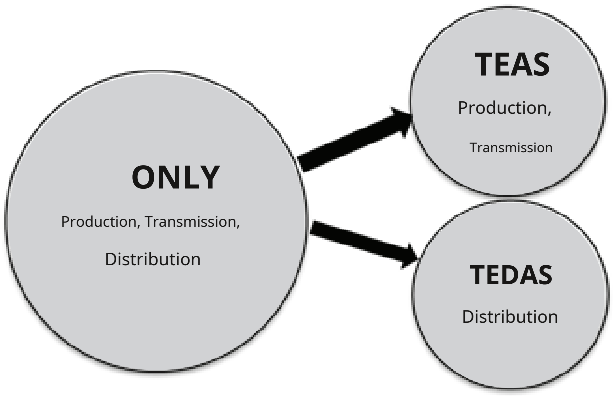
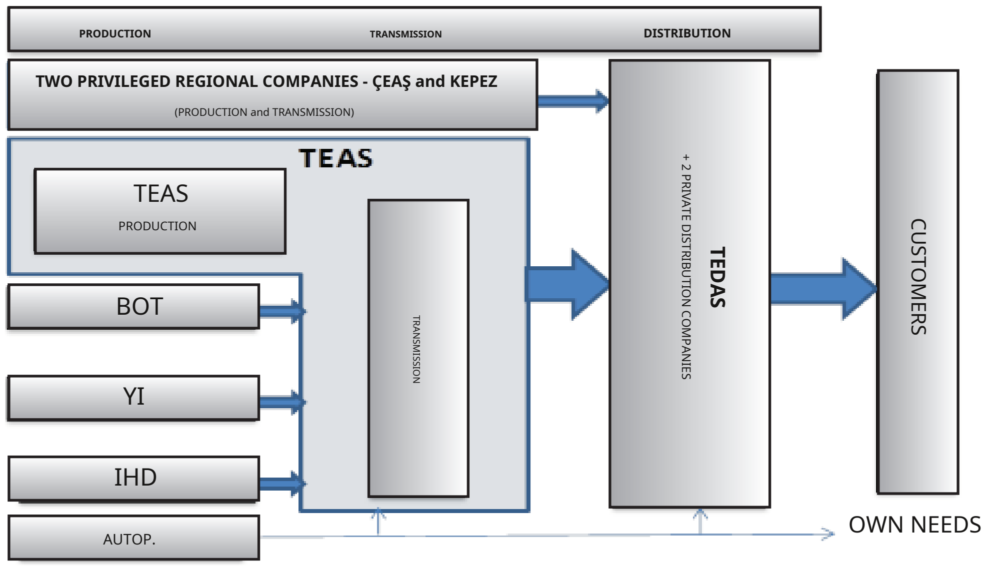


Figure 15 shows the industry structure at the end of this period.

Figure 15. Sector Structure in 2000



During this period, TEAŞ was the sole buyer and seller of electricity produced by power plants under the BOT, BO and TOA model, under long-term electricity purchase contracts with a Treasury-guaranteed take-or-pay commitment. Industrial companies were able to produce electricity for their own use under the autoproducer model.

3.2.1.2 Private Sector Participation in Production

Law No. 3096, adopted in 1984, provided for private sector participation in electricity production through the BOT, TOA and autoproducer models. Secondary legislation regarding the implementation of this law was enacted in September 1985. The main purpose of the law was to provide private sector participation in production, transmission and distribution activities based on private law provisions, instead of the concept of concession, which was used only for two regional transmission/generation and one distribution activity until then, through assignment contracts. However, as a result of the general public opinion and the decisions of the judicial authorities, Law No. 3096 was forced to be implemented as a concession subject to the administrative jurisdiction of the Council of State (the highest administrative court of the country). An exception to this can be the autoproducer model, which was successfully implemented without the need for the concept of concession.

BOT Model

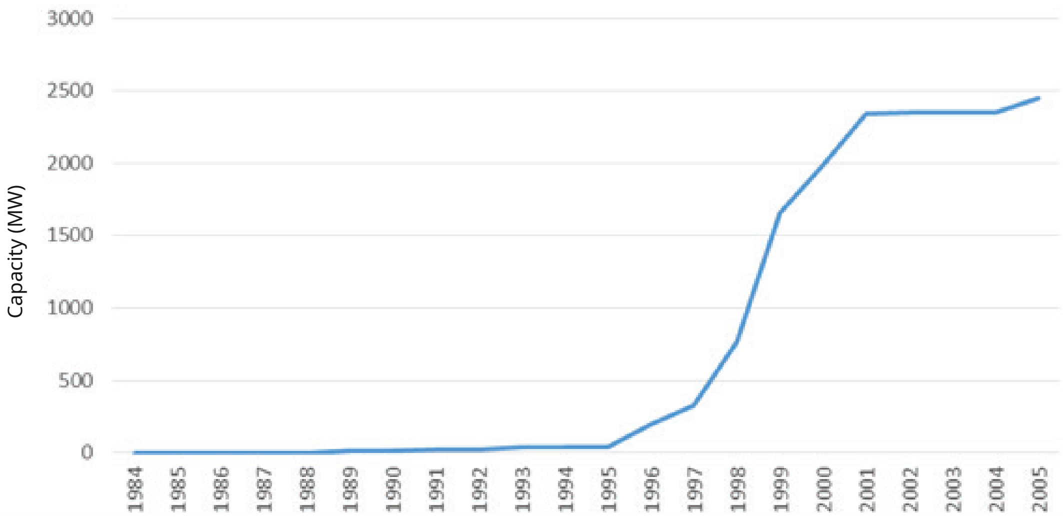
Within the scope of the BOT model, companies are allowed to establish and operate power plants and sell the electricity they produce in these plants to public institutions (TEK and later TEAŞ and TEDAŞ) through long-term electricity purchase contracts and "assignment" or concession contracts made between the Ministry of Energy and Natural Resources and the company. At the end of the contracts, the ownership of the plants will be transferred to the state. The terms and long-term electricity purchase contract prices are determined in the main contract and TEAŞ is obliged to sign electricity purchase contracts in accordance with the main contract. The application of the BOT model is explained in detail in Annex-1.

The BOT Law enacted in 1994 attracted a great deal of interest from domestic and foreign investors, leading them to submit hundreds of project proposals, many of which were unsolicited and not included in the optimum production development plans. However, ETKB and TEAŞ were not adequately equipped to evaluate this unexpected flow of project proposals.

As a result of the BOT model application, 18 hydroelectric power plants, 2 wind power plants and 4 natural gas combined cycle power plants were built between 1984 and 2001.[13] As seen in Figure 16, the total installed capacity of BOT plants in 1994 was only 35 MW; most of these plants were contracted and put into operation after 1994, and these BOT plants-

The total installed capacity of the country has reached 2,450 MW. Compared to the country's energy needs and considering the government's continuous efforts and ambitious expectations, this result cannot be considered satisfactory.

Figure 16. Capacity Development of Power Plants with BOT Model, 1984–2005



Source: TEİAŞ statistics.

The main reasons for this inadequate result were the uncertainties in the legal and administrative framework and the implementation problems discussed in detail in Annex 1. However, the BOT experience has proven that no model can be successful without a clear and transparent legal and administrative framework, a consensus on the basic legal framework and principles, and transparent implementation. Using this model to increase production capacity could have been possible with careful and planned project implementation timing, competitive selection methods, and the level of Treasury guarantees. However, this implementation would also increase the country's contingent liabilities and delay the establishment of a competitive market mechanism.

HRA Model (Production Privatization)

HRA model It includes the transfer of the operating rights of publicly owned power plants to private companies. The ownership of the assets remains with the state. In this model, there was again an assignment contract with the Ministry and an electricity purchase contract with the public company. The HRA model was used for the privatization of publicly owned power plants between 1984 and 2001. In 1996, the operating rights of a hydroelectric power plant (HES) were transferred and in 1997, a tender process was initiated for 16 thermal power plants with a total installed capacity of 9,576 MW. However, although six contracts were signed as a result of the tender, the contracts had to be cancelled as a result of the annulment of the Council of State.

Therefore, the result of the HRA application was quite inadequate. As a result, a 30 MW hydroelectric power plant transferred in 1996 and a 620 MW lignite-fired Çayırhan power plant transferred in 2000 and 2001 in accordance with the concession agreements.[14]None of the other agreements could be implemented.

Although the main reason for the cancellations was the Council of State decisions, there were also other reasons for the failure of this application, which are discussed in Annex-1.

Build-Operate (BO) Model

Due to the insufficient realization of BOT power plants until 1997, instead of examining and comparing hundreds of project proposals submitted without being requested, the government decided to focus on the priority projects it would prefer and to select investors for these projects through competitive bidding in order to obtain more reasonable prices and conditions. Thus, in 1997, with Law No. 4283,**Build-Operate (BO) model**The implementation of this model is explained in Annex-1.

Compared to the BOT model, the BO model has been implemented successfully and in a relatively short period of time. As a result of the tender process, contracts were signed for four natural gas Combined Cycle Power Plants and one imported coal fired power plant in 1998 and 1999. The total installed capacity of these plants is 6,100 MW and all of them were put into operation in 2002-04.

However, some negative results of the BO model implementation have also emerged. Since the use of natural resources would require a concession agreement, the law did not allow the use of resources such as domestic lignite and hydraulic. Therefore, only natural gas and imported coal could be used. (However, even if the legal situation was not like this, additional capacity was urgently needed and only natural gas-fueled power plants could be established in such a short period of time). As a result, the establishment of 4,800 MW BO model gas-fueled power plants created an excessive dependence on imported natural gas in electricity production. In addition, due to take-or-pay obligations, the amount of electricity produced by BO plants, as in the case of BOT plants, has restricted competition in the electricity market.

Autoproducer Model

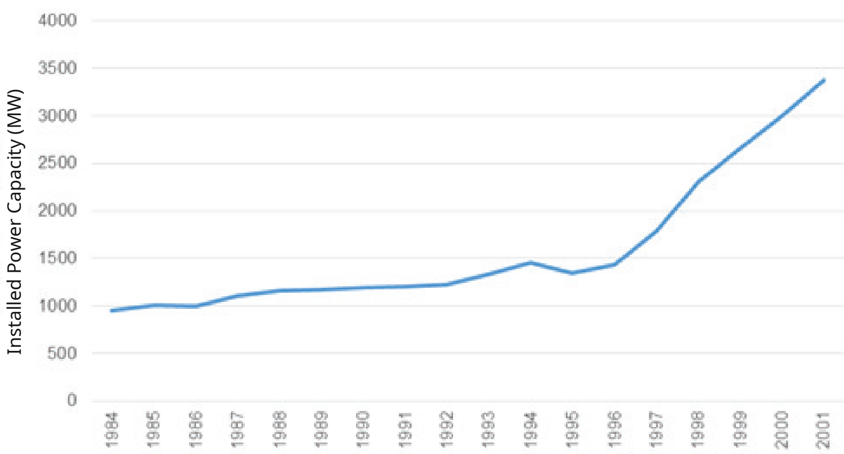
Autoproducer(production for own needs)**Model**It involves industrial companies owning and operating power plants primarily for their own electricity needs. Power plants built with this model in Türkiye are generally cogeneration facilities.[15]and the excess electricity they produced was sold to TEDAŞ. Although there were autoproducer facilities before 1984, these were mostly cogeneration facilities used in public sugar factories and were subject to special regulations. Law No. 3096 provided widespread use of the autoproducer model.

Initially, autoproducer plants were built primarily to produce heat for industrial processes, and electricity generation was not their primary purpose. However, with the tightening of the supply/demand balance, ETKB decided to encourage autoproducer plants and raised the tariff ceiling applied to their sales to TEDAŞ. This led to the construction of new autoproducer plants whose primary purpose was to produce electricity – these were plants with lower thermal efficiency than those established for cogeneration purposes.

In addition, the concept of an “autoproducer group” was introduced. According to this concept, industrial companies could come together to establish a production facility that would meet their own electricity needs, like an autoproducer. Both autoproducers and autoproducer groups could sell the excess energy they produced to TEAŞ or TEDAŞ (within a ceiling), regardless of their production and consumption times.

Among the four models discussed in this section, the model with the best results was the autoproducer model. During the period in question, many autoproducer plants with a total installed capacity of approximately 2,300 MW were put into operation. In addition, there were some autoproducer plants under construction as of 2001. As seen in Figure 17, this application gained momentum after 1997.

Figure 17. Increase in Installed Power of Autoproducer Plants, 1984–2001 (MW)



Source: TEİAŞ statistics.

The autoproducer group application can be considered as the first step towards independent production. However, it has also been an abuse of the autoproducer concept, as many partners have come together with very small shares (even with around 1 percent shares) to establish new power plants that are primarily aimed at selling electricity to TEAŞ and TEDAŞ rather than producing electricity to meet their own needs (after 2008, power plants established solely for electricity production were transformed into production companies and these became independent electricity producers).

Private Sector Participation in the Distribution Sector - Distribution Privatization through the HRA Model

Between 1984 and 2001, two different types of contracts were used for the privatization of electricity distribution under the HRA model. In the first model, which was used in two distribution regions (Aktaş and Kayseri), the energy supply company (TEAŞ) assumed all the risk and the distribution company was guaranteed a predetermined profit.*Profit*"determined as "a reasonable return on capital").

The second model uses a tender process. The main difference between this model and the first model is that in this model some risks are left to the company and the reconciliation (setting) process is eliminated. [16]According to the second model, the operation of distribution regions could be transferred to private companies for a limited period. The ownership of the assets remained with the state. The companies had exclusive rights to operate the distribution network in the region and to supply electricity to all consumers in the region (except for industrial companies supplied by autoproducers).

Although Türkiye tendered almost all distribution regions in 1996, the Council of State revoked the authorization of most companies and the regions*operating rights*could not be transferred successfully. Therefore, this process could not be concluded except for two regions as explained in Annex-1.

3.2.1.3 Summary of the Period 1984 - 2001

This period was marked by structural changes that (a) ended the state monopoly in electricity production and distribution and (b) enabled private sector participation in the electricity sector. At the beginning of the period, the Turkish Electricity Authority (TEK) operated as a vertically integrated monopoly in the fields of production, transmission, distribution and trade. The enactment of Law No. 3096 in 1984 allowed private sector participation in the electricity sector. This law essentially ended TEK's monopoly position in production by enabling private sector participation in production through investment models such as BOT, HRA, BI and autoproducer.

However, these first steps did not have a sufficiently solid legal basis. The liberalization of the electricity sector during this period was not the result of a long-term restructuring plan but rather a result of high demand growth and the urgent need for investment that arose accordingly. The general result of the first phase of the reform efforts can be summarized as a moderate level of private capital inflow into the generation sector. The high risk premiums resulting from regulatory uncertainties and country risk negatively affecting the investment environment led to high prices for new investments in the generation sector. In addition, most of the risks in the contracts were on the buyer (public companies).

This process was full of interruptions and reversals for the following reasons:

- Lack of consensus between judicial authorities and governments on private sector participation in electricity activities and significant delays and hesitations due to the following factors:

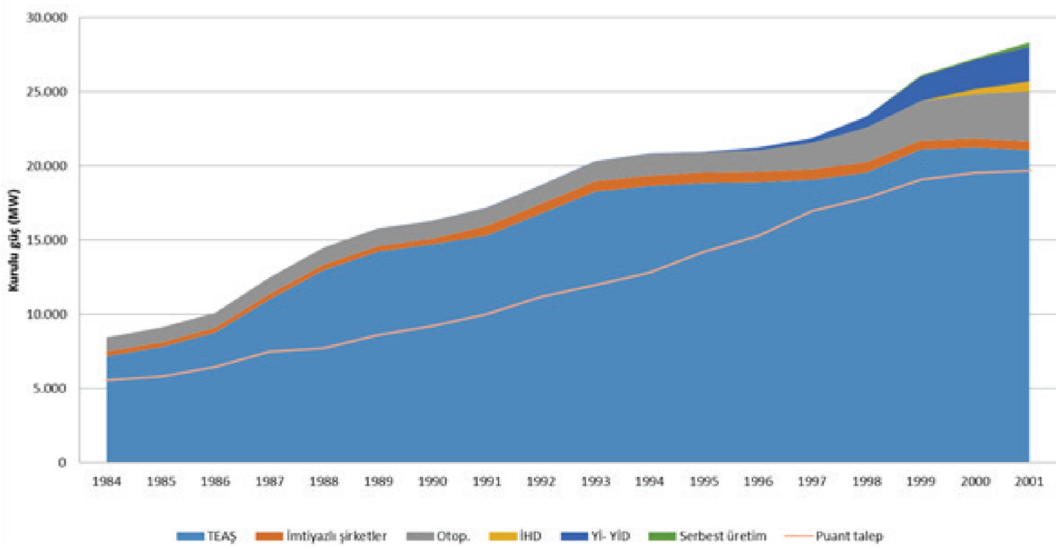
  Prolonged discussions regarding the legal framework and
  Judicial decisions given against the principles set forth in laws no. 3096 and 3996;

- Lack of consensus among public institutions on the way the BOT and TOA models should be implemented – resulting in the State Planning Organization (SPO), the Treasury and TEAŞ resisting ETKB's implementation of the BOT and TOA models;
- Unsuccessful efforts to privatize production and distribution activities;

- Deteriorating supply security due to insufficient production investments; and
- Lack of stability, frequently changing governments, accusations of corruption and frequent changes in bureaucracy.

As of 2001, an installed power capacity of approximately 11,000 MW was put into operation within the scope of the legal framework introduced during this period, including the BOT, BO and autoproducer power plants under construction. However, as seen in Figure 18, as a result of the slowdown in public investments due to BOT investment expectations and the delays in implementation, the capacity margin (the difference between the installed power and the peak demand) decreased sharply after 1994 and supply security deteriorated towards the 2000s.

Figure 18. Development of Installed Power and Peak Demand, 1984–2001 (MW)



Source: TEİAŞ Statistics

Towards the end of this period, in order to overcome urgent regional supply problems, a practice called "mobile power plants" was initiated. According to this model, small power plants (initially 25 MW each) were built by private companies and their capacities were "leased" by TEAŞ for a period of five years starting in 1999. Later, this concept was used to solve the problem of a worsening supply deficit, and both the number and unit power of the power plants were increased (100 MW each). Although demand fell sharply in 2001, the construction of the power plants continued due to existing contracts; as a result, a total capacity of 795 MW was put into operation by the private sector with this model between 1999 and 2003. These were mostly fuel-oil or diesel-fired power plants (chimney-fired combustion engines), and although some were dismantled after the contracts expired, some still continue to operate as independent producers (free production).

During this period, there was no intra-market competition and limited competition for entry to the market. In other words, there was a certain level of competition among companies to obtain the rights or privileges to build and operate power plants and sell the electricity produced ("competition for the market"). However, except for the autoproducer model, each consumer had to buy energy from the distribution company, and TEAŞ was the sole supplier of the distribution companies. There was no market and there was no legal basis for competition among suppliers.

Table 4 below summarizes some of the electricity sector indicators as of the end of this phase.

Table 4. Türkiye's Electricity Sector: Some Selected Indicators, 2001

2001	Public	Special							Total
		Prerogative Secret.	BOT	YI	IHD	Auto.	Independent Elk. Prod.	Total Special	
Production Capacity (MW)	21,063	610	2,338	0	650	3,374	297	7.269	28,332
Production Capacity Ownership (%)	74.3%	2.2%	8.3%	0.0%	2.3%	11.9%	1.0%	25.7%	
Transmission Lines (km)	43,654								
Number / capacity of Transmission Transformers (MVA)	1,090 / 62,015								
Rural Electrification	100								

Note: Mobile power plants are considered as independent electricity producers. Source: TEİAŞ statistics.

3.2.2 Second Stage: Establishment of a Competitive Electricity Market

3.2.2.1 Basic Motivation and Key Elements

In the late 1990s, taking into account the lessons learned from previous liberalization attempts, a more carefully structured transformation process was initiated with the aim of increasing the economic efficiency of the energy sector and attracting private sector investment in the energy sector. Although a private sector participation model for attracting private sector investment existed from the early 1980s (described above), this model required take-or-pay obligations and created contingent liabilities for public institutions while leaving almost all market risks to the buyer.

The problems encountered in the previous period (the high cost of production of BOT plants and the contingent liabilities assumed by the state due to Treasury guarantees) showed that a different model was needed to attract private sector investments. An investment environment – that is, a market – was needed to attract private sector investments without the guarantees of the state or public companies; instead,**The market itself should attract new production investments.**

Therefore, the main objective was to create a competitive market structure with the expectation of attracting investments, increasing efficiency and improving the reliability and quality of supply. However, competition requires a large number of buyers, a large number of sellers and an open access (AE) regime. To meet these requirements, the sector needed to be restructured, a regulatory framework for pricing and monitoring monopolistic activities had to be established, barriers to entry had to be removed and trading mechanisms had to be put in place.

At a time when Türkiye was making efforts to join the EU, the publication of the first EU Electricity Directive in 1996 constituted an important milestone for the Turkish electricity sector. In January 1997, with the financing provided by the World Bank, Türkiye's Ministry of Energy and Natural Resources (ETKB) began work on the preparation of a legal framework for a competitive electricity market in line with the conditions of the EU Directive. A working group was established within the ETKB to prepare an Electricity Market Law (EMK). A draft law was prepared with the support of the World Bank and the European Commission. In parallel, another working group began preparations for the Natural Gas Market Law (NGML). The aim of these efforts was ultimately to ensure a transition from a vertically integrated monopolistic system in the energy sector to a market structure that would provide full retail competition.

Due to the deep economic crisis in 2000 and 2001, the government initiated comprehensive reforms in some sectors, including the energy sector. In a sense, this crisis accelerated the implementation of the above-mentioned proposals. In addition, disagreements among public institutions regarding previous practices and lawsuits regarding practices at that time also increased public support for these reforms.

3.2.2.2 Basic Principles and Key Elements of the Electricity Market Law 2001

The Electricity Market Law No. 4628 ("EPK") was published in March 2001. Many changes were made to the law in the following years. Finally, following the revisions, the new Electricity Market Law No. 6446 ("new EML") came into force on March 30, 2013.

The purpose of the EPK was determined as follows:

> *To provide sufficient, high-quality, continuous, low-cost and environmentally friendly electricity to consumers, to establish a financially strong, stable and transparent electricity market operating in accordance with private law provisions in a competitive environment, and to ensure independent regulation and supervision in this market.*

The EML issued in 2001 determined the legal framework for the sector; defined the institutional structure, market activities and the roles and responsibilities of market players; and established the Energy Market Regulatory Authority (EPDK) for the independent regulation and supervision of this market. More specifically, the EML issued in 2001 introduced the following principles for the establishment of a competitive market. (These principles were also preserved in the new EML adopted in 2013):

- Establishing a licensing framework for market entry;
- Legal separation of the transmission system and market operation from generation and distribution activities;
- To meet the unbundling requirement, TEAŞ is split into three separate public companies: EÜAŞ for generation, TEİAŞ for transmission and market operation, and TETAŞ for trading (discussed below);
- Until legal separation (2013), accounting separation for distribution and retail activities;
- Non-discriminatory pricing and tariff mechanisms;
- Non-discriminatory regulated third party access to transmission and distribution networks;
- Non-discriminatory access of production companies and suppliers to eligible consumers in their distribution areas;
- The concept of free consumerism, where all consumers (the ultimate goal) have the freedom to choose their suppliers (they have access to competing suppliers);
- Legal basis for the establishment of competitive bilateral contracts and balancing markets;
- Privatization of production and distribution assets; and
- A temporary period of implementation until full liberalization.

Market activities fall into two categories.*Subject to regulation*Market activities consist of (a) transmission, (b) distribution, (c) retail sales and retail sales services to non-eligible consumers, and (d) TE-TAŞ's wholesale activities.

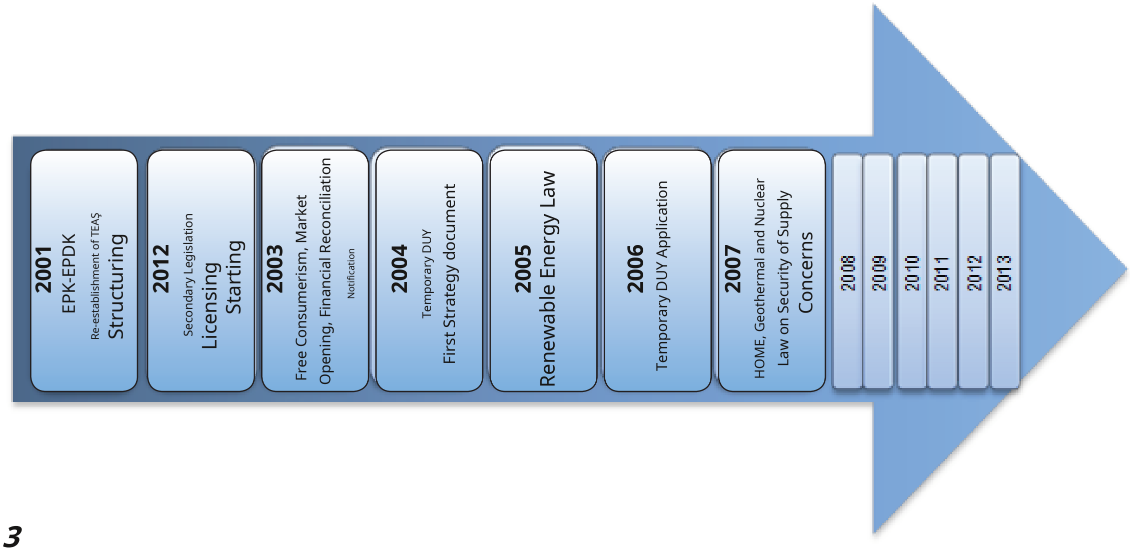
*Competitive*Market activities consist of (a) production, (b) wholesale (except for bilateral contracts of TETAŞ, which are subject to regulation, and transition period contracts), and (c) retail sales to free consumers.

(In the new EML, wholesale and retail sales activities are called "supply activities").

3.2.2.3 Major Implementation Steps Between 2001 and 2007

Türkiye has been implementing a comprehensive reform in the energy sector since 2001. Although the legal and regulatory framework and market structures have evolved step by step over time, this process has can be divided into two main stages. Between 2001 and 2007, the main legal and regulatory arrangements were developed (see Figure 19) and the market structure was changed – but some transitional problems were also encountered. In the second stage, which started after 2008, reforms were accelerated and a competitive market was developed. The following sections discuss the key steps taken in this process.

Figure 19. Major Implementation Steps in the 2001-07 Period



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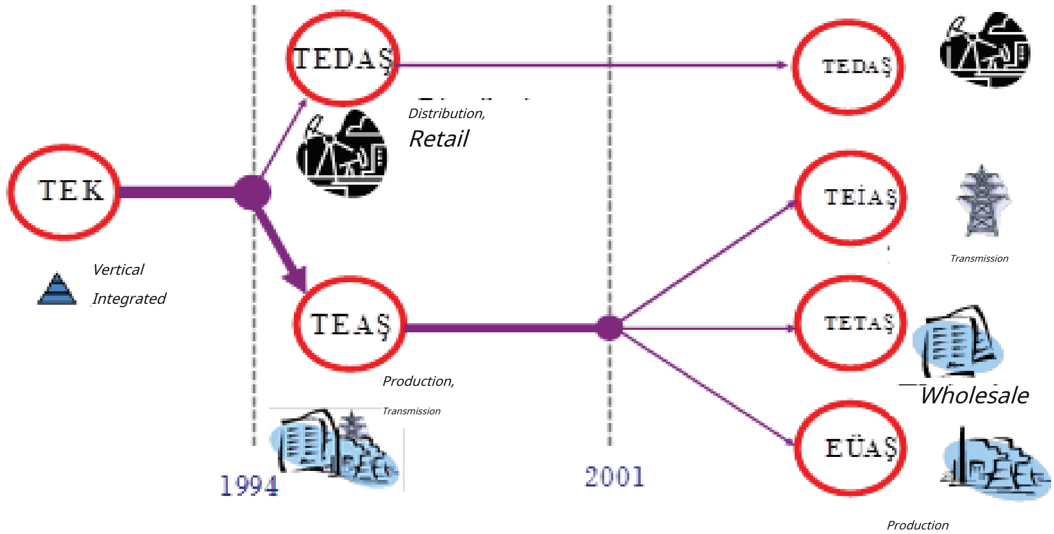
One of the first steps was the restructuring of public electricity companies. In line with the principle of separation of market activities, the state-owned TEAŞ was divided into three companies responsible for transmission, generation and wholesale activities, as shown in Figure 20. One of the main reasons for this was the need to create a transmission company that would act as an independent system and market operator, which was necessary for a competitive market structure.[17]

Figure 20. Restructuring of Public Companies



TEAŞ was restructured into three new public enterprises:

- **Turkish Electricity Transmission Corporation (TEİAŞ):**It was established to carry out electricity transmission activities and as a system and market operator.
- **Electricity Production Joint Stock Company (EÜAŞ):**was established to carry out electricity generation activities;

- **Turkish Electricity Trading and Contracting Corporation (TETAŞ):**YID was established to carry out electricity wholesale activities, including the management of existing long-term electricity purchase agreements with Yİ and İHD companies. TETAŞ YID,
It purchases electricity produced by the companies Yİ and İHD, as well as low-cost electricity produced in EÜAŞ's large-capacity hydroelectric power plants, and sells it to distribution companies at regulated prices.

TEDASand these three companies are public players in the market. As will be discussed later, for the privatization to be carried out in the period 2008-13**TEDAS**It was restructured in 2005.

3.2.2.5 Establishment of the Energy Market Regulatory Authority (EPDK)

One of the important steps taken in the reform process was the establishment of the Energy Market Regulatory Authority (EPDK) for the purpose of independent regulation and supervision of the market. When it was first established with the EPK, its name*Electric*The institution, which is the Market Regulatory Authority, was established with the Natural Gas Market Law No. 4646 issued in 2001.*Energy*It was renamed as the Market Regulatory Authority. With the Petroleum Market Law No. 5015 and the Liquefied Petroleum Gas (LPG) Market Law No. 5307, EMRA was also given the authority to regulate and supervise the petroleum and LPG markets. The first Board members of EMRA started their duties on November 19, 2001, when EMRA started its operations.

During the Preparatory Period that ended on September 3, 2002, the necessary secondary legislation was prepared by EMRA. The first draft market rules (Electricity Market Implementation Manual and later the Temporary Balancing and Settlement Regulation, or G-DUY) were developed in 2002-03, at a time when there was sufficient generation reserve margin. Licensing activities began in September 2002 and the market was opened to eligible consumers in March 2003. Initially, the consumption limit for becoming an eligible consumer was set at 9 GWh per year (as will be discussed in the following sections, this limit was gradually lowered by EMRA over time).

Among the important secondary legislation prepared by EPDK in the 2002-03 period is the Licensing Regulation (LY).

- Network Regulation
- Electricity Market Distribution Regulation (EPDY)
- Interim Balancing and Reconciliation Regulation (DUY)
- Ancillary Services Regulation
- Tariff Regulation

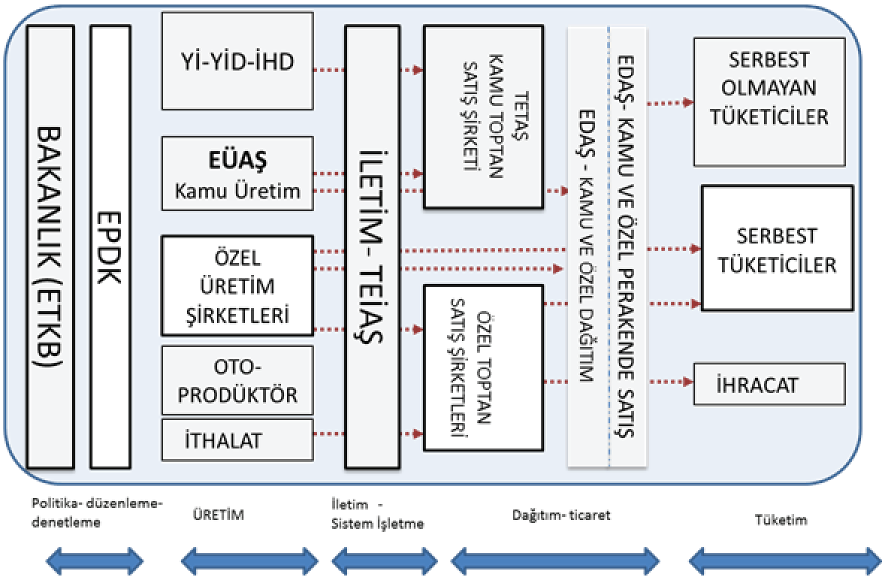
It is available.

Another important step was the attempts to adapt the BOT projects that had valid existing contracts but had not yet been implemented to the market. The License Regulation explained that if the owners of these projects waived their rights arising from the contract, they would be entitled to receive a license without the license conditions specified in the Regulation. (Later, the EML was amended to include a similar provision.) In this context, there were 31 projects with a total installed capacity of 2,855 MW. 15 of them (total installed capacity of 1,300 MW) were cancelled through mutual agreement. All of these companies obtained production licenses, realized their projects and became market players.[18]In fact, they were among the first players in the market to merge with existing autoproducer companies. This was an amicable solution and ensured a smooth transition.

3.2.2.6 Market Structure

The above-mentioned restructuring and unbundling steps and the entry of new market participants have led to a significant restructuring in the Turkish electricity market. Figure 21 shows the structure of the electricity sector after the EML.

Figure 21. Market Structure After EPK



The market rules described in the Balancing and Settlement Regulation (BSR) are implemented by PMUM, which acts as the market operator. (The implementation of BSR is explained in the relevant sections of this report.)

It should be noted that this structure changed with the adoption of the new EML in 2013, as explained in the following sections.

3.2.2.7 2004 Strategy Document

The market design envisaged that the market would become operational in a short period of time and that rapid progress would be made in the privatization of distribution companies (EDAŞ). These two steps would create the necessary ground for the formation of transparent and predictable market prices; ensure confidence among investors in the implementation of balancing and settlement rules (BUY), and thus ensure that reliable buyers would support the financing and implementation of new generation projects.

Although the Electricity Market Law set out the basic principles, a roadmap had to be created for the development of the market – and in particular, the balancing and reconciliation mechanism, steps towards the privatization of distribution and generation assets, and transitional measures for tariff implementation and marketing of public generation. However, despite the government's determination regarding the goals of the reform program – specifically, the implementation of a competitive market and the privatization of distribution and generation – progress in implementation had been limited. The implementation goals and implementation steps had been agreed upon, but the necessary steps had not been taken. Reform efforts were not effectively coordinated, and perhaps more importantly, there was no consensus on transitional approaches. While there was broad agreement on the privatization of distribution and generation and achieving a competitive market structure, the following were not taken by the ETKB and the Ministry of Finance:

- Establishment of initial contracts (commitment contracts) between generation and distribution companies to ensure a smooth start-up of the market and facilitate privatization;
- Moving to a pricing regime that reflects costs at the retail level prior to privatization; and
- Targeted subsidies to manage the impact of price increases on low-income consumers.

  The necessity of such transitional measures and regulations was expressed.

Therefore, with the support of international experts (a Panel of Experts financed by the World Bank), ETKB, EPDK, Treasury, SPO[19]As a result of the joint work of the Privatization Administration, a strategy document titled "Electricity Sector Reform and Privatization Strategy Document" was prepared and published on 17 March 2004 as a decision of the High Planning Council at the ministerial level, convened under the chairmanship of the Prime Minister. The following decisions were among the prominent decisions in the strategy document:

- Customization:

  In order to create a financially strong and sustainable retail sector that will help attract new generation investments to the electricity sector, it was decided to start privatization from the distribution sector. 20 regional distribution companies will be established in 21 distribution regions [one of which was already operated by a private company].

  Generation privatization will begin after distribution privatization and a functioning wholesale market is established. Except for some hydroelectric power plants that will not be privatized, state-owned generation assets will be grouped and portfolio generation companies will be established.

  The timetable for preparatory work on the establishment of regional distribution companies, determination of licensing processes and tariff structures, etc. is also determined in the strategy document.

  It is anticipated that the necessary preparatory work and the necessary legal and regulatory changes will be completed by mid-2005 and distribution privatization will be completed by 2007.

- Transitional Period Practices:

  With the transitional (committed) contracts of EÜAŞ and TETAŞ, it was decided that the distribution companies would sell electricity to meet 85 percent of the regional demands of the non-free consumers. Except for the TETAŞ contracts, the duration of these contracts will be 5 years. In order to apply a single national sales price to consumers, it was decided to implement a price equalization mechanism (cross-subsidy between regions). In this context, if the regional tariff is higher than the tariff reflecting the costs, each distribution company will transfer the excess money it collects to TETAŞ and this excess money will be transferred to the distribution companies whose tariffs reflecting the costs are higher than the national tariff. The national tariff is kept at a level that will ensure this transfer.

- Market Development:

  A temporary Balancing and Settlement mechanism will be prepared and implemented. A virtual trial period (without cash requirements) is envisaged for the training of market participants before the actual implementation.

  The final DUY will be prepared and a wholesale trading platform will be established where hourly settlement is made.

The 2004 Strategy Document also included measures to ensure supply security and strengthen TEİAŞ. Since the implementation of some of the measures in the Strategy Document would require changes to the Electricity Market Law and related legislation, a roadmap for these changes was also envisaged in the Strategy Document. It was envisaged that the preparatory work and legislative changes would be carried out under the coordination of ETKB.

3.2.2.8 Implementation of the 2004 Strategy Document

Customization

Preparatory work for the restructuring of distribution companies, determination of revenue requirements, determination of loss and theft rates, account separation and establishment of EÜAŞ portfolio groups was completed in 2004–05, with some delay according to the schedule envisaged in the Strategy Document. In the meantime, TEDAŞ was transferred to the management of the Privatization Administration and 20 regional distribution companies were established and licensed.

However, although preparations were completed by the last quarter of 2006, the distribution privatization was unexpectedly postponed by the government just before the tender stage. The rationale for this decision is explained in the Privatization section of this report.

Transitional Period Measures

The necessary legal and regulatory changes and amendments to the Electricity Market Law were made in 2006, and the necessary legal basis for the national tariff application, price equalization mechanism and transitional period contracts were created.

Market Development in the Period 2004-07 (DUY Application)

The market rules were initially designed in 2003 and in November 2004 the legal framework (i.e. the “Temporary” Balancing and Settlement Regulation or G-DUY) was completed, PMUM (market operating center within TEİAŞ) was established and virtual (non-cash basis) implementation started. However, since TEDAŞ’s reluctance to participate even in the virtual implementation also affected the decision makers, the real implementation could only start in August 2006. Since TEDAŞ could not assess the regional demands accurately, (a) it was worried that it would be burdened with additional burdens as a result of balancing market operations due to imbalances and (b) since there was no intention to apply a tariff reflecting the costs at that time, this additional cost would increase its already high losses.

Following a regional outage due to a major thermal power plant failure and insufficient balancing capacity, ETKB decided to urgently implement the balancing and settlement regulation. After the implementation of G-DUY, PMUM provided a trading platform for market participants. However, the suppressed regulated tariffs (discussed in more detail below) prevented eligible consumers from leaving the regulated tariffs and remained as non-eligible consumers (and even some consumers who had become eligible consumers returned to the distribution companies). As a result, private generation companies were forced to sell the majority of their generation to PMUM, thus turning the balancing market into a kind of pool. This led to another difficulty. Distribution companies (mostly state-owned companies at the time) procured the remaining amounts of their energy needs (over and above the amount provided by TETAŞ and EÜAŞ) and the power needs arising from the imbalance from PMUM, but had to sell this to non-eligible consumers at a tariff that did not reflect their costs. As a result, this situation led to delays in the payments of TEDAŞ distribution companies to suppliers.

However, despite the problematic implementation, the implementation of the balancing and settlement market was one of the important steps in the reform process and initiated new production investments.

The 2004 Strategy Document provided a roadmap for the reform process and aimed to increase the confidence of market participants, especially private companies that could potentially invest in Türkiye. In fact, the strategy document was initially generally welcomed by participants. However, hesitations and delays in establishing a market area (balancing and day-ahead markets) and the decision to postpone distribution privatization led to a loss of confidence. In addition, interventions aimed at keeping final consumer prices under control (below costs) further reduced the confidence of market players. This had a negative impact on supply security due to insufficient production investments.

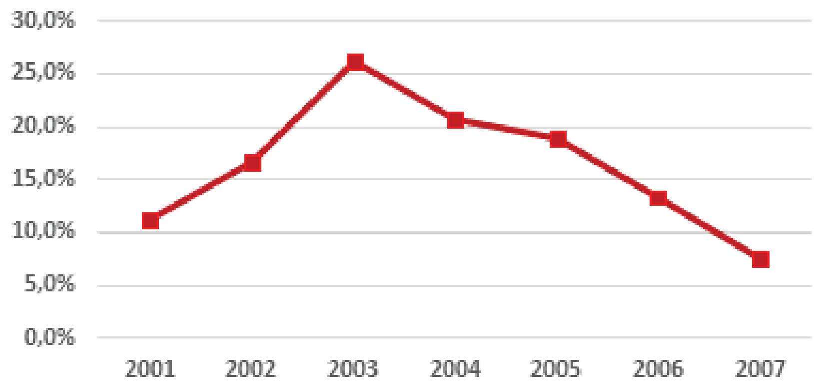
Despite its delay in implementation, the 2004 strategy document was an important step in the reform process. The decisions and principles set out in the document formed the basis for privatization, transitional measures and the establishment of the wholesale market.

3.2.2.9 Supply/Demand Balance in the 2001-07 Period

Inadequate Manufacturing Investments: The Supply Security Situation That Gives Warning Signs

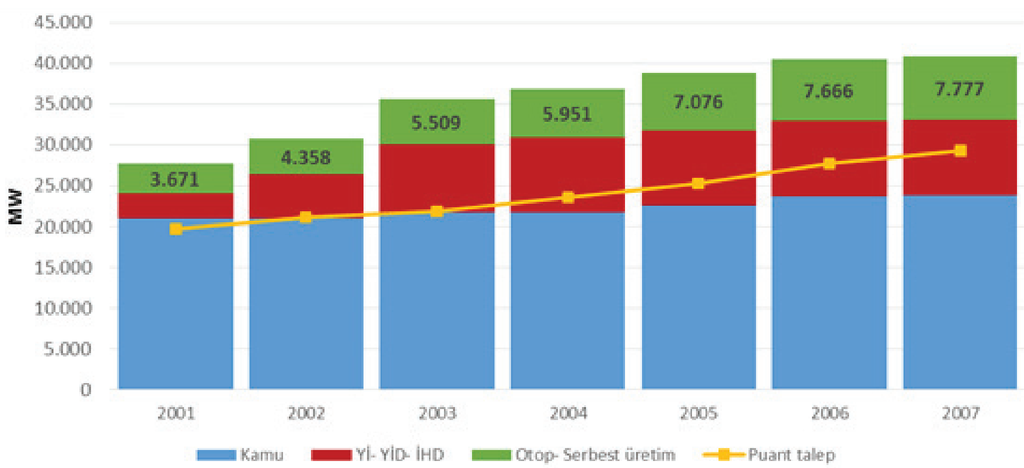
The annual average demand growth rate during the 2002-07 period was approximately 7 percent. Due to the sharp decline in demand in 2001 and the commissioning of the BO plants in 2002 and 2003, the reserve margin[20] was sufficiently high in the beginning. However, as Figure 22 shows, after 2003 the reserve margin has declined sharply.

Figure 22. Reserve Margin, 2001–07



Studies conducted in 2006 indicated that if demand continued to rise as predicted, a supply crisis would occur starting in 2008. The main reason for this was the inadequacy of production investments. Apart from the hydroelectric power plants built by DSI, no public investment was made. Previous models such as BO and BOT were no longer used. As seen in Figure 23, only 4,000 MW of production investment was made by the private sector in the seven-year period (the majority of which were unfinished old BOT projects converted into autoproducer facilities and independent electricity producers, including those initiated before 2001). In addition, the utilization rates of hydroelectric power plants were gradually deteriorating due to the deteriorating hydrological conditions.

Figure 23. Development of Generation Capacity, 2001–07 (MW)

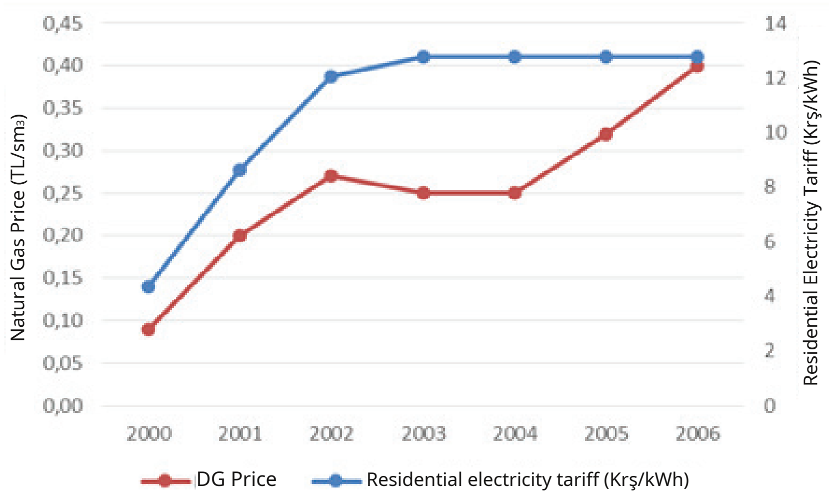


Source: TEIAS.

There were several reasons why the private sector was hesitant to invest in manufacturing:

- As seen in Figure 24, despite the increase in fuel costs and other costs, electricity prices have not changed at all for the last five years. Although there was no need for tariff increases until 2005 due to the high hydroelectricity production and relatively low natural gas prices, tariffs had to be increased in order to cover the costs starting from 2005. Although there were free consumers, the low retail tariffs acted as a deterrent to transitions and these tariffs were not sufficient to cover the production costs of private (mostly natural gas-fired) power plants. Therefore, free consumers preferred to buy their electricity from distribution companies at regulated prices. This regulated tariff structure did not encourage distribution companies to make contracts with generation companies at a price that would provide sufficient income to cover their investments.

Figure 24. Natural Gas Price and Residential Tariff, 2000–06



Source: BOTAŞ and TEDAŞ.

Note: Mid-year prices were used. Old Turkish Lira was converted to New Turkish Lira.

- There was no mechanism to provide long-term price signals. Although the balancing and settlement regulation (B-SAR) existed, it was not implemented until late 2006. So, as discussed in the previous section, there was practically no market for energy trading until late 2006.
- The market concept was new to Türkiye. It had not been implemented before. Until 2005, the demand of distribution companies was met by public production and TETAŞ sales.
- Even after the implementation of the G-DUY in 2006, there was no possibility of bilateral contracting due to the following reasons:

    TEDAŞ's past payment performance was not encouraging for prospective generation investors considering long-term bilateral contracts. Distribution privatization was scheduled to be completed by 2007, and its postponement weakened market confidence. The uncertainty about the future of the distribution sector led to reluctance to enter into long-term contracts and reduced the incentive for new generation investments.

    Due to the increase in demand and imbalances, distribution companies had to purchase additional energy in addition to the transition period contract amounts. However, due to uncertainty, both suppliers and distribution companies did not opt for new contracts and instead purchased from the balancing market at imbalance prices. As explained in the previous section, the market structure for independent power producers temporarily changed from a dual contract market model to a central pool model.

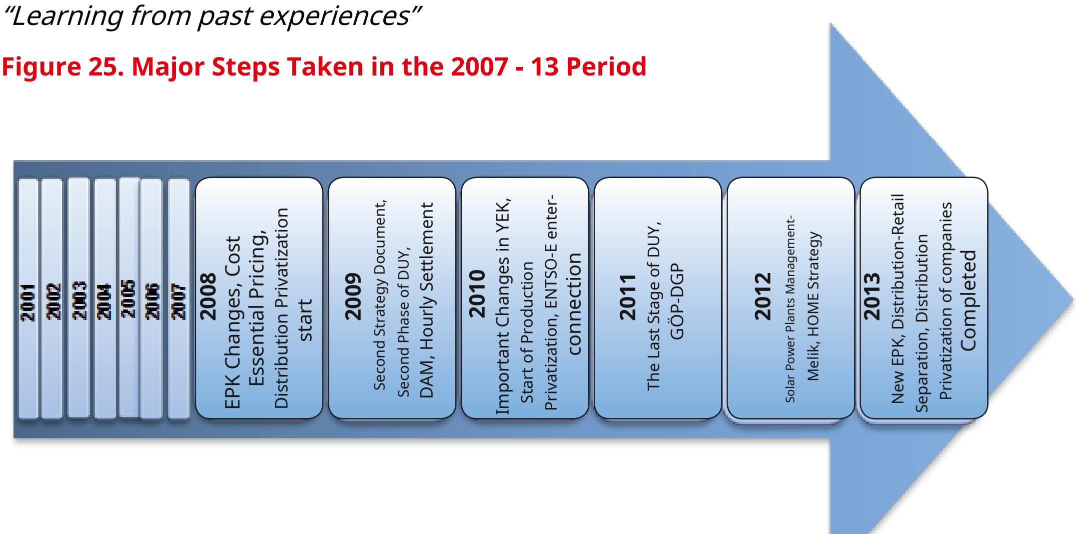
Considering that the number of new generation licenses increased after 2006, the implementation of the temporary DUY, although not functioning as desired and not sufficient to establish long-term confidence, has been an incentive for new investments. However, the most significant increase in investments occurred after the implementation of cost-recovery pricing, the start of distribution privatization in 2008, and the implementation of well-functioning market platforms in 2009 and 2001.

The supply/demand balance deteriorated due to the high demand growth in 2007 and the first half of 2008. However, in the second half of 2008, electricity demand began to fall due to the global economic crisis. If this crisis and the resulting decrease in demand had not occurred, restrictions in electricity supply would have been inevitable starting in 2009.

3.2.3 Post-2008: New Steps Towards a Competitive Market

"Learning from past experiences"

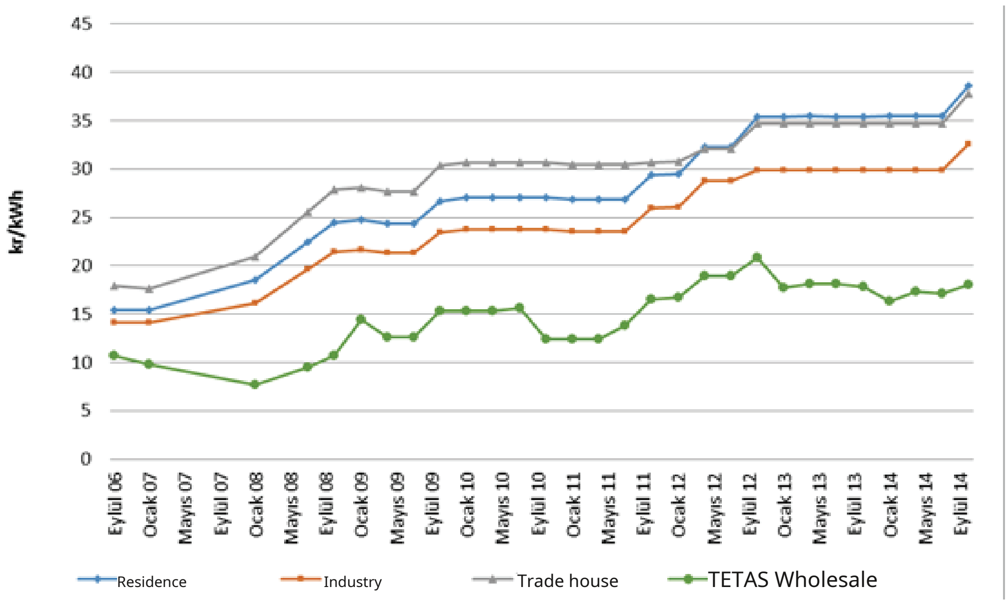
Figure 25. Major Steps Taken in the 2007 - 13 Period



3.2.3.1 Cost-Response Pricing

The increasing risk of electricity shortages since 2009 and the unsustainable financial performance of state-owned companies have led the Turkish government to take serious measures as of early 2008. Regulated electricity tariffs were increased significantly for the first time since 2003 in January 2008. After a gap of approximately one year, three significant tariff increases were implemented (January 2008, July 2008 and October 2008) and the average retail tariff increased by approximately 50 percent to reach levels where finances are fully covered. This has significantly improved the financial sustainability of the sector, encouraged more efficient consumption behavior and attracted private sector investment into the sector. A cost-based or "Automatic" Pricing Mechanism (AFM) has been implemented to maintain levels where costs are fully covered. Within the scope of OFM, the prices of Turkish Coal Enterprises (TKİ), BO-TAŞ, EÜAŞ, TETAŞ and distribution companies would be subject to adjustment every three months according to the formulas given in the mechanism (the first three by the companies/government, the last by EPDK).[21] The changes in average non-free consumer tariffs (including taxes) and regulated TETAŞ tariffs for residences, businesses and industries are shown in Figure 26.[22]

Figure 26. Residential and Industrial Tariffs Applied Since 2006



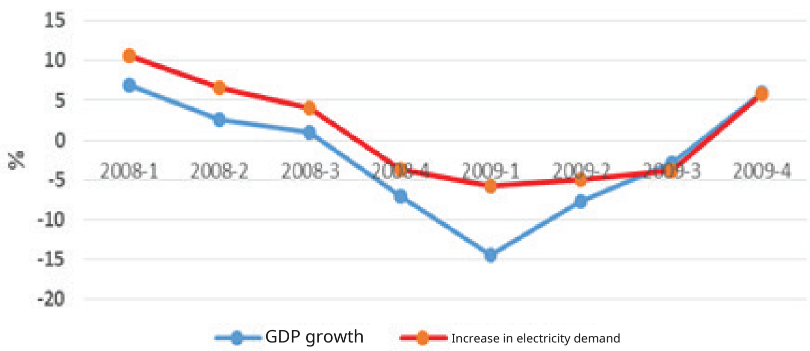
Source: EPDK and TEDAŞ statistics.

3.2.3.2 Supply Security Measures and Amendments to the EML

In 2006, with the support of the World Bank, ETKB initiated a series of studies to assess the supply security situation.[23] The main question addressed in these studies was whether the market design and implementation had any negative impact on security of supply and, if so, what possible measures could be taken to compensate for these. The studies showed that even if the errors in implementation were corrected (discussed above), in order to increase security of supply, the responsibilities of the relevant institutions should be clearly defined, a monitoring mechanism should be established and possibly some new market mechanisms (such as capacity mechanisms, tenders, obligations to purchase sufficient capacity) should be developed. These proposals for long-term structural change formed the basis of the amendments made to the EML in 2008 and the Strategy Paper published in 2009 (see next section).

The slowdown in electricity demand growth and the decline in demand in late 2008 and early 2009 (Figure 27) gave Türkiye additional time and opened a window of opportunity to attract more investment in production capacity and to ensure energy efficiency. Although the supply/demand balance improved due to the decline in demand, some short- and long-term measures were determined to improve long-term supply security. In 2008, the Electricity Market Law was amended to allow for measures to be taken to better monitor and assess electricity supply security. However, plans for long-term measures such as the Capacity Mechanism lost their urgency and were therefore not implemented.

Figure 27. G , 2008–09



3.2.3.3 2009 Electricity Market and Supply Security Strategy Document

A new strategy document was prepared in 2008 and published in May 2009 after being approved by the High Planning Council. “Electricity Market and Supply Security Strategy Document”[24]
In this document titled “The steps to be taken for market opening and ensuring supply security and the targets regarding domestic resources to be used in electricity supply in the medium and long term” have been determined. The following main topics are addressed in the Strategy Document:

- **Market implementation steps:** The government reiterated its commitment to establishing a competitive electricity market and outlined a roadmap for the implementation of wholesale market mechanisms such as Day Ahead and Balancing Power Markets. It also envisaged an independent market operator to operate an electricity exchange. It aimed to fully open the market by 2015.
- **Customization:** In the Strategy Document, it was accepted that distribution and production privatizations are important tools for the creation of a competitive market structure. It was also stated that the main goal of privatization is to establish competition in the sector, increase efficiency in the production and distribution sectors and ensure supply security.
- **Security of Supply:** The electricity strategy requires the Ministry of Energy and Natural Resources to closely monitor supply/demand balance projections and regularly report to the government on these projections and recommended measures to ensure supply security.

It was stated that if public investment is required for new production capacity despite the measures taken, these will be addressed within the scope of the government's budget process. In addition, it was envisaged that additional mechanisms such as the capacity mechanism and electricity/capacity auctions will be evaluated to improve supply security.

- **Future targets regarding domestic and renewable resources:**Since Türkiye's excessive dependence on high-cost imported natural gas for electricity production (over 40 percent) creates concerns about the current account deficit and energy security, the Strategy Document explains that Türkiye aims to increase the share of domestic resources such as lignite and hydraulic in electricity production and to fully utilize their potential by 2023. In addition, the Strategy Document aims to increase the share of renewable resources in electricity production to over 30 percent by 2023.
- The Strategy Document also includes the Coordination Union for the Transmission of Electricity in Europe (UCTE), which was renamed the European Network of Transmission System Operators for Electricity (ENTSO-E) on 1 July 2009. It also determined the principles for establishing interconnection with neighbors, including the steps to be taken for interconnection with the neighbors.

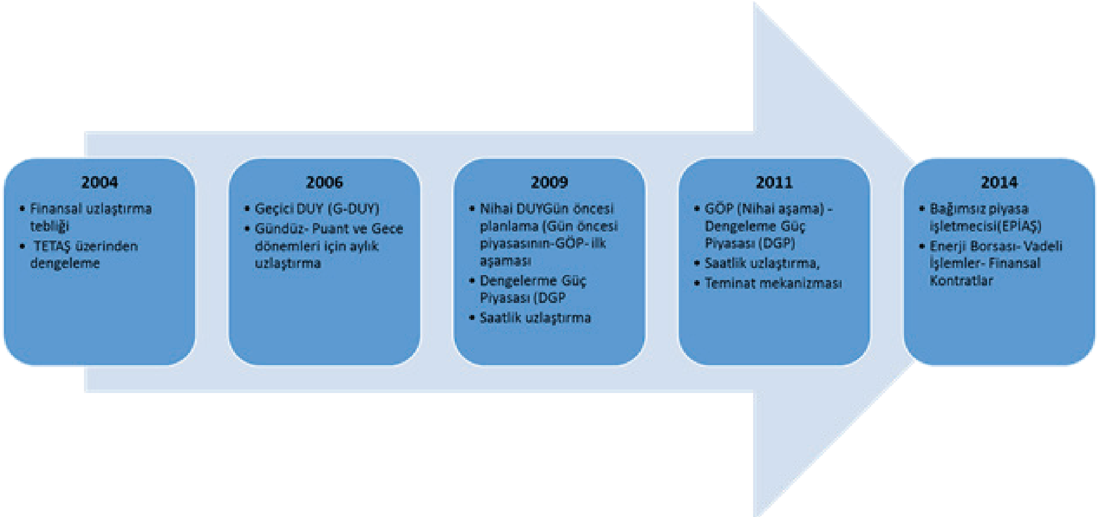
Implementation of the 2009 Strategy Document

The threat of an impending supply shortage due to low private sector investment, losses resulting from pricing policies and the deteriorating performance of public distribution companies proved that previous policies were not sustainable. The necessary steps were postponed until they could no longer be postponed. Therefore, contrary to the strategy published in 2004, decisions regarding the wholesale market and privatizations were implemented without significant delay, as described in the following sections.

3.2.3.4 Development of Wholesale and Retail Markets: Trade Mechanisms

The market structure implemented in Türkiye is based on bilateral contracts between buyers and sellers and is complemented by a central day-ahead market and a balancing and settlement mechanism. In order to introduce wholesale competition and create a trading area, it was necessary to design and implement the necessary rules and procedures for reconciling imbalances, scheduling production and load dispatch. The implementation of the Balancing and Settlement Regime was one of the important steps. Since a well-developed metering and IT infrastructure and well-organized market participants are required for the functioning of a wholesale market, market rules were implemented gradually. The stages of market implementation can be seen in Figure 28.

Figure 28. Milestones of Market Development



The market rules were first designed in 2003 and the first Balancing and Settlement Regulation (Temporary Balancing and Settlement Regulation or G-DUY) - which constituted the legal framework - was completed in November 2004. However, due to the reasons explained in the previous sections, the implementation could only be started temporarily (pilot) in August 2006. Until 2006, a simple balancing and transportation regime was used, where the balancing powers of private generation companies were provided by TETAŞ at regulated purchase and sale prices. Once implemented, G-DUY provided a trading platform for market participants. However, as explained earlier, it turned into a pool due to the suppressed regulated tariffs.

This created another difficulty. The distribution companies (mostly state-owned companies at the time) obtained the remaining amounts of their energy needs (over and above the amount provided by TETAŞ and EÜAŞ) and the needs arising from the imbalance from PMUM. However, due to the higher prices and suppressed tariffs in PMUM, the distribution companies had difficulty in making payments to TETAŞ, EÜAŞ and even PMUM. This situation also delayed PMUM's own payments to the private sector. In addition, the overdue debts of the distribution companies (TEDAŞ) to TETAŞ and EÜAŞ and therefore the debts of TETAŞ and EÜAŞ to BOTAŞ also accumulated. This impasse was relieved only after the introduction of cost-recovery tariffs and the transition of free consumers back to other suppliers.

The mechanism implemented from 2006 to 2009 was sometimes called the “day-ahead balancing market”. In fact, it was a “day-ahead scheduling/planning mechanism (DAP)”. The generation companies submitted their hourly generation schedules for the following 15-day period twice a month (not every day) and their prices if they were used in day-ahead and real-time balancing (prices were requested for loading and shedding from their power plants). Daily demands were determined by TEİAŞ’s national load dispatch center for each hour of the following day and the system was balanced according to the physical capacity offers of the generation companies. The marginal price at the supply/demand intersection was determined according to the load-up and load-shedding offers. Therefore, the system was balanced by TEİAŞ one day in advance. Generation scheduling was done by TE-İAŞ and announced to the generation companies. In addition, real-time balancing was done by TEİAŞ based on the prices of the generation companies during the day. As the metering and IT systems were not complete, reconciliation was also done differently: there were three separate reconciliation time slots – daytime (11 hours), peak (5 hours) and night (8 hours). This was a precaution to have a balanced system the day before in order to provide a more manageable real-time reconciliation.

With the development of the infrastructure, detailed rules for the second phase of the DUY were developed, and these rules almost completely changed the first phase DUY. The second phase came into effect in April 2009 and began to be implemented in December 2009. This phase was a more complex Day Ahead Scheduling mechanism. Load quotations and load quotations were now submitted on a daily basis for each hour of the following day, rather than twice a month. Marginal prices were calculated and announced one day in advance. However, the demand for the following day was determined by TEİAŞ. Instead of day, peak and night time slots, the settlement time slot was now one hour.

As a result, the final phase of DUY began in December 2011. The balancing market has evolved into a true Day Ahead Market (DAM), a voluntary electricity trading platform where supply and demand are balanced by the bids and offers of suppliers and consumers. TEIAS now balances the market one day in advance based on its own demand forecasts. This platform has become a market where supply, demand and prices are determined by the bids and offers of participants. Real-time balancing is carried out by TEIAS in the real-time Balancing Power Market (BPM) based on the bid and offer prices submitted by participants one day in advance.

Work on the establishment of an “intraday market” has reached an advanced stage and the intraday market is expected to become operational in 2015.

There have been significant delays in the implementation of both the Interim DUY and the Final DUY (GÖP and DGP). The point reached today could have been reached earlier. As mentioned in the previous sections, delays in cost-recovery pricing and distribution privatization have also delayed implementation. However, even if there had been no delay, a gradual pace of implementation was inevitable. Neither the technical infrastructure could be built nor the experience among market players could be developed in such a short period of time. For this reason, a simple methodology was used until 2006; then, starting with virtual (non-cash-based) implementation, interim methods (defined in G-DUY) were introduced; and finally, wholesale markets -GÖP and DGP- were established.

The market model is based on physical bilateral contracts between market participants and balancing (day-ahead and real-time) and settlement mechanisms. The balancing mechanism components are the Day-Ahead Market, the Balancing Power Market and ancillary services – all of which provide opportunities for electricity trading.

The introduction of trading and balancing mechanisms have been important steps in reforming the sector. As currently operated, the markets can be described as:

- **Binary Contract Market:**a market where long-term contracts for energy quantities are settled at a mutually agreed price between buyers and sellers. Price formation depends on bilateral contracts. Bilateral contracts provide a hedge against volume and price risk for both buyers and sellers.
- **Day Ahead Market (DAM):**It is a market where buyers and sellers submit hourly bids and offers for sales subject to settlement at the market clearing price. Price formation depends on day-ahead supply and demand (marginal pricing). DAM operates as a market where uncontracted production can be bought and sold within an offer-based system.
- **Balancing Power Market (BPM):**is a market where participants are the parties responsible for the balance (they may come together to form balancing groups). After the DAM closes and the generation and demand schedules are finalized, generation companies submit load offers (to buy energy if the system has a surplus) and load shedding offers (to sell energy if the system has a deficit) for each hour of the following day. Price formation depends on the real-time supply/ demand balance.

In addition to the wholesale market mechanisms described above, Ancillary Services can provide additional income for generation companies. These services are used for the reliable operation of the electricity system and can be provided through ancillary services contract with TEİAŞ.[25]

Energy Markets Operations Corporation (EPİAŞ)

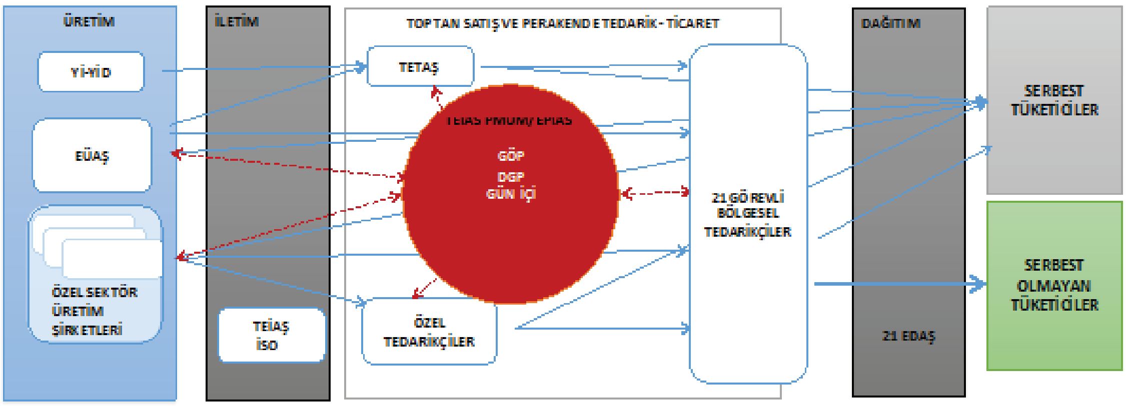
Until the new Electricity Market Law enacted in 2013 (Law No. 6446, which replaced Law No. 4628), market operation was carried out through a separate unit (PMUM) affiliated to TEİAŞ. With the new EML, market operation activity has been defined as “operation of organized wholesale electricity markets and financial reconciliation transactions of activities carried out in these markets”. This activity, which will be carried out with the Market Operation License, will be separated from TEİAŞ and carried out by an independent company called EPİAŞ. However, TEİAŞ will continue to operate the balancing power market and ancillary services market.

EPİAŞ will be responsible for the operation of organized wholesale markets (such as the GÖP and Intraday Market) and the development of an Energy Exchange (which will also include the natural gas market). It will also operate a market for standardized electricity contracts (i.e. capital market instruments) and derivative markets where derivatives based on electrical energy and/or capacity are bought and sold. EPİAŞ will also serve as a market operator for gas trading.

The shareholders of EPİAŞ are TEİAŞ and BOTAŞ (30%), Borsa Istanbul (30%) and the private sector (40%). EPİAŞ started its operations in 2015.[26]

The final market structure is shown in Figure 29. (NOTE: With the new EML, autoproducer licenses have been converted into production licenses).

Figure 29. Final Market Structure

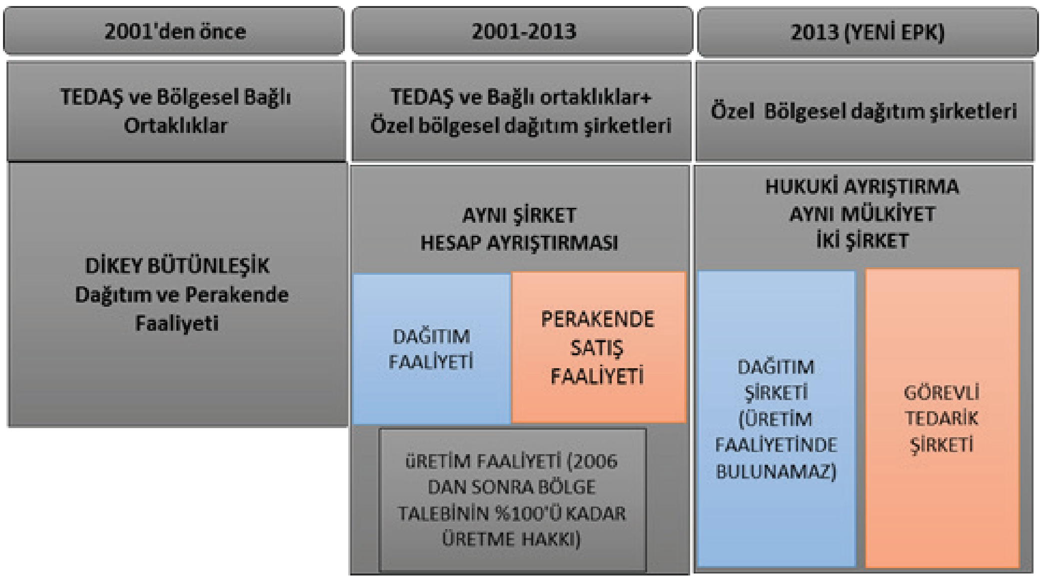


3.2.3.5 Legal Separation of Distribution and Retail Activities

Until January 2013, distribution and retail activities were carried out by the same distribution companies under separate accounts (i.e. through account separation). These companies had two licenses: a distribution license to operate the distribution system in their region and a retail license to supply electricity to non-eligible consumers in their region. As stated in the Second Strategy Document and the EML amendments, these activities are now legally separated. As of the end of 2012, distribution companies are legally separated into a distribution company and an "incumbent" supply company.[27] However, the legislation allowed the incumbent supply companies to perform their duties under the distribution company in the first half of 2013.

The transition from a single vertically integrated structure to a legally separated regional company structure is shown schematically in Figure 30.

Figure 30. Decomposition of the Distribution



Translated from Turkish to English - www.onlinedoctranslator.com

Distribution companies operate and maintain the distribution network and make the necessary network investments in order to provide electricity distribution and connection services to all system users, including free consumers who are connected and/or will be connected to the distribution system, without discrimination, in accordance with the provisions of their licenses and the Electricity Market Distribution Regulation. Legal entities holding a distribution license also prepare distribution investment plans and regional demand projections regarding the necessary distribution facilities to be constructed in the regions specified in their licenses.

Distribution companies are obliged to purchase electrical energy and supply it to the system in order to replenish the energy lost as a result of losses and thefts. They read the meters of all distribution system users – including free consumers who are served by another supplier – and keep their records. Distribution companies are obliged to provide distribution services to all parties without discrimination. According to the New Electricity Market Law, a distribution company cannot engage in any activity other than distribution activity or be a direct partner of a legal entity engaged in another market activity. The New Electricity Market Law only prohibits direct ownership; therefore, it is possible for a production company to indirectly own a distribution company.

According to the new Electricity Market Law, a designated supply company can sell electric energy and/or capacity to non-eligible consumers in the region it is authorized to and to all eligible consumers nationwide. They also serve as last resort suppliers to consumers in their region.

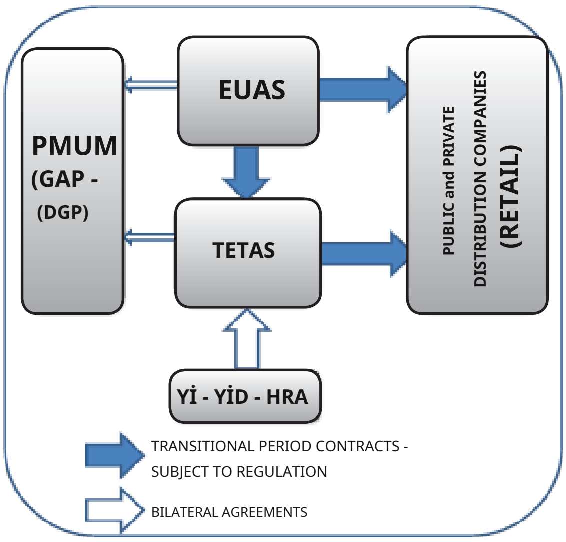
3.2.3.6 The Role of EÜAŞ and TETAŞ

Before the new Electricity Market Law enacted in 2013, the roles of EÜAŞ and TETAŞ were limited. EÜAŞ, which owned and operated publicly owned power plants, was not allowed to make new generation investments except for those necessary for supply security. EÜAŞ could only take over hydroelectric power plants built by the State Hydraulic Works (DSİ). Its total generation was allocated to TETAŞ and distribution companies through transitional contracts. It also participated in the day-ahead market for the uncontracted part of its generation and in the balancing power market for balancing purposes.

The EML defined TETAŞ's role as a public wholesale company responsible for the execution of the former TEAŞ's “existing contracts” (Yİ-YİD-İHD contracts and import contracts signed before 2001). TETAŞ can only sign new import contracts with the authorization of the Council of Ministers. After the first Strategy Document, a portion of EÜAŞ's hydroelectric production was allocated to TETAŞ in order to reduce the total cost of the existing high-cost contracts. TETAŞ could only sell its electricity to distribution companies through temporary contracts, and the prices of these contracts were regulated by the EPDK.

The roles of EÜAŞ and TETAŞ before the EPK issued in 2013 are shown in Figure 31. It can be said that the market design did not initially foresee a significant role for TETAŞ and EÜAŞ after the transition period. Due to the hydroelectric power plants that would remain in the EÜAŞ portfolio, EÜAŞ would have a limited role in the market after privatization. On the other hand, TETAŞ was considered as a “temporary” institution whose role would gradually decrease and whose role would end after the expiration of the “current contracts”. However, as will be explained in the Nuclear section, TETAŞ was authorized to sign electricity purchase contracts with the nuclear power plant company that is expected to be put into operation by 2023. Therefore, TETAŞ will continue to exist after the expiration of the current contracts.

Figure 31. The Role of EÜAŞ and TETAŞ Before the 2013 EML



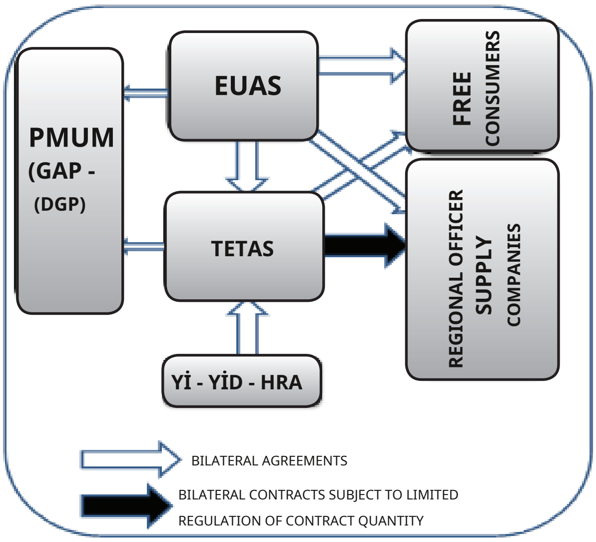
The existence of the public wholesale company (TETAŞ) ensured a smooth transition from a single-buyer model to a competitive market. On the other hand, it was used to fulfill the state's obligations towards the BOT plants, while at the same time it was the main supplier of the public distribution companies, which were commercially unstable before privatization. The transitional contracts also provided a way to supply electricity to the privatized distribution companies during the long and gradual privatization process.

With the new EML, EÜAŞ and TETAŞ can be considered as active players in the market. According to the new Electricity Market Law;

- There are no clear restrictions or conditions regarding EÜAŞ's new production investments.
- EÜAŞ has equal rights and responsibilities with private legal entities holding a production license in the market.
- EÜAŞ may become a partner in private production companies established to build and operate new production facilities (especially strategic production investments such as nuclear power plants and domestic lignite-fired thermal power plants).
- TETAŞ's rights and responsibilities are equal to those of private wholesale companies in the market (however, the prices to be applied in sales to distribution companies will still be subject to regulation).
- Distribution companies must purchase electricity from TETAŞ to compensate for losses, theft and lighting consumption in their regions.
- The assigned regional supply companies – which are also the "last resort suppliers" in the distribution regions – will purchase a portion of their needs in this context from TETAŞ. The amount will be determined by EMRA.

Therefore, the roles of EÜAŞ and TETAŞ have changed and they have now become active market players, as seen in Figure 32.

Figure 32. The Role of EÜAŞ and TETAŞ After the 2013 EML



3.2.3.7 Customization

General Approach

Previous attempts at privatization in the electricity sector have always led to legal problems. In order to overcome these problems, the Privatization Administration (PA) received a legal opinion from the Council of State regarding the privatization methods that could be applied before determining the model to be applied for electricity production and distribution privatizations.

According to the Council of State's interpretation, production facilities built on a primary resource and using streams, which are a public asset, cannot be owned by private parties. For this reason, similar facilities such as hydroelectric power plants and geothermal power plants can only be privatized through the transfer of operating rights (TOR) model, where the ownership of the assets remains with the state.

On the other hand, thermal power plants are not built on a fuel source that is public property, so the ownership of the assets of coal, lignite and combined cycle natural gas power plants can be sold. However, coal mines that feed lignite power plants can only be transferred to the private sector through the TOA model.

Similarly, the Council of State's interpretation regarding distribution facilities was that the only permissible privatization method was the HRA, as the sale of distribution assets would mean the sale of the real estate on which they are located, which is generally public property.

The privatization methods were determined by the PA accordingly. Along with the electricity market reform implementation, a privatization program was launched in 2006. According to the proposal in the First Strategy Document, priority was given to the privatization of distribution first – the reason for this was to create a reliable distribution sector and to give confidence to potential private generation companies. TEDAŞ could not provide this confidence in any way. If generation privatization had started before distribution, the main customer of generation companies would have been TEDAŞ and generation companies would not have made contracts with TEDAŞ without state guarantees. This situation would have created an approach similar to the privatization method before 2001, which was not a competitive market approach.

The second problem is the lack of reliable metering, billing and balancing/settlement functions. Such an environment requires time and investment. The third issue is the desire to reduce losses and thefts under effective private sector management.

Distribution Customization

In the First Strategy Document, it was envisaged that distribution privatization would start in March 2005 and be completed by the end of 2006. Preparations were only completed in November 2006. However, despite the completion of preparations, distribution privatization was postponed by the government just before the tender stage. The government's reasons for this postponement were as follows:

- Huge investments had to be made in the distribution system.
- If these investments were not made after privatization, service quality would deteriorate.
- Therefore, these investments would first be made by TEDAŞ and the privatization process would continue later.

Since one of the aims of privatization was to take the investment burden off public companies, this situation was in contradiction with the privatization decision. Although not explicitly stated, the real reasons for the government's decision may be as follows:

- Estimates showed that electricity tariffs would need to be increased significantly to finance the necessary investments.
- The operation and maintenance component of the tariff would also need to be increased to cover operation and maintenance costs, including loss and leakage impacts.
- Such a tariff increase was a politically sensitive issue (see section on pricing policy during 2002–07).

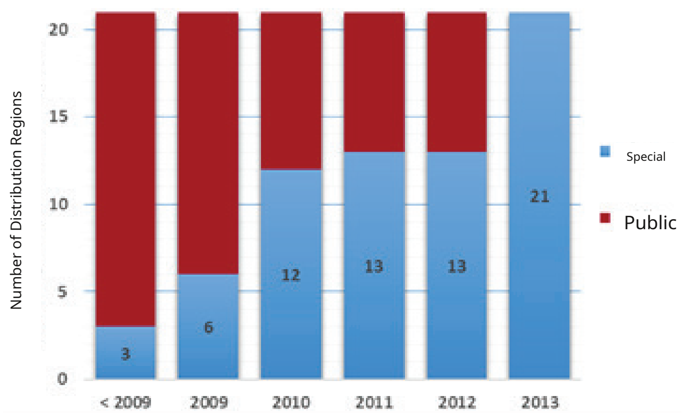
Therefore, distribution privatization was delayed and could only be started in 2008 after the approval of a new Cost-Based Pricing Mechanism.

The distribution companies were privatized through a share sale model based on the transfer of operating rights. According to this model, the investor is the sole owner of the distribution company's shares - but not the distribution network assets or other elements required for the operation of the distribution assets. The ownership of these distribution assets remained with TEDAŞ.

As a first step, the operating rights of the distribution regions were transferred to regional public distribution companies (TEDAŞ subsidiaries). Later, the shares of these companies were sold by the ÖİB. Investors who owned the shares were given the right to operate the distribution assets in accordance with the HRA agreement with TEDAŞ and the share sales agreement with the ÖİB.

Under the envisaged market structure, privatized electricity distribution companies will operate as monopolies (not as retailers but as distribution service providers) in their distribution regions under the distribution license granted by EMRA. Under the agreement, operators must fulfill their investment obligations for both the renewal and expansion of grid assets.

In addition to the three regions privatized under the previous privatization model, distribution privatization was carried out through successive tenders. As shown in Figure 33, the number of privatized regions increased gradually between 2009 and 2013, and by November 2013, all distribution regions had been privatized.



Source: Privatization Administration.

However, the distribution privatization process did not proceed as smoothly as planned. For reasons explained below, the process slowed down during 2010-12.

The first package, put out to tender in 2008, consisted of four regional companies; three of these were transferred in 2009 (one was delayed until 2013 due to a legal challenge). The second package, consisting of seven companies, was tendered in October 2009 and the winning companies took over the regions in 2010.

Although additional tenders were launched for the remaining seven regions in 2010, the tenders of five regional distribution companies were ultimately cancelled because the bidders could not fulfill their obligations. The tenders of two regional companies were cancelled by the Privatization High Council.

One of the reasons why the third and final stage of the tenders initially failed was the very high bid prices based on unrealistic and optimistic expectations regarding the tariff parameters to be used in the second tariff implementation period. Bidders later realized that their bid amounts were unrealistic when the relevant parameters (such as gross margin) were determined by EMRA in 2010 and the regions turned out to be less profitable than expected.

Another reason for the delay in the process was the Competition Board's decision regarding market share limits. According to the decision, the energy that distribution companies owned by a group of companies can distribute cannot exceed 30 percent of the total electricity distributed in Türkiye. Due to this decision taken after the privatization tenders were completed, some groups of companies had to give up on taking over the shares of the distribution companies to which they submitted the highest bids. On the other hand, although the US Dollar/ Turkish Lira exchange rate was approximately 1.5 during the tender process, it rose to 1.8 in the third quarter of 2001 (bids were given in US dollars).[28] Therefore, they were unable to take over the distribution areas and the Privatization Administration had to repeat the tenders.

Currently, all distribution companies have been transferred to the private sector. The distribution companies, transfer dates and the privatization revenues obtained are shown in Table 5.

Table 5. Results of Privatization Tenders

Distribution Company	Successful Bidder	Transfer Date	Transfer Price (million US$)
Capital city	Enerjisa – verbund	2009	1,225
Sakarya	Akenerji – Chez	2009	600
Purport	Alkarko	2009	440
Osmangazi	Meat Silver	2010	485
Yesilirmak	Calik Energy	2010	441.5
Coruh	Aqsa	2010	227
Uludag	Limak, Colin, Cengiz	2010	940
Camlibel	Limak, Colin, Cengiz	2010	258.5
Euphrates	Aqsa	2010	230.25
Thrace	IC Ictas	2011	575
Bosphorus	Limak, Colin, Cengiz	2013	1,960
Mediterrenian	Limak, Colin, Cengiz	2013	546
Gediz	Elsan-Tumas-Karacay	2013	1,231
Tigris	İşkaya-East	2013	387
Aras	Cellar	2013	128.5
Ayedash	Enerjisa - EON	2013	1,227
Taurus Mountains	Enerjisa - EON	2013	1,725
Lake Van	Turkers	2013	118
TOTAL PRIVATIZATION REVENUE			**12,745**

Source: Privatization Administration.

The Turkish Government has received approximately US$12.75 billion in revenue from the privatization of the distribution companies. However, as stated in the first and second Strategy Documents, the purpose of the privatization was not to support the budget. Its main purpose was to improve the performance of the distribution companies, reduce losses and costs through efficient operations and investments, and pass these gains on to consumers through lower electricity prices. Despite the significant revenues, high transfer fees have created and continue to create significant difficulties for the new owners; this issue will be discussed in the following sections.

Operational Performance of Privatized Distribution Companies

Due to the delay in distribution privatization until 2009 and the gradual transfer process between 2009 and 2013, it is not possible at present to accurately assess the gains and/or shortcomings of privatization. However, the following observations can be made:

Collection Rate and Payments to Suppliers:

According to information from distribution companies, the collection rate in privatized regions, except for some regions in the east and southeast of Türkiye, is above 95 percent. This shows that the previous low collection rates were not primarily due to high prices but rather a weakness of public companies.

Transitional agreements were in force until 2012[29] and the main suppliers of the distribution companies were EÜAŞ and TETAŞ. In 2008, before privatization, TEDAŞ's total accumulated debt to EÜAŞ and TETAŞ had reached approximately 10 billion TL. Since EÜAŞ could not collect its receivables, it could not make payments to gas and coal companies. This problem was a deadlock that could only be solved with a law passed in 2011 that allowed offsetting between public energy companies.

Since privatization, this problem has been reduced to some extent, except for (a) one company that defaulted on its payments in 2012 and 2013 (it transferred resources outside the company) and (b) three regions where loss and theft rates and collection rates are high and companies have difficulty collecting enough revenue to pay their energy costs and distribution charges.[30]
Most of the privatized distribution companies are currently making their payments in full. It is expected that companies in these regions will continue to face difficulties at the current tariff level.

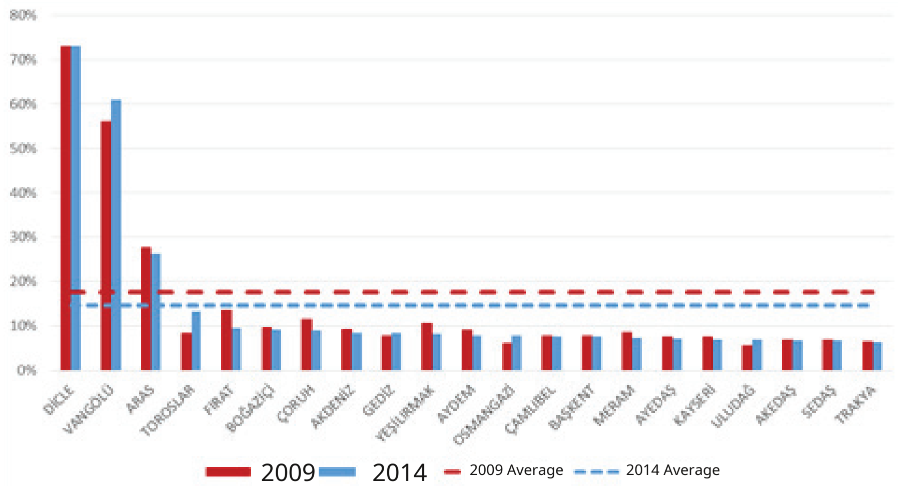
Reducing Losses:

In addition to reducing the investment burden on the public sector, an important benefit expected from distribution privatizations is the reduction of loss and theft rates to reasonable levels throughout the country.

Essentially, the most desired development is that the leakages are brought under control as a result of the implementation of the necessary measures by private operators in the first stage. Tariffs are determined according to loss and leakage reduction targets. In order to create an incentive element for private distribution companies, if they exhibit better performance and reduce the loss-leakage rates below the determined target rates, the additional revenues obtained are left to the distribution companies. On the other hand, if a distribution company cannot achieve the loss-leakage reduction targets, it is not allowed to reflect the additional costs in the tariffs. In other words, one of the basic duties of distribution companies is to reduce the losses and leakages in their regions. Otherwise, these companies will bear all the income losses.

Loss and theft rates in the distribution regions for 2009 and 2014 are shown in Figure 34.

Figure 34. Loss and Illegal Use Rates of Distribution Regions, 2009 and 2014



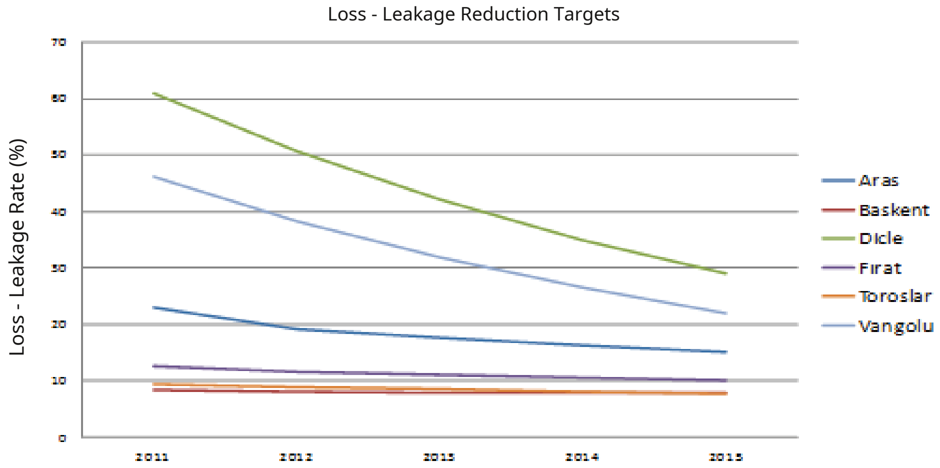
Source: EMRA.

Loss and theft rates vary significantly among regional distribution companies. This large difference is the main reason for the introduction of the national Price Equalization Mechanism, which allows cross-subsidization between regions.

The average rate, which was 17.7 percent in 2009, was reduced to 16 percent in 2013 and 14.56 percent in 2014. Except for three regions with high loss rates, Türkiye's average loss-theft rate was 9 percent in 2011 and was reduced to 8.1 percent in 2014.[31].

Since there were significant delays in the privatization program, the loss reduction targets determined for the first tariff period (2006-10) could not be achieved, therefore EMRA determined new targets for the period 2011-15. The targets determined for some of the distribution regions are shown in Figure 35.

Figure 35. Loss-Theft Reduction Targets for Selected Distribution Regions, 2011–15



Source: EMRA.

In 2012, the technical loss rate in the distribution sector was 8.2 percent and the leakage rate was above the OECD average.[32] The majority of the losses/leakages occurred in the poorer distribution regions in the east of Türkiye. The national average is almost 14.5 percent. As previously mentioned, the reduction targets were not achieved in regions with high loss/leakage rates, especially in the Tigris and Van Lakes. For this reason, in 2013, the loss and theft reduction targets for the Aras, Tigris, Toroslar and Van Lake regions were revised and increased in order to ensure financial sustainability. However, due to the high rate of illegal use, problems still persist for the Tigris, Van Lake and Aras regions and the targets will be revised again. According to the evaluation of EMRA, the targets were generally achieved except for the three regions with high loss/leakage rates. EMRA will determine new loss/leakage rates for the 2016-2020 tariff implementation period.

Service Quality

There is no official and reliable data to determine whether the quality of service has improved. Furthermore, it is too early to assess the performance of these companies as privatization was only completed after 2008 and most companies were transferred only in 2013. Collection and performance-based assessment will only be possible after the full implementation of the Electricity Supply Security and Quality Regulation (ESQR).

Problems in Application

For both the first (2006–10) and second (2011–15) tariff implementation periods, there were no investment programs based on regional demand forecasts. Although a national demand forecast was available, it cannot be said that there were reliable regional demand forecasts that could serve as a basis for investment planning. Therefore, it is possible that there was over- or under-investment by the end of the tariff period.

In 2006, EPDK approved the distribution companies' 5-year distribution tariffs based on their assumed investment programs. However, after privatization, the distribution companies, now in the private sector, claimed that the assumed investment programs were insufficient to meet the real needs for system expansion and requested that their investment programs be revised (thereby actually requesting an increase in their tariffs), which led to problems. The suppressed investment programs and the revenue requirements determined based on them also led the companies to ask third parties (customers) to make investments for connection or supply. The underlying reason for the inadequacy of the investment programs was the government's efforts to keep prices low. However, investment allowances were increased in the second tariff period and these increases were also reflected in the distribution tariff. The distribution tariff, which also included losses and thefts, was 2008

Although the total increase in residential tariff during 2008-14 was 73 percent, the distribution and loss component increased by more than 200 percent, while the energy component increased by only 43 percent.

Before 2006, distribution companies were allowed to engage in generation activities provided that they obtained a generation license and that the amount of electricity they produced annually did not exceed 20 percent of the amount of electricity consumed in their regions in the previous year. However, the 20 percent limit was removed with the amendment to the EML in 2006. From that date until the new EML was adopted, distribution companies could hold generation licenses and be their own suppliers. In addition, distribution companies could purchase electricity under bilateral contracts signed with their subsidiaries, generation companies. The EML allowed generation companies to enter into a partnership relationship with distribution companies; however, this relationship did not result in the exercise of "control" over these companies as defined in the Law. Most of the privatized distribution companies were purchased by investors who also operated on the generation side. The fact that a distribution company is owned by a generation company provides opportunities for vertical integration. This has raised concerns about access to the distribution system and the provision of non-discriminatory operation of the system.

This possibility has been eliminated with the new EML. After the legal separation, distribution companies are no longer allowed to engage in production activities. However, there are no restrictions for regional retail companies (i.e. incumbent regional suppliers owned by the group that owns the distribution company). If the owner of the regional company also owns the production facility, "self-supply" or "self-sale" is possible.

Although distribution and retail activities were separated in early 2013, this was not an ownership separation, so the ownership of regional distribution companies and incumbent retail companies remained with the same owners. It is also known that most of the partners of distribution companies and owners of regional supply companies are also owners/partners of generation companies. As some generation companies openly stated, these companies aim to provide a large portion of the electricity demand in their distribution regions from their generation portfolios. Although this is one of the main motivations for investing in generation, EMRA should carefully monitor this behavior to ensure fair retail competition.

Depending on the financing conditions, high transfer fees and predetermined loss-leakage reduction targets caused problems and companies requested a tariff increase. For the "distribution network" operation, which is the main duty of distribution companies, the main revenues are determined according to a revenue ceiling methodology. The distribution tariff is determined at a level that will cover the operation and maintenance expenses, investment programs and loss-leakage figures. Distribution companies can obtain a fair capital return for their investment expenses (10-year payback period and 10.49% interest). However, the investment must be financed by the distribution companies and the payback through the tariff is proportional to the investment realized. For loss and leakage, if they can reduce the losses below the target figure, they can benefit from this. For operation and maintenance expenses, if they can manage the activity effectively, they can cover their expenses. Therefore, they should be careful to meet the targets and not cause cost overruns in their expenses.

It should be noted that the previous loss and theft targets were determined based on information provided by TEDAŞ. Even for most of the regional companies that had not yet been privatized in 2009, the new targets were determined based on information from TEDAŞ. After privatization, some companies claimed that these loss and theft figures did not reflect the actual loss and theft figures, and that the actual figures were higher. Furthermore, as mentioned in the previous section, the loss and theft targets were not met and the actual losses increased for the four regions. However, one of the reasons for this increase is the political turmoil in Türkiye's southeastern neighbors and the increased demand caused by the more than one million refugees coming to Türkiye from these countries. Some companies - especially those in regions with high loss and theft rates - have difficulty reducing losses and are unable to increase their collection rates.

Regional incumbents (i.e., the unbundled retail arms of distribution companies) can sell electricity and/or capacity to non-eligible consumers in their authorized region and to eligible consumers nationwide at regulated tariffs. Each supplier also serves as a supplier of last resort in its region.

The retail tariff is determined according to the "price ceiling methodology." The price ceiling is determined using the following formula:

Selling price/kWh = 1.0349 x buying price/kWh

This applies to sales to non-eligible consumers, which have a profit margin of 3.49%. This profit margin, which was previously 2.27%, has been increased at the request of the distribution companies. The incumbent companies can purchase electricity from TE-TAS (at the regulated price), DGP and GÖP, and other suppliers through bilateral contracts. The purchase price is determined according to their share of the total supply, and they are allowed to reflect GÖP prices for the portion they receive from GÖP and other suppliers. Their sales to eligible consumers are not regulated and are determined competitively. Therefore, their main source of income, apart from the income they receive from eligible consumers, is the profit margin of 3.49%.

To be able to meet the financing and operating costs for approved investments and to pay the transfer fee debts.[33]and to be able to pay suppliers for the energy they purchase, regional distribution and retail supply companies must be efficient, experienced, and financially strong—and their collection rates must be high. In fact, the rationale for privatization is based precisely on these considerations.

However, requirements such as technical capacity and management skills were not sought during the privatization tenders. The main determining factor in the tender process was the transfer fee. As stated in the previous sections of this report, the high transfer fee offers in the tender led to either (a) delays in the privatization process or (b) continuous efforts to increase both the tariffs and the loss-theft reduction targets.

Another problem is monitoring and auditing the investments that have been made. Distribution companies present their investment programs for the following year in accordance with their approved budgets every year; in this context, the realizations of the distribution facilities that have been put into operation during the year are also presented. Although it seems possible to audit the investments with this method, when the amount of investments made in the 21 distribution regions is considered to be very large,[34]In fact, it is quite difficult to control the physical realization of each component.

According to the first EML, the supervision and oversight of distribution companies were among the duties of the Energy Market Regulatory Authority. However, the new EML stipulates that the supervision of distribution companies will be carried out by the ETKB. The ETKB will supervise the distribution companies and send their reports to the EPDK, which will then make its decision based on the reports prepared by the ETKB. Although the final decision-making authority is seen as the EPDK, transferring such authority to the ETKB is not compatible with the principle of "independent supervision", which is one of the main reasons for having an independent regulatory institution.

Production Customization

Initially, it was assumed that generation privatization would be feasible and useful only after (a) there were strong commercial buyers in the market (such as private distribution companies and wholesale companies) who could contract for the output of newly privatized generation companies and (b) a developed market existed. Therefore, in the first Strategy Document, it was decided that generation privatization would not be initiated until certain progress had been made in distribution privatization and wholesale-retail trading mechanisms had been put in place.

The initial strategy was as follows:

- All thermal power plants (TPPs) would be privatized.
- All hydroelectric power plants, except for some reservoir-type hydroelectric power plants (HES), mostly located on transboundary river basins, would also be privatized.

- For the privatization of production facilities, the operating rights of hydroelectric power plants would be transferred, but the assets of thermal power plants would be sold. In the case of the privatization of a lignite or coal-fired thermal power plant, the operating rights of the relevant coal or lignite mines would be transferred.

- The EÜAŞ power plants to be privatized would be grouped under several "portfolio generation companies" and these portfolio generation companies would be privatized.

However, although preparations for the establishment of portfolio groups were completed, portfolio companies were not established; instead, EÜAŞ portfolio groups continued to operate within EÜAŞ. Although the Privatization Administration (ÖİB) later regrouped the power plants and rearranged the portfolios, the public generation portfolio companies were not officially announced. Instead, ÖİB decided to privatize thermal power plants individually and hydroelectric power plants by grouping them according to their locations as portfolio generation companies. On the other hand, some thermal power plants, such as Kemerköy and Yeniköy, which use the same lignite mine, were privatized together.

The privatization of production started with the tenders of HRA held by the PA for small river type hydroelectric power plants not included in the portfolios. After three tenders, 59 plants (310 MW) were privatized as follows:

1. Generation privatization started in 2008 with the privatization of seven small HEPPs, one geothermal power plant and one small gas turbine (total installed power capacity 141 MW), and all power plants were transferred.
2. In 2010, 56 run-of-river small hydropower plants (total installed power capacity 140 MW) were tendered, of which 28 were transferred (100 MW) and the rest were cancelled.
3. Thirdly, in 2012, three old BOT model HEPPs (transferred to EÜAŞ in 2010-11 as their contracts expired) and 14 run-of-river HEPPs with a total installed power capacity of 64 MW were put out to tender and transferred. Finally, in 2014, 5 small HEPPs (5.54 MW) were put out to tender and transferred.

As a second stage, some thermal power plants are being put out to tender one by one and privatized. As of July 2015, the situation is as follows:

- The 1200 MW Hamitabad Natural Gas KÇGS was transferred to Limak Natural Gas Production Company for US$ 105 million on August 1, 2013.
- The 600 MW Seyitömer Lignite-Fired Power Plant was transferred to Çelikler Seyitömer Electricity Generation Company for US$2,248 million on June 17, 2013.
- The 457 MW Kangal Lignite-Fired Power Plant was transferred to Kangal Electricity Generation Company (Konya Şeker) for US$985 million on 14 August 2013.
- The 300 MW Çatalağzı Hard Coal-fired TS was transferred to Elsan Electrical Devices Industry and Trade Company (Bereket Energy) for a price of US$350 million on December 22, 2014.

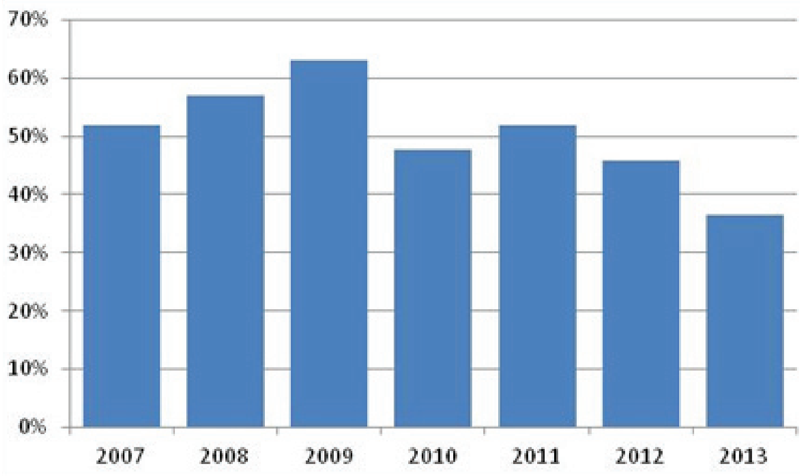
- 3x210 MW Yatağan Lignite Fired Power Plant was transferred to Elsan Electrical Devices Industry and Trade Company (Bereket Energy) for 1,091 million US$ on 01 December 2014.
- 2x210 MW Yeniköy Lignite-Fired Power Plant and 3x210 MW Kemerköy Lignite-Fired Power Plant and port facilities were commissioned on 23 December 2014 for a total cost of 2.671 million US$.in returnIt was transferred to IC İçtaş Electricity Production and Trading Company.
- The 210 MW Orhaneli Lignite-Fired Power Plant and the 365 MW Tunçbilek Lignite-Fired Power Plant were commissioned on June 22, 2015 for a total of US$521 million.in returnSteels Orhaneli was transferred to Tunçbilek Electricity Production company.
- The 990 MW Soma B Lignite-fired TS was commissioned on June 22, 2015 for US$685.5 million. in return It was transferred to Soma Electricity Production Trade Company (Konya Şeker).

- A tender was held on 22 March 2014 for six run-of-river power plants with a total installed capacity of 5.54 MW, and the highest bid submitted was US$6.6 million. The decision of the Privatization High Board was taken on 7 August; payment has not yet been made at the time of writing this report.
- Tenders for five additional run-of-river power plants with a total installed capacity of 2.84 MW were held on May 30, 2014, with the highest bid submitted being US$8.85 million. (Not yet transferred)

Consequences of Manufacturing Privatization.

The utilization factor of EÜAŞ thermal power plants, especially lignite-fired power plants, is low due to the age of the plants, their poor performance and poor operating efficiency. Capacity factor of EÜAŞ lignite-fired power plants between 2007 and 2013[35]It is shown in Figure 36.

Figure 36. Capacity Factor of EÜAŞ's Lignite-Fired Thermal Power Plants, 2007–13



Source: TEİAŞ statistics.

Normally, considering the low cost of domestic lignite, these plants should always have a competitive advantage as base load plants. In addition, it is expected that their distribution rates, and therefore their utilization rates, will be high (i.e. high capacity factor). The privatization of EÜAŞ thermal power plants will ultimately improve the operational efficiency of these plants and contribute to supply security by reducing the country's natural gas imports. However, most of these plants will need to be rehabilitated in order to improve their operational performance. Production costs may increase unless they are balanced by the cost reductions that will be provided by the efficiency increases due to rehabilitation investments.

The same applies to the privatized natural gas power plants of EÜAŞ. Except for the Bursa KÇGT power plant, the plants are old and their efficiency levels are so low (below 50%) that rehabilitation can only be possible by replacing the gas turbines with more efficient ones. Otherwise, it is not possible for the existing DG power plants to compete with the new natural gas power plants with much higher efficiency rates (58-60%).

The privatization of EÜAŞ's reservoir-type hydroelectric power plants will also affect market prices. EÜAŞ's prices are currently determined by the average cost of thermal and hydroelectric portfolios, and the majority of EÜAŞ's production is sold to TETAŞ at a price consisting of this average cost plus a profit margin. However, after privatization, private companies will want to maximize their revenues by concentrating their deliveries in high-demand or peak consumption time periods. In these time periods, high-cost DG plants determine the price in GÖP and DGP prices. In other words, these plants will no longer be priced according to their costs, but according to the market marginal prices, which are mostly determined by DG plants.

3.2.3.8 The Role of the Competition Authority in Market Reform

According to Article 167 of the Constitution of the Republic of Turkey, the State is obliged to take all necessary measures to prevent monopolization and cartelization that may occur in the markets, either de facto or as a result of agreements. In accordance with this obligation, the State enacted Law No. 4054 on the Protection of Competition in 1994 and established the Competition Authority (RK) in 1997 to implement the law.

The main purpose of the Competition Law is to prohibit cartels and other restrictions on competition, to prevent abuses by a company that is dominant in a certain market, and to prevent the formation of new monopolies by monitoring certain mergers and acquisitions. The RK contributed to the reform process through its decisions and official opinions in the market design and privatization process. In this context, prior to the distribution privatization, the Competition Authority**legal separation of distribution and retail activities**was determined as a precondition for privatization. This condition was introduced through the amendment of the EML and was put into practice in 2013.

The Competition Authority also monitored distribution privatization tenders and did not allow some transfers because the new owner had a share of more than 30 percent in total retail activity.

The Competition Authority is also examining the claims of free consumers and suppliers against retail and distribution companies. There are allegations that distribution companies do not treat all suppliers equally (they discriminate against authorized suppliers whose owners are the same as the distribution company). Similarly, the Competition Authority is also examining allegations that they do not treat applications equally by creating difficulties in connecting unlicensed production facilities to the distribution network. According to the Competition Authority's assessment, these behaviors indicate abuse of market power and the Competition Authority's decision requires the EPDK to take the necessary measures.

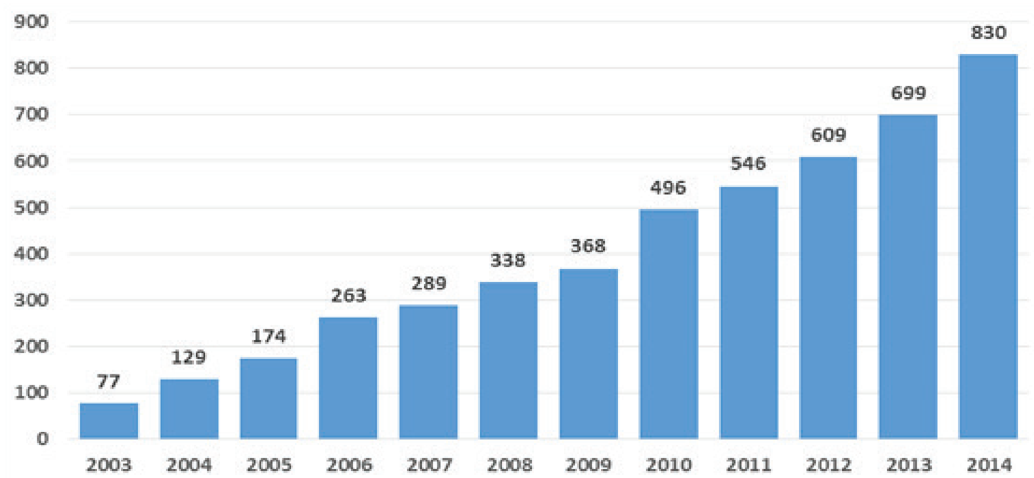
The Competition Authority also helps develop market competition by preparing detailed reports addressing issues and challenges in the electricity, gas and oil sectors. The role of the Competition Authority is vital in the effective implementation of competition in the electricity and gas sectors.

3.2.4 Achievements

3.2.4.1 Market Activity

Since 2003, the number of participants registered with PMUM (Electricity Market Financial Reconciliation Center within TEAŞ) has been increasing steadily as seen in Figure 378.

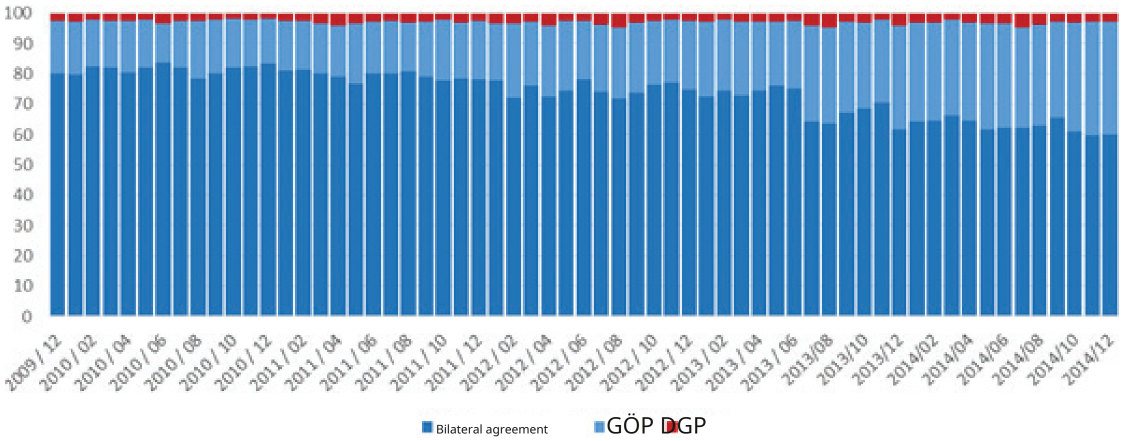
Figure 37. Number of PMUM Participants, 2003–14



Source: TEİAŞ/PMUM.

- The number of private sector generation companies has increased significantly, demonstrating the attractiveness of Türkiye's electricity market for the private sector. The number of wholesale licenses has increased particularly after the introduction of functioning balancing and day-ahead market trading platforms.
- Approximately 70 percent of electricity trade in Türkiye is made through bilateral contracts. The remaining electricity trade is mainly made in the DAM and imbalances are settled in the DPM. The shares of DAM, DPM and bilateral contracts in electricity trade since the introduction of day-ahead trading are shown in Figure 38.

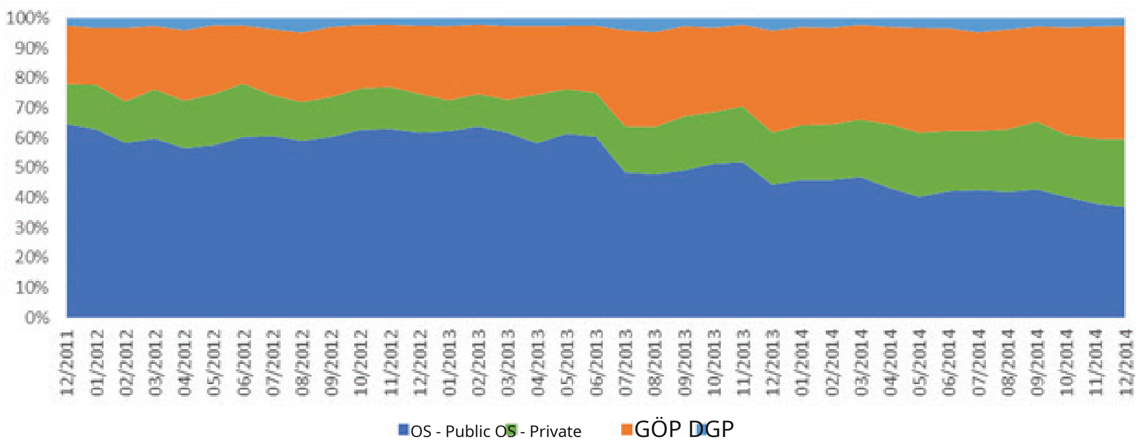
Figure 38. Quantities of Electricity Traded through Bilateral Contracts, DAM and DGP



Source: TEİAŞ/PMUM.

On the other hand, as seen in Figure 39, the share of bilateral contracts between consumers and public suppliers has been decreasing since 2013 due to the privatization of public generation facilities. However, the share of bilateral contracts of private suppliers has not increased by the same amount. This suggests that, at least for now, private suppliers prefer to sell electricity in the GAM rather than through bilateral contracts. The duration of bilateral contracts is usually one year.

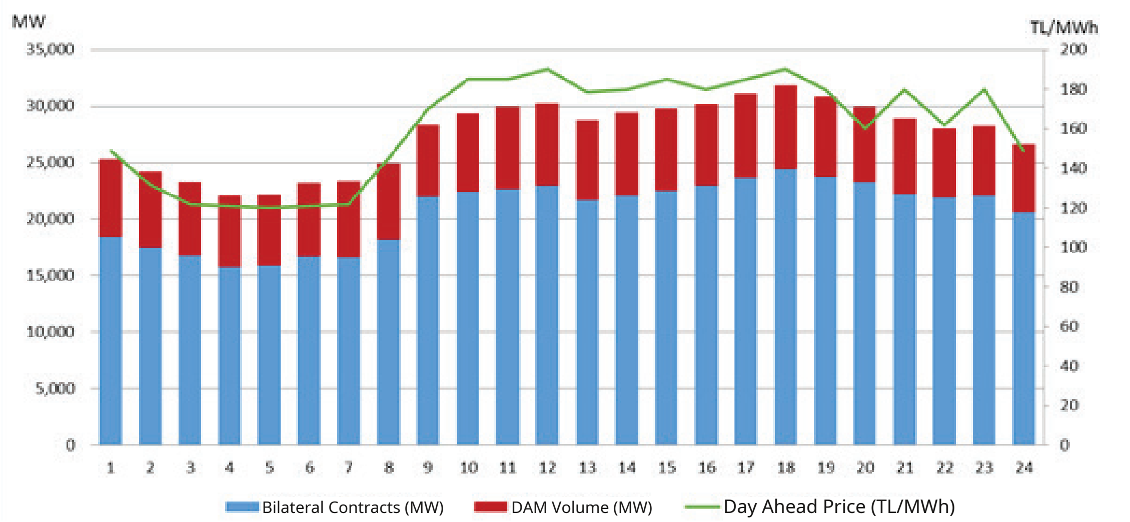
Figure 39. Shares of Electricity Traded through GAM, DGP and Bilateral Contracts, 2011-14



Source: TEİAŞ/PMUM.

Prices in the Day-Ahead Market are generally based on the supply/demand balance. For example, Figure 40 shows the hourly demand on November 13, 2013, the volumes traded through bilateral contracts and in the DAM, and the hourly marginal clearing prices in the DAM.

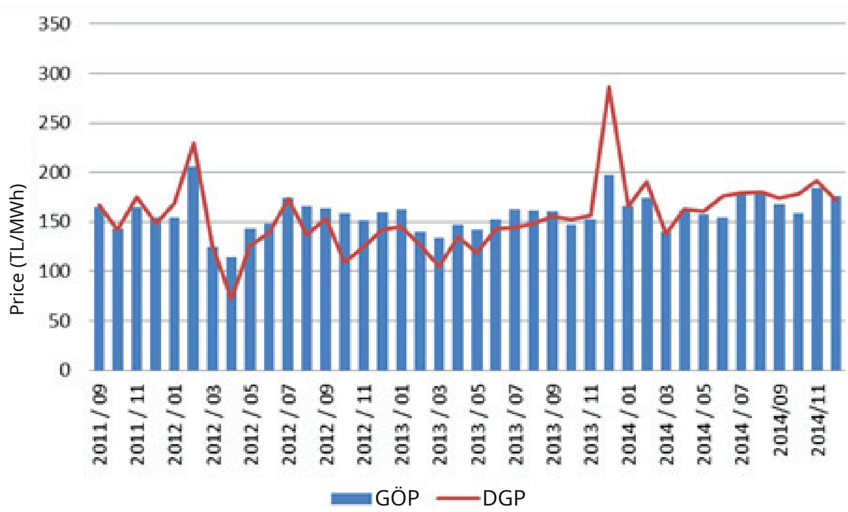
Figure 40. DAM Volume and Marginal Prices, 13 November 2013



Source: TEİAŞ/PMUM.

As seen in Figure 41, the DAM market clearing price and the DPM marginal prices generally follow seasonal changes in supply and demand. The highest levels in February 2012 and December 2013 reflect supply shortages due to natural gas supply limitations. The relatively low prices in March and April 2012 reflect increases in production from run-of-river hydroelectric power plants due to increased water revenues. Similarly, the rising prices in the summer of 2014 reflect an increase in thermal production (mostly natural gas) due to the dry year of 2014 and insufficient water revenues. This also shows the dependence of production prices on hydrological conditions.

Figure 41. Changes in Wholesale Market Prices Since the Beginning of DPM and DPM Changes

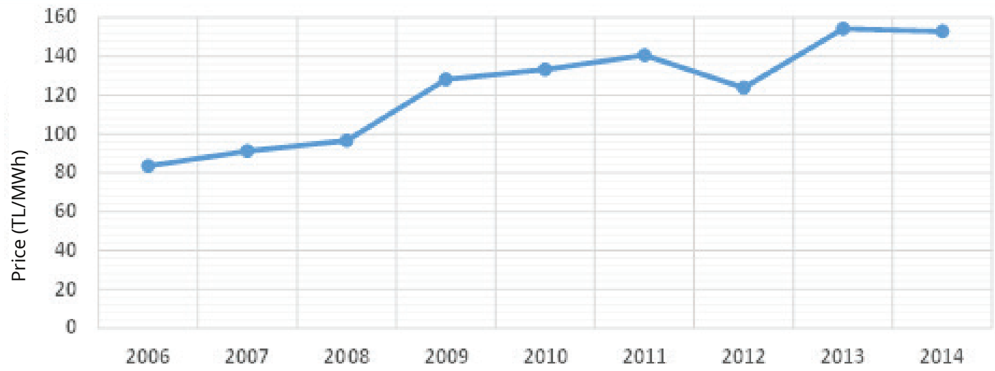


Source: TEİAŞ/PMUM.

Wholesale activity is not regulated and has no tariff (except for TETAŞ). The level of wholesale electricity prices depends on bilateral contract prices and price formations in the GÖP and DGP. However, as mentioned earlier, the share of bilateral contracts is approximately 70 percent, and currently the suppliers in most of these contracts are public companies (EÜAŞ and TETAŞ). The existing contracts (between TETAŞ and the BO and BOT companies) accounted for approximately 24 percent of total production as of 2013, and their prices are determined in advance in the contracts. Although the share of public companies in total production is decreasing, the government can still influence market prices through sales of EÜAŞ and TETAŞ.

Türkiye Average Wholesale Electricity Price (TORETOSAF) is an indicator of changes in the average wholesale electricity price. The changes in TORETOSAF, determined and announced by EMRA every year, between 2006 and 2014 are shown in Figure 42.

Figure 42. Türkiye Average Wholesale Electricity Price (TORETOSAF), 2006–14

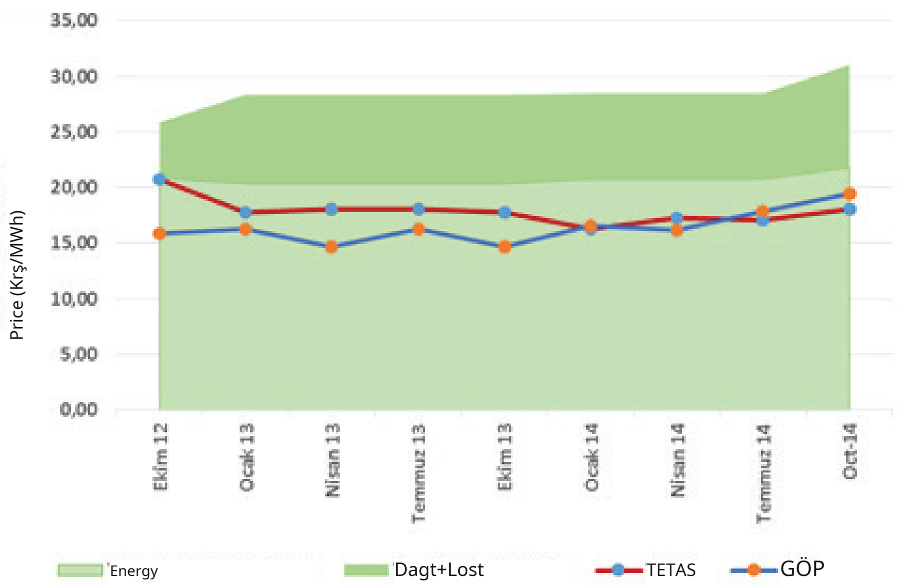


Source: EMRA.

The wholesale market price is largely dependent on the cost of electricity generated by natural gas-fired power plants (since these power plants are marginal in the market merit order) and the gas import prices in US$. Although the Turkish Lira depreciated by approximately 25 percent against the dollar in 2013-14, this change was not fully reflected in wholesale prices. As will be discussed in the Natural Gas section, the main reasons for this were the fixed natural gas price in TL during the period and the increased competition in the market.

On the other hand, as seen in Figure 43, TETAŞ's regulated wholesale tariff decreased in the period 2012-2014. TETAŞ receives electricity from EÜAŞ, BOT and BO power plants. TETAŞ's costs depend on EÜAŞ's prices and also on the production of gas-fired BO and BO power plants, whose tariffs are set in US$. Even under these adverse conditions, the decrease in TETAŞ's price can be explained by two factors: (1) a possible reduction in the price charged by EÜAŞ to TETAŞ, despite the dramatic decrease in EÜAŞ's cheaper hydroelectric production due to the dry season in 2014, (2) a decrease in the revenue and profit targets of EÜAŞ and TETAŞ determined by the government in each fiscal year.

Figure 43. Wholesale Prices and Final Consumer Residential Tariffs, 2012–14



Source: TETAŞ/TEİAŞ/EPDK.

Hence, the fixed final consumer prices can be explained by (a) the government's natural gas pricing policy discussed in the Natural Gas Market section and (b) the adjustment of regulated TETAŞ (EÜAŞ) wholesale prices due to political and social concerns. As a result of this pricing policy, final consumer tariffs were kept fixed for 22 months in 2013-14 and finally increased by 9 percent in October 2014.

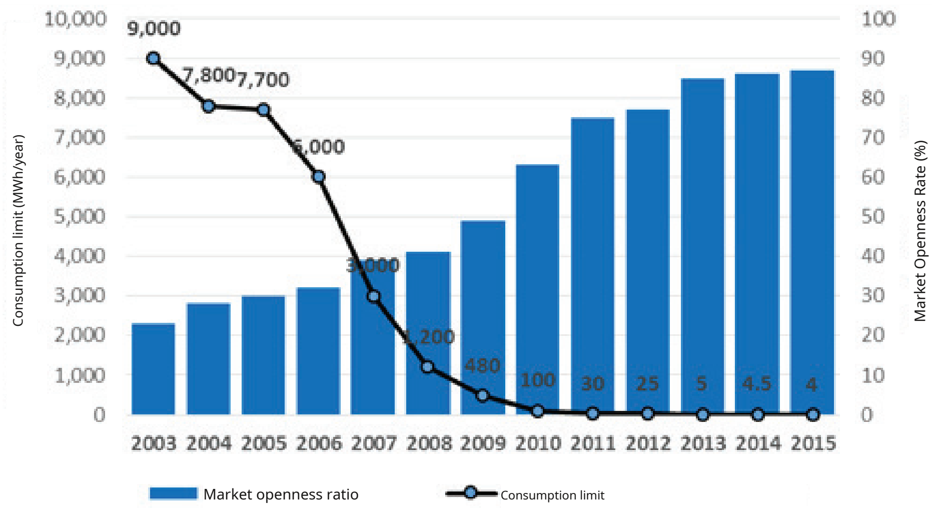
Unlike the physical markets mentioned above, Türkiye's financial markets are not yet well developed. A futures market has recently been established in Izmir and there is also an over-the-counter market, but these markets are very shallow and developing rather slowly.

Although the transition from a single-buyer system to full competition is not yet complete, the development of the wholesale market in Türkiye is a significant achievement. Government and private sector participants have learned a lot and gained experience. As the market develops, remaining problems will be resolved and the need for government intervention will be eliminated. The establishment of EPİAŞ will increase electricity trading volumes and instruments.

3.2.4.2 Free Consumerism: Theoretical and Actual Market Openness

In 2003, the consumption limit to become a free consumer was 9 GWh per year. This limit was gradually reduced to 4 MWh as of January 2015, as seen in Figure 44. In the same period, the theoretical market openness rate[36]exceeded 85 percent.

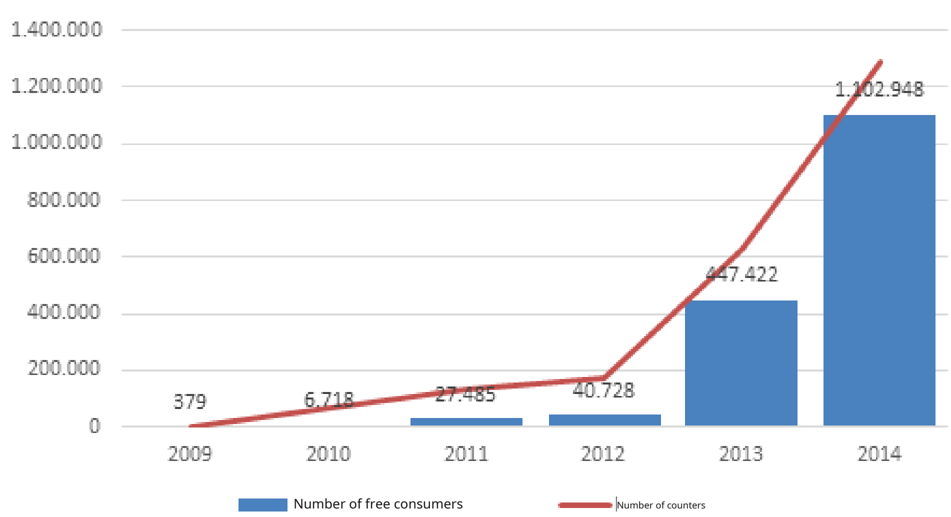
Figure 44. Evolution of Consumer Freedom Boundaries and Market Openness, 2003–15



Source: TEİAŞ/PMUM.

The number of free consumers exercising their right to choose their suppliers remained at very low levels until 2010. As seen in Figure 45, the number of free consumers increased significantly from the beginning of 2010. The main reasons for this are the lowering of the consumption limit and favorable market prices. The reason for the big increase in 2013 is the removal of collective free consumerism with the new EML.[37]; eligible consumers now have to register individually.

Figure 45. Number of Free Consumers and Registered Meters, 2009–14



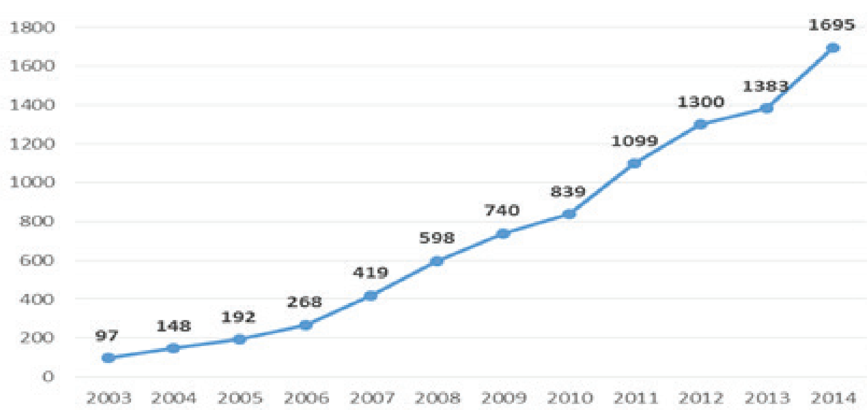
Source: TEİAŞ/PMUM.

Suppliers of free consumers are mostly production, retail and wholesale companies (i.e. suppliers and trading companies). Wholesale companies purchase electricity under bilateral agreements and in the day-ahead market. They are also responsible for balancing the consumption of their consumers through means such as the balancing market. In order to implement the right of free consumerism, it is important to have metering systems that can measure hourly consumption demand. The number of registered meters was only about 2,000 in 2009, but has recently reached 1,463,000.

3.2.4.3 Production Investments

According to the Electricity Market Law, production investments are made by the private sector. Unless there is a supply security problem detected, the public production company EÜAŞ is not allowed to invest in a new production facility. Large reservoir-type hydroelectric power plants (HES) planned and/or under construction before the EML constitute an exception to this principle. Despite some supply/demand balance problems in the last 10 years, this policy has been consistently followed. As a result of the gradual development of the new market structure, private sector production investments have increased significantly. The increase in the number of production licenses is shown in Figure 46.[38]

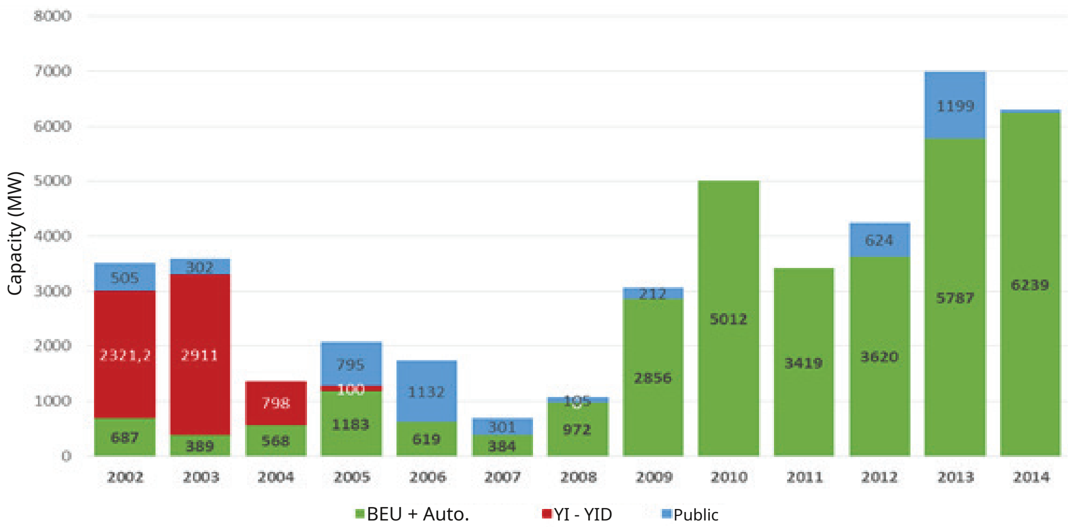
Figure 46. Development of Production Licenses, 2003–14



Source: EMRA, 2014 Activity Report

Between 2002 and 2015, 43,100 MW of new power plant capacity was commissioned. 74% of this new capacity (31,735 MW) came from private sector investments (independent power producers and autoproducers). Figure 47 shows the capacity and ownership status of power plants commissioned during the 2002–14 period.[39]

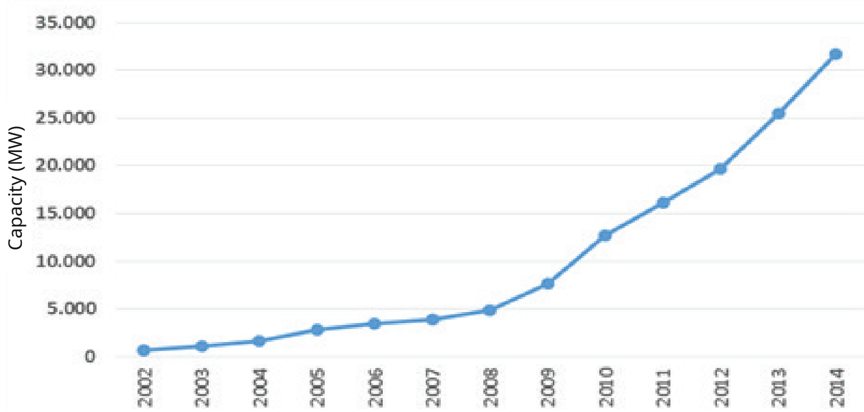
Figure 47. Capacity and Ownership Status of Power Plants Put into Operation, 2002–14



Source: ETKB.

Excluding the BO and BOT plants commissioned in 2002-04, the installed capacity of new power plants built by private companies in the 12-year period was approximately 32,000 MW. As Figure 8 shows, private investment accelerated after 2007, and 88 percent of this capacity was built in 2007-14. The reform process enabled many private companies to make large generation investments, and the average annual investment in 2008-14 was approximately US$4 billion (excluding those under construction). Most of the generation investments were made by Turkish companies, but there were also some foreign investors, mostly in partnership with local companies. Both Turkish and foreign banks financed the investments. International financial institutions (IFIs), especially in renewable generation investments, also made significant contributions.

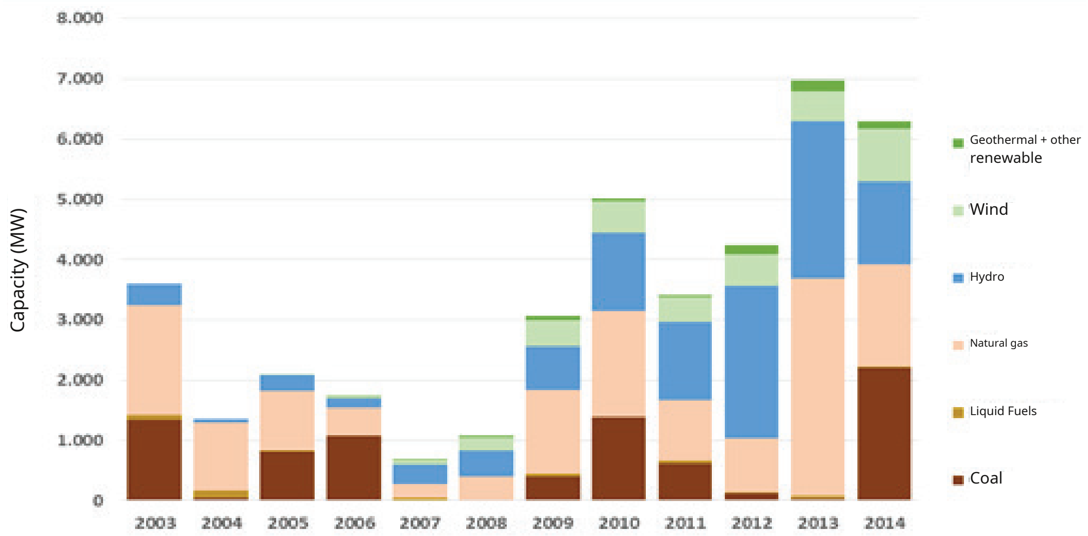
Figure 48. Capacity of New Power Plants Built by Private Companies, 2002–14 (MW)



Source: ETKB and TEİAŞ.

The distribution of new investments by fuel type is shown in Figure 49. It should be noted that, with the exception of the fixed price-feedback tariff applied to renewable energy (which is lower than the fixed price-feedback tariff applied in most countries), investments are made under competitive market conditions without any take-or-pay guarantees from the state, unlike the private sector investments made under the BO or BOT models. (As will be discussed in the Renewable Energy section, since a large part of renewable production is also bought and sold in the market due to favorable market prices, it is possible to say that investments in renewable energy are also made under competitive market conditions.)

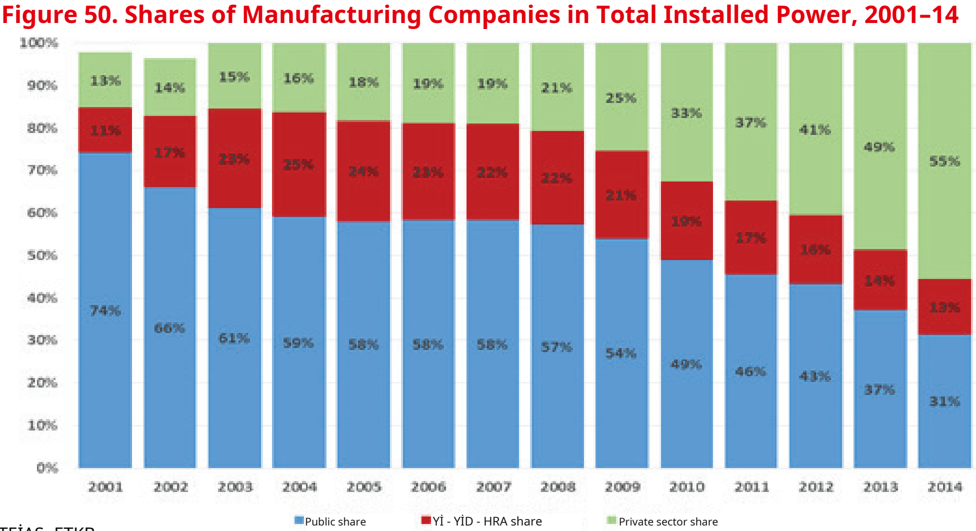
Figure 49. Distribution of Generation Investments by Fuel Type, 2003–14 (MW)



Source: TEİAŞ- ETKB.

As seen in Figure 50, the share of market-based private sector capacity in total installed capacity has reached 55 percent, meaning that in less than 14 years since the EML came into effect in 2001, the majority of Türkiye's electricity supply has come from market-based electricity. This share will increase further with the envisaged investments and privatization. Build-Operate (BO) model power plants (10 percent of total capacity) can also be included in the private sector share, as they are private sector generation investments. This situation reveals a significant change, considering that the public generation share was almost 100 percent until the mid-1990s.

Figure 50. Shares of Manufacturing Companies in Total Installed Power, 2001–14

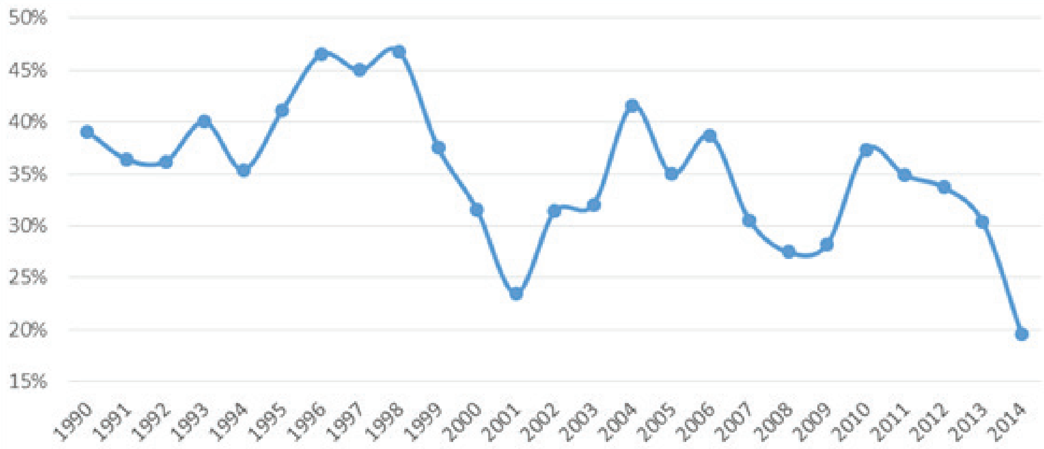


Source: TEİAŞ- ETKB.

Production Investments and Supply Security

As explained earlier, Turkey has experienced many problems related to supply/demand balance in the last 40 years. Due to insufficient generation investments and variable hydrological conditions, the installed capacity margin has exhibited large variability. Despite higher capacity reserves, periods of very tight supply/demand balance have been observed in the past. This is due to the composition of installed power capacity and low availability levels of existing thermal power plants. Historical generation data show that hydrological conditions in large river basins are unstable. While the historical average utilization factor of HEPP is approximately 37 percent, this factor varies between 50 percent and 25 percent, as seen in Figure 51.

Figure 51. Capacity Factor of Hydroelectric Power Plants, 1990–2014

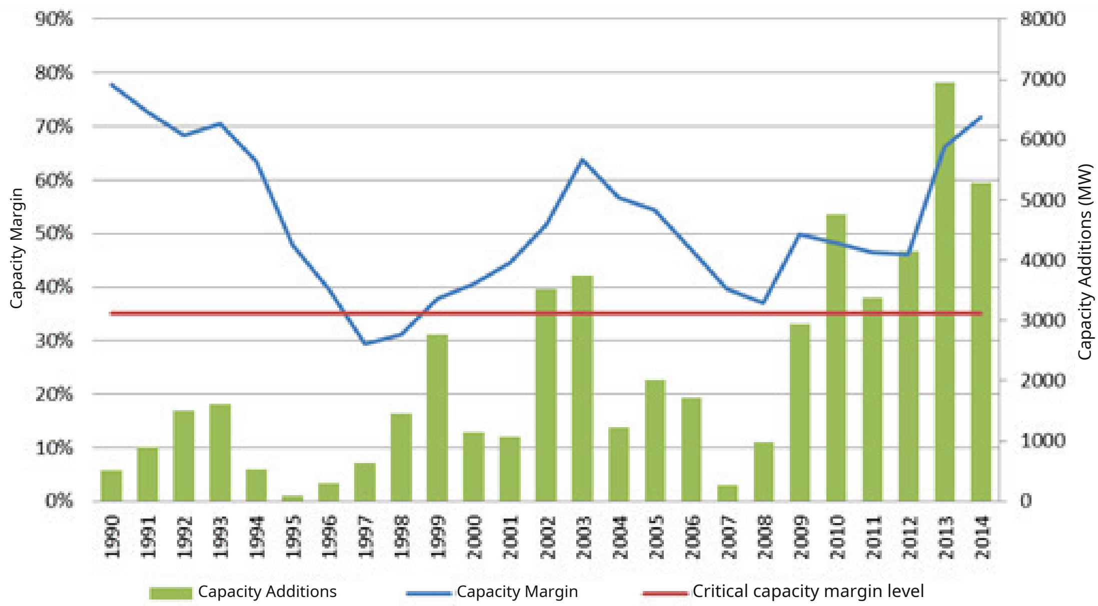


Source: TEİAŞ Statistics.

On the other hand, in addition to the significant amount of hydroelectric capacity, the shares of other intermittent renewable energy sources have also started to increase in recent years. Due to the changes in hydrological conditions, the shares of hydroelectric and renewable energy sources in total production also show significant variations.

Currently, the capacity margin is around 70 percent. However, this high capacity margin (reserve) is not a reliable indicator of the adequacy and reliability of Türkiye's electricity system. Past experience shows that when the capacity margin falls below 35 percent, it is not possible to provide a reliable energy supply (since the availability of hydroelectric and other renewable energy power plants is low, and especially in dry years/periods, when the availability of old thermal power plants is low) (see Figure 52). Therefore, in order to have a sufficient availability reserve margin in favorable hydrological conditions (i.e. *Emreamade*(the margin between electricity generation capacity and peak demand), the installed capacity should be at least 35 percent above peak demand, provided that the operational performance of old thermal power plants is improved (through rehabilitation and effective management).

Figure 52. Production Investments and Installed Capacity Margin, 1990–2014



Source: Calculated from TEİAŞ statistics.

As seen in the figure above, There have been major fluctuations in capacity margin. 1990s In the early years, public investments started to decrease based on the assumption that new private sector investments would increase through the BOT model. However, due to the inadequate legal and administrative structure at that time, private sector generation investments remained insufficient and the capacity margin decreased significantly. The subsequent BOT initiative was late considering that the construction of these plants took a long time; BOT plants were put into operation in the period of 200-02, but by that time the government had already decided to switch to a different regime for the electricity sector. Although a new market regime was adopted in 2001, a long transition period was experienced due to inadequacies in implementation. Private sector investments gained momentum only after the wholesale market mechanism was introduced in 2006, cost-based pricing was introduced in 2008 and distribution privatization was initiated.

As stated in the 2009 Strategy Document, increasing the share of domestic resources in electricity generation will increase supply security. As discussed in the Renewable Energy section, the development of renewable energy is an important achievement.

Similarly, Turkey is trying to increase the share of lignite, its most important domestic resource, in total electricity production. In order to use lignite resources more in electricity production, some lignite mines have been opened to the private sector and the government supports investments in lignite-fired thermal power plants. Although the result is not as striking as in renewable energy sources, the number and capacity of private sector lignite power plants are increasing.

While the share of renewable resources and lignite in total electricity generation is expected to increase, the share of imported resources such as natural gas and imported coal is expected to decrease. This will increase supply security on the one hand and help improve the current account balance on the other.

3.2.5 Electricity Interconnections and Regional Electricity Trading

3.2.5.1 Overview of Interconnections

Since the 1970s, Türkiye has established electrical interconnections with all its neighbors and has participated in regional system integration initiatives. The aims of doing so are:

- to contribute to the supply/demand balance,
- reducing investments through spare and capacity sharing,

- improving energy quality, and
- facilitating electricity trade.

Table 6 provides a list of interconnections along with their voltage levels and operating modes.

Table 6. Interconnections with Neighboring Countries

Interconnection	Voltage (kV)	Mode
Georgia I	220	Asynchronous - Island
Georgia II	400	Back to Back DC
Armenia	220	Not operating
Azerbaijan (Nakhichevan)	154	Asynchronous - Island
Iran-1	154	Asynchronous - Island
Iran-2	400	Asynchronous - Island
Iraq	400	Asynchronous - Island
Syria	400	Asynchronous - Island
Bulgaria-1	400	Synchronicity
Bulgaria-2	400	Synchronicity
Greece	400	Synchronicity

As can be seen from the table, most of the connection lines are operated in island mode. That is, Türkiye's regional grids from which imports are made are asynchronous with the grid of the exporting country, but isolated from the rest of the Turkish grid. The island mode of operation is inefficient and is not preferred. Exceptions to this are the back-to-back DC connection with Georgia and the synchronous connections with the European grid (via Bulgaria and Greece). Except for the European connection, the interconnections with other countries are asynchronous.[40]

Turkey aims to synchronize with neighboring countries and cooperates with various international forums to establish large and regional interconnected systems. Since the mid-1990s, Turkey has wanted to be part of the interconnected European network. Following Türkiye's formal application in 2000, UCTE[41]decided to start preparations for synchronous connection. In order to meet the requirements of UCTE, Turkey has made extensive changes to its electricity system to enable it to operate in parallel and synchronously with the European transmission grid. It has also made significant investments in improving the control systems of some of its major power plants in order to facilitate frequency regulation. Due to Türkiye's powerful 400 kV system, designed and built in accordance with international standards, no significant investment in transmission infrastructure, control and protection systems has been required.

In September 2010, after two important projects were implemented under a joint Turkey-UCTE group and isolated system tests were successfully completed, Turkey was synchronously connected to the ENTSO-E grid via Bulgaria and Greece interconnection lines and the trial operation started. During the trial operation, commercial export and import capacities were limited. Although a one-year trial operation was initially envisaged with a limited import capacity of 400 MW and an export capacity of 300 MW, the period was extended in 2013 and the import and export capacities were increased to 550 MW and 400 MW respectively. Finally, in April 2014, the ENTSO-E Committees[42]It was decided that Türkiye's electricity transmission system would be allowed to operate in continuous synchronization with the system of Continental Europe. After the completion of the necessary formalities, TEİAŞ became an associate member of ENTSO-E and its import and export capacities could now be increased up to the technical limits of the interconnection lines (approximately 3,000 MW) as long as there were no other limitations of the internal electricity systems.

ENTSO-E rules do not allow a country operating synchronously with its own system to: (a) make any interconnection with third countries other than DC connection or (b) make a connection at a voltage level of 110 kV or lower.[43] In addition, a technical study of these connections must be carried out and permission must be obtained from ENTSO-E. This means that, except for the ENTSO-E connection (two Bulgarian and one Greek connections), all other connections will be asynchronous and all interfaces must consist of back-to-back DC facilities. In this context, a new interconnection line between Turkey and Georgia was completed and put into operation in 2014.

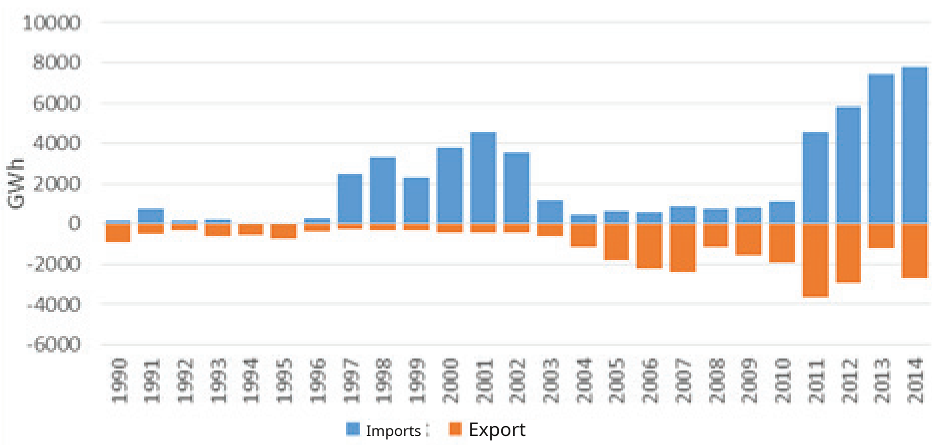
Türkiye also continues to invest in developing energy trade opportunities with its neighbors. For example, TEİAŞ has begun construction of a second 400 kV line with Iraq and is examining the feasibility of back-to-back facilities for connections to Iran and Syria.

According to Türkiye's Import-Export Regulation, import and export are subject to available capacity, approval by ET-KB and approval by EMRA. In order to import or export electricity, a company must have a supplier license and pay "system usage" and "system operation" tariffs and "market operation fee". In case of capacity constraint, available transmission capacity is allocated by "explicit auction" method. Eligible market participants are TETAŞ, wholesale companies, retail companies (import only) and assigned retail suppliers (import only). As discussed below, these regulations need to be amended in order to match Türkiye's electricity market with the European market.

3.2.5.2 Cross-Border Electricity Trade

Electricity import/export amounts since 1990 are shown in Figure 53.

Figure 53. Electricity Import and Export, 1990–2014



Source: TEİAŞ Statistics.

Since supply is generally dependent on hydrological conditions and domestic production capacity, until recently the main driver for imports was to balance supply and demand. In the 1970s and 1980s, electricity imports from Bulgaria played an important role in meeting Türkiye's domestic demand due to chronic inadequacies in electricity investments. Before 2003, all import and export transactions were carried out under intergovernmental agreements and bilateral agreements between public electricity enterprises. "Island" mode or unit steering mode in operation[44] allowed limited electricity exchange.

Especially since the ENTSO-E connection, commercial transactions have increased – imports were mainly from Bulgaria, Iran and Georgia, while exports were made to Syria, Iraq and Greece. After the removal of capacity limitations by ENTSO-E and the commissioning of the new 400 kV DC connection to Georgia, import and export volumes are expected to increase further.

Facilitating large commercial energy exchanges will also increase competition in the market and have positive effects on prices in addition to the traditional benefits of reserve sharing and investment reduction. For now, imports seem attractive as market prices in Türkiye are relatively high (as price-setting producers are natural gas power plants).

Except for the European market, Türkiye's neighbors do not have competitive and free markets and energy trade is largely state-controlled. Therefore, at least for now, a more realistic option than a fully competitive regional electricity market is for electricity companies (and possibly a few exporters from neighboring countries) to sell/trade in the Turkish market. On the other hand, electricity produced at heavily subsidized gas prices in Eastern and Southern countries may pose a problem for domestic producers and investors if their interconnection capacities with these countries increase.

Once ENTSO-E synchronization and membership is achieved, the next step will be market coupling with the European internal market. In the longer term, the ENTSO-E connection will also facilitate other regional initiatives such as the Mediterranean Electricity Ring (MED-RING), as Türkiye's ENTSO-E connection forms a key part of the Middle East-to-Europe line. As surrounding markets develop and cross-border capacities increase, Turkey – thanks to its geographical location and relatively developed internal electricity market – can play a key role in regional electricity trading as an energy hub.

The Western and Northern European countries, from France to Finland, have integrated their electricity markets. This integration process is managed by a project called Inter-Regional Price Coupling (PCR) and regulated by a Multi-Regional Coupling (MRC) agreement. (PCR is a joint initiative of 7 European power central markets (exchanges) and aims to ensure the use of a common solution model for price setting in day-ahead markets and the allocation of cross-border line capacities in electricity trading throughout Europe). Romania, Hungary, the Czech Republic and Slovakia have integrated their markets and are interested in joining the Western and Northern European markets through market coupling. The Independent Bulgarian Energy Exchange (IBEX), the new market operator of Bulgaria, wants to join the European market coupling. Turkey will have the potential to join the emerging European electricity market through the implementation of EPİAŞ's PCR algorithm (EUPHEMIA). This is a significant opportunity for Türkiye, but significant efforts and regulatory actions are required by EPİAŞ to make this happen.

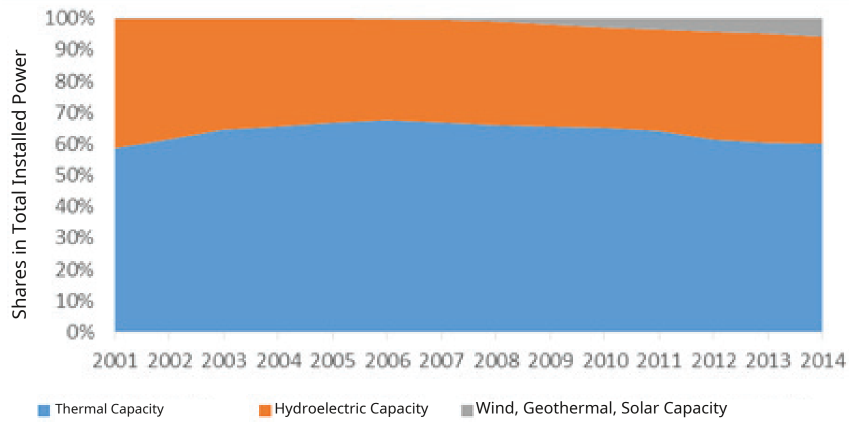
Market matching is the matching of day-ahead markets using the EUPHEMIA algorithm. EPİAŞ will need to implement this algorithm and allocate a certain portion of Türkiye's transmission capacity with Europe to market matching. Currently, TEİAŞ allocates cross-border capacity using an explicit auction method. A certain portion of the transmission capacity at the European border will need to be allocated to matching for the implicit auction to be conducted within the scope of day-ahead electricity trading in market matching. This type of auction is the most complex but most efficient trading mechanism and is the model implemented under the PCR. It is also the most transparent model (the greater the share of cross-border capacity allocated to market matching, the greater the transparency in cross-border trading). In the Northern European (Baltic) region, Transmission System Operators have allocated all of their available cross-border capacity to the regional day-ahead market (Nord Pool Spot) that they have established as a joint ownership. EPİAŞ does not need to develop all of its market matching operational capacity in-house; instead, it can contract with a PCR service provider. IBEX also chose this option to avoid costly and time-consuming capacity development efforts and to achieve market matching much earlier than it could have done on its own.

3.3 Renewable Energy (in Electricity Production)

One of the important achievements of Türkiye's electricity sector reform process is the increase in the share of renewable resources in electricity generation. Turkey has significant renewable energy resources, which constitute the second largest domestic energy source after coal. The main renewable energy sources in Türkiye are hydro, biomass, wind, biogas, geothermal and solar. However, the share of renewable resources in the country's primary energy supply is still low at approximately 11 percent.[45]

As of December 2014, the total installed capacity of renewable energy power plants is 27,700 MW. As seen in Figure 54, the share of renewable energy power plants in the total installed capacity has been approximately 40 percent in the last 13 years (despite recent developments in wind, geothermal and solar energy, 88 percent of renewable capacity consists of hydroelectricity). However, considering that the total installed capacity has more than doubled in the period in question, it can be concluded that the increase in renewable energy capacity is significant. Approximately 16,000 MW of new generation capacity based on renewable energy sources has been put into operation during this period.

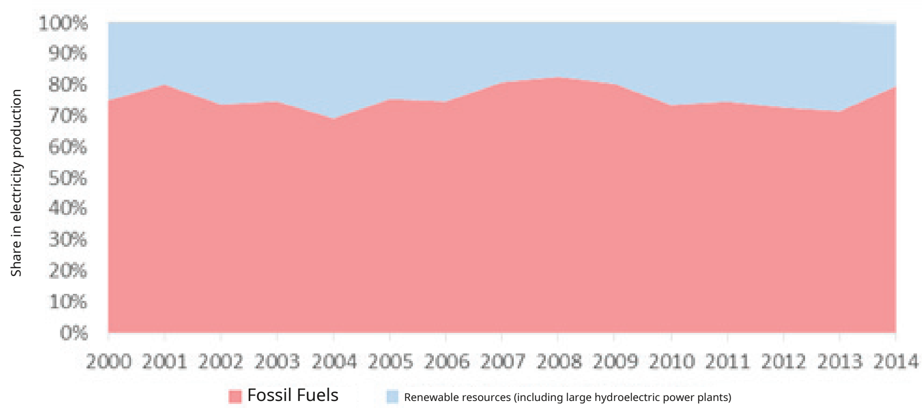
Figure 54. Renewable Resources: Shares in Installed Power, 2001–2014



Source: TEIAS.

On the other hand, as seen in Figure 55, due to the significant share of hydroelectric production, the share of renewable resources in total electricity production varies between 17 percent and 30 percent depending on hydrological conditions.

Figure 55. Share of Renewable Resources in Electricity Production, 2001–2014



Source: TEIAS.

The use of domestic renewable resources is of vital importance in Türkiye's efforts to reduce its dependence on imported energy resources, ensure energy supply security, and prevent greenhouse gas emissions from increasing. Türkiye's energy policy aims to increase the share of renewable energy resources in electricity generation to 30 percent. Compared to the current rate (average of 24 percent over the last decade), this may seem like a modest goal at first glance. However, given the annual demand growth of over 5 percent, the amount of electricity generated from renewable energy resources will need to be doubled in nine years to achieve the 30 percent target by 2023.

Although Türkiye has made significant progress in this area in terms of both legislation and implementation, there are still problems in practice.

3.3.1 Historical Background

Apart from hydroelectric resources, the use of renewable resources for electricity generation in Türkiye did not come to the agenda until the mid-1980s. However, studies on the development of hydroelectric resources were initiated in 1935 after the establishment of EIEI for the purpose of investigating the hydroelectric potential of the country and developing projects. After the establishment of the State Hydraulic Works (DSI) in 1954, the pace of hydroelectric projects increased. The first geothermal power plant was put into operation in 1984 (17.5 MW) and EIEI started to work on wind energy in the mid-1980s. However, there was no separate regulatory framework for renewable energy until 2005. Although attempts were made to develop small hydroelectric and wind projects within the scope of the BOT model, only 18.9 MW wind power plants and 220 MW small hydroelectric power plants were put into operation by 2001.

Following the enactment of the Electricity Market Law (EPK) in March 2001, the development of renewable energy capacity began and the process gained momentum with the enactment of the renewable energy law. This issue is discussed in the following section.

3.3.2 Legislation and Developments

The fundamental law regarding the use of renewable energy sources for electricity generation is the Law No. 5346 on the Use of Renewable Energy Sources in Electricity Generation (known as the Renewable Energy Law –YEK-). The law, which was adopted on May 18, 2005, has been amended twice. Legislation other than this Law consists of the EML (old and new), other laws related to the sector shown in Table 7, and relevant secondary legislation (regulations, circulars, etc.).

Table 7. Basic Legislation on Renewable Energy Resources

Year	Legislation
2001	Electricity Market Law (EPK) (No. 4628)
2005	Law on the Use of Renewable Energy Resources in Electricity Generation (YEK) (No. 5346)
2007	Energy Efficiency Law (EVK) (No. 5627)
2007	Geothermal Law (JK) (No. 5686)
2008	Law on Amendments to the Electricity Market Law (No. 5784)
2011	Amendments to the Law on the Use of Renewable Energy Resources in Electricity Generation
2013	New Electricity Market Law (new EML) (No. 6446)

ETKB is the main institution responsible for the preparation of legislation and determination of policies/strategies for the development of renewable energy. The Electricity Market Law also gave EMRA the responsibility for promoting renewable energy sources in the electricity market. Specifically, the Electricity Market Licensing Regulation (LY) stipulates that EMRA shall (a) take the necessary measures to promote the use of domestic and renewable energy sources and (b) work with relevant institutions to develop and implement incentives in this area.

Although the EML allowed private companies to build hydroelectric power plants, there was initially no regulation defining (a) the rights and obligations of the parties regarding water use or (b) the procedures for obtaining a hydroelectric power plant license. One of the important steps in the development of renewable energy in Türkiye was the 2003**"“Regulation on the Procedures and Principles Regarding the Signing of Water Usage Right Agreements for the Purpose of Carrying Out Production Activities in the Electricity Market”**has been published.[46]

This regulation not only defined the procedures but also allowed private companies to invest in projects developed by DSI and EIEI. Since 1935, EIEI and DSI have been conducting studies in river basins to determine hydroelectric capacity and preparing feasibility studies and plans for candidate hydroelectric power plant projects in various river basins. However, DSI was only interested in the construction of large dams and the private sector could only construct and operate hydroelectric power plants under the BOT model before 2001. Therefore, this regulation was an important step for the construction of hydroelectric projects (especially small-scale ones) by the private sector.

3.3.2.1 Renewable Energy Law (YEK)

YEK has brought certain advantages in terms of base price and priority distribution. The purpose of the law has been determined as the expansion of the use of renewable energy sources for the purpose of generating electricity, the introduction of these sources into the economy in a reliable, economical and high-quality manner, the increase of resource diversity, the reduction of greenhouse gas emissions, the evaluation of waste, the protection of the environment and the development of the manufacturing sector needed to achieve these goals.

According to the Renewable Energy Law, renewable resources are determined as hydraulic, wind, solar, geothermal, biomass, gas obtained from biomass, wave, current energy and tidal energy. Although all types of hydraulic resources, including large dams, are considered “renewable”, only river-type or canal-type HEPPs and HEPPs with a reservoir area of less than fifteen square kilometers are included in the support mechanisms for renewable energy resources.

Initially, the Turkish Average Wholesale Electricity Price was used to promote all types of renewable energy; later, a floor price of €0.05 (5 eurocents) per kWh and a ceiling price of €0.055 (5.5 eurocents) per kWh were applied.

The Renewable Energy Law has been amended on different dates and the latest comprehensive amendment came into force on January 8, 2011 as a result of long-term discussions among all stakeholders. According to the Renewable Energy Law and related regulations, a “renewable energy pool” (Renewable Energy Resources Support Mechanism - YEKDEM) has been put into practice. In this practice, the support is provided by distributing the total cost of electricity provided to the pool among all suppliers selling electricity to end users, instead of charging the energy produced in each facility directly to the buyer.

Under the previous legislation, only legal entities with a retail sales license were obliged to purchase electricity generated from renewable energy sources. In the new support mechanism, all suppliers are now obliged to share the cost of renewable energy in the pool (details of this support mechanism are explained in Annex 2). Companies generating electricity from renewable energy sources can choose between participating in the support mechanism or selling electricity on the market. However, they must declare their preferences for the following year in October and cannot trade on the market in the relevant year after entering the pool.

One of the important changes was the rearrangement of tariffs according to source types, as seen in Table 8. Tariffs are applied for a period of 10 years from the date of first operation for facilities that entered into operation between May 18, 2005 and December 31, 2015. The Council of Ministers is authorized to extend the application period of these fixed price guaranteed tariffs, provided that they are not higher than the fixed price guaranteed tariff levels for the first application period. The application period was extended in 2013 with the same tariff level.

Table 8. Fixed Price Guaranteed Tariffs for Renewable Energy Sources

Type	US$cents/kWh
Hydroelectric Power Plant	7.30
Wind Farm	7.30
Geothermal Power Plant	10.50
Biomass Power Plant	13.30
Solar Power Plant	13.30

At this point, it is necessary to discuss the reasons why the fixed price guaranteed tariff levels, especially for wind and solar, are set at lower levels than project sponsors expect. One of the reasons for setting the fixed price guaranteed tariff for wind at this level is to encourage the construction of efficient power plants. It is thought that moderately efficient power plants will become profitable over time as investment costs decrease. Considering the system reliability and energy quality threats caused by transmission connection problems and the intermittent and variable nature of wind power plant production, a gradual progress was deemed necessary.

Similarly, when determining the fixed price tariff level for solar energy, the expectation that solar energy investment costs would gradually decrease over time was taken into account. This expectation has come true and with the decrease in costs, the price of 13.3 US¢ has become attractive for solar power plants in Türkiye, which has higher solar radiation and sunny days than many European countries offering higher tariffs.

The law also includes an additional incentive mechanism for domestically manufactured mechanical and/or electromechanical equipment used in power plants, as seen in Table 9..[47]

Table 9. Additional Bonus for Domestic Production

Type	Maximum Domestic Production Premium (USD¢/kWh)	Maximum Possible Tariff (USD/kWh)
Hydroelectric Power Plant	2.3	9.6
Wind Farm	3.7	11
Geothermal Power Plant	2.7	13.2
Biomass	5.6	18.9
Photovoltaic Solar	6.7	20
Concentrated Sun	9.2	22.5

The law sets specific premiums for different types of equipment. This will allow investors to receive premiums for the electromechanical parts of the plant, although the domestic equipment content rate must be at least 55 percent. Therefore, it is unrealistic to expect project owners to receive the maximum domestic production premium in the medium term.

Other critical provisions of the legislation include:

- For solar and wind license applications, field measurements are required.
- Solar and wind license applications can only be submitted on the dates determined in accordance with the Electricity Market License Regulation.

Other important incentives offered for renewable energy according to legislative sources are listed below:

- In the Renewable Energy Law:

  85% discount on easement, permit or rental fees for the first 10 years of operation;

  Use of natural reserves and national parks/nature parks, provided that the necessary permits are obtained;[48]And

Exemption from the mandatory 1% turnover share payment applied to business activities carried out on immovable properties belonging to the Treasury.

- In the License Regulation (LY):

  90 percent exemption from licensing fees and exemption from annual license payments for the first 8 years of operation; and

  Priority in system connection.

- In the Tax Incentives within the scope of the Council of Ministers Decision on State Aid for Investments;

  VAT exemption on domestic equipment for Investment Support Certificate holders; and

  Exemption from VAT, Customs Duty and Resource Utilization Support Fund payments on imports made by Investment Support Certificate holders.

- In the Law on Support for Research and Development Activities:

  Deducting all Research and Development (R&D) expenses from the Corporate Tax base;

  Income Tax exemption (for 80 percent of salary income of eligible R&D and support staff);

  Social Security Premium support for five years; and

  Stamp Duty exemption.

All companies that generate electricity based on renewable energy sources can benefit from these incentives, regardless of whether they participate in YEKDEM or not.

On the other hand, the government has set a target of 30 percent for the use of renewable energy sources in electricity generation by 2023, and in this context, Türkiye:

- to make the entire economically usable hydroelectric potential available,
- Reaching an installed wind-based power capacity of 20,000 MW,
- to use its full geothermal potential (currently set at 1,000 MW) by 2023.
- To reach an installed biomass-based power capacity of 1.00 MW

aims.

Moreover;

- It is aimed to expand the use of solar energy for electricity generation and to ensure maximum use of the country's potential. Regarding the use of solar energy for electricity generation, technological developments will be closely monitored and put into practice. ETKB has set a target of 3,000 MW for 2019 and at least 5,000 MW for 2023. Production Plans will take into account possible changes in the use potential of other renewable energy sources based on developments in technology and legislation. If the use of these sources increases, the share of fossil fuels, especially imported sources, in the plans will be reduced accordingly.

Another important milestone in the development of renewable energy in Türkiye is unlicensed production (or distributed production), a concept introduced by the Energy Efficiency Law in 2007. According to the law, electricity production facilities based on renewable energy sources below 200 kW could be built and operated by private individuals or legal entities without obtaining a license from the Energy Market Regulatory Authority (EMRA). With the amendment made to the Renewable Energy Law in 2010, this limit was increased to 500 kW, while producers were allowed to sell their excess production to regional suppliers.

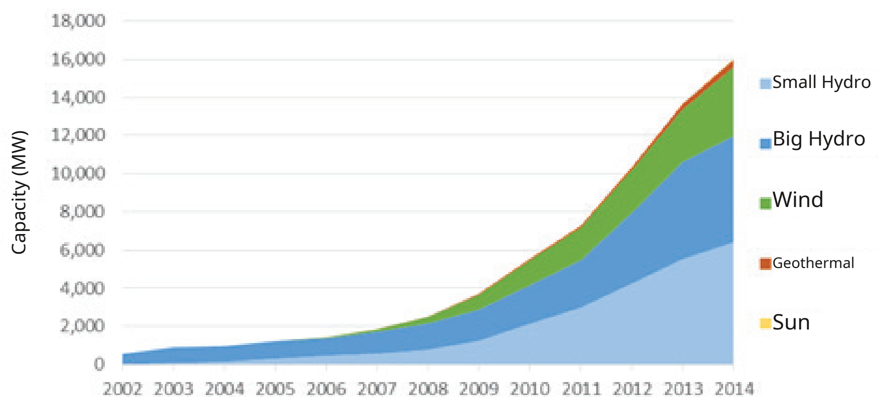
and finally, in the new EML (2013), this limit was increased to 1 MW. As will be discussed in the following sections, although progress in this area is limited, the new legislation has paved the way for investments in mini hydroelectric, wind and especially rooftop solar photovoltaic (PV) plants. All of these will significantly help to increase the share of solar energy in the overall energy mix.

3.3.3 Progress

Until 2006, the share of renewable energy sources in electricity production, other than hydroelectric sources, was very low. When the Renewable Energy Law was enacted in 2005, the installed capacity of Türkiye's wind power plants was only 20 MW (17.4 MW of this capacity was built under the BOT model in the 1998-2001 period, and 2.7 MW under the autoproducer model) and the installed capacity of geothermal power plants was only 15 MW. Although the EML introduced some incentives for renewable energy sources, the lack of a support mechanism limited the interest of the private sector in hydroelectric and wind projects. What had been realized until then was mostly old BOT plants that had given up their rights in their existing contracts (alim guarantees and Treasury payment guarantees) and accordingly obtained licenses for their projects in the free market.

As will be discussed in the following sections, the regulatory framework for renewable energy and the development of the electricity market facilitated generation investments, and as seen in Figure 56, there were significant increases in generation capacity based on renewable energy sources, especially after 2007.

Figure 56. Developments in Newly Built Renewable Capacity Since 2002



Source: TEI

The main reasons for this increase can be stated as follows:

- The support mechanism and fixed price guaranteed tariff level specified in the Renewable Energy Law guarantees sales at least at the fixed price guaranteed tariff (although it is not a very high tariff compared to other countries). This situation has facilitated the provision of financing from local and foreign creditors. The support mechanism provides long-term certainty and reduces investment risk. It provides a certain income stream for the project, whether it is sufficient or not. Creditors generally see this as a guaranteed income and high market prices as a premium.
- The World Bank's support for renewable energy projects ($200 million and later $500 million) was a significant initiative. Local banks were initially hesitant because they had no experience in financing energy projects, but starting with TKB and TSKB (the originator banks of World Bank loans), the banks' project evaluation teams learned the process and the critical issues.

This situation encouraged other local banks to provide loans. With the initial $200 million loan provided by the World Bank, projects with a total installed capacity of approximately 700 MW were put into operation.

- The establishment of wholesale trading mechanisms such as DGP and GÖP and the average price level of 8–9 US¢/kWh (until mid-2014; this price varies depending on the exchange rate) attracted investment. Since market prices are sufficient to provide a fair return, most companies preferred to sell in the market rather than participate in the renewable energy pool (support mechanism). Although the intermittent production of wind farms is likely to cause imbalances, wholesale companies mitigate the imbalance risk with their portfolios consisting of thermal-hydro-wind and purchase the electricity produced by wind farms. However, after the depreciation of the Turkish Lira against the US dollar in 2013, the pool became more attractive and many plants are now selling to the renewable energy pool, which offers a fixed feed-in tariff without any imbalance risk. The fixed feed-in tariff and especially the wholesale prices are at a level that will provide a fair return for efficient wind and hydro power plants.

The development of potential and production capacity is summarized below for each resource type separately; a more detailed analysis is presented in Annex 2.

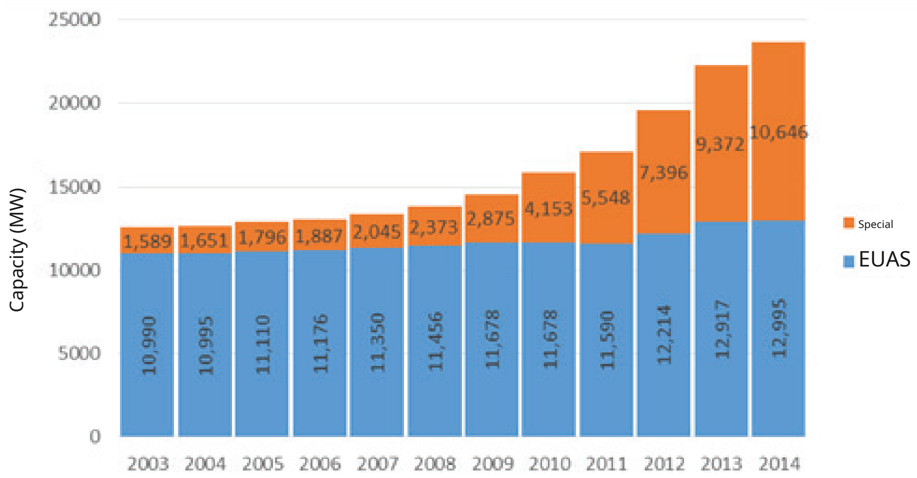
3.3.3.1 Hydroelectric

Türkiye's annual hydroelectric generation potential is reported as 140,000 GWh (considering the historical average usage factor, it can be assumed that Türkiye has a potential of approximately 40,000 MW).[49]

In 2001, the total installed hydroelectric power capacity was 870 MW, including BOT projects. **11,673 MW**It was issued in 2003 and opened the use of hydroelectric resources to the private sector. **"Regulation on the Procedures and Principles Regarding the Signing of Water Usage Rights Agreements for the Purpose of Carrying Out Production Activities in the Electricity Market"**and especially after the publication of the Renewable Energy Law, the number of hydroelectric power plants has increased significantly.

As of January 2015, the total installed capacity of 521 HEPPs in operation is 23,643 MW. Of these plants, 444 (7,036 MW) are run-of-river type and the rest are reservoir type. The capacity of private sector HEPPs is 10,646 MW. Although all HEPPs are considered as renewable energy facilities, it should be noted that only run-of-river HEPPs and reservoir type HEPPs with a reservoir area of less than fifteen square kilometers can benefit from support mechanisms for renewable energy sources. The development of hydroelectric capacity during the period 2003-14 is shown in Figure 57.

Figure 57. Development of Hydroelectric Power Plant Capacity, 2003–14



Source: TEİAŞ statistics.

According to the project progress reports of EMRA, in addition to the existing power plant capacity, 365 licensed private sector HEPP projects with a total installed power capacity of 13,300 MW are under construction.[50] If these projects are realised, approximately 85 percent of Türkiye's total hydroelectric capacity will be in use.

However, the private sector has also encountered problems in developing this hydroelectric potential. The main problems are as follows:

- The need to integrate a large number of HEPPs into the transmission network,
- Environmental sustainability,
- Unfeasible projects developed by inexperienced or incompetent project owners,
- In case of multiple applications, the project owner selection process,
- High bid prices offered for some projects in tenders,
- Lack of river basin development and management plans,
- The long administrative process in the project and construction phases, and
- Inadequate construction supervision.

Each of these issues and challenges are discussed in detail in Annex-2.

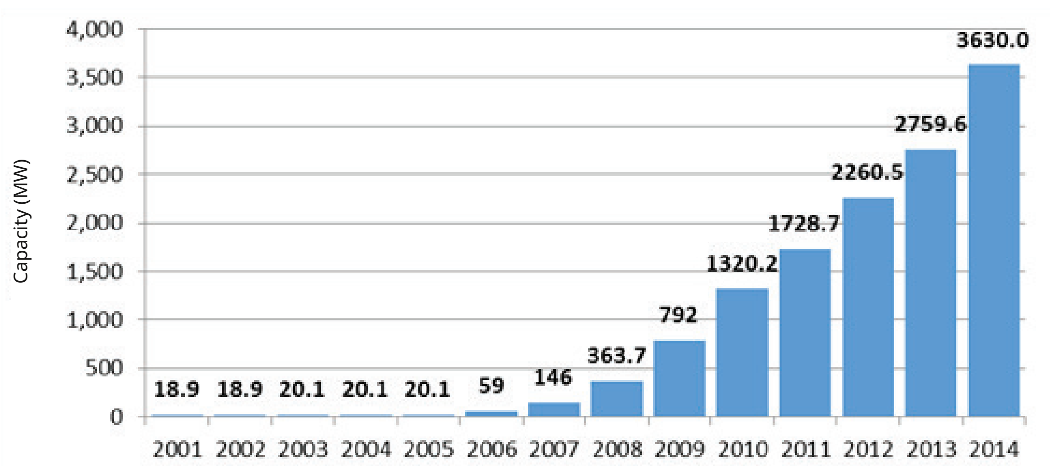
Current and future problems and difficulties may lead to sub-optimal use of the total available potential or at least delayed use of the full potential. Nevertheless, the result achieved is satisfactory and can be considered a significant success.

3.3.3.2 Wind

Türkiye has a significant wind potential waiting to be used. REPA[51]The study revealed that the potential in high-efficiency fields is approximately 19,000 MW, and the technically applicable installed power potential in regions with wind speeds between 7.5 and 8 m/s is 29,259 MW. In other words, Turkey has a wind energy production potential of 48,000 MW with medium-high efficiency in regions with annual average wind speeds of 7.5 m/s or higher. High-potential areas are located in the Aegean and Marmara regions of Türkiye and in the coastal areas of the Eastern Mediterranean region.

Türkiye’s first wind power plant (WPP) was put into operation in 1998 and has an installed capacity of 8.7 MW. In 2001, the total WPP capacity was only 18.9 MW and all of them were built under the BOT model. However, as of the end of 2014, there were 90 WPPs in operation and their total installed capacity was 3,630 MW. The development of WPP capacity since 2001 is shown in Figure 58.

Figure 58. Wind Farm Capacity, 2001–14 (MW)



Source: TEIAS.

The development of wind energy in Türkiye has not been smooth. There have been many setbacks and delays. These include problems with the integration of a large number of power plants into the transmission grid, multiple applications for the same transmission capacity and/or the lack of a selection process in case of overlapping project sites. The capacity of wind power plants started to increase after 2006, but accelerated after 2009 with the implementation of a more comprehensive administrative framework. A detailed description of this development and the problems and challenges encountered are discussed in Annex 2.

As of January 2015, in addition to the existing RESs, there are 182 licensed projects with a total installed capacity of 6,013 MW.[52] Only 27 of these plants (837 MW) have exceeded 30 percent completion, although most were licensed before 2011. However, the chaotic past has provided valuable lessons for both the administration and investors, and progress from now on is expected to be smoother and more gradual.

In order to increase the share of wind in total electricity generation, the capacity of the transmission system operator TEİ-AŞ to integrate the increasing amounts of wind and other intermittent renewable energy generation into Türkiye's electricity system needs to be strengthened. In addition, the environmental challenges that large wind energy projects will create will need to be resolved.

Although the Strategy Document adopted in 2009 foresees a wind power plant capacity of 20,000 MW by 2023, it will be very difficult to establish and achieve approximately 16,000 MW of capacity in the next 8 years if certain measures are not taken. Similarly, it will be difficult to achieve the 10,000 MW target specified in the 2015-19 strategic plan of the ETKB.

Projects are mostly financed by export credit agencies and international financial institutions such as the World Bank and EBRD (through domestic banks), as well as some voluntary carbon trading mechanisms, but financing remains a significant bottleneck.

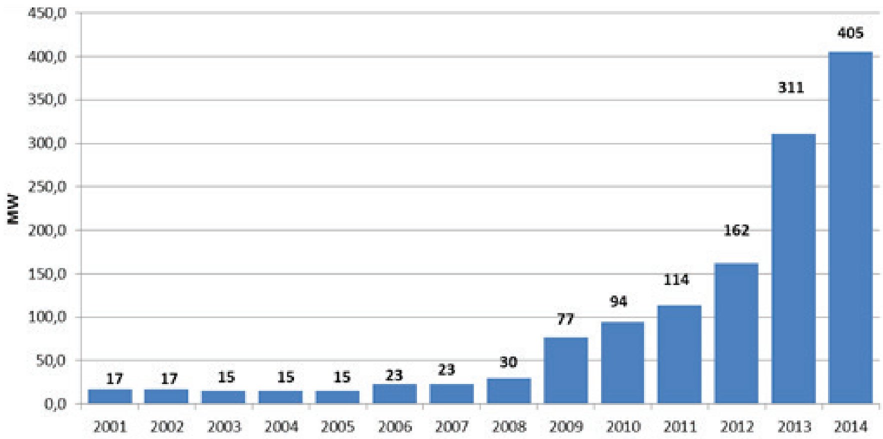
3.3.3.3 Geothermal

The theoretical thermal potential of Türkiye's geothermal resources has been determined as 31,500 megawatts (MWt). General Directorate of Mineral Research and Exploration (MTA)[53] According to the Turkish Statistical Institute, Türkiye's heat capacity (including natural resources) has reached 14,000 MWt.[54] Geothermal energy is used for central heating, thermal tourism, greenhouse heating, industrial applications and electricity generation purposes. The number of geothermal fields that can be used for electricity generation is 25 and their capacity is 1,000 MW.[55]

One of the important steps towards the development of geothermal energy is the Law on Geothermal Resources and Mineral Waters, enacted in 2007. The purpose of the law is to regulate activities related to the exploration, protection and use of geothermal resources.

The first geothermal power plant with an installed capacity of 17.5 MW was put into operation in 1985. After the enactment of the Geothermal and Renewable Energy Laws, most of the geothermal fields considered suitable for electricity production were transferred to the private sector through tenders, and private companies were allowed to explore and develop new geothermal fields under the supervision and control of the state. (The current geothermal power plant was privatized in 2008.) As seen in Figure 59, new power plants have been built and put into operation by private companies since 2006.

Figure 59. Geothermal Power Plant Capacity, 2001–14



Source: TEIAS

Although Turkey's geothermal capacity is much lower than its wind and hydroelectric capacity, its geothermal capacity has developed rapidly and one third of the country's total capacity has already been put into use. In addition to the power plants in operation, there are additional licensed projects (327 MW) and the total licensed capacity has reached 732 MW. It is possible to say that the target stated in the Strategy Document can be easily achieved.

One of the reasons for this significant progress is the sufficiently high fixed feed-in tariff level (10.5 US¢/kWh). This price is at an attractive level and, unlike wind and hydroelectric power plants, independent electricity producers operating in the geothermal field prefer to remain in the renewable energy pool (i.e. support mechanism) instead of selling the electricity they produce on the wholesale market. Unlike wind and hydroelectric power plants, where the production pattern is intermittent and seasonal, geothermal power plants are considered a reliable source because their capacity factors are high (around 80%).

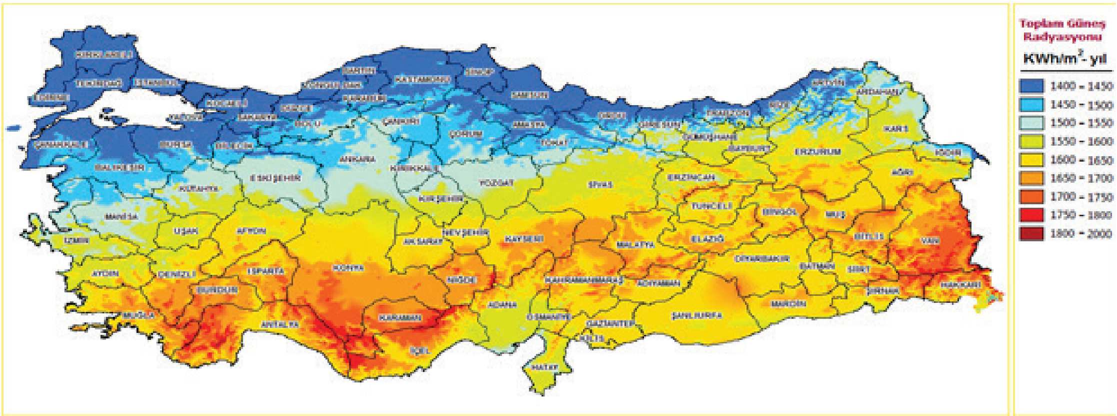
3.3.3.4 Sun

Türkiye has a significant solar energy potential thanks to its favorable geographical location. The evaluation of solar energy potential made by EIEI based on data measured by the General Directorate of State Meteorological Service is presented below:[56]

- The average annual sunshine duration is 2,640 hours (7.2 hours/day). This duration varies between 1,996 hours and 3,016 hours depending on the location. The average annual solar radiation is 1,521 kWh/m^2-year (average: 3.6, minimum 1.5, maximum 3.7 kWh/m^2 -day). Based on these values, the theoretical solar energy potential in Türkiye is 376 TWh.
- According to the report prepared by the World Energy Council/Turkish National Committee in 2009, annual electricity production based on solar energy could reach 50 TWh, based on technical and economic developments.[57]

The map in Figure 60 shows the distribution of solar radiation in Türkiye.

Figure 60. Solar Radiation Map (GEPA)



Sources: ETKB, General Directorate of Renewable Energy.

Note: GEPA = Solar Energy Potential Atlas.

The main users of solar energy in Türkiye are domestic hot water systems using flat plate collectors. Turkey is one of the leading countries in the world in this field with a total collector area of more than 10 million square meters. These systems are mostly used in the Aegean and Mediterranean regions. Total energy production is 768,000 TEP (tons of oil equivalent), which constitutes approximately 0.6 percent of the country's primary energy supply.[58] This sector is in a developed state and has a quality manufacturing and export capacity. The number of companies operating in this field is approximately 100. Annual manufacturing capacity is 750,000 m².

Turkey ranks second in the world in the use of solar energy for water heating. However, despite the high use of solar energy for other purposes –– solar energy is currently an underdeveloped area in Türkiye. Due to the high unit cost of electricity production, commercial electricity production has not been possible without incentive mechanisms.

The fixed feed-in tariff level (0.055 Eurocents) foreseen in the first version of the Renewable Energy Law was not considered high enough by investors to invest in solar power plants. Therefore, applications for solar power plant investments were not made until recently. Solar power plant capacity was almost non-existent (except for experimental facilities at some universities and isolated PV plants such as telecommunications facilities and forest fire monitoring towers) and there was no commercial application.

However, following the amendments to the Renewable Energy Law in 2010 and the preparation of the relevant regulations between 2011-13, this picture has changed. In the amended Law, the fixed feed-in tariff level was increased to US$0.133 (US$13.3¢). This tariff was still low compared to the incentive prices offered in the EU at that time. However, due to the higher radiation intensity and the higher number of sunny days, the utilization factor of production facilities in Türkiye is also much higher than in most European countries.

A regulatory roadmap has been determined for the licensing of solar power plants. According to the law, the total solar power capacity to be connected to the grid by 2013 could not exceed 600 MW (excluding unlicensed rooftop solar power systems). The Council of Ministers is authorized to determine the capacity of solar power plants connected to the grid. According to the Electricity Market Licensing Regulation, the installed capacity of each solar power plant cannot exceed 50 MW and each project must be connected to the nearest transformer center.[59]

EMRA has published the regulation regarding the procedures to be followed and TEİAŞ has announced the transformer centers to which solar power plants can be connected and the current interconnection capacity.

ru owners are required to prepare technical documentation including solar radiation measurements before applying to EPDK. Applications are evaluated by ETKB's Renewable Energy General Directorate (YEGM) and then sent to TEİAŞ. Applications for 600 MW were received in June 2013 and since then the total capacity of applications has reached almost 9,000 MW.

According to the legislation, in case of multiple applications for the same connection capacity, the capacity is distributed as a result of a tender process. Two tenders were held in May 2014 and January 2015. The tenders will be completed in 2015.

There is no definitive target set in the 2009 Strategy Document. In 2015, ETKB set a target of 3,000 MW for 2019.[60]and currently a capacity of 5,000 MW is targeted for 2023. Given the high potential and the downward trend in installation costs, this target is thought to be achievable. In fact, the high number of applications for 600 MW is an indication of investor appetite.

Additionally, rooftop PV application is expected to increase total solar energy production capacity due to the “license-free production” opportunity.

Although it was practically zero in 2013, solar energy capacity reached 40.2 MW by the end of 2014, mostly thanks to rooftop PV systems (unlicensed production facilities) and some projects aimed at providing electricity to irrigation pumps in Southeastern Anatolia.[61].

Considering the decline in investment costs of solar energy facilities, it may be possible for Türkiye to develop a rich solar energy-based electricity generation potential in the medium term with support prices not higher than the market price.

3.3.3.5 Biomass

Biomass constitutes approximately 3 percent of Türkiye's total primary energy supply. It is a traditional energy source, as it uses animal and agricultural waste, mostly for heating purposes. However, the share of biomass/biogas power plants in the country's total installed capacity is negligible (0.3%). In 2006, the total capacity was only 41 MW. As of the end of 2014, 58 power plants with a total capacity of 289 MW were in operation. Most of these were built after the amendment to the Renewable Energy Law and the increase in fixed-price tariffs, and the majority use municipal waste or landfill gas.

In addition to the existing power plants, there are 10 new power plant projects (39 MW).[62]Investors are dependent on municipal governments, as municipalities are responsible for solid waste management storage facilities, especially for landfill gas. The waste management problems of municipal governments will further encourage the development of the biomass sector.

The expected increase in the use of biomass for electricity generation is mainly due to the “unlicensed production” legislation (see next section). This legislation may attract investors to rural projects using agricultural and forestry waste in rural areas. This will also facilitate investments in rural areas and provide socio-economic benefits.

3.3.4 Unlicensed Production

Another important milestone in the development of renewable energy in Türkiye is the “unlicensed production” (or distributed production) application introduced by the Energy Efficiency Law in 2007. According to this law, electricity production facilities using renewable energy sources and having an installed capacity below 200 kW can be built and operated by private individuals or legal entities without obtaining a license from the Energy Market Regulatory Authority (EMRA). This limit was later increased to 500 kW and finally to 1 MW in the new Energy Market Regulatory Authority (2013).

The introduction of unlicensed generation opportunity aims to encourage both the production of cogeneration plants and production based on renewable resources, with the aim of (a) increasing the share of electricity generation based on renewable resources, (b) reducing grid losses by facilitating distributed generation, and (c) increasing efficiency.

According to the legislation, the following electricity generation activities are exempt from the requirement to obtain a license and, unlike other market activities, do not require the establishment of a company:

- Isolated facilities and emergency generators,
- Micro-cogeneration plants (i.e. cogeneration plants smaller than 50 kW), and
- Power plants with a capacity of up to 1,000 kW based on renewable resources. (The Council of Ministers is authorized to increase this limit up to five times based on the capacity of the transmission and distribution network and issues related to supply security.)

In other words, private individuals can set up these facilities in their homes, farms, residences, etc. to meet their own needs and sell the excess electricity to the distribution system they are connected to through the renewable energy support system. Private individuals or legal entities in the same region can pool their consumption to set up a joint production facility. Typical examples of such renewable energy based production facilities include rooftop solar PV applications, micro-hydroelectric power plants, small wind turbines, and biomass power plants.

Production facilities within this scope can only be connected to the distribution system. Distribution companies are obliged to provide their connection if the network capacity is sufficient at the relevant voltage level (LV or HV).[63] They can only reject or limit connection requests in cases specified in the relevant legislation.[64] This regulation determines the technical and administrative procedures and principles regarding connection, operation, measurement and payment. The technical limits regarding connection points are also determined in the regulation. The excess electricity generated in these facilities is given to the distribution network and the regional supply companies in charge cannot refuse to receive the electricity given to the network. At each connection point, there is a measurement system for measuring the energy taken from the network and given to the network. In case of collective use, the difference between collective consumption and production is determined. The price of electricity given to the network is determined according to the fixed price guaranteed tariff specified in the Renewable Energy Law. In each distribution region, it is assumed that the total electricity provided by these suppliers is given to the "renewable energy pool" by the distribution company and the total price of electricity purchased in this pool is paid to the distribution company according to the procedures specified in the Renewable Energy Law and the relevant secondary legislation.

This practice was defined in the Energy Efficiency Law enacted in 2007 and was added to the Electricity Market Law in 2008 and the Renewable Energy Law in 2011. However, due to technical and administrative issues that needed to be resolved before such a new concept could be put into practice, secondary legislation was only finalised in 2011 and amended again in 2013.

Traditional distribution system design and operating procedures were developed for the transfer of electrical energy from generation sources to passive consumption points (passive loads). However, the implementation of the new regulation has created a new philosophy: consumption points may no longer be passive loads and there may be reverse flows from these points to the distribution system. Therefore, along with the strengthening of the medium and low voltage grid, new protection and measurement methods and new operating procedures need to be implemented. Further work and development on the "smart grid" will be necessary to implement this concept more smoothly.

Since the regulations were published only recently, implementation did not gain momentum until 2013. However, it attracted great public interest. The table shows the distribution of applications as of July 10, 2015.

Table 10. Unlicensed Production Projects

Source	Project Applications		Approved Applications		In business	
	Number	Capacity (MW)	Number	Capacity (MW)	Number	Capacity (MW)
Wind	149	108.0	54.0	36.1	2.0	0.5
Sun	2,717	2,227.0	1,068.0	846.0	215.0	125.5
Biomass	21	17.7	12.0	12.0	5.0	5.6
Total	**2,887**	**2,352.7**	**1,134.0**	**894.1**	**222.0**	**131.6**

Source: TEDAS

The large number of projects is an indication of their high level of public acceptance and interest. Unlicensed generation – especially solar PV – is expected to increase the share of renewable energy in the overall energy mix, as in many countries.

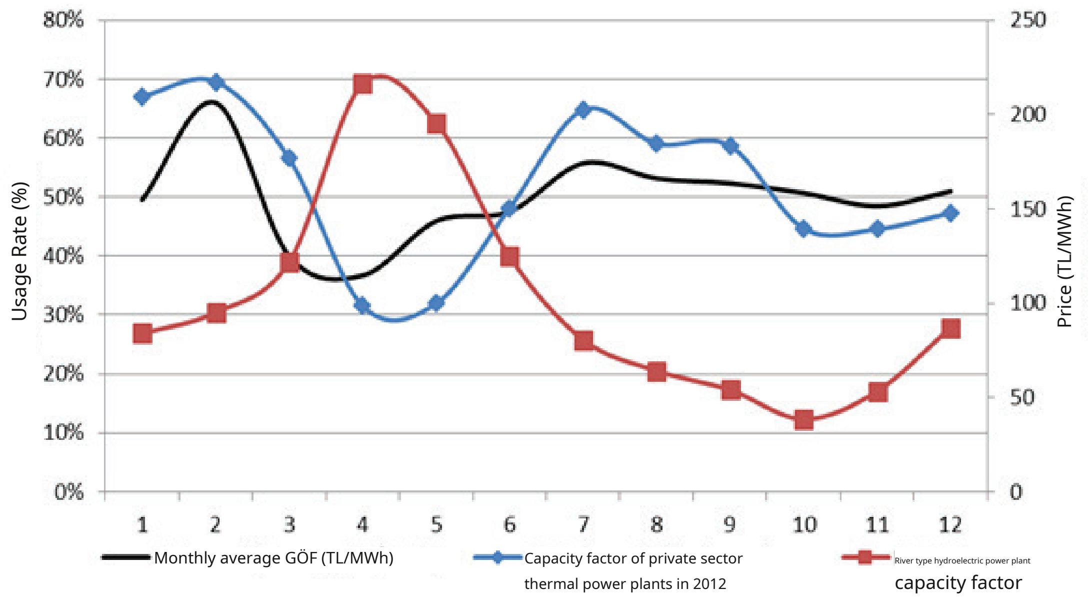
3.3.4.1 Impact of Support Provided for Renewable Energy Resources on Wholesale Market Prices and Security of Supply

One of the reasons for supporting renewable energy is to reduce import dependency and increase security of supply. Indeed, along with other benefits such as reducing greenhouse gas emissions, successes to date have shown that support mechanisms (renewable energy pools, priority allocation, fixed feed-in tariffs) attract significant private sector generation investment, thus helping to meet the increasing demand for electricity. The share of small hydro, wind and solar in total electricity generation is currently small, but is expected to increase significantly.

The electricity production of small hydro, wind and solar power plants is considered as "unconstrained" production and these plants are distributed without a competitive selection mechanism in the wholesale market. That is, they are always at the lower end of the merit order curve. Normally, their available capacity is lower than the available capacity of thermal power plants and the demand is met only by base load plants such as coal and efficient natural gas power plants and finally by less efficient/expensive natural gas power plants and liquid fuel power plants during peak demand times. Therefore, the marginal price in the day-ahead market is mostly determined by natural gas-fired power plants.

As a natural consequence of this, when available capacities are high, the share of renewable energy source-based production facilities in total electricity consumption increases, the share of thermal generation decreases, and the marginal cost in the wholesale market decreases. The relationship between renewable energy source-based production and the average price in the day-ahead market in 2012 is shown in Figure 61.

Figure 61. Power Plants and Thermal Power Plants Based on Renewable Energy Sources



Sources: TEİAŞ electricity statistics and PMUM.

Note: GÖF= day ahead price.

It is observed that during the rainy season (March-May) the capacity factor of river type hydroelectric power plants increases, the capacity factor of thermal production decreases, and thus the wholesale market prices decrease. Therefore, at first glance, it can be concluded that another benefit of renewable energy sources is that they reduce electricity prices. However, this determination will only be valid if the decrease in wholesale prices can be fully reflected in consumer prices. In fact, there is a cost to production based on renewable energy sources, and this cost is paid by consumers through renewable energy support mechanisms. Therefore, the decrease in wholesale prices cannot be fully reflected to consumers.

This fact will not pose a problem for thermal power plant owners as long as the share of production based on renewable energy sources is small. However, as the share of production based on renewable energy sources increases, especially in rainy years, a large part of the hourly demand will be met by hydraulic and wind sources and especially by solar power plants during daylight hours. Naturally, the production of these facilities will not be realized continuously, it will only occur during sunny daylight hours, windy periods and/or rainy years. However, it will inevitably affect the operation of fossil fuel power plants. As a result, the average utilization factor of thermal power plants may be lower than expected.[65] For example, due to the high share of solar energy in Germany, on some days the production based on solar energy reaches such a high level that some base load power plants have to reduce or even stop their production. At such times, daily wholesale market prices naturally fall, sometimes reaching zero. Therefore, the high share of renewable energy poses a challenge for power plants using fossil fuels.

This may be a natural and desirable outcome. However, it also creates difficulties:

- Since many renewable energy power plants have low availability, there needs to be sufficient available spare thermal capacity to avoid compromising supply security and system reliability. Keeping this spare capacity also comes at a cost.
- Türkiye needs new base load generation capacity to cope with increasing demand. However, investment decisions depend on future market prices and revenue calculations based on future production volumes in energy markets.

- The long-term marginal prices in the wholesale market should be at a level that provides sufficient income to cover investment and operating costs at a fair profit. Otherwise, it may not be feasible to invest in large base-load power plants, which generally do not have sufficient flexibility to operate during peak load periods. However, as discussed earlier, wholesale prices will fall when there is a large amount of off-market renewable generation. If this effect reduces the utilization factor of base-load power plants and income can only be obtained from the wholesale electricity market, the investment may not be feasible.
- Since it will not be possible to meet demand and peak consumption and have a reliable supply with only renewable resource-based production, at least in the medium term; investments in base-load power plants should be continued in addition to the country's maximum benefit from renewable resource-based electricity production. A decrease in investor appetite will have significant effects on Türkiye's electricity sector.
- Therefore, in addition to the current energy market, there should be new mechanisms to secure investments and attract investors. A possible solution could be to implement a capacity mechanism that would provide a fair return on investment. However, this mechanism should be market-based, unlike the old BOT models.
- In addition, due to the opportunities brought by different time zones and different peak periods, the necessity of strengthening interconnections and developing regional trade in order to ensure more efficient use of the production portfolio also emerges.

Depending on the amount of price support, another important impact of renewable energy sources, especially for unlicensed solar energy production facilities, will probably be on end-user electricity tariffs. When the unlicensed production application was introduced in 2007, the main purpose was to facilitate small and distributed production facilities, especially for the facility owners to meet their own needs. However, in the regulatory changes made later, no limit was determined for the consumption to meet their own needs. Therefore, each applicant can establish a production facility with a production capacity below 1 MW, regardless of their own consumption, and the distribution companies must purchase the electricity produced by them at the price specified in the law for the first ten years of operation. If there is no obligation to use it for their own needs, project owners may aim for trade and the share of solar energy production determined well above market prices may increase. As a result, end-user prices may increase due to the support mechanism. It has been observed that in some countries, high support prices have become a burden and some governments have had to adjust them. Since the capacity of high-priced solar energy production is still low, this situation does not constitute an urgent problem for Türkiye. However, considering the high potential available, this issue may also become a problem for Turkey. To eliminate this problem, the support tariff can be adjusted periodically in parallel with the decreasing investment cost and a limit can be imposed on the usage rate for its own needs.

3.4.Nuclear energy

For more than 40 years, Turkey has wanted to build nuclear power plants (NPPs) to diversify its electricity supply sources in order to meet the increasing demand safely. It is aimed to increase the share of nuclear power plants in electricity production to 10 percent by 2023 and to continue to increase this rate in the long term. In 1956, the Atomic Energy Commission General Secretariat was established in Ankara as an institution affiliated to the Prime Ministry. A year later, Turkey became one of the founding members of the International Atomic Energy Agency. In 1982, the Commission was restructured and the Turkish Atomic Energy Authority was established with Law No. 2690. In the 1960s, two research reactors were commissioned in Türkiye (one at the Çekmece Nuclear Research Center and the other at Istanbul Technical University).

Since 1967, Turkey has been trying to establish a nuclear power plant through competitive bidding; a total of three tenders have been held for this purpose. In all three tenders, the plant was planned as a public investment and the state was expected to be the owner or at least a shareholder of the plant. However, due to various reasons, these tenders could not be concluded successfully.

In 2007, a new Law on Construction and Operation of Nuclear Power Plants was adopted, and in 2008, companies were invited to bid for the construction and operation of a nuclear power plant in Akkuyu, a small town on the Mediterranean coast. For the first time, the model was envisaged as a BOT rather than a public investment. Although no Treasury guarantee was offered, TETAŞ was identified as the buyer. No other company submitted a bid, except for a consortium led by Russia's state-owned nuclear company Atomstroyexport, and the tender was eventually cancelled.

After several unsuccessful attempts to build the power plant through competitive bidding, the government decided to include the plant in its own generation capacity through direct intergovernmental negotiations. Akkuyu and Sinop were selected as the locations for the two power plants to be built.

Akkuyu

As a result of negotiations with the Russian Federation, the “Agreement between the Government of the Republic of Turkey and the Government of the Russian Federation on Cooperation in the Establishment and Operation of a Nuclear Power Plant (NPP) at the Akkuyu Field in the Republic of Turkey” was signed on May 12, 2010. The agreement includes four VVERs, each with a capacity of 1,200 MW, at Akkuyu.[66]-1200 type reactor is planned to be installed. The agreement was approved by the parliaments of both countries in Türkiye on July 21, 2010 and in Russia on December 13, 2010.

In accordance with the agreement, the Russian side established and registered a company called Akkuyu NGS Electricity Production Joint Stock Company (“Akkuyu Project Company” or APP) in Türkiye on 13 December 2010.[67] The company is responsible for the design, construction, maintenance, operation and decommissioning of the plant for 60 years, and TETAŞ will be the purchaser of electricity generated by the plant for the first 15 years. TETAŞ will purchase 70 percent of the electricity generated by the first and second units and 30 percent of the electricity generated by the third and fourth units at a price of 12.35 US¢/kWh (weighted average, excluding VAT). The remaining electricity will be sold by the company to the market at market price. This will be the first NPP project to be implemented with the Build-Operate (BOO) model. The project also envisages the maximum possible participation of Turkish companies and companies from other countries in the construction and installation activities. Once all four units are operational, the total annual electricity generation capacity of the plant is expected to be 35 billion kWh.

Initially, it was planned that the first unit would be put into operation in 2019, and the other units would be put into operation one after the other by 2023. The project company, Akkuyu Nuclear Power Plant Electricity Generation Inc., submitted an environmental impact assessment (EIA) report in December 2011 before the deadline and aimed to start construction work in 2013. The report was rejected twice, but the third report was approved in December 2014. APC is expected to apply for a construction permit to the Turkish Atomic Energy Authority (TAEK) in 2015. TAEK has purchased technical support services from competent nuclear consulting companies to review and evaluate the construction permit application. The construction permit is expected to be issued in 2017, and construction work is expected to begin in full thereafter.

The company had planned to commission the first unit (1,200 MW) in 2020 and the other three units of 1,200 MW each, one after the other, one after the other. However, delays to date and international experience with the construction/commissioning processes of NPPs suggest that the first unit may be commissioned later than planned.

Sinop

In addition to the Akkuyu nuclear power plant, Turkey aims to build another nuclear power plant in Sinop (on the Central-Northern Black Sea coast) through a joint venture between EÜAŞ and a foreign nuclear energy company. In this regard, some negotiations were conducted with South Korea's electricity company KEPCO and a joint declaration was signed in 2010. However, no agreement was reached with South Korea during the negotiations and negotiations were initiated with Japan and several other candidate countries.

An Intergovernmental Agreement was signed between Turkey and Japan in May 2013 and ratified in May 2015. According to the agreement, 49 percent of the capital of the project company will be provided by Turkey (EÜAŞ will have a 49 percent stake) and a consortium consisting of Mitsubishi Heavy Industries Ltd., Itochu Corporation (Japan) and GDF Suez SA (France) will have a 51 percent stake as long as the Power Purchase Agreement is in force.

Sinop power plant consists of 1,120 MW ATMEA-1 type nuclear reactors each[68]It will have four units (total installed capacity 4,480 MW). The estimated cost of the project is US$22 billion. The first unit is expected to be commissioned in 2023 and the other units are expected to be commissioned one after the other, with the last unit entering service in 2028.

Technical feasibility studies are ongoing and negotiations between EÜAŞ and the Japanese consortium regarding the establishment of the project company have not yet been completed.

Turkish Atomic Energy Authority

The Turkish Atomic Energy Authority (TAEK) is the institution responsible for determining nuclear and radiation safety regulations and issuing construction and operation licenses for nuclear power plants. At the same time, TAEK is an institution affiliated with the Ministry of Energy and Natural Resources, which is responsible for promoting the use of nuclear energy. Therefore, the Ministry of Energy and Natural Resources has prepared a Nuclear Energy Draft Law, which aims to separate the regulatory and other functions of TAEK and establish a new independent nuclear regulatory authority.

3.5Future Prospects and Challenges in the Electricity Market

3.5.1 Supply/Demand Balance and Security of Supply

The annual growth rate of consumption slowed to an average of 5.7 percent in the 2002-13 period (the average for the last 40 years was 8.3 percent). However, due to expected economic growth and population growth, consumption is expected to continue to increase in the coming years, albeit at a slower rate. ETKB projections foresee an increase of approximately 72 percent (annually 5.6 percent) in the next 10-year period.[69]As a rough estimate, if an average annual GDP growth of 4.5 percent and a smaller elasticity coefficient due to productivity gains are assumed, an average annual demand increase of 5 percent can be expected with the implementation of demand-side management systems and savings measures. Accordingly, peak demand will also increase. Electricity generation capacity will also need to be increased to meet the increased consumption.[70]

Following the introduction of cost-recovery pricing, privatization of distribution, support for renewable energy and development of the wholesale market, generation investments have accelerated. With the decline in demand in 2008-09 due to the economic crisis and the addition of new capacity during 2008-13, the capacity margin has increased to a level sufficient to ensure safe operation (72 percent as of 2014).

However, considering past experiences and potential future demand increases, it can be easily assessed that Türkiye will need new investments to maintain sufficient reserve margin for a secure operation. Past evidence suggests that in order to have sufficient available capacity, the installed capacity margin should not fall below 35 percent. According to the latest progress report of the Energy Market Regulatory Authority[71]and according to TEİAŞ's Generation Capacity Projection Report (2013–17), at least 15,000 MW of additional new capacity will be put into operation by 2018, and the capacity margin will remain above 50 percent. Therefore, it can be said that there is no urgent supply security problem in the short term, provided that there is sufficient gas supply. In order not to encounter new supply security problems for the period after 2018, in addition to nuclear projects – and considering the time required for construction – investors should have already made decisions on new generation investments.

However, the following factors should also be taken into consideration when evaluating past investments:

- Past investments were largely made in the 2007-09 period, when all estimates indicated that Türkiye needed new generation investments in the medium term to avoid supply security problems. However, there is currently a supply surplus in the market that could last until 2020, given the slowing demand and the additions to renewable capacity (especially solar and wind). (The period of surplus may be shortened if economic growth is faster than the projected 4.5 percent). This excess capacity will affect wholesale prices and reduce the utilization factors of new thermal power plants.
- During the 2007-12 period, financing was more easily available due to favorable financial and economic conditions in global markets.
- Political and regulatory risks were low and there was a strong belief that free and competitive markets would continue to operate consistently.

Two of the most important factors in attracting investments were confidence in the country's legal and regulatory framework and consistency in the application of market rules. In this context, the legal, administrative and regulatory framework has provided an attractive investment environment over the last eight years.

Predictability in the regulatory environment is one of the preconditions for increasing and sustaining private sector participation. Turkey has chosen private sector participation through new investments and privatization of existing facilities as the best way to achieve a sustainable long-term solution in the energy sector in the areas of energy security, competitiveness and operational efficiency. Any concerns regarding a fair, transparent and stable political/legal system will at least increase the country and regulatory environment risk. Therefore, the reform process should be continued as planned in order to maintain high levels of investor confidence and attract investments in the current global political and economic conditions and the current supply/demand balance.

Long-term price signals and long-term bilateral contracts are useful in attracting investments. Currently, the share of bilateral contracts in the market is around 70 percent, but they are mostly between the public and private sectors and their duration does not exceed one year. It is expected that long-term price signals will be given by the markets operated by EPİAŞ (in the field of physical electricity trading) and Borsa İstanbul (in the field of financial instruments related to trading and risk management). Otherwise, the volatility of spot prices may be a risk for suppliers and retail companies.

Another important factor regarding supply security is the adequacy and quality of the transmission system. In this context, transmission investments need to continue in order to integrate renewable energy source-based production into the system more rapidly. Although some problems were experienced in the past due to the lack of coordination with the licensing process and the failure to make transmission investments on time, the new EML offers a coordinated approach in this sense. However, TEİAŞ must have the ability to plan and announce the available capacity in advance, complete transmission investments on time and operate the electricity system reliably. This will only be possible if TEİAŞ has sufficient institutional and technical capacity. This issue is related to the governance issue in SOEs and will be discussed in more detail in the following sections.

More efficient use of existing thermal units will also help increase supply. As mentioned in the section on generation privatizations, the utilization factors in EÜAŞ's thermal power plants, especially lignite-fired power plants, are low and have fallen further in recent years. Most of EÜAŞ's power plants are old. Rehabilitation or renewal of these power plants will increase their efficiency and availability. The additional supply provided by these power plants will also contribute to supply security.

Implementing more effective efficiency programs and demand-side management measures will help both increase supply security and reduce greenhouse gas emissions.

On the other hand, Türkiye's heavy dependence on imported natural gas for electricity generation leads to temporary supply shortages. As discussed in the section on the natural gas market, sufficient storage and the lack of daily supply (send-out) capacity poses a significant risk to electricity supply security. In addition, Türkiye's hydroelectric production is highly dependent on hydrological conditions and exhibits significant variability. In the event of a natural gas shortage in a dry year or during a dry season, the effects will be further exacerbated. Therefore, diversification of natural gas sources and timely completion of storage facilities are necessary to ensure supply security.

In addition to measures for a reliable natural gas supply, measures to reduce the share of natural gas in electricity generation will also help increase supply security. The installed capacity of lignite-fired power plants in operation is approximately 8,500 MW. After the commissioning of the five projects under construction (total installed capacity of 2,000 MW), Turkey will be using approximately 50 percent of its total domestic lignite-based electricity generation capacity. As the share of lignite in total production increases, the share of imported resources such as natural gas and imported coal is expected to decrease. Since this will increase supply security, additional support (incentives) can be provided to new lignite-fired power plants. However, this support should not be in the form of take-or-pay guarantees as in the past BOT application.

Another issue related to supply security is the need for new base load thermal generation capacity and the potential negative impacts of supported renewable energy-based generation capacity on the private sector's decision to invest in base load thermal generation capacity, as explained in the previous section on renewable energy.

The period of excess supply should be considered as an opportunity to evaluate the capacity mechanisms that came to the fore during the supply crises of 2007-08.

3.5.2 Development of the Electricity Market

As discussed earlier, Turkey has gradually established a well-functioning electricity market over the past decade. The legal, regulatory and institutional framework has attracted and facilitated market-based private sector investments, the number of market participants and eligible consumers has increased significantly, distribution privatizations have been completed and wholesale competition has been achieved to a significant extent, but market development efforts still need to continue.

The introduction of the intraday market and the establishment of EPİAŞ are important steps. The new Electricity Market Law enacted in 2013 foresaw the establishment of the Energy Market Operation Corporation (EPİAŞ) to take over the electricity market operation function from PMUM/TEİAŞ. EPİAŞ was established and 97 private companies became shareholders of the company. EPİAŞ is expected to become fully operational in 2015. Financial trading instruments will be operated by Borsa İstanbul. Therefore, both transparency and efficiency in market operation will be increased and EPIAŞ will serve as Türkiye’s energy exchange – this will probably be the first step towards a regional energy exchange.

There is a perception that wholesale electricity market prices are being intervened in through BOTAŞ, EÜAŞ and TETAŞ prices in order to keep end-user prices stable (and to protect consumers from the “opportunistic behavior” of some private generation companies in times of supply shortages). Interventions aimed at protecting consumers from price fluctuations and opportunistic behaviors can be seen as a legitimate behavior. However, this goal can be achieved more adequately by improving market rules and increasing transparency in market operations. If an intervention is still needed, it should be done in an open and transparent way. Otherwise, such interventions may lead to concerns about the future of the market. Subsidies should target low-income consumers. In addition, interviews with market participants have shown that there are other problems such as insufficient transparency in TEİAŞ’s market operation and distribution processes. In addition to improving market operation, EPİAŞ will also help solve the transparency problem. On the other hand, transparency will also need to be increased in the Balancing Power Market operations and congestion management procedures to be operated by TEİAŞ.

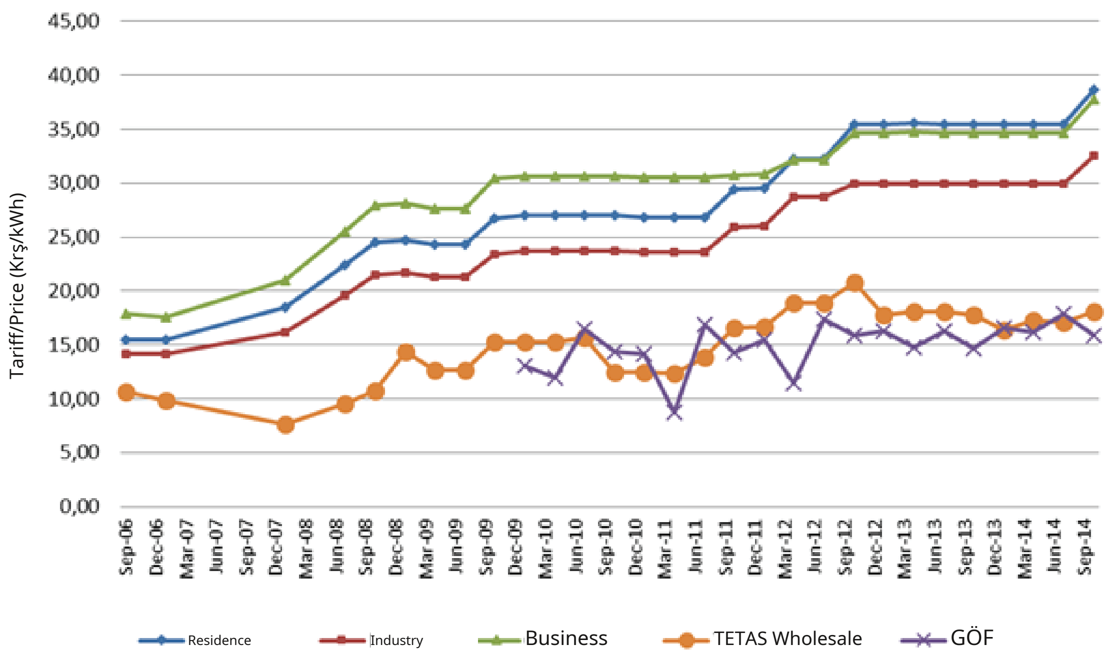
The last strategy document was prepared in 2008 and published six years ago in 2009; most of the targets regarding market implementation have been achieved. However, additional steps are needed to ensure market development. In fact, some of the steps to be taken for the next process have been determined in the EML amendments and EPDK-ETKB decisions. However, it would be useful to prepare and explain the strategies and implementation roadmap for future development efforts. These should include the principles and implementation program regarding the development of the wholesale market and other issues specified below:

- Market Development:
  - Financial markets and derivatives markets
  - Additional steps towards wholesale and retail competition
  - Gradual abolition of the inter-regional price equalization mechanism (national tariff)
  - Implementation of capacity mechanism (if used)
  - Matching with other regional markets
- Other:
  - Protection plans for low-income households Demand side management
  - Renewable energy support policy
  - Energy efficiency
  - Local resource use targets.

3.5.3 End User Tariffs and Purchasing Power

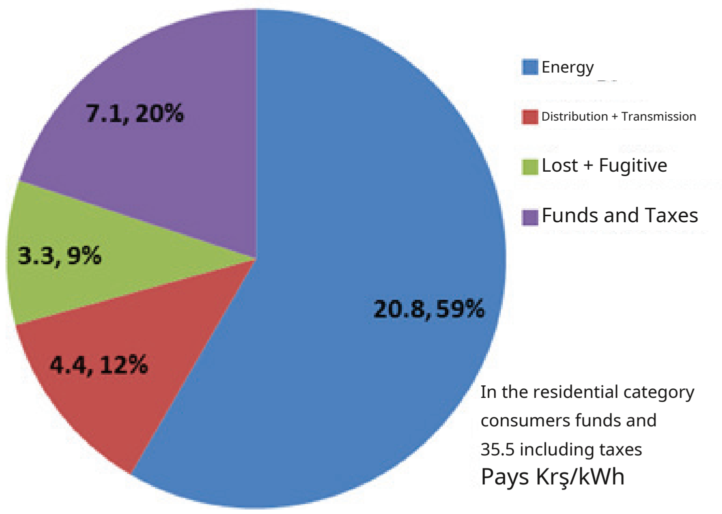
Figure 62 shows end-user electricity prices and wholesale market prices since 2006, and day-ahead prices (DAP) since 2009. Except for the last two years, end-user prices have generally followed wholesale prices. (The rationale for flat tariffs is discussed in Section 3.2.4.1.) Except for 2006 and the first half of 2007, when prices were suppressed, the residential tariff, including funds and taxes, has almost doubled to $0.18 (18 US¢).

Figure 62. Non-Free Consumer Tariffs (Including Funds and Taxes) and Wholesale Prices (Excluding Taxes)



Source: Based on TEDAŞ, EPDK and TEİAŞ statistics.

Figure 63 shows the composition of the electricity price for a consumer in the residential category.

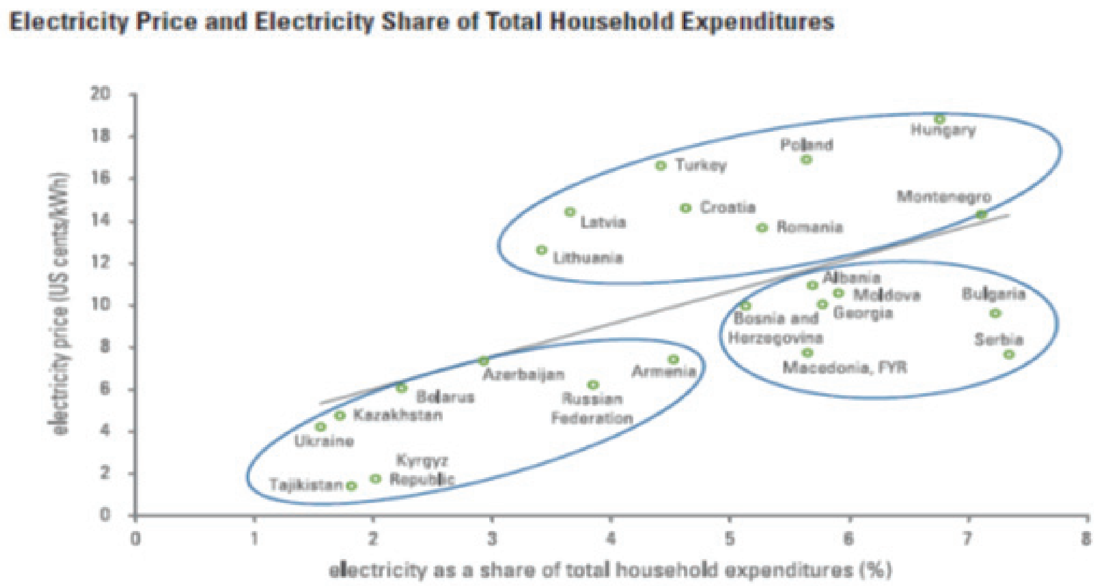


Source: T

Here, due to the large differences between regions, a price equalization mechanism[72]It should be noted that there is an average national tariff in place across all regions. If this cross-subsidization between regions were to be removed, prices would be much higher in regions with high loss-leakage rates.

As of 2013, per capita electricity consumption is around 240 kWh/month (2,880 kWh/year) and average consumption per household is around 150 kWh/month (1,800 kWh/year). That is, the average annual electricity expenditure of a consumer in the residential category is around 650 TL. *average*Annual equalized household disposable income (13,250 TL)[72]This constitutes about 5 percent of total household expenditure, compared to 1.5 percent of the total household expenditure. As Figure 64 shows, electricity prices in Türkiye are relatively high compared to prices applied in Eastern European and Central Asian countries.[74]

Figure 64. Electricity Prices and Total Households in Eastern European and Central Asian Countries Share of Electricity Expense in Expenditure

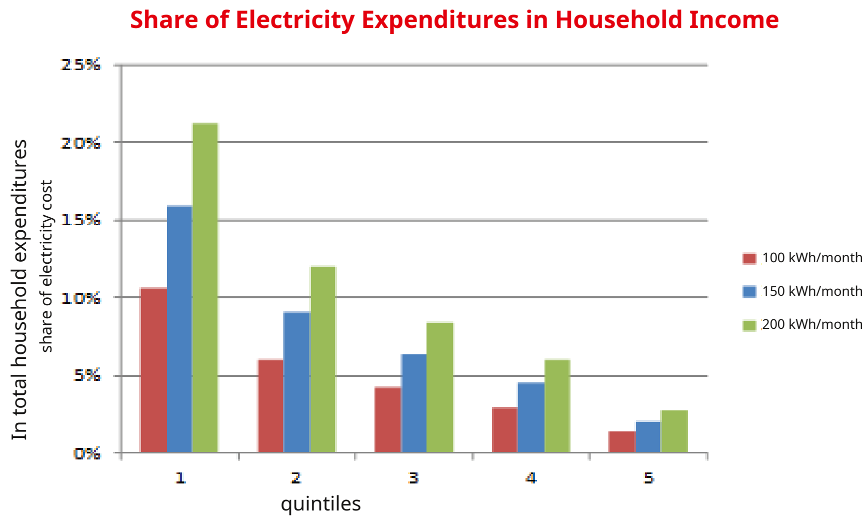


Source: World Bank.

Average residential prices are higher for countries that have made progress in electricity sector reform, implemented cost-reflective prices and reduced subsidies.

On the other hand, when the share of electricity in household expenses is compared with annual household disposable incomes on the basis of income quintiles,[75]As seen in Figure 65, the share of this expense varies dramatically.

Figure 65. Annual Consumption Rates for Different Income Groups and Different Household Consumption Levels



Source: Based on TEDAŞ and TÜİK data, 2014.

Even at a low level of electricity consumption (100 kWh/month), the share of electricity expenditure is observed to be 11 percent for the bottom 20 percent income group. At the 150 kWh/month consumption level, this share is over 15 percent for the bottom 20 percent income group. The same share was 12 percent and 18 percent for 100 kWh/month and 150 kWh/month consumption levels in 2008, respectively. It is possible to say that there has been a slight improvement since 2008 due to the improvement in income shares, but this can also be attributed to the suppressed electricity prices in the last two years.

Members of the lowest income group spend more than 10 percent of their household disposable income on electricity alone. If other energy expenditures such as natural gas and/or heating are included, this proportion would be well over 10 percent, so consumers in this income group can be considered energy poor.

According to the government's targets, all consumers will be eligible consumers by 2015 (if this date is not extended). Once this point is reached, there will be no more eligible consumers and no regulated retail sales tariff. Instead, a "last resort supply" tariff will be used for consumers who cannot get their electricity from a supplier through bilateral agreements. This tariff will also apply to consumers who are eligible to become eligible consumers but prefer to get their electricity from an incumbent supplier. The new EML foresees that the last resort supply tariff will be set at a level that will encourage consumers to look for a new supplier – while also providing a reasonable profit for the incumbent retail companies. Consequently, the last resort supply tariff is expected to be higher than the prices obtainable in the market. With the removal of subsidies from gas prices and the decrease in the share of EÜAŞ/TETAŞ, retail sales prices in the market may be higher than today's levels.

With the removal of natural gas subsidies and the increase in electricity prices to levels that cover costs, energy expenditure will increase even further for families in the lowest income bracket and even the second income bracket. A recent impact assessment across Turkey found that the majority of households in Türkiye were able to pay their electricity bills despite the price increases, but households without regular monthly income, rural households and households that depend on electricity for their livelihoods – such as farmers who use electric water pumps for irrigation – were less likely to pay.

or small urban businesses – have shown that they are vulnerable to increases in electricity prices.

In order for reforms to be implemented successfully and investments to be attracted, prices must be set at least at a level where costs are covered (and this level must also include internalized environmental costs) and price subsidies/interventions must be removed. A social safety net must be put in place to protect low-income consumers. General subsidies through tariffs are an expensive way to protect consumers. Therefore, applying equal and low energy prices to all income groups as practiced today is not a solution and it also supports consumers who do not need support. **Current pricing policies help not only the poor but also the higher income groups who do not need such subsidies.**

Therefore, in addition to existing social support programs, a**targeted price or subsidy policy**should be implemented and subsidies provided to high-income groups should be removed. The cost of such a support mechanism may be lower than the cost of a general-scale subsidy.

This will encourage efficient use of energy, which will also help solve the problem of chronic illegal use.

3.6 Natural Gas Market

The natural gas sector is one of Türkiye's most important strategic sectors. Although natural gas entered Türkiye's energy market only 27 years ago, today Turkey has become a major consumer of natural gas and is among the four largest importers of natural gas in Europe (the other three are France, Germany and Italy).

Natural gas plays an important role in Türkiye's total primary energy supply (approximately 30 percent) and especially in electricity generation (its average share over the last 10 years is over 45 percent). Therefore, issues concerning the natural gas market, such as supply and price, directly affect the electricity market and the industry as a whole.

In addition, since it is an imported resource, natural gas plays an important role in the foreign trade balance. Türkiye's annual natural gas import cost is 18 billion US$[76](2013) and constitutes a significant share of the current account deficit.

In addition to its importance in the domestic market, Türkiye's geographical location between source regions (the Caspian Sea and the Middle East) and consumption regions (Europe) has a significant impact on the natural gas market and transit issues on international gas trade. Therefore, the structure and development of Türkiye's domestic natural gas market has a significant impact on the realization of the ideal of becoming an international energy hub.

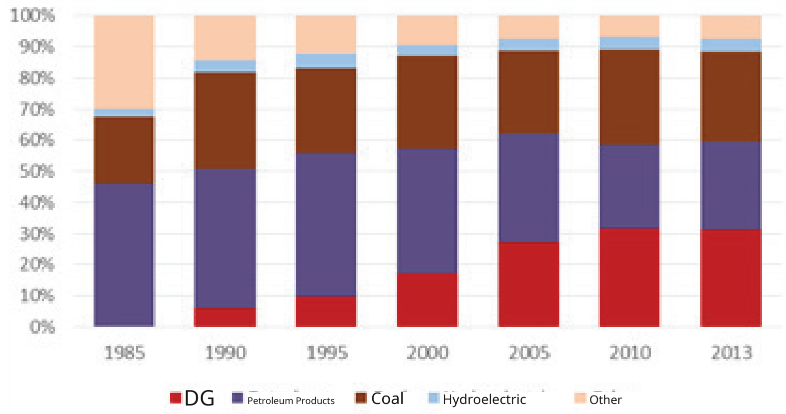
As a result, the development of Türkiye's natural gas market has a direct impact on the energy sector and is an important factor in the country's energy sector reform efforts.

3.6.1 Overview

Natural gas is a relatively new resource in Türkiye. Although it was first discovered in the country in 1970, significant consumption began in 1987 with the import of natural gas from Russia to diversify electricity generation sources and to prevent air pollution caused by coal-fired heating in large cities, especially Ankara. The first important projects were the natural gas pipeline project from Malkoçlar (on the Bulgarian border) to Ankara (1988); the Hamitabat KÇGT Power Plant (1989) and the gas supply project to Istanbul and Bursa (1992). The Marmara Ereğlisi LNG Terminal Project was also started in the same period as the second important project in the natural gas infrastructure and the facility was put into operation in 1994.

As seen in Figure 66, the role of natural gas in Türkiye's energy supply has increased rapidly after 1985. According to ETKB statistics, natural gas has a 31.3 percent share in total primary energy supply as of 2013. Natural gas has replaced petroleum products in heating and electricity generation.

Figure 66. Primary Energy Supply Sources of Türkiye, 1985–2013

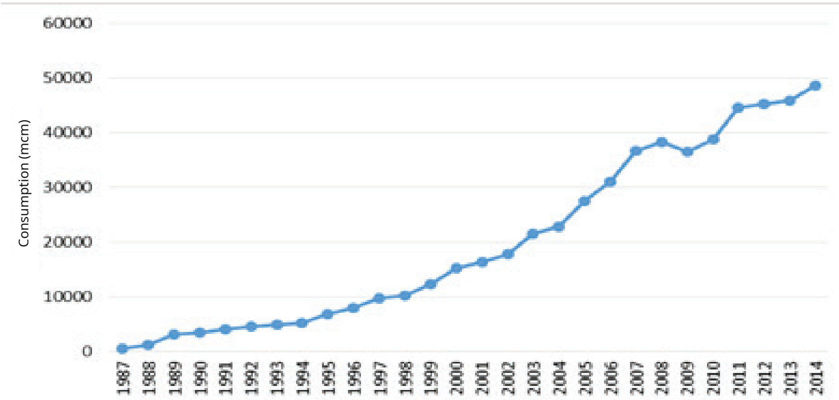


Source: ETKB.

Note: DG = natural gas

As of 2014, natural gas consumption reached 48.7 billion cubic meters (BCM)[77]As seen in Figure 67, the annual natural gas demand increase in Türkiye has been at very high levels in the last 20 years.

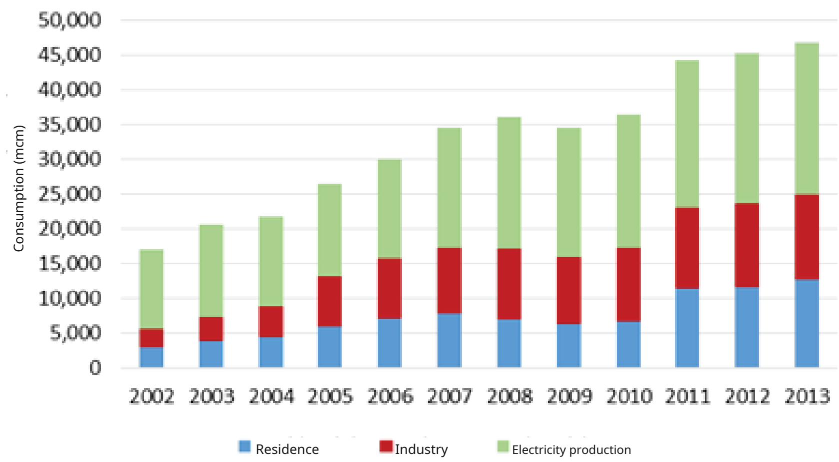
Figure 67. Natural Gas Consumption, 1987–2014 (mcm)



Source: EPDK, BOTAŞ.

Natural gas consumption by sector is shown in Figure 68. Although the initial increase was due to the electricity sector, natural gas consumption in residences has also increased, especially with the expansion of natural gas transmission and distribution networks in the country. In 2013, the electricity sector's share in total consumption was approximately 48 percent.

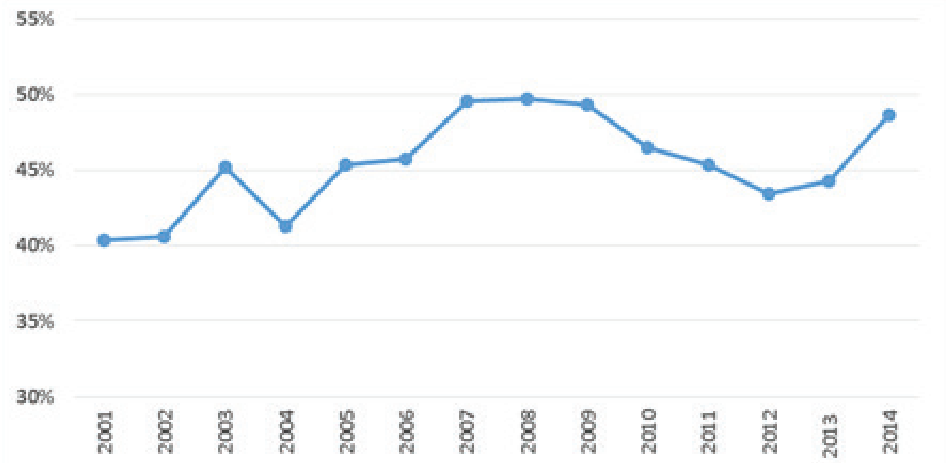
Figure 68. Natural Gas Consumption by Sectors, 2002–13 (mcm)



Source: EMRA.

Natural gas is currently an important source of electricity generation for Turkey. As seen in Figure 69, the share of electricity generation based on natural gas varies between 40% and 50%, depending on hydrological conditions and reserves in hydroelectric power plants. As discussed in the following sections, this dependence on imported natural gas raises concerns about supply security. In addition, seasonal electricity supply problems may occur during periods of increased residential consumption due to insufficient storage capacity.

Figure 69. Share of Natural Gas Based Electricity Production in Total Production, 2001–14



Source: TEIAS.

3.6.1.1 Supply

Since domestic production is almost non-existent (less than 2 percent of total consumption), the market is dependent on imports. Supply is largely provided through BOTAŞ's long-term import contracts (pipeline gas and LNG), some of which have been transferred to the private sector. Table 11 shows the long-term contracts in force.

Table 11. Current Long-Term Gas Contracts

Agreement	Amount (*) BCM/Year	Contract Date	Starting Year
Russian Federation (Western Route-BOTAŞ)(**)	4	14/02/98	1998
Algeria (LNG)	4.4	14/04/88	1994
Nigeria (LNG)	1.3	09/11/95	1999
Iranian	9.6	08/08/96	2001
Russian Federation (Blue Stream)	16	15/12/97	2003
Russian Federation (Western Route - Private Sector)(***)	10		
Turkmenistan(****)	15.6	21/05/99	not in business
Azerbaijan (Phase I)	6.6	12/03/01	2007
Azerbaijan (Phase II)	6	25/10/11	2017/18
Azerbaijan (BOTAŞ International (BIL))	0.15	26/10/11	2013

Source: BOTAS.

* Indicates the plateau amount - 9600 Kcal/m_3.

* * It was initially 8 bcm, 4 bcm of which was transferred to the private sector.

* * * 4 bcm contract transfer, 6 bcm from BOTAŞ's terminated western route contract. Following an announcement and application process carried out in accordance with the DGPK, import licenses were granted to four different private sector companies.

* * * * The Turkmenistan agreement is not expected to come into effect in the medium term.

In addition to gas imports via pipelines, LNG imports were also liberalized on a spot basis through legislative amendments made in 2008. BOTAŞ and the private sector company EGE-GAZ have been importing LNG since 2009. Table 12 shows imports during the period 2005–13. Despite diversification of import sources, Russia's share remains above 50 percent.

Table 12. Natural Gas Imports, 2005–13 (bcm)

Year	Russia	Iranian	Azerbaijan	Algeria LNG	Nigeria LNG	Spot LNG	Total
2005	17.52	4.2	0.0	3.8	1.0	0	26.6
2006	19.32	5.6	0.0	4.1	1.1	0.08	30.2
2007	22.76	6.1	1.3	4.2	1.4	0.17	35.8
2008	23.16	4.1	4.6	4.1	1.0	0.33	37.4
2009	19.47	5.3	5.0	4.5	0.9	0.78	35.9
2010	17.58	7.8	4.5	3.9	1.2	3.1	38.0
2011	25.41	8.2	3.8	4.2	1.2	1.1	43.9
2012	26.49	8.2	3.4	4.1	1.3	2.5	45.9
2013	26.21	8.7	4.2	3.9	1.3	0.89	45.3

Source: EMRA 2013 Natural Gas Report.

As of today, the total annual amount of long-term import contracts is about 52 bcm, excluding the Turkmenistan contract. To cope with the increasing demand, additional gas volumes need to be provided through spot LNG, short-term and long-term new contracts.

BOTAŞ exports up to 0.75 billion cubic meters of natural gas annually to Greece from its exit point in Ipsala, located on the Türkiye-Greece border.

3.6.1.2 Demand Projection

Historically, gas demand has grown slowly in the 1990s and more rapidly over the following decade. Demand is expected to continue to grow, albeit at a slower rate than in the past decade, as the market reaches saturation.

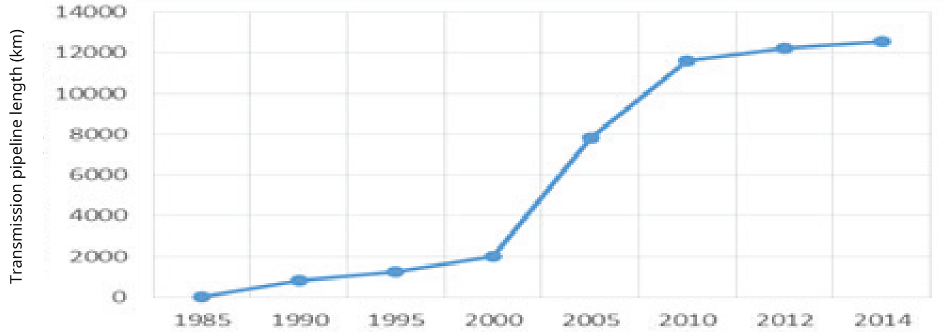
The gas network expansion to include distribution areas and the licensing process for distribution areas are almost complete. Projects are ongoing in five out of 81 cities and are expected to be completed by 2016. The remaining cities account for less than 2 percent of the total demand potential. On the other hand, investments in urban gas distribution infrastructure have progressed quite rapidly and more than 90 percent of the infrastructure needed to supply natural gas to homes is now in service; this rate is expected to exceed 95 percent by 2016. Consequently, the rate of increase in consumption in the residential sector will slow down and the increases will be driven more by increased penetration, industrial and especially electricity sector consumption. Therefore, the future composition of electricity generation will determine natural gas demand.

On the other hand, due to the high cost of natural gas and the high levels of natural gas imports posing a concern for energy supply security, the government aims to reduce the share of natural gas in electricity generation to less than 30 percent by 2023.[78]There has been a slight decline in the last five years, mainly due to the increased use of renewable energy sources and the slowdown in the growth rate of electricity demand. (Assuming an electricity production of 400 TWh for 2023, reducing the share of natural gas-based electricity generation to below 30 percent by 2023 would mean limiting the amount of electricity generation based on natural gas to approximately 135 TWh – currently around 105 TWh.) Given the slower-than-expected progress in domestic coal and renewable energy source-based generation projects and possible delays in nuclear power plant projects, this target may be difficult to achieve. However, it is possible to achieve this target with a delay of several years. Consequently, the increase in natural gas demand may slow down. However, the increase will continue, and consumption is expected to reach 70 bcm by 2030.

3.6.1.3 Gas Transmission Network

The owner and operator of the gas transmission network is BOTAŞ.[79] Figure 70 shows the evolution of the Transmission system since 1985.

Figure 70. Development of Natural Gas Transmission Pipelines, 1985–2014



Source: BOTAS.

The expansion of the transmission network to cover the entire country has been largely completed, and the total length of high-pressure lines reached 12,561 km as of July 2015.

Natural gas is supplied to the main transmission network from four import entry points, two LNG terminals, one underground storage facility and two domestic production sites. Future investments will focus on the construction of loop lines and new compressor stations to increase gas distribution capacity. In addition to the nine compressor stations currently in operation, construction of a new compressor station in Eskişehir began in 2012 and is expected to be operational soon. Figure 71 shows BOTAŞ's high-pressure transmission lines and compressor stations.

3.6.1.4 Distribution

While only six cities had access to natural gas in 2002, the number of gas distribution regions has reached 69, covering 74 cities, thanks to the tender process that EPDK has been implementing since 2004. This expansion is one of the main reasons for the increase in natural gas consumption in Türkiye. This issue will be discussed in more detail in the following sections.

3.6.1.5 LNG and Storage

There are currently two LNG terminals in Türkiye:

- Marmara Ereğlisi LNG Terminal belongs to BOTAŞ and has a storage capacity of 3 x 85,000 cubic meters of LNG. The annual gasification capacity of this terminal[80]Its capacity is 6 bcm and a maximum of 22.5 million cubic meters of gasified LNG per day can be delivered to the transmission system.[81]
- The LNG storage capacity of the Aliağa LNG terminal, which belongs to a private company EGEGAZ, is 2 x It is 140,000 cubic meters. Annual gasification capacity is 6 bcm and daily gasification capacity is 16 million cubic meters.

The only underground storage facility in Türkiye is the Silivri Underground Storage Facility, which consists of two depleted gas fields and is owned and operated by TP.[82]The storage capacity is 2,661 bcm. A maximum of 20 million cubic meters of gas can be supplied to the system from the facility on a daily basis.

3.6.1.6 Investment Plans for LNG Terminals

- BOTAŞ plans to increase the storage and gasification capacity of Marmara Ereğlisi LNG Terminal by installing the fourth LNG storage tank and additional equipment such as high pressure pump, LNG vaporizers, Pipeline Compressor, etc. Basic Project Engineering studies for this project have been completed.
- License applications for four new LNG facility investments have been submitted to EMRA. These are located in Aliağa and Çandarlı on the Aegean Sea coast and Yumurtalık on the Mediterranean coast. The earliest date that the new LNG terminals can enter operation will be 2018.
- It has been reported that talks have been held between the energy ministries of Türkiye and Qatar regarding Qatar's investment in an LNG facility in Türkiye.

Each of the new LNG terminals will have a regasification capacity of approximately 6-7 bcm.

3.6.1.7 New Underground Storage Investments

- The Salt Lake Underground Storage Facility is being built by BOTAŞ. Salt caves are created by introducing water brought from the Hirfanlı Dam via pipeline into the salt formation. The first phase of the project is planned to be completed in 2017 and the second phase in 2020, with an operating gas capacity of 0.5 and 1 bcm respectively, and ultimately offering a maximum daily withdrawal capacity of 40 mcm.
- The storage capacity of the existing Silivri Natural Gas Storage Facility (TP) will be increased to 2,841 bcm and the daily withdrawal capacity to 40 mcm by 2015 as part of the second phase investment. In the third phase, TP plans to increase the storage capacity of the Silivri Facility to 4.3 bcm and the daily withdrawal capacity to 75 mcm by 2020.
- Two licenses have been granted to private companies by EMRA for new underground storage projects planned to have a total storage capacity of 2-3 bcm in Tarsus. The 2015–19 Strategic Plan of ETKB envisages increasing the storage capacity to 10 percent of annual consumption in the medium term and 20 percent in the long term.

3.6.2 Natural Gas Market Reform

Before the Natural Gas Market Law No. 4646 (DGPK) was enacted, BOTAŞ was the main supplier, the only company with an import monopoly and operating as a transmission company. In the distribution sector, gas was supplied to three cities by municipalities (Ankara 1988, Istanbul 1993, Izmit 1994,) and to two cities by BOTAŞ (Bursa 1993 and Eskisehir 1996).[83].

The first efforts to liberalize the gas market were initiated in the late 1990s, inspired by the policy of creating a market economy and the EU's 1998 "Gas" directive, and following the Electricity Market Law, the Natural Gas Market Law was adopted in April 2001.[84] The DGPK aims to establish a legal framework for the establishment of a fair, financially strong, transparent and competitive natural gas market under the supervision of an independent regulatory institution. The main features of the DGPK can be summarized as the establishment of a fully competitive market for wholesale gas supply, the separation of BOTAŞ's main functions and thus the end of BOTAŞ's monopoly position in the market.

The underlying strategic objective was to ensure a secure supply of natural gas in a competitive domestic wholesale market, appropriately manage potential supply threats in the medium term, and minimize the state's future contingent liabilities by shifting risks to the private sector.

The main provisions of the DGPK were as follows:

- Independent regulation and supervision by the Energy Market Regulatory Authority;
- Establishing a licensing regime regulated by EMRA for separate activities;
- Competition rules, including segregation of accounts and activities; prevention of dominant positions in the market (no supplier having more than a 20 percent share of annual gas consumption); disclosure and open access; and
- "The concept of "free consumer".

Natural Gas Market Activities in DGPK are determined as follows:[85]

- Transmission
- Distribution
- Imports
- Export
- Wholesale
- Storage (LNG terminals and underground storage facilities)
- CNG (compressed natural gas) transportation, distribution and trading.

The law also introduced the following transitional measures and limitations:[86]

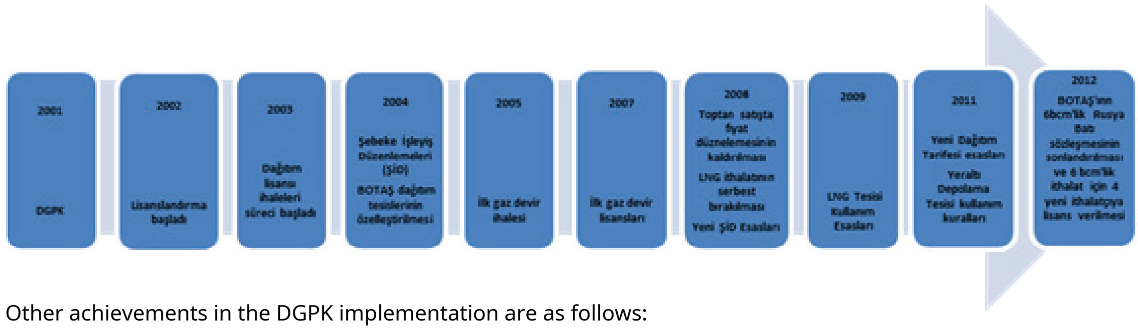
- BOTAŞ's share in the gas market would be reduced to 20 percent by 2009;
- BOTAŞ would hold tenders for contracts or volume transfers of at least 10 percent of the market each year;
- BOTAŞ would not enter into new import/purchase contracts (later the Law was amended in 2008, allowing BOTAŞ and other private companies to purchase spot LNG);
- New gas import contracts would not be possible with countries that already have contracts with BOTAŞ, but expired contracts could be renewed;
- BOTAŞ would be completely unbundled by 2009 and the unbundled activities, except for gas supply and transmission, would be privatized within two years.

The main justification for the first two transitional measures was to provide sufficient time for BOTAŞ to reduce its share, while the third and fourth measures were designed to protect BOTAŞ because its existing contracts contained take-or-pay provisions. As will be discussed in the following sections, the overly ambitious targets for reducing its market share were not achieved and import restrictions led to supply security problems. The provisions for unbundling ownership were also quite ambitious for the time. Such unbundling conditions were introduced in the EU only after the 2009 Gas Directive.

3.6.2.1 Progress

Significant progress has been made towards liberalising the gas market, although implementation has been slower compared to the electricity market and many of the initial target dates have not been met. The main implementation steps are shown in Figure 72.

Figure 72. Major Steps of Natural Gas Market Reform

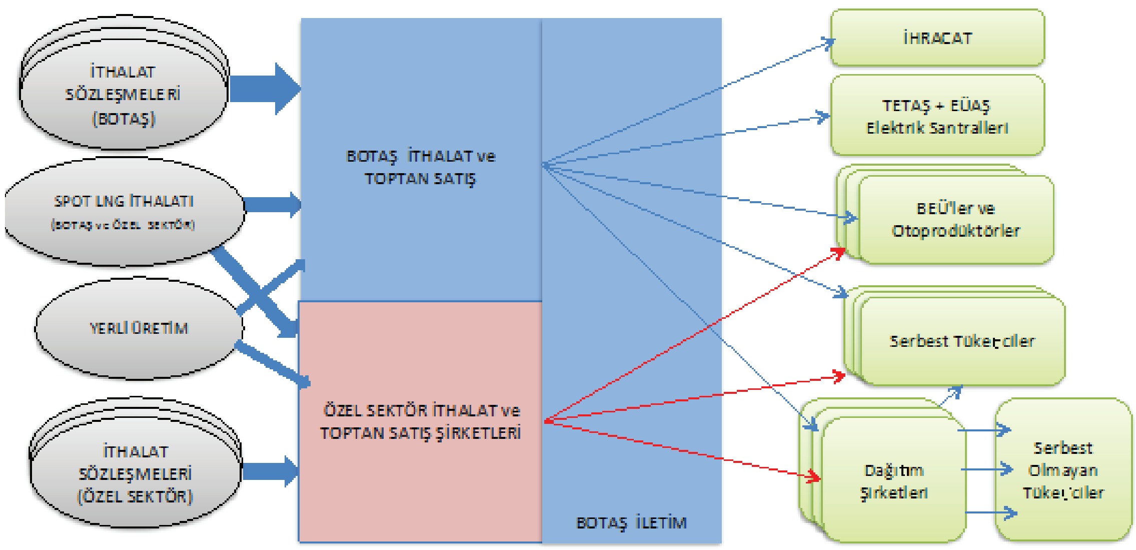


Other achievements in the DGPK implementation are as follows:

- Completion of the legal and regulatory framework;
- Privatization of BOTAŞ's distribution activities;
- Expansion of the distribution system by private distribution companies through successive tenders held by the Energy Market Regulatory Authority;
- Ending BOTAŞ's monopoly position by developing wholesale activities and granting licenses to new wholesale companies;
- Entry of new suppliers and importers into the market through the transfer of some of BOTAŞ's contracts to new private import companies (through gas transfer tenders), thus reducing BOTAŞ's share in import and wholesale trade;
- Liberalization of LNG imports;
- Opening the transmission system to third party access;
- Implementation of the Network Operation Regulations (NOR) that determine the procedures and principles for the relations between shippers and the transmission system operator, and
- Implementation of an Electronic Bulletin Board (EBT) with shippers, where reservation and capacity allocation processes are carried out and instructions are given.

The current market structure is shown in Figure 73.

Figure 73. Natural Gas Market Structure



Note: BEU: Independent electricity producers

Table 13 shows the number of licenses issued by EMRA to market players as of January 2015.

Table 13. Licenses Granted in the Natural Gas Market

License Type		Number of Licenses
Imports*	Pipeline	15
	LNG	2
	Spot LNG	39
Export		9
Transmission	Pipeline	1
	LNG	18
Distribution		69
Wholesale		49
Storage		6
CNG**		118
Total		326

Source: EPDK Monthly DG Report, January 2015.

* The number of import licenses does not indicate the number of importers, as a separate license is required for each import. BOTAŞ has six import licenses and other private import companies have eight licenses for imports via pipelines (seven for contracts and quantity transfers and one for imports from Iraq).

* * CNG licenses are required for CNG (compressed natural gas) transportation, distribution and trade.

3.6.2.2 Transmission and Third Party Access

Although all transmission activities (via pipelines) are carried out by a division of BOTAŞ, legislation does not prohibit private parties from constructing and operating natural gas transmission systems. For pipelines, BOTAŞ is the sole transmission licensee; 18 private companies hold LNG transmission licenses. Licensees are allowed to carry out LNG filling, transportation and delivery activities; however, the transmission license is limited to LNG transportation only in Turkish territorial waters and territory.

Ensuring non-discriminatory third party access (PPA) to the transmission network is an important factor in bringing competition to a gas market. In order to ensure non-discriminatory third party access, the Transmission System Operation Regulation was prepared and published by EMRA within the scope of the DGPK. As a requirement of this regulation, all transmission license holders are obliged to publish the "Network Operation Regulations" (i.e. the Turkish transmission network rules) and the "Transportation Agreement and Connection Agreement".

In this context, the Network Operation Regulations (NOR) were prepared by BOTAŞ, approved by EPDK and published in September 2004. The NOR has been amended as necessary. The main provisions of the NOR are as follows:

- Capacity allocation is made on an annual basis based on an entry-exit system.
- Transmission tariffs are determined according to the revenue cap method.
- Transmission system users*carriers*They are called shippers. Therefore, shippers are wholesale or import companies that contract with end users or exporters.
- Shippers reserve import capacity from the carrier.
- The balancing regime is applied daily based on the pre-published imbalance price.
- BOTAŞ purchases balancing services from shippers based on month-ahead contracts; all transmission services provided from storage are purchased through shippers.
- There are "hard day" provisions under which BOTAŞ can instruct shippers to provide balancing gas from certain storage facilities.

3.6.2.3 Distribution Activity and Development of Gas Distribution

Distribution licensees are subject to the obligation to supply and also to the obligation to provide distribution services to suppliers and free consumers. In addition to supplying gas to non-free consumers, distribution licensees may also provide gas to free consumers in their region. However, except for valid technical reasons, they cannot refuse to provide distribution services to free consumers who obtain gas from other suppliers.

Except for the Istanbul distribution region, which is owned and operated by the municipality,[87]All previously existing distribution regions have been privatized. In addition, distribution licenses were granted for provinces that did not previously have a natural gas distribution system, following a series of tenders held by the Energy Market Regulatory Authority. (In these regions, distribution license holders were first required to build the entire distribution system and then distribute and sell natural gas.) Although competition existed during the distribution license granting process, there was no open access to distribution networks after the license was granted; nor was there any supply competition for non-eligible consumers in the region covered by the license. The free consumer limit was kept the same for the first five years. However, in order to increase retail competition, the Energy Market Regulatory Authority later lowered the free consumer limit, as explained in the Free Consumers section below.

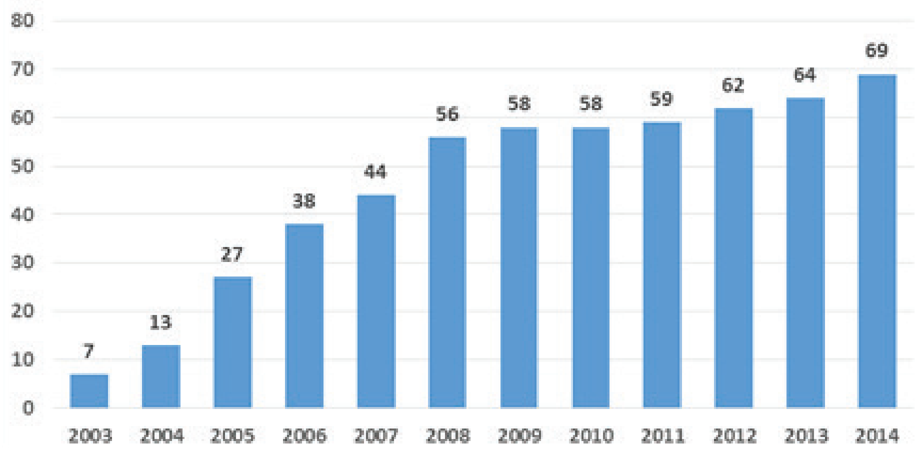
The gas distribution tenders have attracted great interest from local investors and EPDK has been able to successfully complete a large number of tenders and licenses in a short period of time. In order for companies to participate in the tenders, they had to meet certain financial capacity and experience criteria. The main criterion for the selection of the successful bidder was the distribution fee offered by the companies participating in the tender (The distribution fee consists of unit service and amortization fees). The tenders were concluded by selecting the bidder offering the lowest distribution fee. For the successful bidders, the offered distribution fee is valid for a period of 8 years, after which it is determined by EPDK.

There were significant differences in the fees offered for different regions. In some tenders, the winning bidders offered zero distribution fees (i.e., the winning bidders did not charge any distribution fees, assuming that their only income would be the one-time connection fee). These very low bids raised concerns about the success and overall sustainability of the process – and therefore its effectiveness in achieving the long-term gas expansion objectives – and the methodology employed was criticized by many authorities. However, these concerns turned out to be unfounded.

Some companies have reached the end of the eight-year period. In order to determine the distribution fees to be applied thereafter, EMRA determined the Procedures and Principles Regarding Tariff Calculation for Natural Gas Distribution Companies with a Board Decision taken in 2011.

As a result of the distribution tenders held one after another in the 2003-145 period, the number of distribution regions reached 69 (Figure 74).

Figure 74. Development of the Number of Gas Distribution Regions, 2003–14

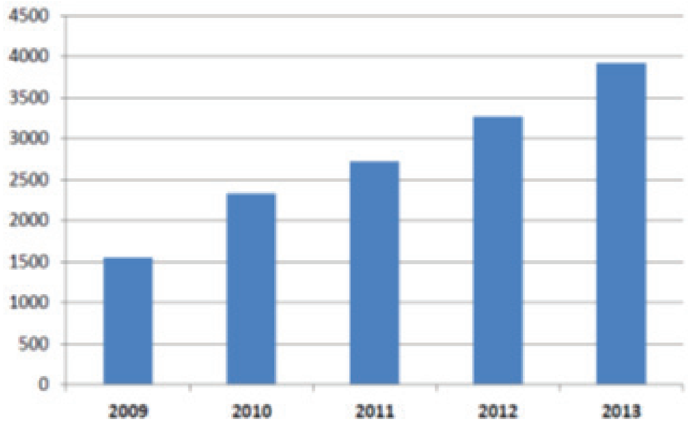


Source: EMRA.

In 2013, the government instructed BOTAŞ to work on supplying gas to provinces outside of its distribution regions. As a result of the expansion of the natural gas transmission network by BOTAŞ and the construction of distribution networks by distribution companies, the number of residential consumers in 69 regions increased to 9.5 million and the number of free consumers increased to 372,000 as of 2013.[88]has been reached.

Distribution companies licensed through distribution tenders are obliged to invest in gas networks in their regions. As of the end of 2013, the total amount of investments made by these companies reached 3.9 billion TL, as seen in Figure 75. During the same period, the total value of investments made by existing distribution companies in regions not licensed through the tender process reached 5.4 billion TL. Investments are audited by independent audit companies authorized by the Energy Market Regulatory Authority.

Figure 75. Annual Distribution Investments by New Distribution Companies, 2009–13



Source: EPDK 2013 DG Market Report (vertical axis: million TL).

According to the DGPK, distribution companies cannot purchase more than 50 percent of the gas they supply from the same supplier and must document that they purchase gas from the most economical source. However, due to BOTAŞ's dominance in the market, these provisions could not be implemented.

3.6.2.4 Parsing

The DGPK includes unbundling provisions for BOTAŞ and other natural gas companies entering the market. According to the DGPK, accounting unbundling is implemented in BOTAŞ and it is envisaged that legal unbundling will be completed by 2009. The law envisages: (a) import, transmission, storage and distribution activities to be carried out by different legal entities and (b) ownership unbundling between transmission, storage, import and wholesale activities within BOTAŞ as of 2009. However, this goal was not achieved and BOTAŞ maintained its legal status. However, accounting unbundling in activities opened the way for third party access to BOTAŞ’s transmission network and LNG terminal.

Distribution and retail activities are not separated for incumbent operators. DGPK requires distribution companies to separate their accounts for retail and distribution activities.

3.6.2.5 Free Consumers

According to the DGPK, the following consumers are considered free and have the right to choose their suppliers:

- Consumers with annual consumption over 1 million cubic meters
- Electricity generation companies
- Cogeneration plants
- Domestic natural gas producers

The DGPK also authorizes EPDK to reduce the free consumer limit until all consumers are free. EPDK also has the authority to determine the free consumer limit for consumers in new distribution regions. Currently, the free consumer limit in these regions is 15 million cubic meters for the first five years of operation. (This period has already expired for some regions.) A special limit of 800,000 cubic meters has been set for the recently privatized Başkentgaz distribution company operating in the Ankara region, which will be applied until August 2017.

Except for consumers in newly tendered regions, the free consumer limit has been gradually reduced. In 2013, all consumers except consumers in the residential category were accepted as free consumers. For consumers in the residential category, the free consumer limit was reduced to 300,000 cubic meters. With this reduction, the share of free consumer consumption in distribution regions reached 19 percent. However, only 11 percent of these consumers used this right.[89] As of 2013, the number of free consumers is approximately 372,000. In December 2014, the free consumer limit was reduced to 75,000 cubic meters per year, and the free consumers in the distribution regions reached 435,786.[90]On the other hand, the standard contracts prepared by EMRA in 2013 for natural gas transportation and delivery services in distribution regions provide transparency for transitions between suppliers.

In 2012, the consumption of free consumers served by distribution companies was approximately 3.8 bcm, while the consumption of free consumers served by other suppliers was 18 bcm.[91]Consumption of all free consumers cannot be measured on a daily basis.

Naturally, the increase in the number of free consumers will depend on the number of suppliers and the level of competition in the market. The gradual reduction of the free consumer limit is an indication of EMRA's determination to increase retail competition.

3.6.2.6 Contract Transfers

According to the DGPC[92]The process of transferring BOTAŞ's purchase contracts to private companies began in 2004. However, due to commercial and legal issues regarding the transfer of contracts, the first tender was cancelled. Following the amendment to the Natural Gas Market Law in 2005, the approval of the seller party was required as a precondition for participation in the tender. In 2005, a second tender was launched for 64 lots (250 mcm per lot) for purchase contracts with Algeria, Iran, Nigeria and Russia. However, no party other than Russia consented. As a result, 16 lots (4 bcm) were transferred within the scope of the Natural Gas Sales and Purchase Agreement signed between BOTAŞ and Gazprom Export LLC dated 18 February 1998.

Another tender was opened in 2011 for the transfer of a section of 6 bcm/year within the scope of the Natural Gas Sales and Purchase Agreement between Gazprom Export LLC and BOTAŞ dated 15 December 1997, but the tender was cancelled due to lack of suitable offers. BOTAŞ's West Line Contract dated 14 February 1986 and amounting to 6 bcm/year was terminated by BOTAŞ and as of 2013, 4 private companies started to import 6 bcm/year of natural gas through the West Line. As a result of the 4 bcm gas contract transfer program and the 6 bcm import license announcement procedure, seven companies gained the right to import 10 bcm of gas from Russia as seen in Table 14 (9.729 million standard cubic meters, 9.155 kcal/cubic meter).

Table 14. Contract Transfers

Licensee	Contract amount (million cubic meters – 9000 kcal)	Contract amount (million cubic meters – 9155 kcal)
Bati Hatti Inc.	1,000	983
Kibar Energy Inc.	1,000	983
Bosphorus Gas Corporation Inc.	2,500	2,458
Akfel Energy Industry and Trade Inc.	2,250	2,212
Enerco	2,500	2,458
Shell	250	246
Eurasia Gas	500	492

Source: EMRA.

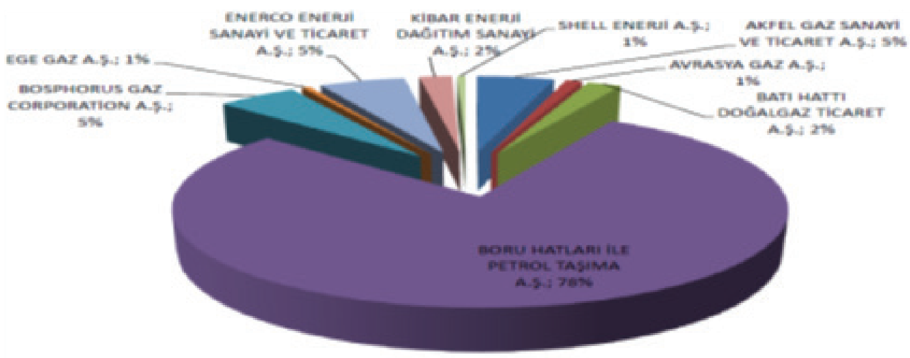
It is worth noting that Gazprom, the main supplier, has a stake in some of these companies. For example, Gazprombank has a 40 percent stake in Akfel and a 60 percent stake in Avrasya, and Gazprom Germany has a 75 percent stake in Bosphorus Gas.[93]

Consequently, the target set out in the DGPK (reducing BOTAŞ's share to 20 percent by 2009) has not been achieved. Indeed, there has been criticism since its introduction that this target was unnecessarily ambitious. Even in more developed markets, the proportion of supply controlled by the largest supplier can be higher; for example, 50 percent in Germany and the United Kingdom, 75 percent in Italy and Spain, and 90 percent in France as of 2004.[94]

After the first unsuccessful tender for contract transfer in 2005, the changes made in the DGPK made it possible to make a “volume transfer” in cases where contract transfer failed. However, no attempt has been made to transfer volumes so far. Perhaps the low profit margin is not attractive to new companies and the lack of change in contract terms is also not attractive to BOTAŞ (because the take or pay obligation remains with BOTAŞ).

Figure 76 shows the importers' shares in total natural gas imports as of 2013. After the last contract transfer, BOTAŞ's share decreased to 78 percent.

Figure 76. Importers’ Shares, 2013



Source: EP

3.6.2.7 Development of the Wholesale Market

The liberalization of the wholesale market was only possible after the first contract transfer in 2007 and the liberalization of spot LNG imports in 2008. Although the Network Operation Regulations (SIA) Regulation was published in 2004, BOTAŞ was the only player in the market until 2007. The SIA amendment made in 2008 made it possible to trade natural gas and transfer ownership in a virtual environment. Shippers (wholesale and import companies) can access the transmission network by signing Standard Transportation Contracts (STS) with BOTAŞ. The number of shippers, which was two in 2007, increased to 27 in 2013.

Shippers can access the network in accordance with the ŞİD Regulation (which also defines the procedures and principles regarding third party access to the transmission network) and the provisions of the STS. Shippers are deemed to have accepted the provisions of the ŞİD when they sign the STS. The “Capacity Registration Documents” documenting the capacities allocated by the shippers constitute an annex of the STS. The duration of an STS can vary between one month and one year.

The capacities to be allocated are determined separately for each physical entry and exit point within technical constraints and capacity reservation applications are submitted within this framework. An Entry/Exit System is applied for capacity reservation. The duration of each reservation is minimum one month and maximum one year and the capacity is expressed in standard cubic meters per day.

The balancing period is determined on a daily basis. The “balancing gas price” is determined on a monthly basis by taking the weighted average of the offers received before the month and the gas withdrawals realized during the month.

is being held.[95] The carrier is responsible for ensuring the physical balance of the network, and no separate balancing service subject to a tariff is defined under the concept of "Additional Service".

The current BOTAŞ Electronic Bulletin Board (EBT) is used to manage the network and publish data that forms the basis of a large part of the trading activity. Shippers are given instructions via EBT, which can be accessed via the internet. All capacity demands and supply and consumption estimates are submitted by shippers, all via EBT, and network constraints, balancing instructions, balancing prices and capacities are announced by BOTAŞ. Instructions are completed within a certain period of time one day in advance, and requests for changes to the program are not accepted except for force majeure reasons.

However, according to private sector market participants, there are some deficiencies in market operation regulations and EBT that pose risks to shippers. Some of the issues they noted were security of user and system data, lack of intraday data, poor reporting, poor SCADA communication, lack of user friendliness and significant backdating.

It was announced by EMRA that the revised version of the Electronic Bulletin Table for transmission activities entered into force in January 2015 in order to ensure greater transparency in grid operations. In addition, another important step was taken by EMRA by initiating the virtual implementation of the new market-based balancing regime for transmission, paving the way for possible changes to be made to the Grid Regulation. In this context, EMRA issued the virtual implementation legislation and in 2015, the web module for the virtual implementation for transmission activities was included in the revised Electronic Bulletin Table for transmission. The implementation of the new market-based balancing regime for transmission is expected to start in 2015.

Ownership transfers between Shippers are carried out through virtual points called "Transfer Entry/Exit Points" defined at each entry point. On the other hand, a virtual "National Balancing Point" defined for the entire network is used for day-ahead gas exchanges and minimizing day-after imbalances between Shippers.

The NOP allocation provisions allow the relevant shippers to agree on the quantities among themselves at all multiple entry and exit points, as long as the total metered quantity remains the same.

As of 2014, 42 wholesale license holders and importers have participated in the wholesale market. Private wholesale companies can purchase gas from BOTAŞ, private importers or domestic producers (TP and private sector). They can sell gas to distribution companies, free consumers and compressed natural gas (CNG) supply companies. Import companies also have the right to sell directly to distribution companies and free consumers. However, in this case, the distribution companies must not be a legal entity of the importer. Production companies can sell their products directly provided that they obtain a wholesale license from the Energy Market Regulatory Authority.

3.6.2.8 Gas Pricing Overview: Historical Trends and Current Prices

BOTAŞ's long-term pipeline and LNG import contracts are priced based on formulas tied to international oil prices. The spot LNG price in Türkiye is linked to the international spot market.

The above factors, together with the quantities purchased under each contract, determine BOTAŞ's gas purchasing cost and constitute the weighted average gas cost (AOGM). The cost of private import companies depends on the contracts between these companies and suppliers.

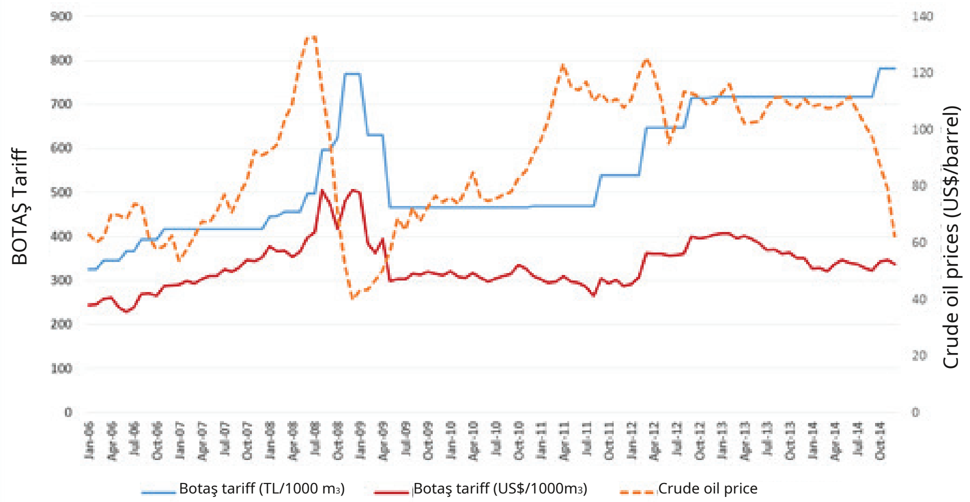
Wholesale Prices and Subsidies

Gas prices in Türkiye are effectively controlled by BOTAŞ, as it is still the dominant importer. Given the slow pace of the contract transfer program, it is unlikely that BOTAŞ's role will change in the short to medium term.

Since AOGM is the main determinant of BOTAŞ's costs, BOTAŞ must cover these costs from its sales and reflect changes in these costs in sales prices within a reasonable period of time.

The government approved the cost-based or "Automatic" Pricing Mechanism (OFM) for state-owned enterprises in March 2008.[97] BOTAŞ was also included in the OFM mechanism to determine the sales prices to be applied to distribution companies and free consumers. The mechanism requires BOTAŞ to update its tariff by taking into account variables such as import prices and the exchange rate between the Turkish Lira and the US$. The BOTAŞ tariff for free consumers (in TL and US$) and changes in crude oil prices during the 2006-14 period are shown in Figure 77.

Figure 77. BOTAŞ's Gas Prices and Crude Oil Prices for Free Consumers,



Sources: BOTAŞ, EPDK.

The following observations can be made:

- BOTAŞ tariff is adjusted according to changes in oil prices as an international principle (with a delay depending on the contract terms).
- Although crude oil prices increased after mid-2010, no tariff adjustments were made between May 2009 and October 2011. During this period, the tariff was set at US$300-350/1000m^{3}was in the range.
- The prices applied by BOTAŞ to consumers have been adjusted three times since October 2011, and since then the cumulative increase in wholesale prices applied to residential and industrial consumers has exceeded 48 percent. In the period October 2012 – October 2014, BO-TAŞ kept wholesale prices constant. Since mid-2013, due to the depreciation of the Turkish Lira, the tariff based on US$ has been increased again to 350 $/1000 m^{3}fell to.
- Except for a short period after OFM came into effect, the tariff for large eligible consumers was US$400/1000m^{3}It remained under .

Competition Authority and Court of Accounts in BOTAŞ reports[98] As mentioned, the tariffs applied by BOTAŞ to free consumers and distribution companies have been set below the AOGM since mid-2009, and in order to compensate for this loss, the sales prices to EÜAŞ, Yİ and YİD power plants have been set higher than the sales prices applied to independent electricity producers (this is effectively a cross-subsidy). The Court of Accounts also stated that this pricing policy was changed in 2013.[99] This pricing policy is a reflection of the government's policy of applying lower gas prices to industrial and residential consumers, including free electricity producers, from time to time. The decline in gas import prices following the decline in international oil prices provides an opportunity to gradually eliminate this price difference.

Due to its dominant position in the market, BOTAŞ's sales prices are seen as a benchmark by private wholesale companies. Therefore, BOTAŞ's pricing policy-

The import prices of private import companies and the costs of wholesale companies are not lower than the prices BOTAŞ charges to its consumers in the market, they cannot compete with BOTAŞ's prices. After the discount that Gazprom gave to private import companies (some of which are Gazprom shareholders) in 2013 so that private suppliers could sell their gas in the market, Gazprom offered these companies gas at 350 US$/1000 $m^3$was selling for as low a price as[100]. They received an additional temporary discount in 2014 and the price for the first half of 2015 was 300 US$/1000 m^3This price was almost close to BOTAŞ's free consumer tariff.

It has been officially announced that price negotiations between BOTAŞ and Gazprom are ongoing. In addition to a possible reduction in the import price, the impact of the decline in oil prices will also be reflected in BOTAŞ's import price. After BOTAŞ's import cost decreases, it is expected that the difference between the prices reflecting the costs and the real prices will decrease and its subsidy will be gradually removed. This will help further liberalize imports and develop the wholesale market.

3.6.3 Analysis of the 2001–14 Period

After the publication of the DGPK in 2001, the implementation of the law was expected to create a competitive, financially sound and transparent natural gas market; ensure supply security; manage potential medium-term oversupply concerns; and minimize the state's future contingent liabilities by shifting risks to the private sector. The law envisaged a policy with very ambitious goals for the establishment of a competitive gas market. However, all of these have not yet been realized and a new bill is being prepared.

Although the DGPK was prepared in the same period as the EML, progress in the natural gas market has lagged far behind that in the electricity market. This slow progress can be attributed to various reasons. For example;

- The strategic role of natural gas in economic development;
- Supply security concerns arising from very high import dependency;
- International energy relations and its role in energy policy;
- Türkiye's role as a transit country and its ideal of being an energy hub for numerous producers and consumers;
- Unlike the electricity sector, there is no domestic experience in liberalizing the gas sector and no free markets in the gas supplying countries; and
- EU gas markets have also made only limited progress in liberalisation until recently.

Therefore, policy developments towards the establishment of a free and competitive market have been dependent on geopolitical conditions and international energy market conditions. The reasons stated above are: (a) whether to continue sector reform as a candidate country for EU membership (which requires full adoption of the EU acquis,[101]) or (b) to become a major energy hub and corridor to Europe through a vertically integrated national company, assuming that liberalization would prevent Türkiye from becoming a major regional energy player and would jeopardize its security of supply. Consequently, unlike the situation in the electricity market, a clear strategy and roadmap for further liberalization have not been determined for the natural gas market, including the role of BOTAŞ in this structure.

The NGML aims to liberalize the market and reduce the state's share. However, BOTAŞ is still the dominant player in the market, no pricing reflecting costs is applied, and BOTAŞ is not functionally separated. Although some of the targets set in the NGML were not achieved in the 13-year period as discussed in the previous section, significant progress has been made towards a liberalized gas market as summarized in Table 15.

Table 15. Progress Towards a Liberalized Gas Market

Regulatory Framework	
A new market entry system: Licensing	
Regulated UTE Regime	
Gas Expansion Program - Distribution Tenders	
Market Opening	
Gas transfer program - Reduction of BOTAŞ's share	
Separation of activities	
Effectively functioning wholesale trade mechanism	
Abolition of monopolies	
Cost-Reflecting Pricing	

Insufficient progress in some areas, such as the Gas Transfer Programme and the reduction of BOTAŞ's market share to 20%, is due to the very ambitious targets set in the NGML. However, it is also clear that a fully functioning wholesale market and full competition do not yet exist.

3.6.4 Future Prospects and Challenges

3.6.4.1 DGPK Amendment

Since some provisions regarding import restrictions, unbundling, contract transfer and market share could not be implemented within the period specified in the Law, amendments to the DGPK have been on the agenda for some time - since 2008 - but there was no consensus, especially regarding the role of BOTAŞ and its share in the market.

However, ETKB eventually prepared a draft law that included a revision of the DGPK and submitted it to the Turkish Grand National Assembly in August 2014. Important provisions in the new draft law include:

- BOTAŞ will be restructured into three separate companies. BOTAŞ will remain an import and trading company, but two new companies will be established – one to own and operate the transmission system, the other for storage and LNG activities. The ownership separation will be completed within one year of the law coming into force.

- This restriction will be lifted for import companies (other than BOTAŞ) that are not allowed to import gas from countries that already have contracts with BOTAŞ.
- BOTAŞ will not be able to sign new pipeline gas contracts until its market share (import share) drops to 20 percent, but it will be able to extend the term of its existing contracts. Although BOTAŞ is allowed to import LNG, it will only be able to sign new pipeline gas import contracts in case of a threat to supply security or for export purposes with a decision of the Council of Ministers. On the other hand, although the purpose of this provision is to reduce BOTAŞ's market share, unlike the current law, there is no time limit for this reduction. Instead, the amended law prevents BOTAŞ from signing new gas sales contracts after 2015.
- Wholesale gas trading instruments will be developed and EPİAŞ, established in accordance with the new EML, will also be a gas shopping platform.
- As a new provision, the draft amendment includes a separate provision on security of supply. The Ministry is responsible for taking the necessary measures for security of natural gas supply.

There are also new provisions regarding distribution companies, storage, transportation, etc. No specific time has been set for the adoption of the draft amendment, but it is expected to be adopted within 2015. The draft law will be finalized during the discussion process in the Turkish Grand National Assembly.

3.6.4.2 Improvement of Balancing and Settlement Mechanisms and Gas Trading Platform

Unlike the electricity market, the balancing and settlement mechanisms in the natural gas market have not yet been fully developed. In order to increase the effectiveness of market-based balancing and settlement, a balancing market needs to be established. Real-time balancing will be carried out by BOTAŞ (transmission company) as the system operator. However, difficulties in collecting consumption data hinder the management of system balancing. Improvements need to be made in the measurement and remote information systems (SCADA) and the existing Electronic Bulletin Board (EBT). A day-ahead trading platform and more advanced markets should be established together with EPİAŞ. The establishment of an effective trading platform will also support the concept of an “energy center”. Such a center can determine the correct price based on market dynamics determined by supply and demand.

As mentioned earlier, the structure and development of the natural gas market in Türkiye also has a significant impact on the realization of Türkiye's ideal of becoming an energy hub. However, in order to achieve this goal, a well-functioning natural gas market and functioning platforms must be established. Naturally, in order to establish such a market, the physical infrastructure must be adequately developed, the regulatory framework must be in place, and market and trade frameworks must be improved. Current efforts to develop the EBT and the amendment of the Natural Gas Market Law are important steps towards this goal.

In order to establish a well-functioning gas market and an energy center, some studies are being carried out by ETKB and the sector. In this context, the Turkish Gas Market Center Project (Leonardo Da Vinci Program) is ongoing. The partners of this project include PETFORM (Turkish Petroleum Platform Association), EFET (European Energy Traders Federation), ICIS (Independent Chemical Information Services) and the Ministry of Energy and Natural Resources of the Republic of Turkey. Another project financed under the EU's IPA program for Türkiye, aimed at establishing an effective gas trading platform and improving the balancing-settlement system, is being carried out by ETKB in coordination with the World Bank.

3.6.4.3 Cost-Based Pricing and Subsidies

The high cost of gas and the indirect effects of these prices, which stem from Türkiye’s heavy dependence on imported gas for electricity generation, directly affect the competitiveness of Turkish industry and the living standards of its citizens. Therefore, the need for state price controls and the resulting cross-subsidies may be considered necessary (although it can be argued as a valid excuse).

It can be argued that greater liberalization and competition (which require cost-reflective pricing and minimal government intervention) could reduce the cost of gas for consumers. However, since the price of imported gas is largely determined by suppliers through existing contracts and is indexed to oil prices, competition in the domestic market will have only a partial impact on the price of gas as long as gas demand is met primarily through existing contracts.

The discounts that Gazprom has applied to private importers may be seen as a sign that price reductions can be achieved through contract negotiations. However, real price reductions will only be possible over time through greater diversification of sources. In the past, liberalization of gas imports posed a threat due to the risk of medium-term contract surpluses and take-or-pay. However, as will be discussed in the following sections, existing contracts are insufficient to meet increasing demand and new sources must be found. This will also facilitate the achievement of the goal of becoming an energy hub.

If BOTAŞ tariffs are determined under the AOGM, import liberalization will not provide the full potential benefits, as new importers other than source countries' own companies, such as Gazprom's local subsidiaries, will not want to enter the market.

It should be noted here that Turkish consumers are among the consumers who consume gas at the cheapest prices compared to most European countries. However, even when subsidized, the consumer price (including the distribution tariff) is still high for low-income households. Therefore, a transparent subsidy mechanism should be implemented targeting low-income groups instead of subsidizing all consumers.

3.6.4.4 Infrastructure

In order to meet the increasing amounts of gas in the system, the natural gas transmission network needs to be expanded to increase its transportation capacity and new storage facilities and LNG terminals need to be built. In order to ensure supply security, importers, wholesale companies and last resort suppliers must have access to sufficient storage capacity to meet their storage obligations.

3.6.4.5 Supply/Demand Balance and

Challenges *Long-Term Supply-Demand Balance:*

As mentioned earlier, current supply agreements and domestic production are currently sufficiently balancing domestic consumption. However, new sources will be needed to cope with increasing demand. Türkiye's policy is to further diversify its sources while increasing imports from existing suppliers. In this context, developments and opportunities can be summarized as follows:

- *Additional supply from Azerbaijan:*According to an Intergovernmental Agreement between Turkey and Azerbaijan, an additional 6 bcm of gas will be imported annually from Azerbaijan by BOTAŞ (from Shah Deniz Phase II). (This increase is related to the Trans-Anatolian Pipeline Project (TANAP) which envisages gas transfer to Europe via Türkiye.)
- *Additional Gas Supplies from the Russian Federation:*Türkiye is negotiating with Russia to increase Blue Stream capacity, and an additional 3 bcm of gas per year is expected in this context. An additional 6 bcm of gas supply via the newly announced Turkish Stream (which will replace South Stream) is also on the agenda.
- *Extension of the LNG Agreement with Algeria:*The term of the LNG Sales and Purchase Agreement between BOTAŞ and Sonatrach for LNG imports from Algeria has been extended.
- *Supply Expectations from Iraq:*It can be assumed that 2 bcm of gas could be imported from Iraq annually during 2016-18, which could gradually reach a maximum value of 10 bcm by 2030.
- *Eastern Mediterranean*–Possible supply from Israel and Cyprus.
- *Additional LNG imports and new LNG terminals*. New licenses and realization of new underground storage projects.

It is possible to say that the supply-demand balance can be maintained in the long term, provided that supply expectations are met and expiring contracts are extended. However, depending on the increase in demand, a supply deficit may arise in the 2015-17 period. This deficit can be partially closed by increasing spot LNG imports.

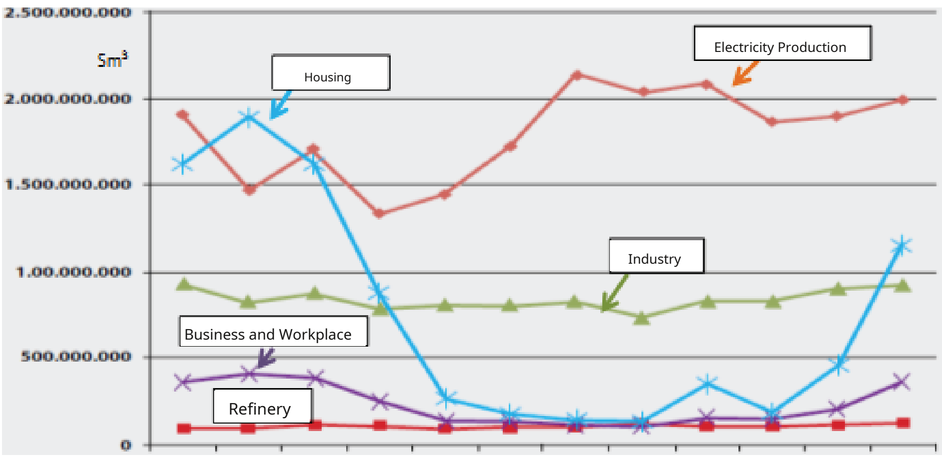
Seasonal Supply Deficits

The lack of adequate storage facilities leads to seasonal problems, especially during the cold season when residential consumption increases. – This problem arises from insufficient daily supply capacity.

The maximum daily supply is the sum of (a) daily contract quantities under pipeline import contracts, (b) maximum daily withdrawals from LNG terminals and underground storage facilities, and (c) domestic daily production. Currently, these figures are approximately 140, 36, 17, and 0.5 million cubic meters, respectively, and 193.5 million cubic meters in total. However, this amount is dependent on LNG and gas levels at LNG terminals and underground storage facilities.

On the other hand, daily demand varies according to seasonal consumption. As seen in Figure 78, monthly residential demand varies considerably and this seasonality in residential consumption will increase as the number of domestic consumers increases. Thus, on very cold days, peak demand exceeds 200 million cubic meters and daily supply cannot meet this peak demand.

Figure 78. Seasonal Consumption Trends of Different Consumer Groups (2013)



Source: EMRA.

Problems experienced during peak demand periods also arise from failures in the transmission infrastructure and the inadequacy of the compressor stations' capacities, especially in transporting gas from Iran and Azerbaijan to the high consumption regions in the west of Türkiye.

Current storage capacity raises concerns regarding supply security and market stability.

With the increase in capacity of TP's underground storage facility and the completion of the first phase of BOTAŞ's Salt Lake Storage Facility, seasonal supply shortages will ease from 2017 and will further ease after the construction of new LNG facilities and the completion of the second phase of the Salt Lake Storage Facility in 2020.

Interestingly, one of the main concerns from the enactment of the NGML until recently was the medium-term supply surplus due to contract oversupply, and supply security was not an immediate concern. However, with the successful implementation of the gas utilization program and the increase in the share of natural gas in electricity generation, the main problem has now become to meet the increasing demand and ensure supply security.

3.7 Price and Subsidy Reform in the Petroleum Market

Before the reforms, Türkiye's oil sector was dominated by state-owned vertically integrated enterprises. Before 1990, the state-owned distribution company Petrol Ofisi and the state-owned refinery company TÜPRAŞ were subsidiaries of the national oil company TP. At that time, the sector was governed by public decrees, and prices of petroleum products were largely determined by the government through these decrees.

The oil sector reform was initiated in the 1980s as part of a comprehensive economy-wide reform process aimed at transitioning to a market economy. Prior to these reforms, the state had a dominant position in economic activities, both in terms of (a) ownership of enterprises in critical sectors such as energy and petrochemicals, and (b) allocation of financial resources, particularly through state banks.

The reform of the petroleum sector had various objectives, including improving the state's financial situation and increasing sectoral efficiency. Under the law enacted in 1989, import, refining, distribution and retail companies were theoretically allowed to set the prices of crude oil and petroleum products. The privatization process of state-owned refining and distribution companies was initiated in 1990 and successfully completed in 2005. However, this did not lead to the liberalization of prices in the 1990s. This is because, although the free price regime was legally accepted, the state maintained control over the state-owned enterprises that were dominant in the petroleum products market and determined the prices of petroleum products in practice.

In June 2013, Turkey was established to provide a competitive, transparent, reliable and stable environment for oil and gas exploration and production activities, and to regulate the rights and responsibilities of oil-related rights holders and third parties according to measurable criteria. **Petroleum Law**accepted. The law has brought certain incentives to the sector. One of these is that all kinds of equipment imported for exploration activities, such as seismic materials, drilling equipment, vehicles, ships and aircraft, are exempt from taxes, tariffs and duties. It has also been stipulated that right holders can transfer the materials they import for petroleum activities to other right holders and their contractors.

In 1998 the government**Automatic Pricing Mechanism**(OFM) and this mechanism was implemented between July 1998 and the end of 2004. With OFM, price ceilings were determined for almost all petroleum products in Türkiye based on international oil prices and exchange rates. Essentially, refining companies and import companies could freely determine prices within the ceiling prices. However, there were still license requirements for imports and capacity requirements for storage, and these requirements created major barriers to entry into the market. In practice, distribution companies and retailers were not allowed to freely determine their prices; prices were determined by the state. Before OFM, TÜPRAŞ, which usually suffered losses because the government kept the prices of petroleum products low, benefited greatly from OFM and became a stable business.

In early 2005, the government decided not to lift price caps, which led to an increase in pre-tax prices. Since then, fuel prices have been determined by the market. Diesel and gasoline prices in Türkiye are currently among the highest in OECD countries, due to relatively high consumption taxes reflected in retail prices.

Petroleum Market Law It was enacted in 2003 to institutionalize the market economy and ensure harmonization with EU legislation. The law took the authority to regulate the petroleum market from the Ministry of Energy and Natural Resources (ETKB) and gave it to the Energy Market Regulatory Authority (EPDK), an independent institution established in 2001 as the regulator of electricity and natural gas markets. Within the scope of the Petroleum Market Law, the control exerted by the state over the petroleum market through means such as license requirements and import limits has been significantly reduced.

Within the scope of the law, the privatization of state economic enterprises was accelerated and completed in 2005.

3.7.1.1 Tax

Like many other emerging economies facing challenges related to high domestic debt and budget deficits, Turkey has been struggling to generate revenue to cover fiscal deficits.**Fuel taxes**Thus, while fuel taxes could theoretically be implemented for many alternative purposes, including environmental purposes (e.g. to internalize external costs such as noise, road safety, air pollution, and traffic congestion), the main reason fuel taxes are relatively high in Türkiye has generally been purely financial. That is, revenues are needed for fiscal consolidation, and fuel taxes are much harder to evade compared to Türkiye's general income tax system.

Value Added Tax (VAT) was introduced in Türkiye in 1985. It is similar to the VAT system in the European Union and requires payments to the tax authorities at every point in the sales chain. In order to simplify the indirect tax system and harmonize it with the EU system, it was introduced on 1 August 2002.**special consumption tax (SCT)**was put into effect and different indirect taxes and funds were abolished (including petroleum consumption tax, fuel price stabilization fund, motor vehicle purchase tax, environmental fund, additional vehicle purchase additional tax, additional VAT, etc.). SCT was structured as a single tax applied equally to both domestic and imported products such as alcoholic beverages, cigarettes, motor vehicles and petroleum products. When SCT came into effect, the high VAT rates were reduced to a maximum of 18 percent. Currently, 18 percent VAT is applied to all energy products in Türkiye. In addition, SCT is applied to motor vehicle fuels. SCT is a fixed amount per liter or kilogram for each type of fuel and is subject to inflation adjustment by the government from time to time. The Council of Ministers is authorized to increase the taxes applied to motor vehicle fuels by up to 50 percent or to eliminate them.

In Türkiye**energy related taxes**mainly collected from the transport sector. Although not explicitly for an environmental purpose, diesel and gasoline tax rates are differentiated according to the fuel composition (octane rating for gasoline and sulphur content for diesel). As in many countries, the tax rate per litre for gasoline is higher than for diesel, and biodiesel has more tax advantages than diesel. The current level of excise duty on gasoline is the highest in OECD countries. LPG and natural gas are taxed lower. As a result, LPG consumption has increased significantly since the early 2000s. Domestic aviation activities are currently exempt from energy taxes. A tax rate is set for fuel used in maritime transport, but there are some exemptions.

In addition to fuel tax, there are highly differentiated rates for vehicles.**motor vehicle tax and special consumption tax**Energy taxes are not differentiated between user sectors, mainly in the heating and process use sectors. In these areas, LPG and natural gas consumption taxes are set at a lower level compared to road use. Other gases and coal are exempt from tax. LPG consumption tax rate is lower than gasoline and diesel.

A plan for using natural gas in electricity generation**special consumption tax**While the use of coal, diesel and fuel oil for the same purpose is not taxed.[102]. Although the majority of energy-related tax revenues come from vehicle fuels, the transport sector’s share of energy use – around 15 percent – is lower than in most OECD countries. Diesel, which is taxed at a lower rate than gasoline, accounts for more than 50 percent of the sector’s total energy consumption. Gasoline, which is taxed the highest in OECD countries, has a share of just 16 percent, followed by LPG and natural gas, which are taxed more fairly.

Since fuels used in aviation are exempt from tax and the shipping sector is subject to lower tax rates, the aviation, marine and railway sectors are taxed at much lower levels on average. In the heating and process category, natural gas accounts for approximately 30 percent of energy use and is taxed. Coal use has a similar share in energy content but is not taxed. On the other hand, the emissions map shows that coal accounts for more than 40 percent of CO2 emissions in the category and more than 20 percent of total CO2 emissions from energy. Lignite, one of Türkiye's most important energy sources, is still widely used by households for heating purposes. Diesel and other petroleum products are taxed at a higher rate and account for approximately 20 percent of energy use for heating and process purposes. Renewable energy sources and waste account for approximately 14 percent of both energy use and emissions from heating and process use.

While natural gas, which accounts for approximately 46 percent of the energy sources used in electricity production and approximately 36 percent of the carbon emissions resulting from this use, is taxed, coal, which accounts for approximately 38 percent of electricity production and 55 percent of emissions, is not taxed.

Although pre-tax fuel prices and the VAT applied to them constitute two important components of the relatively high fuel prices in Türkiye, governments are not directly held responsible for them, and concerns about increases in pre-tax prices are often associated with developments in international oil markets that are beyond the government's control. The politically problematic part of end-user fuel prices is the special consumption tax (SCT) and the perceived asymmetry in the adjustment of gasoline prices in Türkiye to changes in crude oil prices. As a recent study using structural vector auto-regression has shown, when crude oil prices rise, this is reflected in increased tariffs, while when crude oil prices fall, tariffs do not change. However, recent developments in exchange rates (i.e. the appreciation of the US dollar against the Turkish lira) do not allow the full reflection of the decline in crude oil prices on domestic market prices.

Even Türkiye’s finance ministers have publicly acknowledged on several occasions that fuel end-user prices in Türkiye are high, primarily due to high taxes, but have also emphasized that taxes are critical to meeting the revenue needs of the central government budget. Therefore, the government is not expected to reduce any fuel taxes in the short term – and probably not in the long term either.

The large difference between pre-tax and post-tax fuel prices is the main motivation for smuggling. Currently, oil smuggling is a chronic problem on Türkiye's borders with Iraq and Iran.

3.7.1.2 Poverty Reduction Measures

Erdoğlu’s (2014) analysis shows that the income elasticities for all three types of fuel used in transportation (gasoline, diesel, LPG) are positive, meaning that people tend to consume more fuel as their income increases. Long-term elasticities are always higher than short-term elasticities, meaning that consumers are more sensitive to price and income changes in the long run. The price elasticity of gasoline is negative in both the short and long run. However, interestingly, the price elasticities for diesel and LPG are positive in both the short and long run. This emphasizes that the demand for diesel and LPG increases even if prices increase. This is explained by the fact that gasoline-powered vehicle owners can easily convert their vehicles to LPG systems, thus translating an increase in gasoline prices into a decrease in gasoline consumption. The finding of a positive diesel price elasticity for gasoline demand supports this interpretation; that is, as the price of diesel increases, the demand for gasoline also increases.

The overall demand for fuels used in the transportation sector in Türkiye is not at all flexible and sensitive to increases in pre-tax prices or taxes. Therefore, fuel prices in Türkiye

The market is open to opportunistic behavior by corporations (through excessive profits) or the state (through excessive taxes). While it is possible to prevent opportunistic behavior by corporations through effective regulation, it is much more difficult to prevent opportunistic behavior by the state and can only be limited by pressure from civil society organizations on the government.

A number of targeted measures have been taken to mitigate the negative impacts of the reforms, including:

- *Tax exemption for LPG consumption.*Between 1999 and 2001, the government supported households' use of LPG for cooking purposes by abolishing both the value-added tax and the special consumption tax. These tax exemptions caused the price of LPG to fall below that of both gasoline and diesel. Since normal engines could not use LPG, the government expected that LPG would be used in vehicles to be limited. However, an informal sector quickly emerged to convert gasoline-powered engines to LPG. With a payback period of less than two years, this process was deemed simple and cheap enough for vehicle users to convert their vehicles to LPG. This provision led to significant increases in LPG consumption. Realizing the resulting tax loss, the government began to gradually remove this tax exemption at the end of 2000.
- *Tax exemption for public transport.*According to the new Corporate Tax Law enacted in 2006, public transportation companies owned and operated by municipalities, village legal entities or special provincial administrations are exempt from both value added tax and consumption taxes.
- *Tax refund for diesel used in agriculture.*A tax refund program was launched by the Ministry of Agriculture in 2007 to help farmers grow certain crops. The program identifies three different types of crops, each subject to a different aid rate. Aid amounts are calculated based on the size of the land used to grow the specified crops and are paid according to a schedule determined by the Council of Ministers. There are no restrictions on how the grant money can be spent. This measure will be phased out.

Appendix 1: Application of BOT, BI and HRA Models in the Period 1984-2014

Results and Problems Obtained in the Implementation of the BOT Model

In December 1984, Law No. 3096 was enacted to ensure private sector participation in the electricity sector. This law introduced models such as build-operate-state (BOT), transfer of operating rights (TOR) and autoproducer for private sector production investments, ending the monopoly position of TEK in the field of production. Due to insufficient progress made before 1994, Law No. 3996 (BOT Law covering other sectors as well as the energy sector) was enacted in 1994. The projects to be carried out within the scope of Law No. 3096 were also provided with the opportunity to provide state guarantees and to make contracts subject to private law provisions.

As a result of the implementation of the BOT model, 24 power plants with a total installed capacity of 2,450 MW were built (18 HEPPs, 2 wind power plants and 4 natural gas CCGTs) in a 17-year period (1984-2001).[103] Considering the needs, the continuous efforts of the government and the ambitious expectations, this result cannot be considered a success. Several reasons have been effective in the inadequacy of this application.

Uncertain and Ever-Changing Legal Framework

Initially, the BOT model was a new concept and there was serious opposition to the model. Law No. 3096 created a legal framework but did not provide the necessary conditions to attract foreign investors. Initially, there were no state guarantees for payments by state enterprises and no possibility of international arbitration to resolve disputes. The government's attempts to apply the BOT model to contracts subject to private law provisions before 1990 were annulled by the Council of State, the country's highest administrative court.

In order to reopen the way for contracts subject to private law provisions and to provide state guarantees for payments to be made by public institutions, Law No. 3996 was adopted in 1994, covering other sectors as well as the energy sector. It was accepted that the projects to be carried out within the scope of Law No. 3096 would also be eligible for state guarantees and contracts subject to private law provisions.

Law No. 3996 allowed for contracts to be made subject to private law provisions and for disputes to be subject to international arbitration without the review or approval of the Council of State. However, in 1995, the Constitutional Court ruled that according to the Constitution of the Republic of Turkey, private sector participation in public services could only be possible within the scope of concession law and that private law provisions could not be used. Although the government desired to ensure private sector participation in the electricity sector, the Constitution of the Republic of Turkey defined electricity service as a public service to be provided only by state economic enterprises. Therefore, the private sector could only be authorized to participate in the sector through concession agreements to be made with the state, under which the ownership of the investments would remain with the state at the end of the concession period.

As a result, except for some BOT production projects that came into effect before the Constitutional Court's annulment, projects initiated after the enactment of Law No. 3096 had to be carried out through concession agreements. The possibility of concluding contracts subject to private law provisions through international arbitration became possible only with the constitutional amendment made in 1999. In addition, a new law (Law No. 4501) was enacted that allowed previously signed concession agreements to be converted into contracts subject to private law provisions.[104]The main reason for this change was to attract private sector investors, especially foreign investors, to the electricity sector, since factors such as contracts subject to administrative law, the intervention of administrative authorities and the absence of international arbitration were perceived as risky by private sector investors.

In summary, the BOT model: (a) administrative contracts, the Council of State[105]There were continuous discussions on whether it would be implemented within the framework of (a) a privilege requiring the supervision and approval of the Council of State and the resolution of disputes through the Council of State; or (b) within the scope of contracts subject to private law provisions that do not require the approval of the Council of State and allow international arbitration for the resolution of disputes. These issues

Some decrees and laws were issued regarding the issue, but most of them were annulled by the Council of State or the Constitutional Court. This debate did not stop until 1999 and caused a loss of time and motivation.

In 1999, the Constitution of the Republic of Turkey was amended, making electricity investments subject to private law provisions, thus paving the way for international arbitration. With this amendment, the role of the Council of State in disputes was limited and the approval process for investments was accelerated. In order to ensure the implementation of the above-mentioned constitutional amendments, a new law on infrastructure projects was enacted in 2000 (Law No. 4501).

Problems in practice have shown that no model can be successful without a clear and transparent legal and administrative framework, supported by a consensus on the main legal framework and principles.

Application Problems

While the domestic and foreign private sector showed no interest in investments until 1993-94, they showed great interest after Law No. 3996 - especially after the signing of contracts for three natural gas power plants at very reasonable prices and without any risk to investors.[106]. The main reasons for investor appetite even after the cancellation were the favorable price, state guarantee and low risk expectation (due to take-or-pay provisions and continuous efforts of the government to implement private law provisions). This situation later led to inflation in project cost and stranded cost on the one hand, and increased the state's contingent liabilities on the other.

As a result, the number of applications made to the Ministry of Energy and Natural Resources (ETKB) has increased significantly. In early 1999, in addition to the 2,400 MW of projects in operation or under construction, there were projects in various stages of operation (pre-feasibility report submitted, in the evaluation phase, awaiting government approval, etc.) and a total of**their capacity is 30,000 MW** exceeding**hundreds of project applications**There were also signed contracts for five power plants (6,100 MW) to be implemented within the scope of the BO model.

The BOT model provides purchase and payment guarantees. All contracts signed (or initialed and awaiting approval) were tariff-front-loaded. That is, tariffs were higher for the first 10 years (usually the first half of the contract period).[107]Therefore, future liabilities had to be taken into account in the model implementation. The amount tied to the annual contract had to be determined according to future demand and supply (taking into account current production, BOT, autoproducer, ongoing public production investments and BO plants). In addition, the model had to be implemented according to an optimum production development plan and the number of plants, their installed power and production, commissioning dates, fuel sources and locations of these plants had to be determined in advance. After this planning, ETKB could announce the roadmap and implementation program. A competitive bidding mechanism could be implemented according to the determined ranking. The basic expectation within the scope of the BOT model was to transfer the risk and at the same time reduce operational costs, increase service quality and ensure the use of new technologies in the design and implementation of projects. In order to achieve these goals, a more effective implementation could be achieved if competitive bidding and qualification were implemented and a clear and transparent framework was found.

However, most of these principles could not be followed. Except for some unsuccessful hydroelectric power plant and wind power plant tenders, pre-qualification requirement and competitive tendering could not be implemented. The method applied was to receive offers from three interested companies and to conduct negotiations based on feasibility studies conducted by investors. The project owners determined the technology, fuel, installed capacity, location and timing of the BOT plants and submitted the feasibility studies to ETKB. The projects developed were based on fixed prices and purchase guarantees, but the risks were still assumed by the state and the efficiency benefits were not passed on to consumers.

During the evaluation of the feasibility reports, ETKB sent all applications to TEAŞ to get technical opinions. TEAŞ, as the system operator and buyer, examined the applications and sent its opinions to ETKB. As the number of projects increased, TEAŞ began to object. There were three main reasons for these objections:

- Lack of planning that may lead to excess or shortage of capacity over time
- The locations of the power plants are selected by the project owners without taking into account the regional supply/demand balance and transmission system conditions; and
- The amount of future payments to be made (due to take-or-pay commitments).

According to the legislation, the State Planning Organization (DPT) approval was required for the signing of BOT contracts. As the number of applications increased, the DPT began to object and not approve the projects. The DPT wanted a planned approach where the project timing was determined according to the future supply/demand balance.

Since payment guarantees were backed by state guarantees, the Treasury was also reluctant due to its increasing contingent liabilities.

Another important reason for the objections of TEAŞ, DPT and the Treasury, especially after 1998, was the newly emerging idea of establishing a competitive market instead of take-or-pay guarantees. (The free market model and the concrete steps taken in this direction also affected the implementation of the HRA. This issue will be discussed in more detail in the following sections.)

Therefore, the government adopted a new implementation program determined jointly by the SPO, ETKB, Treasury and TEAŞ. After long discussions in 1999 and 2000, it was decided that only 29 BOT projects (those that had contracts with ETKB and/or were deemed useful) could continue in addition to those already under construction, and that the rest of the BOT project portfolio should be cancelled. Based on this decision, ETKB cancelled more than 120 projects that were at different stages of implementation and did not have a signed contract in early 2001. However;

- Due to insufficient investment in generation (insufficient realization of BOTs and over-reliance on this model, resulting in insufficient public investment), spare capacity decreased sharply, leading to supply security problems in the 1998-2001 period. If the economic crisis had not occurred in 2001, a partial curtailment program could have been implemented nationwide.
- The 1997-98 supply/demand projections sounded an alarm for the future. They led to the implementation of a solution to increase production capacity by using production technologies that could be implemented quickly through the BO model (i.e. natural gas CCGT), thus creating an over-dependence on natural gas.
- Similarly, after 2000, it led to the use of temporary and costly solutions such as fuel-oil-fired mobile power plants.
- The remaining existing contracts (for plants that had not yet been built) required legislative changes and efforts to transform them into independent electricity producers; after lengthy negotiations, most of these project owners gave up their contractual rights in exchange for preservation of their grid connection and water usage rights and were licensed as independent electricity producers.
- Various legal objections were made for projects that could not be implemented, compensations were demanded, and lengthy local court and local and international arbitration cases were heard.

The take-or-pay guarantees given during this period (for operating BOT plants) required temporary measures to be taken after the competitive market was established.

Results and Problems in the Application of the BI Model

Due to the insufficient realization of BOT power plants until 1997, instead of examining and comparing hundreds of unsolicited project proposals, the government decided to focus on priority projects that it would prefer and to select investors for these projects through competitive bidding in order to obtain more reasonable prices and conditions. Thus, in 1997, with Law No. 4283,**Build-Operate (BO) model**was put into practice.

Under the BOT model, companies are allowed to build and operate power plants and sell the electricity they produce to the public company TEAŞ through long-term power purchase agreements (EPA). However, unlike the BOT model, the power plants are owned by private companies in this model. In addition, the implementation procedure is different: there is no “concession” or “assignment” agreement with ETKB. The only agreement is the power purchase agreement between TEAŞ and the company. Unlike the BOT model, this model envisages a competitive tender procedure for the selection of companies to build the power plants identified in the long-term optimum production development plan. According to the law, tenders would be made by TEAŞ instead of ETKB, and the power purchase agreements would be negotiated and signed by TEAŞ.

Initially, 10 plants were selected and as a first step, five of them were put out to tender (the others were later cancelled). At the end of the tender process, contracts were signed for four natural gas-fired CCGTs and one imported coal-fired plant in 1998 and 1999. The total installed capacity of these plants was 6,100 MW and all of them were put into operation in 2002-04.

Compared to the BOT model, the BO model has been successfully implemented and an installed capacity of 6,000 MW has been added to the production system very quickly. The reasons for this rapid and successful implementation include:

- An international competitive tender was held and more than 30 local and international companies participated in the tender.
- A solid and transparent legal framework was in place, the electricity purchase contract was subject to private law provisions, and international arbitration could be used to resolve disputes.
- Ownership of the power plants would remain in the private sector (they would not be transferred to the state as in the BOT model).
- Due to competition and conditions, prices were at reasonable levels: capacity and O&M tariffs were less than half of the capacity and O&M tariffs of BOTs, which ensured widespread acceptance among public authorities.
- The plants and their locations were determined by TEAŞ in line with the optimum production expansion plan.
- The duration of the electricity purchase obligation was shorter than in the BOT model (total electricity purchase contract duration is 20 years including the construction period).

However, the implementation of the BO model also produced some negative results. In order to avoid legal problems, the Law did not allow the use of domestic resources such as lignite and hydro (the use of natural resources would require concession agreements); therefore, only natural gas and imported coal could be used. Even if this were not the case, additional capacity was urgently needed for the following years and only natural gas power plants could be built in such a short period of time. Therefore, the 4,800 MW BO model natural gas power plants that were put into operation in addition to the existing plants led to excessive dependence on imported natural gas in electricity production. In addition, due to take-or-pay obligations, as in the case of BOT plants, the electricity purchased from BO plants restricted competition in the electricity market.

Results and Issues in Implementing the HRA Model for Production Privatization

The HRA model was used for the privatization of publicly owned power plants in the period 1984-2001. A hydroelectric power plant was transferred in 1996 and a thermal power plant was tendered in 1994. The tender for 16 thermal power plants was initiated in 1997. The total installed capacity of these power plants was 9,576 MW. After the evaluation, contract negotiations were made for eight power plants and concession agreements were signed for six power plants in 1999. With the constitutional and legal amendments allowing the conversion of concession agreements into private law provisions and contracts subject to international arbitration, new implementation agreements were signed with four companies while the other two preferred to continue with concession agreements. However, the Treasury was reluctant to provide treasury guarantees due to the conditional obligations arising from the BO, BOT and HRA contracts. The production HRA process could only be concluded in 2002.

As a result of lawsuits filed by NGOs and unions, the Council of State annulled the decision of the Council of Ministers authorizing ETKB to negotiate contracts in 2001 and 2002, and all contracts except one were annulled. Some of these contracts were subject to private law provisions (they entered into force after 1999), and the Turkish Government was obliged to pay compensation for some projects at the end of the international arbitration process.

Therefore, the result of the HRA application was not satisfactory at all. Finally, a hydroelectric power plant (30 MW, transferred in 1996) and a lignite power plant (Çayırhan, 620 MW, concession agreement, transferred in 2000 and 2001)[108]None of the other agreements could be implemented.

Although the main reason for this unsuccessful implementation was the Council of State decisions, other reasons were also effective:

- Due to the prolonged tendering and negotiation process, changes in the legal framework (discussed in the previous section) and the conversion of already signed concession agreements into contracts subject to private law provisions, a lot of time and effort was spent.
  As in the BOT application, public institutions (Treasury, DPT and TEAŞ) lost their motivation due to the desire to create a new electricity market after 1998-99. Studies conducted show that the guaranteed sales of existing BOT, BOT and transferred IHD power plants[109]It has shown that it will initially constitute a very large part of the electricity produced in Türkiye, thus practically leaving no room for competition in the market.
- Moreover, the fact that these opportunities were subsequently granted to companies selected based on tender documents that did not contain provisions on private law or international arbitration further increased the already existing objections to privatization.
- Corruption allegations related to the BOT and HRA process have created significant confusion (a number of bureaucrats were indicted in 2001 and were the subject of lengthy legal proceedings) and political problems. All these factors have affected the decision-making process and judicial decisions.

All these factors contributed to the failure of the attempts at production privatization through the HRA method under Laws No. 3096 and 3996. Experience shows that it is a mistake to start privatization without a solid legal framework and without considering the future consequences for the market structure.

Results and Problems in the Application of the Distribution HRA Model

In 1995, 29 distribution regions were determined. Four of these were operated by privileged companies at the time (Aktas and Kayseri regions were already operated by the private sector; Çukurova and Kepez regions were also included in the concession agreements of ÇEAŞ and KEPEZ companies). It was decided to transfer the operating rights of the remaining 25 regions through the HRA method defined under Law No. 3096. Tenders were held in 1996 and the winning bidders were determined for 20 regions (bids for five regions were not found suitable). Three of the 20 winning bidders could not fulfill the requirements in their bids. Council of Ministers decisions were issued to assign companies for the remaining 17 regions and ETKB was authorized to conduct contract negotiations. Negotiations regarding the concession agreements for some of the regions were completed and since they were administrative contracts, they were submitted to the Council of State for approval. Following the Council of State approval, concession agreements were signed in the 1997-99 period. Meanwhile, some organizations (NGOs and unions) appealed to the Council of State and objected to the decisions of the Council of Ministers regarding the authorization, requesting the cancellation of the authorization.

While the lawsuits filed against the concession agreements continue. With the constitutional amendment made in 1999, it became possible to sign implementation agreements (subject to private law provisions) instead of concession agreements. Following this change, new legislation was prepared and some of the companies preferred to apply to renew their concession agreements and sign implementation agreements. ETKB. started negotiations by obtaining authorization from the Council of Ministers. In addition to the five concession agreements, six implementation agreements were signed. However, new lawsuits were filed against these agreements.

The lawsuits filed against the Council of Ministers' decisions and contracts took a long time. At the end of the three-year lawsuit process, the Council of State annulled the Council of Ministers' authorization decisions except for two regions, and the contracts could not be implemented. The main reasons given by the Council of State for the annulment of the contracts were (a) the public interest was not taken into consideration in the tender conditions and (b) the investment program for the regions was not requested from the bidders. The corruption allegations against ETKB and the deficiencies in the tender process were also among the reasons for the annulment.

As a result, except for two regions, the privatization process was not successful. After the Electricity Market Law was enacted in 2001, the contracts related to the two regions that were not cancelled were renegotiated and made compatible with the new legislation, and the regions were transferred.

The implementation agreements specified international arbitration as the forum for dispute resolution. Four companies applied to the International Chamber of Commerce (ICC) for arbitration, seeking compensation. One of the cases was rejected, while Türkiye paid approximately US$150 million to the other three companies.

Annex 2: Development of Hydroelectric and Wind Capacity in Türkiye

Hydroelectric

Türkiye's annual hydroelectric generation potential is reported as 140,000 GWh (taking into account the historical average utilization factor, this potential can be used with an installed power capacity of 40,000 MW).[110]

The total installed capacity of hydroelectric power plants in 2001 was 11,673 MW, including 870 MW under BOT projects and 1,120 MW built by concession companies (such as ÇEAŞ and Kepez).

Although the Electricity Market Law allowed private sector companies to build hydroelectric power plants, there was no regulation defining the rights and obligations of the parties regarding water use or the procedures for licensing hydroelectric power plants. One of the important steps in the development of renewable energy in Türkiye was the 2003**""Regulation on the Procedures and Principles Regarding the Signing of Water Usage Right Agreements for the Purpose of Carrying Out Production Activities in the Electricity Market"**has been published.[111]

This regulation not only defined the procedures but also allowed private companies to invest in projects developed by DSI and EIEI. Since 1935, EIEI and DSI since 1953 had been conducting studies in river basins to determine hydroelectric capacity and preparing feasibility studies and plans for candidate hydroelectric power plant projects in various river basins. However, DSI was only interested in the construction of large dams and the private sector could only construct and operate hydroelectric power plants under the BOT model before 2001. Therefore, this regulation was an important step for the construction of hydroelectric projects (especially small-scale ones) by the private sector.

One of the reasons for the publication of such a regulation is the 200 million US$ grant provided for the development of renewable energy in Türkiye.**World Bank loan**(The aim was to determine a methodology for the use of the First Renewable Energy Credit. In order for this credit to be used for small hydroelectric power plants, it was necessary to determine suitable potential projects and therefore to define a procedure for selecting the projects. For this reason, the World Bank credit was an important factor in initiating the work on this regulation. The credit was successfully used through intermediary banks (Development Bank of Turkey - TKB- and Industrial Development Bank of Turkey - TSKB-), and 1 wind power plant, 4 geothermal power plants and 16 small hydroelectric power plants, which were put into operation in the period 2004-09 and had a total installed capacity of 585 MW, were financed.

In 2003**""Regulation on the Procedures and Principles Regarding the Signing of Water Usage Right Agreements for the Purpose of Carrying Out Production Activities in the Electricity Market"**After its publication, the DSI and EIEI project portfolio was announced. The total number of projects was 183 and over time – with the inclusion of some unfinished DSI projects and projects that could be realized under previous intergovernmental agreements – this number reached approximately 400. As a second step, permission was also granted for the construction of projects not included in the DSI-EIEI list but developed by the private sector. In 2004, the number of these projects was 678 and over time it reached 1,215. However, due to the problems explained later in this appendix, DSI did not accept new project applications from the private sector as of October 2007. As of November 2013, DSI had approved 1,618 projects with a total installed capacity of 25,000 MW.

As of January 2015, the total installed capacity of 521 HEPPs in operation is 23,643 MW. 444 of these plants (7,036 MW) are river type and the rest are reservoir type. The capacity of private sector HEPPs is 10,646 MW. Although all HEPPs are considered renewable energy facilities, it should be noted that only river type HEPPs and reservoir type HEPPs with a reservoir area of less than fifteen square kilometers can benefit from support mechanisms for renewable energy sources.

Approximately 80 percent of the new hydroelectric power plant capacity commissioned in the last 10 years has been realized by private sector companies. The vast majority of new power plant investments started after the Renewable Energy Law. According to the project progress reports of EPDK, in addition to the existing power plant capacity, 356 licensed private sector hydroelectric power plants with a total capacity of 10,000 MW are under construction.[112] If these are realised, almost 85 percent of Türkiye's total hydroelectric capacity will be in use.

There has been great progress in hydroelectric power plant investments (around 8,000 MW capacity has been built by the private sector in 10 years). Despite the fact that the fixed feed-in tariff level is considered inadequate (and the private sector has unsuccessfully attempted to increase it), the private sector has built or is trying to build around 20,000 MW of hydroelectric power plants, including those under construction. Although large reservoir-type hydroelectric power plants do not benefit from the support mechanism, they are also being built by the private sector.

In addition to the reasons explained in the previous section, there are other reasons specific to the hydropower sector for investor appetite for hydropower plants.

- The most important cost item of HEPPs consists of construction work. There are many experienced construction companies in Türkiye and most of the HEPPs are owned and constructed by these companies.
- Medium and large-scale reservoir-type power plants have the ability to store water during low-price periods and to produce and sell electricity during peak consumption periods when marginal prices in the market are determined by natural gas power plants. Since the operating costs of hydroelectric power plants are very low, they can make a good profit on top of their marginal costs.

However, this rapid implementation process also led to some problems, which are discussed below.

- Network Connection

As already mentioned, since the market was opened to private investment, approximately 1,500 projects have been developed. The installed capacity of the new projects varies from a few MW to several hundred MW and they are spread all over the country.

This situation has created a bottleneck in terms of grid connection. Previous TEİAŞ grid development plans were prepared for known and generally large reservoir type HEPP projects. TEİAŞ was not ready for the connection of hundreds of new power plants (the same problem applies to wind power plants). Ideally, distribution and transmission plans should have been prepared considering the total HEPP projects in each river basin and basin transformer centers designed to connect several power plants in the same basin should have been foreseen.

The lack of such a planned approach at the beginning caused delays in project implementation. However, over time, new transformer substations and transmission and distribution lines were included in the investment program and constructed. Since TEİAŞ had limited technical and financial resources, the amendment to the Electricity Market Law paved the way for private companies to construct connection lines and transformer substations on behalf of TEİAŞ. If the connection point is approved by TEİAŞ and the new transmission facilities (transformer substation, line) are not included in TEİAŞ's investment plan, or if the proposed timing of the new investment is not suitable for the investor, TEİAŞ may request market participants to finance and construct the connection lines and related equipment on behalf of TEİAŞ or to provide resources for this. After the completion of the construction work and the commissioning of the plant, the investment cost will be repaid to the licensee of the plant within 10 years. This provision accelerated the connection investments.

However, there are still problems with the construction of river basin transformer substations. Since not all projects in the same river basin are constructed within the same time frame, the transformer substation needs to be constructed by the first company. For small (a few MW) hydroelectric power plants, The cost of the transformer center constitutes a burden for the project owner. Although it is reimbursed by TEİAŞ later, financing of transmission facilities poses a problem for small projects if they are realized before the participation of other projects in the same basin.

The new licensing regime introduced by the New Electricity Market Law, which foresees granting new licenses based on TEİAŞ's current capacity, could be a solution to this problem. However, as mentioned earlier, most of the projects are already licensed and some projects will continue to have the same problem.

- Project Owner Selection Process

According to the regulation, a tender process is organized if more than one company applies to a project developed by DSI or EIEI. In addition, projects developed by companies are announced on DSI's website and if there are other applications for the same project site, they are also included in the tender. In each tender, participants offer a contribution fee (TL/kWh) to be paid to DSI after the HEPP is put into operation. The company that offers the highest contribution fee wins the right to build the power plant. Although applicants are required to submit a feasibility report to DSI, these reports are not detailed and DSI only rejects reports that contain very significant errors or indicate violations of basin water use rules. After the successful bidder is selected, DSI requests a more detailed feasibility report and the companies are held responsible for the accuracy of the studies and data regarding the project site and its hydrology. As of 2014, the number of projects subject to tender was 698 (for the others, a tender was not deemed necessary because only one application was made).

This selection method created the following problems:

- Since there is no detailed technical and economic evaluation of the projects, the success of the project depends solely on the project owner. During the "rush to hydroelectric power plant projects" period (2004–10), hundreds of new projects were developed by incompetent companies or individuals without sufficient studies on the project site and hydrology; these projects later experienced problems in the construction and operation stages. Some projects actually produced less electricity than planned and were found to be unfeasible because the construction cost estimates were unrealistic. In addition, DSI amended the regulation, requiring companies to release at least 10 percent of the average water inflow over the last ten years into the river basin for the protection of wildlife. Although this was a useful and necessary provision, many projects were announced after they had already entered the construction phase.
- In some tenders, applicants submitted very high bids for contribution fees (2 - 3 US¢/kWh) to increase their chances of winning. Considering that the support tariff is at 7.3 cents, high contribution fees for inefficient projects have significantly reduced the internal rate of return and these projects are likely to be unsustainable. As of the end of 2013, only 36 of the 698 projects subject to tender have been implemented.
- A separate EIA study is conducted for each project. However, for projects located in the same – or even neighboring – river basins, these studies should have been prepared and evaluated collectively in order to assess the total risks they pose in terms of environmental sustainability. Considering that an increasing number of hydroelectric power plants are being built, cumulative environmental impacts pose an increasing risk. Integrated Basin Management is needed to inform long-term investment and river basin management plans; this should also take into account the formulation of appropriate regulations to reduce the potential cumulative impacts of hydroelectric power plants. This factor was one of the reasons why the courts annulled the EIA reports. Later, a National Basin Strategy was approved by the High Planning Council, but it should have been implemented from the very beginning.
- Especially in the first years of implementation, some project owners did not act carefully and caused damage to the environment during the construction of canals, tunnels and roads.

During the construction and operation phases of HEPPs, appropriate measures were not taken and these caused negative environmental impacts. This situation caused public reactions and many attempts were made to stop these projects. Lawsuits were filed in court against the EIA reports and some EIA reports were cancelled. These effects include damage to natural habitats as a result of clearing vegetation for HEPPs and related structures. This situation also creates a risk of erosion from slopes to the river bed and disruption of ecological flow continuity in bypass areas (the area between the water intake structure and the tail water). In some river basins, the number of projects is so high that the power plants are lined up one after the other and almost no space is left for natural life. This factor is also among the reasons for the public reaction and EIA cancellations.

- One of the reasons for public opposition to projects is the lack of sufficient public consultation prior to the licensing and decision-making processes of projects. Depending on the size of the project and its environmental category, certain consultation activities may be required during the EIA preparation phase; however, generally, meaningful and open consultations with the surrounding community are not conducted before, during and after the construction of the project. As a result, the only authority that people can apply to for redress of their grievances is the courts.
- Public opposition to projects stems not only from cumulative environmental impact issues but also from expropriation issues. Standard expropriation laws and practices in Türkiye require landowners to be notified in advance in writing, specifying when state lands will be expropriated. As an exception to this standard legal framework, the “Urgent Expropriation” procedure can be applied when a project needs to be completed quickly in cases of urgent national need. In such cases, prior written notification to landowners is not required, and expropriation fees are deposited into the landowner’s accounts, while expropriation and construction work can be initiated on the date the landowner is notified. Due to national priority, the Urgent Expropriation exception is applied to almost all renewable energy investments. This method is not a very satisfactory method for managing public reactions and social risks, and the exception has been the subject of litigation in courts, in addition to disputes regarding the expropriation itself.
- From project development to commissioning, many approvals, permits and licenses are required by ministries, EMRA, transmission/distribution companies, municipalities and other local authorities. Project owners complain about the poor coordination among public institutions, the long procedures and the low standards of implementation.

Due to the technical, environmental and social reasons mentioned above, the licenses of 415 projects that were licensed before the new Electricity Market Law were cancelled upon the request of the project owners (328 of them were projects developed by the private sector).[113] The remaining projects continue to have technical, financial, social, legal and/or environmental problems. According to the EPDK's Progress Reports, only 65 of the 396 licensed projects have a progress rate above 20 percent. With the new Electricity Market Law, these projects are given a preliminary license. If they can solve their problems within the given period, they will be entitled to receive a license. Most likely, some of these projects will not be able to receive a license and will be canceled.[114] EPDK started to evaluate all projects in June 2014 and some projects have already been cancelled. The evaluation process is ongoing.

It is possible to say that most of these problems stem from the lack of a sound implementation roadmap, project approvals given by DSI without sufficient evaluation, and carelessly prepared and approved EIA reports. Bad examples have created a general public reaction against all hydroelectric projects, and this has also damaged efforts to develop good projects.

- Other Challenges

Construction Control

Since any incident that may occur during the construction and operation phases may lead to major disasters, the construction quality of structures such as water channels, tunnels and especially dams is of vital importance. Therefore, such construction works should be meticulously inspected by both project owners and public institutions. Although the inspection of projects constructed by private companies is the duty of DSI, DSI has limited capacity to monitor hundreds of projects simultaneously. As a result of various initiatives, the DSI Law was amended in 2014, allowing DSI to transfer its control and inspection duties to third parties that it will authorize. Therefore, although DSI tried to inspect the projects, these inspections were not of the desired quality for the facilities constructed in the 2004-14 period due to its limited capacity.

Underutilization of River Basin Potential

In order to ensure optimum use of water resources (for irrigation, electricity generation, etc.), all basins should be considered together with their branches and river basin development plans should be prepared. With such a plan, it would be possible to determine the optimum capacity of each possible project, the timing and sequence of implementation, etc. Hydroelectric power plant construction permits should also be issued after such a plan was prepared. This could help determine environmental impacts and could be a logical step for basin-based EIAs. Unfortunately, except for some basins whose studies were carried out by DSI and EIEI, most of the projects were considered individually and were permitted without considering a general river basin plan. In addition to inadequate assessment of environmental impacts, this approach prevented the full assessment of hydroelectric potential.

Difficulties Related to the Operation of Hydroelectric Power Plants in the Same Basin

The lack of optimum basin planning may also lead to operational problems and disputes between project owners. There are river type/canal type power plants and reservoir type power plants with a certain reservoir capacity in the same basin. River type power plants should be operated according to the operational status of reservoir type power plants. Sometimes there may not be enough water; for example, if the owner of the reservoir type power plant at the source decides to hold the water and use it during peak periods in order to increase his income, the river type power plant will only be able to receive minimum flow and will operate at low capacity. On the other hand, if the power plant at the source operates at full capacity, a certain amount of water may have to be left in the river type power plant without generating electricity. This situation is already causing disputes among project owners and will continue to cause this and will also cause the total capacity not to be used in the most appropriate way.

The solution to this problem is for DSI to carry out basin operation planning. However, since the power plants have already been built or are under construction, some projects will be negatively affected and will not be able to obtain the revenues predicted in the feasibility studies. According to the “Water Use Agreement” signed between DSI and the project companies, DSI has the authority to reorganize the operation plans when deemed necessary. This situation may pose a risk for investors. However, since they have accepted this possibility by signing the agreement, they do not have the right to object to the DSI decision.

In conclusion, the process of developing hydropower potential in Türkiye by the private sector has not been a smooth process. Current and future problems and challenges may lead to insufficient use of the total usable potential or at least delay the use of the full potential. Nevertheless, the result achieved is quite significant and can be considered a great success.

Wind

Türkiye has a significant wind potential waiting to be used. REPA[115]The study revealed that the potential in high-efficiency fields is approximately 19,000 MW, and the technically applicable installed power potential in regions with wind speeds between 7.5 and 8 m/s is 29,259 MW. In other words, Turkey has a medium-high efficiency wind energy production potential of 48,000 MW in regions with annual average wind speeds of 7.5 m/s or higher. High-potential areas are located in the Aegean and Marmara regions of Türkiye and in the coastal areas of the Eastern Mediterranean region.

Türkiye's first wind power plant (WPP) was put into operation in 1998 and has an installed capacity of 8.7 MW. As of 2001, the total WPP capacity was only 18.9 MW, all of which were constructed under the BOT model. The WPP projects licensed by the Energy Market Regulatory Authority (EPDK) between September 3, 2002 (the date the market opened) and June 4, 2004 (the date when WPP license applications were suspended) were essentially old BOT projects that had been developed in advance. Some of these project owners, as explained above, became license holders by giving up their existing contracts. However, after the establishment of the legal framework with the EML, the high level of potential that had not yet been used attracted the attention of local and foreign investors. In addition to the "old" BOT projects, some license applications were made to the EPDK for new WPP projects. There were no previously determined WPP project areas by public institutions, and there was no published information on the transmission system connection capacity on a regional or transformer center basis. Therefore, companies were evaluating the project sites according to their own evaluations and connection points. However, these applications could not be finalized in terms of connection and system usage.

On the other hand, TEİAŞ criticized the acceptance of all RES license applications and requested a limitation on the applications. The main reason for this criticism was the limited connection capacity and the problems that could arise due to intermittent wind conditions and their possible effects on the system operation. In addition, the regulation was inadequate in terms of making a choice between different applications made for the same project site at that time. Accordingly, the Energy Market Regulatory Authority announced on June 4, 2004 that it suspended all RES license applications - in other words, it stopped the examination, evaluation and licensing processes for six months - until TEİAŞ determined the annual maximum RES capacity to be connected to the grid.

However, TEİAŞ later failed to publish the projections for the RES connections. This situation forced EMRA to continuously extend the suspension decision, and this suspension lasted for more than three years. These developments led to increased public pressure on EMRA, and although the necessary study was not published by TEİAŞ, EMRA decided to reopen the application period on November 1, 2007.

On November 1, 2007, an extraordinary day occurred: EPDK received 751 applications, corresponding to approximately 78,000 MW. Multiple applications were submitted for the same regions, and the total capacity of the projects was far beyond the realizable capacity. Most of the applications were submitted for the same or overlapping regions. However, as expected before November 1, EPDK could not finalize the applications without receiving TEİAŞ's opinion on the connection and system usage. Therefore, a long process began again due to the lack of necessary tools for the evaluation and selection of applications.

As a result, the Electricity Market Law was amended in 2008 and a tender process was introduced for the selection of those who will have the right to connect to the system among the applicants in cases where: (a) more than one company applies for the same power plant site or (b) the total requested capacity exceeds the transformer substation capacity. In the meantime, EİE[116]regarding the pre-selection of projects by TEİAŞ[117]Regulations regarding the tender process to be conducted by TEİAŞ were also published. TEİAŞ also announced its official opinion regarding the total capacity to be connected to the grid. Accordingly, EPDK forwarded TEİAŞ's opinion to the parties applying for licenses and requested them to revise their installed capacities downward. The applications of the applicants who did not reduce their installed capacity in their initial request within 10 days were rejected by EPDK without any further notification.

The remaining applications were reviewed and technically evaluated by EİE, and the applied capacity of approximately 78,000 MW was eventually reduced to 31,268 MW. Of this capacity, 1,378 MW consisted of single applications and licenses were issued to their owners; tenders were held by TEİAŞ for the remaining capacity for which multiple applications were made.

The tender process conducted by TEİAŞ on the basis of maximum contribution fee started in 2010 for 13 different application groups and was concluded in July 2011. A total of 149 projects with a total installed capacity of approximately 5,500 MW were selected. The weighted average contribution fee per kWh was 1.91[118]and the highest contribution rates offered were 6.52, 5.60 and 5.25 kuruş (the highest contribution rates were offered for Antakya, Çan-Çanakkale and İzmir transformer centers, respectively). The winning applicants applied to the Energy Market Regulatory Authority and their projects were licensed. As a result, the evaluation and licensing of the applications received during the 2007 application process took more than three years and a significant time was lost in terms of the construction of the WPPs.

The marketing of wind and hydroelectric projects has also been consistently delayed. The main reason for this is the project trading carried out in the Turkish market. Since the License Regulation prohibits the transfer of licenses (which provided a margin of safety, but project owners were not happy with this), project owners started to sell companies that had one or more licenses. In order to prevent this, the Electricity Market Law was amended and a guarantee letter mechanism was introduced; however, this mechanism did not stop the project owners. The most important negative effect of this secondary project market was the wrong signals it gave to the Regulatory Authority, the Transmission Company and the Ministry. In addition, the cost of the projects increased and market confidence was shaken.

As of December 2014, EPDK is not accepting new license applications. New applications will be allowed on a specific date to be announced by EPDK. According to Article 23 of the New Electricity Market Law, TEİAŞ and distribution companies will publish regional generation connection capacities for the following 5 and 10 year periods each year, and no connection opinion will be given. Therefore, RES investors will primarily consider the available capacities announced by system operators. TEİAŞ is conducting studies to determine regional connection capacities for new projects. The aim of these studies is to determine the new capacity to be used each year starting from 2014. Unused capacities allocated through previous tenders will be determined and added to the new capacity list.

In case of multiple applications for the same connection capacity or connection area, a tender will be held by TE-İAŞ to determine the qualified applicant(s) to be connected to the connection point. The bidders offering the highest price (contribution fee) per MW in the tender will have the right to connect to the grid until the available capacity is reached. The amount offered will be paid in the first three years of operation.[119]

As of January 2015, the installed capacity of 99 wind farms in operation is 3,630 MW. RES development has gained momentum after 2006. Although the fixed feed-in tariff level applied to wind farms is lower than in most countries, there has been a significant increase in wind farm capacity in the last six years. It is possible to say that investors are very interested in wind farm investments. However, as in the development of hydroelectric capacity, the process of developing the country's wind potential by the private sector has not progressed smoothly. In addition to similar problems with hydroelectric projects, such as grid connection problems, long bureaucratic processes and carelessly prepared feasibility studies, there are also problems specific to wind investments.

As of January 2015, in addition to the existing RESs, there are 182 licensed projects with a total installed capacity of 6,013 MW.[120]Although most of them were licensed before 2011, only 27 of the plants (837 MW) have a completion rate of over 30 percent.

Although the Strategy Document adopted in 2009 foresees a wind power plant capacity of 20,000 MW by 2023, it will be very difficult to establish approximately 16,500 MW of capacity in the next 9 years and to achieve this target if certain measures are not taken. In the 2010-14 strategic plan of ETKB[121]The stated target of 10,000 MW has not been achieved. However, the target of 20,000 MW can be achieved with a delay of a few years.

Although the tender process ended in 2011, almost 50 percent of the eligible projects have either not been licensed or, even if licensed, many project companies have not yet signed the connection agreements with TEİAŞ. The main reason for this slow progress is seen to be the high and unrealistic bid prices given during the tender process. Considering the fixed feed-in tariff level or market prices, financing these projects, where bid prices are 3-4 cents/kWh, is quite difficult. The high prices offered for the contribution fee are expected to be an indicator of the efficiency of the operator or the project; in other words, bid prices should normally be based on the feasibility studies of the bidder. Since more efficient projects will have higher revenues, the owners of these projects may offer high prices. In previous tenders, bid prices for some projects have reached levels as high as 4-5 cents/kWh. Not only the support price of 7.3 cents, but even the market prices of 9-10 cents are not enough to make these projects feasible. (If bidders act consciously – and some did not do the necessary research before the tenders – the bid price will show the real value of the project. Unfortunately, past experience has shown that this is not always the case).

The new EML brings a new challenge for project owners with the concept of pre-license. License owners are not allowed to sell their companies during the pre-license period. It is envisaged that this new concept will stop the project trade or at least ensure that projects that have fulfilled their pre-license obligations are transferred to other parties.

According to Articles 5 and 6 of the new EML, the licensing process is divided into two stages. In the first stage, a preliminary license is issued and the investor acquires the necessary permits, approvals and property rights before the construction period. In the second stage, EPDK issues a license valid for the construction and operation period to investors who meet the requirements specified in the preliminary license stage.

According to the new Electricity Market Law, TEİAŞ will announce the available capacity in April each year and EPDK will receive license applications in October.

Considering the low progress rates and the new requirements and time limits introduced by the new EML, it is expected that many more projects will have their licenses cancelled due to failure to meet the requirements on time. Projects with high contribution margins will most likely not be realised and these capacities will be redistributed to the market.

Projects are mostly financed by export credit agencies and international financial institutions such as the World Bank and EBRD (working through domestic banks), as well as contributions from some voluntary carbon trading mechanisms. However, financing remains a significant bottleneck

However, the chaotic process of the past has provided valuable lessons for both the administration and investors. Companies are now much more meticulous in the analysis and selection of projects. In the past, they wanted the removal of metering requirements and forced the EPDK to accept license applications without considering grid integration issues and financing conditions of creditors. But now they want the development to be orderly and gradual. Progress from now on will be slower, but it will ensure that investments that can be made by "real investors" are realized. Regarding the challenges of accelerating wind energy development in Türkiye, project owners[122] Their opinions are as follows:

- Exchange rate risk
- No increase in the fixed price guaranteed tariff
- Contribution to network investments
- Improper project planning
- Wrong turbine selection
- Misleading financial analysis
- Financial and administrative weaknesses of the Transmission Company
- The payback period of network investments made by the license holder is long.
- High contribution fee

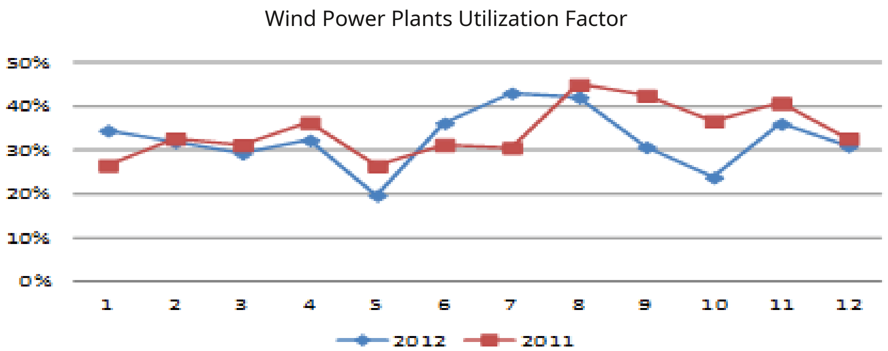
- Lack of application standards in RES commissioning procedures
- Weak coordination among public institutions and long permit processes
- Few local banks can provide loans received from international financial institutions (IFIs)

In addition, the problem of integrating wind power plants into the electricity system remains important. The transmission system operator TEİAŞ needs to improve its ability to integrate the increasing amount of wind and other intermittent renewable resources into Türkiye's electricity system. Currently, the share of RESs in the total installed power is around 5 percent. As this share increases, their negative effects on system operation may become a problem. For this, more transmission investments and control/distribution tools (such as SCADA – central control and data collection) are required to ensure reliable system operation. The establishment of the Wind Power Monitoring and Forecast Center (RITM) by ETKB-YEGM is an important step in this regard. The center uses meteorological information and production data received online from RES sites and publishes RES production estimates and current production data. This data is used by TEİAŞ's National Control Center and other producers. Although not all plants are yet connected to the center, it will allow system operators to estimate hourly wind energy production for the next day and help them overcome discontinuity problems. With the implementation of the TEİAŞ project, which aims to increase the forecasting ability and control capacity of the National Load Dispatch Center against the variability in wind production, this center will enable the system to be operated more effectively.

- Usage Factor of RES in Türkiye

As seen in Figure 79, the average utilization factor of existing wind power plants in Türkiye is approximately 35 percent and varies between 20 and 40 percent. This calculation is based on the monthly installed capacity and monthly production of wind power plants. Naturally, there are efficient fields and plants as well as plants operating at low efficiency.

Figure 79. Wind Power Plant Utilization Factor in 2011 and 2012



Source: TEİAŞ Load Dispatch Reports.

- Environmental Issues

There are also some environmental challenges related to Türkiye's ambitious wind power development plans. Wind project investments are generally concentrated in areas with high wind potential, which are critical for local and migratory birds. The impacts of RES on bird species are twofold: (a) collision risk (birds can directly hit turbines) and (b) habitat loss (wind investments disrupt bird habitats). On the other hand, it is not only the power turbines but also the associated infrastructure that affect the local ecology. The construction of temporary and permanent access roads requires the removal of extensive vegetation and the felling of trees. Mitigation measures should be initiated during the site selection process. The critical issue here is to avoid ecologically sensitive habitats and bird migration routes when determining the location of a RES.

- Lessons learned

There are lessons to be learned from Türkiye's experiences and recommendations based on these experiences can be summarized as follows:

- The private sector and public institutions must be well aware of the challenges and unique conditions of wind energy projects, and a consensus is required between all parties.
- It is quite obvious that it is almost impossible to realize RES without a supporting mechanism; therefore, a sustainable and robust support system should be established at the beginning.
- The support system should be implemented in an environment where the administrative infrastructure is ready. It would be useful to prepare a roadmap for development; and all rules and regulations should be prepared before the license application process is opened.
- In order for RES plants to be constructed in suitable areas, it would be beneficial for the relevant public institution to make measurements and share the results with the market.
- The grid company must carry out the necessary studies to determine the grid capacities required for the connection.
- The characteristics of these sites and their available connection capacities should be announced.
- In case of multiple applications, a tender may be held to select the successful applicant. However, the tender should be held between equal parties. Furthermore, limited connection capacity should not be allocated to an inefficient or unfeasible project simply because it offers the highest contribution. In this context, it would be useful to implement a preliminary selection based on technical and financial competence.
- To integrate wind power plants into the system without causing system reliability problems, the system operator must have forecasting tools and control mechanisms.
- Projects must be developed in accordance with international technical and financial requirements.

How Does the Support Mechanism (YEKDEM) Work?

Electricity producers based on renewable energy sources who do not prefer to sell the electricity they produce in the market can participate in the pool for the first 10 years of operation. Each year, they must apply to EPDK by October 31 to participate in the following year's application. The list of suppliers is published on the EPDK website. The production of these producers is considered as production that is not subject to restrictions and is distributed regardless of their prices. They can provide electricity to the system as long as they produce electricity (to the transmission or distribution network depending on the connection point). There are no contracts or restrictions other than technical limitations. In a sense, they "pour" the electricity they produce into the electricity pool. They are required to inform the system operator one day in advance about their hourly production for the next day; however, this requirement is only for system planning and is indicative. This information is not used to reconcile the daily or hourly imbalances of each RE producer; the total imbalance in the pool is reconciled through another mechanism.

At the end of each month, the amount of electricity produced from each RE supplier is determined. The total cost of RE production is calculated by the market operator as follows:

$$PCOST = \text{total cost of support mechanism (pool cost)} = P_1 * F_1 + P_2 * F_2 + \dots\dots\dots + P_I * F_I$$

Here;

• Pi= electricity produced by supplier i,

• Fi= unit energy price by source (wind, hydro, geothermal..., etc.).

Cost Sharing

According to the Renewable Energy Law and related legislation, the cost of the pool is shared between the legal entities holding supply licenses and generation companies that sell electricity directly to consumers. For each settlement period, the total cost is shared according to the following formula:

$$POA_I = SS_I \times PCOST$$

Here:

• POAi = Payment obligation for supplier (TL)

• SSi = share of supplier i in total supplied electricity (%)

• PCOST = total pool cost (TL)

• SSi is determined as the ratio of the supplier's sales to the total electricity supply to consumers for each settlement period.

As explained above, the support mechanism imposes a payment obligation on suppliers (except for RE producers who do not choose to participate in the pool). In other words, the cost of renewable energy under YEKDEM is shared proportionally by all suppliers.

Notes

1 Liquefied natural gas (LNG) is natural gas that has been converted into a liquid for ease of storage and transportation. It is the

2 simultaneous production of electricity and heat, such as cogeneration.

3 In “take or pay” agreements, the buyer is obligated to either receive the goods or pay a set price.

4 As a result of the quantification of the allegations of irregularities, in April 2001 the State Security Court opened a case against 15 people, including a former energy minister and a former TEAŞ general manager. These people were accused of "taking bribes, being involved in irregularities and establishing an organization to commit crimes." The case is known to the public as Operation White Energy. Although no charges were brought against the incumbent energy minister, he resigned from his post. It should be emphasized that only three people were ultimately convicted.

5 Turkish versions of both the 2004 and 2009 strategy documents can be accessed at www.enerji.gov.tr.

6 With the Transitional Period Agreements, EÜAŞ and TETAŞ undertake to sell a certain amount of electricity to distribution companies at regulated prices.

7 Non-eligible consumers are consumers who do not have the legal right or chance to choose their supplier.

8 The difference between incumbent suppliers and other suppliers is that they also have customers who are not free consumers and they have to serve as the last resort supplier.

9 See Section 2.1.4.1 on the renewable energy security mechanism. It provides that electricity produced from renewable energy sources will be purchased at a price of $55/MWh if renewable energy-based electricity producers cannot obtain a higher price in the market.

10 Compared to the publicly announced support arrangements for the nuclear power project proposed by the Sino-French consortium in the UK – approved by the European Commission in 2014 in a state aid decision that is a benchmark for the European Union – the support arrangements for Türkiye’s Akkuyu plant are much less comprehensive and also much cheaper per unit of electricity for the guaranteed part. The proposed plant in the UK will reportedly be supported by a mechanism that provides a guaranteed price of 92.5 GBP/MWh ($136/MWh at an exchange rate of 1.47) adjusted for inflation for all production in the first 35 years of the 60-year plant life.

11 http://www.oecd.org/corporate/ca/corporategovernanceofstate-ownedenterprises/ oecdguidelinesoncorporategovernanceofstate-ownedenterprises.htm.

12 Source: TÜİK (Turkish Statistical Institute).

13 One of the reservoir type power plants was put into operation in 2004.

14 The power plant has two units. One of the units was already in operation and was transferred in 2000; the other was built and transferred in 2001 after trial operation.

15 Cogeneration is the simultaneous production of electricity and heat, both for use.

16 The reconciliation process (Offset) required that expenses and revenues be determined each year. If the profit was lower than the predetermined level, TEAŞ made up the difference; if the profit exceeded the predetermined level, the company paid the excess amount to TEAŞ.

17 Studies on the separation of transmission and generation had been initiated long ago. TEAŞ's Credit Agreement with the World Bank dated May 15, 1998 envisaged the preparation of a legal framework for the establishment of a national transmission company. This was also one of the issues in the context of the "Economic Stability and Inflation Reduction Measures" program. Therefore, prior to the EML, the Turkish Government issued a decree on restructuring in the amendment dated February 5, 2001.
– 15 days before the EPK.

18 Four of the remaining project owners chose to resort to local and international arbitration. Two of these were unsuccessful, while two received compensation in a certain amount. The remaining contracts were cancelled by mutual agreement.

19 SPO was transformed into the Ministry of Development in 2011.

20 The ratio of the difference between the available production capacity and the peak demand to the peak demand

21 (%). OFM application for natural gas (BOTAŞ) will be discussed in the Natural Gas section.

22 Depending on the connection voltage level, different industrial tariffs are available; the industrial tariff shown in the figure is the medium voltage single-time tariff.

23 A Supply Security Report was prepared and the expert panel that was formed contributed to the work of ETKB in 2006-07.

24 www.enerji.gov.tr.

25 The main ancillary services are primary and secondary frequency control, reactive power control, recovery of the stationary system. Secondary and tertiary frequency control is performed in DGP.

26 As of March 2015, 97 private companies became shareholders and EPİAŞ was officially established.

27 The incumbent supplier is like any other supplier except that it also has customers who are non-eligible consumers and is required to serve as a supplier of last resort.

28 Some examples of unrealistically high bids: Istanbul: $2.990 billion, Izmir: $1.915 billion. In the renewed tender, the prices given for the same regions were $1.06 billion and $1.231 billion, respectively.

29 After 2012, the transition period contracts expired. According to the new EML, distribution companies purchase electricity from TETAŞ to cover their losses, and TETAŞ, as the last resort supplier, provides the energy they need to the incumbent retail companies.

30 One of the private distribution companies was not making payments to TETAŞ. One of the reasons for this was not because of low collection rates, but because the company was transferring the money to other companies within the holding. Despite the warnings of the EPDK, the problem could not be solved and eventually the EPDK intervened, appointed a new board of directors and sold the company to its new owner in February 2015.

31 Source: EMRA

32 In electricity supply, losses (technical) occur naturally and consist mainly of electrical system components such as transmission and distribution lines, transformers and metering systems. Thefts (non-technical loss) consist mainly of electricity theft, non-payment by customers and accounting errors.

33 The transfer fee is included in the income ceiling. In other words, there is no capital return item in the tariffs.

34 Approved investment for the 2011-15 period is approximately TL 9 billion (approximately $3.3 billion as of April 2015).

35 The capacity factor of a power plant is the ratio of its actual production to its potential production.

36 The theoretical market openness ratio is the ratio of the total annual consumption of free consumers to the total annual consumption of all consumers. Effectively, it is an indicator of the level of liberalization.

37 Until the New Electricity Market Law (2013) was enacted, it was possible to combine the consumption of facilities within the same commercial or industrial company in order to become a free consumer – for example, all stores of a commercial company in different locations, or multiple facilities/factories of an industrial company, or GSM companies with thousands of consumption points.

38 Includes production facilities that are in operation, under construction, licensed but not yet started to be constructed.

39 In the same period, due to the decommissioned power plants, the real increase in total installed capacity was 41,100 MW.

40 The three asynchronous connection modes are isolated island, isolated generation, and DC back-to-back.

41 The Coordination Union for the Transmission of Electricity in Europe (UCTE) changed its name to the European Network of Transmission System Operators for Electricity (ENTSO-E) on 1 July 2009.

42 General Assembly of the Regional Group for Continental Europe (RG CE within the Systems Operations Group) and the Regional Group for South East Europe (RG CSE within the Systems Development Committee).

43 For Türkiye, 154 kV.

44 In “island mode,” a power plant unit or entire power plant is isolated from one country’s electrical system and directly connected to another country’s electrical system.

45 ETKB, Energy Balance 2013.

46 Amended in 2007 and 2009.

47 This support is determined separately for each piece of equipment used in each power plant, and the total support that can be provided is shown in the table. Domestic production incentives have been found to be “controversial” in EU progress reports. The EU’s 2011 Turkey Progress Report (http://ec.europa.eu/enlargement/ pdf/key_documents/2011/package/tr_rapport_2011_en.pdf) stated that the compliance of this incentive mechanism with international trade rules has not yet been confirmed. The 2012 Progress Report (“Ability to Assume the Obligations of Membership,” Chapter 4, Section 15: Energy) also referred to domestic production incentives (http://ec.europa.eu/enlargement/pdf/key_documents/2012/package/tr_rapport_2012_en.pdf). According to the report, the compliance of the incentives foreseen in the renewable energy law with respect to WTO or Customs Union trade rules is debatable.

48 This provision is often criticized by environmentalists because, according to a new amendment to the law, olive groves, which are strictly protected by separate legislation, will be opened to use for energy production. People have started to file petitions to protest this.

49 Source: ETKB. This potential was previously announced as 125,000 GWh. However, it has been increased as a result of recent studies conducted by public authorities and the private sector. Due to the increasing cost of electricity production, potential projects that were previously declared unfeasible are now becoming feasible. If all private sector applications are taken into account, the potential increases to 165,000 GWh. However, considering technical, environmental and social factors, it is safer to use the figure of 140,000 GWh.

50 EMRA, 2014 Activity Report.

51 Türkiye Wind Energy Potential Atlas (REPA) was prepared by EIEI in 2007. EPDK,

52 January 2015 Progress Report

53 MTA was established in 1935 to conduct scientific and technological research on mineral exploration and geology.

54 Source: MTA.

55 Although the capacity was announced as 600 MW in the 2009 Strategy Document, the capacity was increased with new exploration.

56 ETKB General Directorate of Renewable Energy (YEGM).

57 World Energy Council Turkish National Committee, Solar Energy Report, 2009.

58 ETKB 2012 Energy Balance Table.

59 This limitation indicates a slow and careful approach. A gradual progress has been preferred after learning from the uncontrolled and chaotic developments in the wind.

60 ETKB 2015–2019 Strategic Plan. TEİAŞ, Installed

61 Power Document, December 2014. EPDK, April

62 2014 Progress Report.

63 LV = effective voltage less than 1,000 volts; HV = effective voltage greater than 1,000 volts.

64 “Regulation on Unlicensed Production Activities” published on July 21, 2011 and amended in 2013.

65 The utilization factor is the ratio of a power plant's actual production in a given time frame to the production it could produce if it operated during all hours of the relevant time frame.

66 VVER – Abbreviation of the Russian term Vodo-Vodyanoi Energetichesky Reaktor: water-water power reactor, or water-cooled and water-moderated reactor. It was first developed in the Soviet Union. VVER power plants are in use in Armenia, Bulgaria, the Czech Republic, Finland, Hungary, India, Iran, Slovakia, Ukraine and the Russian Federation. The proposed plant is the third generation of this type.

67 The shareholders of Akkuyu NPP JSC are Rosenergoatom Concern OJSC (92.85%), Inter RAO UES JSC (3.47%), Atomstroyexport JSC (3.47%), Atomenergoremont OJSC (0.1%) and Atomtekhenergo JSC (0.1%). According to the agreement, the maximum share of the company's capital that foreign investors can own at any given time is 49%.

68 Designed by AREVA (France) and Mitsubishi (Japan), ATMEA-1 is a Generation III+ type pressurized water reactor with a capacity of 1,100 MWe.

69 ETKB Blue Book, 2013.

70 According to the Mediterranean Energy Perspectives: Turkey report published by OME in 2014, between 2014 and 2030, Türkiye's generation capacity is expected to increase from 68 GW to 125 GW under the conservative scenario and to slightly less than 110 GW under the Proactive Scenario.

71 EMRA reports the progress of licensed production projects twice a year.

72 The Price Equalization Mechanism is explained in Section 3.2.2.7. This practice was planned to be terminated in 2015; however, it was extended until 2020 with the new EML.

73 TÜİK (Turkish Statistical Institute), Income and Living Conditions Survey, 2006–2013.

74 World Bank, Balancing act: Cutting Energy Subsidies While Maintaining Affordability. Europe and Central Asia report. Washington, DC: World Bank, 2013.

75 A statistical value of a data set representing 20 percent of a given population. The first quintile represents the lowest quintile of the data (1–20%); the second quintile (21–40%); etc.

76 Calculated from the data in the COURT OF ACCOUNTS BOTAŞ 2013 Report.

77 Source: www.enerji.gov.tr- "Energy and Natural Resources Outlook- April 2015 (No 8) Report 2009

78 Strategy Document.

79 Although the DGPK allows licensing of multiple transmission networks within Türkiye, BO-TAŞ is currently the only company with a pipeline transmission license.

80 Gasification is the process of converting liquefied natural gas (LNG) back into natural gas at atmospheric temperature.

81 Normally, the gasification capacity is 17 mcm and can be increased to 22.5 mcm at peak times; however, according to BOTAŞ, this is not a sustainable withdrawal rate.

82 State-owned Turkish Petroleum Company.

83 In addition, a very small part of Adapazarı was able to use gas since 1993; Adapazarı urban distribution network was completed in 2003.

84 The economic crisis of 2000-01 and the stand-by agreements with the IMF also accelerated the process.

85 "Transit" is not among the defined market activities. The regulatory framework for gas transit is established within the scope of Law No. 4586 on the Transit of Petroleum by Pipelines.

86 DGPK Temporary Article 2.

87 The privatization of Istanbul Gaz is on the agenda and is expected to take place in 2015.

88 EPDK 2013 Natural Gas Market Report.

89 ep. EPDK 2013 Natural Gas Market Report..

90 EPDK- January 2015 NG Market Monthly

91 Report, EPDK 2013 Natural Gas Market Report

92 DGPK states that BOTAŞ cannot make new natural gas import contracts (other than LNG). It also requires BOTAŞ to transfer its existing contracts (or contract amounts) to other legal entities with import licenses until the total amount of import contracts or sales falls to 20 percent of national consumption. BOTAŞ was asked to do this through contract transfer tenders.

93 Gulmira Rzayeva, "Natural Gas in Türkiye's Domestic Energy Market: Policies and Challenges," Oxford Institute for Energy Studies, 2014.

94 World Bank, Gas Sector Strategy Report, 2004.

95 Although the regulation requires BOTAŞ to announce balancing prices every month, this announcement is often delayed and not determined transparently, according to private sector participants.

96 SCADA stands for "central monitoring, control and data collection". It is a system that controls remote devices through communication channels.

97 According to the Automatic Pricing Mechanism (APM), energy SOEs are required to meet the financial targets set in the General Investment and Financing Program through new tariffs that reflect costs.

98 Competition Authority, DG Sector Report 2012 COURT OF

99 ACCOUNTS - 2013 BOTAS Report

100 Gulmira Rzayeva, "Natural Gas in Türkiye's Domestic Energy Market: Policies and Challenges," Oxford Energy Studies Institute, 2014.

101 The acquis or Community acquis is the European Union's (EU) system from 1958 to the present. It represents the sum of the laws and obligations.

102 Fuel oil and diesel temporarily until 2019

One of the 103 reservoir type power plants was put into operation in 2004.

104 This provision has caused many problems as a result of the international arbitration process regarding the cancelled HRA projects. This issue is discussed in the following sections.

105 The Council of State is the highest administrative court of the country.

106 Although the provisions regarding private law in Law No. 3996 were annulled one year later, this contract-s were signed before the cancellation. They were criticized after 2001 for their high cost, inconvenient conditions and questionable legal validity.

107 Especially the BOT agreements of 1997, in which ESA tariffs were much lower than the BOT agreements, Although the price bids for new BOT applications after 2007 were lower than those signed in the 1994-97 period, the BOT tariffs were still higher because of the lack of competition in selection and differences in ownership status.

108 The power plant has two units. One of the units was already in operation and was transferred in 2000; the other It was built and handed over in 2001 after trial operation.

109 Due to purchase guarantees, these power plants are sold at the market price ranking (merit order) regardless of their place. They should be considered as power plants that will operate without any restrictions.

110 Source: ETKB. Previously, this potential was announced as 125,000 GWh. However, public authorities and has been increased as a result of recent studies by the private sector. Due to the increasing cost of electricity generation, potential projects that were previously declared unfeasible are now becoming feasible. If all private sector applications are taken into account, the potential increases to 165,000 GWh. However, considering technical, environmental and social factors, it is safer to use the figure of 140,000 GWh.

111 Amended in 2007 and 2009. 112

EMRA, January 2015 Progress Report.

113 WEC and Turkish National Committee, 2013 Energy Report.

114 According to Articles 5 and 6 of the New EML, the licensing process is divided into two stages. In the first stage, a A preliminary license is given and the investor acquires the necessary permits, approvals and property rights before the construction period. In the second stage, EPDK grants a license that will be valid for the construction and operation period to investors who meet the requirements specified in the preliminary license stage.

115 Türkiye Wind Energy Potential Atlas (REPA) was prepared by EIEI in 2007.

116 Regulation on Technical Evaluation of Wind Energy Based License Applications.

117 Regulation on Wind Energy Tenders.

118 Approximately 1 US cent.

119 Previously, the contribution fee was offered on a TL/kWh basis; it was changed to TL/MW with the new EPDK.

120 EPDK, January 2015 Progress Report

121 ETKB 2010–2014 Strategic Plan, Target 2.2: “As of 2009, the wind power plant installed capacity was 802.8 MW “The capacity will be increased to 10,000 MW by 2015.”

122 Report of the Turkish Wind Energy Association (TÜREB) dated November 2012.