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# Turkey's Energy Transition Milestones and Challenges

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Energy & Extractives Global Practice  
Europe and Central Asia Region



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## Turkey's Energy Transition - Milestones and Challenges



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## Turkey's Energy Transition - Milestones and Challenges



# Abbreviations and Acronyms

*All dollar amounts are U.S. dollars unless otherwise indicated.*

AKP	Justice and Development Party
APM	automatic pricing mechanism
bcm	billion cubic meters
BOO	build, own and operate
BOT	build, operate, and transfer
BOTAŞ	Petroleum Pipeline Corporation of Turkey
BPM	Balancing Power Market
BSR	Balancing and Settlement Regulation
CCGT	combined-cycle gas turbine (plant)
CNG	compressed natural gas
CPS	country partnership strategy
CA	Competition Authority
DAM	Day-Ahead Market
DAS	Day-Ahead Scheduling mechanism
Danıştay	Turkish Council of State (the highest administrative court)
DistCo	distribution company
DSI	State Hydraulic Works
EBB	Electronic Bulletin Board
EBRD	European Bank for Reconstruction and Development
EC	European Commission
EE	energy efficiency
EIA	environmental impact assessment
EIE/EIEI	General Directorate of Electric Power Resources Survey and Development Administration
EML	Electricity Market Law of 2001, No. 4628 (the “new EML” of 2013 is No. 6446)
EMDR	Electricity Market Distribution Regulation
EMRA	Energy Market Regulatory Authority
ENTSO-E	European Network of Transmission System Operators for Electricity
EPIAŞ	Energy Market Operation Company (the “new PMUM”)
ESMAP	Energy Sector Management Assistance Program
EU	European Union
EÜAŞ	Electricity Generation Company of Turkey
GDEA	General Directorate for Energy Affairs
GDEU	General Directorate for EU Affairs and Foreign Relations
GDP	gross domestic product
GenCo	generation company
GWh	gigawatt-hours
HEPP	hydroelectric power plant
IFI	international financial institution
IPO	initial public offering
IPP	independent power producer
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LR	Licensing Regulation
mcm	million cubic meters
MENR	Ministry of Energy and Natural Resources
MoD	Ministry of Development
MoEU	Ministry of Environment and Urbanization
MoFW	Ministry of Forestry and Water Affairs
MVA	megavolt amperes (one million volt amperes)
MW	megawatt



## Turkey's Energy Transition - Milestones and Challenges

MWe	megawatt electrical
MWh	megawatt-hour
NG	natural gas
NGML	Natural Gas Market Law
NOP	Network Operation Principles
NPP	nuclear power plant
OECD	Organisation for Economic Co-operation and Development
O&M	operation and maintenance
PA	Privatization Administration
PMUM	Electricity Market Financial Reconciliation Center (electricity market operator within TEİAŞ)
PV	photovoltaics
PPP	public-private partnership
PSP	Private sector participation
RE	renewable energy
REL	Renewable Energy Law
RoR	run-of-river
Sayıstay	Turkish Court of Accounts
SCT	special consumption tax
SDIF	Savings Deposit Insurance Fund
SME	small and medium enterprise
SOE	state-owned enterprise
SPO	State Planning Organization (after 2011, the Ministry of Development)
STC	Standard Transportation Contract
TAEK	Turkish Atomic Energy Authority
TANAP	Trans-Anatolian Pipeline
TAP	Trans-Adriatic Pipeline
TAWEP	Turkish Average Wholesale Electricity Price
TBSR	Transitional Balancing and Settlement Regulation
TEAŞ	Electricity Generation and Transmission Company of Turkey
TEDAŞ	Electricity Distribution Company of Turkey
TEİAŞ	Electricity Transmission Company of Turkey
TEK	Turkish Electricity Authority
TETAŞ	Electricity Trading and Contracting Corporation of Turkey
TL	Turkish lira
toe	tonne of oil equivalent
TOOR	transfer of operational rights
TPA	third-party access
TP	Turkish Petroleum Corporation
TPP	thermal power plant
TSO	transmission system operator
TWh	terawatt-hour
TSKB	Turkish Industrial Development Bank
UCTE	Union of Coordination of Transmission of Electricity (ENTSO-E after July 2009)
WACOG	weighted average cost of gas
WPP	wind power plant
YEGM	General Directorate of Renewable Energy (of MENR)
YEKDEM	Renewable Energy Resources Support Mechanism



# Executive Summary

## Executive Summary

Through a variety of interlinked measures, Turkey's energy reforms have achieved energy security for a fast-growing economy with rapidly increasing energy needs. These measures include legislation regarding electricity, gas, renewable energy, and energy efficiency; the establishment of an energy sector regulatory authority; energy price reform; the creation of a functional electricity market and large-scale introduction of natural gas; the restructuring of state-owned energy enterprises; and large-scale private sector participation through privatization and new investment. As a result, (a) an electricity market with over 800 participants has been developed; (b) from 2001 to 2014 over 31,000 megawatts (MW) of market-based, private-sector power generation capacity was commissioned; (c) investors took over the entire power distribution system between 2008 and 2013; and (d) the regulatory framework for renewables and development of electricity market facilitated 16,000 MW generation capacity addition based on renewable sources in the 2001-2014 period.

Turkey first opened its energy sector to the private sector in 1984 as part of an overall shift toward a market economy. However, simply removing the public sector monopoly proved insufficient and, in the absence of a solid legal and regulatory framework and a functioning energy market, progress remained limited. Faced with the prospect of electricity shortages, legislative changes were made in 1994 and 1997 that provided for sovereign guarantees to attract private sector investment in electricity generation. About 8,550 MW was contracted under long-term power purchase agreements, with guarantees by Turkey's Treasury backstopping the public utility's payments. This provided temporary relief but not a long-term solution to energy security.

Taking into account the prospect of membership in the European Union (EU), the EU's 1996 electricity and gas directives, and energy reforms in Europe the Turkish government decided to establish a working group to review available options and prepare a new way forward. This preparation effort enabled Turkey to move forward when the time was right. Turkey's energy market reforms were launched in 2001 as part of the government's response to a deep economic crisis; as is often the case in fundamental reforms, the crisis provided the pressure, determination, and momentum to put the reform designs into implementation. Economic growth slowed down toward the end of the century, then collapsed as Turkey slipped into a deep economic and financial crisis in 2000–01. Comprehensive reforms were launched with the support of the International Monetary Fund and the World Bank. Very strong measures were taken by the government in several sectors, perhaps most notably in the banking sector, though the energy sector was not far behind: an Electricity Market Law and a Natural Gas Market Law were both enacted in 2001. Both laws were ambitious and far-reaching. Together they provided for sectoral restructuring, the establishment of electricity and gas markets, market opening, electricity suppliers (traders), bilateral contracting, open access to networks, and the establishment of an Energy Market Regulatory Authority (EMRA).

The 2001 laws provided the necessary legal foundation. A systematic, step-by-step effort followed to put in place the required regulatory framework, restructure state-owned power companies, and develop a centralized electricity trading platform (PMUM). Although the initial response from prospective private investors was encouraging, it was ultimately insufficient to ensure electricity supply security because retail tariffs were kept below cost-recovery levels through 2007. The introduction of a new, cost-based energy pricing mechanism in 2008 and a series of tariff adjustments in 2008–09 brought the power sector to financial viability, supporting a large volume of market-based generation investment and enabling the government to start the delayed distribution privatization program.

Past success may help to show the way forward, but it does not guarantee future success. Turkey's economy continues to grow. The demand for energy, especially electrical energy, continues to grow. The energy sector will have to meet this challenge to secure an energy supply for Turkey's growth and development and the welfare of its citizens. Notwithstanding the remarkable accomplishments to date, reform in the energy sector must continue if Turkey is to continue to secure its electricity and gas supplies without reverting to the large-scale – and, in the long run, unsustainable – government support mechanisms of the 1990s.

Electricity market development continues under a new Electricity Market Law, enacted in 2013, providing for the establishment of a new Energy Market Operations Company, EPIAŞ. It will be a joint venture between the electricity transmission system operator, TEİAŞ (30% equity share); Turkey's stock exchange, Borsa İstanbul (30%); and electricity and gas market participants (40%). As soon as EPIAŞ has taken electricity market operations functions from TEİAŞ it will expand into the gas sector. In parallel, Borsa İstanbul will develop a financial risk management platform for market participants.

In contrast to Turkey's remarkable progress in gasification and gas distribution privatization, its gas market development is well behind electricity, and gas supply security is at risk. Gas demand exceeds available supply during cold winter days, resulting in supply curtailments. With the government's support, BOTAS has recently contracted additional supply from Azerbaijan, expected to be delivered by 2018. More will be required, including spot imports of liquefied natural gas (LNG)<sup>1</sup> as an immediate measure and new contracts/sources as existing contracts expire. A comprehensive set of measures is needed to secure supply in the medium-to-long term. The forthcoming amendment of the 2001 Natural Gas Market Law will be an important step in terms of unbundling the national gas company, BOTAS; further liberalizing imports; and establishing an effective gas trading platform. Furthermore, establishing cost-reflective pricing and removing cross-subsidies would facilitate competition. These measures are needed if Turkey is to achieve gas supply security, increase private sector participation in gas imports, and realize its ambition of becoming a regional energy hub.

Most Turkish energy consumers have accepted higher energy prices as an inevitable cost of development. However, acceptance does not mean that all households can comfortably afford to pay their energy bills. Targeted social support and energy efficiency programs for low-income consumers could be considered as an integral part of the overall electricity and gas market liberalization. The possibility of social support in the form of direct cash to consumers (without affecting energy prices) was provided for in the 2001 laws but has not yet been pursued.

This review presents an integrated set of measures for government consideration to continue developing the electricity and gas markets and to reassure market participants that the liberalization continues and the governance and transparency of public institutions and energy SOEs will improve:

- The amendment of the Natural Gas Market Law could be enacted.
- Taking advantage of declining gas import prices, the government could allow cost-reflective and transparent wholesale gas price adjustments by BOTAS.
- The development of a social safety mechanism for low-income energy consumers would take some time (even if added to one of the existing subsidy mechanisms funded from the budget) but the government could announce that it has decided to establish such a mechanism.
- The development of EPIAŞ could be accelerated so that EPIAŞ could be fully operational within 2015.

- The Energy Ministry, BOTAS, and TEIAS could disclose and explain to market participants their gas supply curtailment and electricity congestion management mechanisms before these mechanisms are applied during the 2015–16 winter and whenever they are being used.
- The government could announce that it has decided to list the shares of TEIAS, parts of BOTAS (after unbundling), EÜAŞ, TETAS, and TP through a program of initial public offerings on the Borsa Istanbul.

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

- The modernization of energy SOE governance and the listing of key energy enterprises are important policy priorities. Management autonomy is undermined by Decree Law No. 233 on State Economic Enterprises; the Law on the Court of Accounts; Public Procurement Law; and a series of controls by the Ministry of Energy, the Ministry of Development, and the Treasury. Though established as companies, BOTAS, EÜAŞ, TEIAS, and TETAS still face substantial challenges in the conversion into modern, autonomous, and professionally-run state-owned enterprises.
- Energy market participants are looking for increased transparency in regulatory processes (EMRA), market operations (PMUM/EPIAŞ), trading activities of EUAŞ and TETAS, and electricity and gas transmission system operations in such areas as balancing, dispatch, congestion management, and supply curtailment (TEIAS and BOTAS).
- The environmental impact assessment and project clearance process has at times been overwhelmed by the high number of applications. Developers have complained about complicated procedures, delays, and lack of transparency. Environmentalists and citizens have expressed concern about inconsistent application of environmental permitting and licensing procedures/guidelines and the adequacy of public information provided for decisions made. There is need for more transparency in the process and justification of decisions, whether approvals or rejections.

Securing public support for energy reforms – and for the investments the reforms are designed to attract – is in principle simpler than attracting private investment, but perhaps just as challenging in practice. It requires information-sharing, education, consultation, engagement, and transparency – continuously, relentlessly, with no exceptions; otherwise continued public support will be undermined.



## Turkey's Energy Transition - Milestones and Challenges



# Overview

Through a variety of interlinked measures, Turkey's energy reforms have achieved energy security for a fast-growing economy with rapidly increasing energy needs. These measures include legislation regarding electricity, gas, renewable energy, and energy efficiency; the establishment of an energy sector regulatory authority; energy price reform; the creation of a functional electricity market and large-scale introduction of natural gas; the restructuring of state-owned energy enterprises; and large-scale private sector participation through privatization and new investment. As a result, (a) an electricity market with over 800 participants has been developed, (b) from 2001 to 2014 over 30,000 megawatts (MW) of market-based, private-sector power generation capacity was commissioned; and (c) investors took over the entire power distribution system between 2008 and 2013.

The "secret" of Turkey's success is the three-way collaboration and risk-taking between successive governments, public institutions and state-owned energy companies, and Turkish investors and their mostly Turkish financiers. This collaboration developed slowly and intensified "step by step," a familiar expression in energy reform discussions in Turkey. It started in the 1980s, when the energy sector was opened for private initiatives, and flourished following the enactment in 2001 of electricity and natural gas market laws that launched the liberalization of Turkey's energy markets – a process that continues today.

The legal and regulatory framework and industry and market structures evolved over time, step by step. Energy prices were adjusted at a pace considered acceptable to consumers. Successive governments, public institutions and state-owned energy companies, and investors and financiers were ready to put the framework and structures to work. They were ready and able to take the risks: political risks, operational risks, financial risks. Such risk-taking made Turkey's energy reform possible. It is not easily replicable; in fact it is very difficult to replicate. Other countries will have to find their own way forward but can learn from Turkey's experience – both its past reform milestones and its current reform challenges.

The objectives of this review of Turkey's milestones and challenges are to (a) inform future energy reforms and reformers seeking to learn and benefit from Turkey's experience and (b) to contribute to the dialogue on future energy reforms in Turkey.

This overview section will summarize, and the main report will present in full, Turkey's accomplishments in developing and implementing market-oriented energy reforms as well as selected key reform challenges going forward. In terms of reform milestones, the primary focus is on the electric power and natural gas sectors, although energy pricing and subsidies in the petroleum sector are also addressed. The report covers mainly the period starting from 2001, when progressive electricity and natural gas market laws were enacted, though the preceding period – from the opening of the energy sector to private investment in 1984 up to the enactment of the new energy market laws in 2001 – is covered briefly to present key milestones and to highlight key lessons.

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

The first part of this overview will present Turkey's energy transition milestones. These include accomplishments in legislation and regulation, pricing developments, sector restructuring, industry and market structure, electricity market development, the introduction of natural gas into Turkey's energy supply mix, natural gas market development, the role of Turkish investors



and their financiers, renewable energy development, nuclear power, and political leadership – as well as support for reforms, pricing and subsidies.

The second part of this overview will present the key challenges facing Turkey’s energy sector as a contribution to the ongoing reform dialogue in Turkey. The challenges include the reform of the natural gas market, further development of the electricity market, and governance issues in the energy sector. Discussion of environmental and social issues and challenges has been integrated into the relevant sections.



## 2.1 Overview Part I: Energy Reform Milestones

International experience shows that implementation of comprehensive reforms usually takes a long time and requires a long-term commitment. Turkey is no exception. As explained later in Part II, although reforms started in the 1980s, they continue today and major challenges remain.

Turkey's energy reforms can be divided into two distinct phases:

- Phase 1: opening to the private sector in the 1980s and 1990s; and
- Phase 2: market-based reforms since 2001.

Energy security – securing the energy supply to support economic growth and the welfare of citizens – has been the primary domestic reform driver through both phases, with one exception: macro and fiscal issues. The need to maintain budget and external balances became an increasing concern in the late 1990s and eventually the primary domestic driver for the market-based reforms launched in 2001, at a time of deep economic crisis and a temporary decline in energy demand. Attracting market-based private investment – especially for power generation without long-term power purchase agreements (PPAs) and large-scale state guarantees – was adopted as the main means for achieving energy security without jeopardizing macro and fiscal balances. Energy security concerns led and effectively forced the government to accelerate reforms from 2008.

Turkey is a candidate for membership in the European Union (EU). Accession negotiations started in October 2005. Turkey views the accession process as its own, fundamental “modernization project.” The prospects of membership in the EU and European energy collaboration and integration have been influential external drivers for energy reform. The design of Turkey's 2001 market-based reforms was inspired by the EU's 1996 electricity and natural gas directives and reforms in Europe, including the restructuring and privatization of the electric power industry in England and Wales and the development of the Nordic electricity market. Because Turkey's vision of developing into an energy hub will benefit both Turkey and the EU, market integration is in the interest of both sides.

### 2.1.1 Phase 1: Opening up to the Private Sector in the 1980s and 1990s

#### *2.1.1.1 Economic Liberalization toward a Market Economy*

Turkey opened the energy sector to the private sector as part of an overall shift toward a market economy. Emerging from a severe economic crisis in the late 1970s, a military coup in 1980, and political turmoil in the early 1980s, Turkey changed course in 1983. The country embarked on a path to move from state-controlled import-substitution industrialization, featuring heavy state ownership and control, toward a liberal market economy, both in domestic markets and international trade. This broader economic policy shift was reflected in the electricity power sector in 1984 with the enactment of a law granting authorization to institutions other than the Turkish Electricity Authority (TEK) for generation, transmission, distribution, and trade of electricity under build-operate-transfer (BOT), transfer of operational rights (TOOR), and autoproduction models. Experience and results in using these three models is discussed below

#### *2.1.1.2 Energy Sector Restructuring*

Originally established in 1970 as an integrated authority for electricity generation, transmission, and rural electrification, TEK effectively became a monopoly in 1982 with the consolidation of municipal distribution activities into TEK. However, the 1984 Law ended TEK's effective monopoly position and TEK was corporatized into a state-owned enterprise. Power sector restructuring continued in 1993 after TEK was split into the Turkish Electricity Generation and Transmission Company (TEAŞ) and the Turkish Electricity Distribution Company (TEDAŞ). TEAŞ and TEDAŞ were designated as buyers of electricity from BOT and TOOR companies and autoproducers connected to the transmission and distribution grids, respectively.



The Turkish Petroleum Corporation (TP- Originally TPAO) was established in 1954 as Turkey's national oil company for hydrocarbon exploration, drilling, production, refinery, and marketing. Following a series of restructuring and privatization measures, however, TPAO has focused its activities primarily on upstream (exploration, drilling, well completion and production) though it also operates Turkey's only natural gas storage facilities. Turkey's Petroleum Pipeline Corporation (BOTAS) is one of several companies in Turkey's oil and gas sector that originate from TP. TP established BOTAS in 1974 for the purpose of transporting crude oil through pipelines. After Turkey signed its first agreement with the Soviet Union to import natural gas in 1986, however, BOTAS expanded its scope to cover natural gas transportation and trade, thereby becoming a trading company and effectively Turkey's national gas company. In contrast to the liberalization and restructuring in the power sector, BOTAS enjoyed – via a 1990 government decree – monopoly rights on natural gas importation, distribution, sales and pricing.

### **2.1.1.3 Private Sector Participation (PSP) in the Power Sector**

Four models were used for PSP: transfer of the operational rights (TOOR), Build, Operate and Transfer (BOT), Build, Own and Operate (BOO), and Autoproduction.

#### *Experience with the TOOR Model*

The **TOOR model** provides for the transfer of the operational rights of public assets (in this case the power generation and distribution assets of TEK, TEAŞ and TEDAŞ) to private management along with new investment by the private sector for the duration of the TOOR contract. Of the many attempts in the 1980s and 1990s to use the TOOR model to attract private companies into the power sector, most ultimately failed because of fundamental legal issues in the transfer of public assets to private management, unavailability of sovereign guarantees (for generation) before 1994, and regulatory uncertainties (in distribution and generation).

Efforts to transfer distribution and generation assets in 90s initially experienced similar fates. The Ministry of Energy and Natural Resources (MENR) organized public auctions in which it offered many of Turkey's 78 electricity distribution regions to private management and signed contracts for 11 regions. The legal basis of such contracts was challenged, however, all the way to the *Danıştay* (the Turkish Council of State, the country's highest administrative court). The Court annulled most of the 11 contracts and ultimately only two contracts could be executed.

MENR also offered 16 power stations to private management and signed contracts for six of them with the approval of the Council of Ministers. But here, too, the legal basis was challenged and all but one contract were annulled by the *Danıştay*.

Nevertheless, though the TOOR efforts of the 1980s and 1990s largely fell victim to the absence of a solid legal framework, the experience gained enabled Turkey to make the legal amendments necessary to establish a sound legal basis for the successful use of the TOOR model in the 2008–13 electricity distribution privatization program.

#### *Experience with the Autoproducer Model*

The **autoproducer model** provides for the ownership and operation of power plants by industrial companies, primarily for their own electricity needs. Although there had been autoproducer plants in Turkey before 1984, they were used mostly in state-owned sugar factories and cogeneration<sup>2</sup> plants and were governed through special regulations. The 1984 law, and subsequent regulations in 1994–99 allowing companies to set up jointly-owned plants, triggered widespread investment in autoproduction facilities. About 2,300 MW of generation capacity was installed by 2001. Although not envisioned at the time of the 1984 Law, these plants played an important role in the development of Turkey's electricity market two decades later.



## *Experience with the BOT and BOO Models*

The BOT model involves three stages:

1. The financing and building of an asset – in this case, power plants that generate electricity by a private company;
2. The operation of the power plant, with output being sold to a public entity under a long-term agreement – in this case, the sale of electricity to TEK and TEAŞ under power purchase agreements; and
3. The transfer of the asset to the State at the end of the contract period.

Because the 1984 Law proved to be an insufficient legal basis for implementing the BOT model, a specific law on BOT implementation was enacted in 1994. In addition to addressing legal uncertainties about the BOT model, the 1994 Law provided for sovereign guarantees by Turkey's Treasury for TEAŞ' payments under the power purchase agreements.

The 1994 BOT Law triggered a massive response from prospective foreign and local investors. They submitted over 200 project proposals that, if built, would have tripled Turkey's generation capacity. The Ministry of Energy and Natural Resources (MENR) and TEAŞ were not equipped to handle this unexpected influx of unsolicited proposals. Ultimately 24 BOT contracts (for a total of 2,450 MW of generation capacity) were negotiated and executed, but most of the proposals did not lead to transactions.

### **BOT Model:**

Instead of trying to review and compare hundreds of unsolicited proposals, the government decided to focus on priority projects of its own choice and to select investors for these projects through competitive bidding in order to secure more reasonable prices and conditions. A variation of the BOT model was introduced in which the transfer of the power stations to TEAŞ at the end of the contract period was eliminated in order to reduce legal uncertainties and thereby improve the bankability of the projects. Five contracts for a total of 6,100 MW of generation capacity were awarded using this build-own-operate (BOO) model.

#### **2.1.1.4 Change of Course**

In total about 8,550 MW of generation capacity was contracted and executed under the BOT and BOO laws. All contracts included take or pay clauses. TEAŞ' purchasing obligations are backstopped by sovereign guarantees from Turkey's Treasury. The BOT/BOO model, with competitive selection and Treasury guarantees, could have been used beyond the five competitively bid projects and would probably have worked to secure some additional generation capacity. However, instead of relying on more and more guarantees, Turkey embarked on a market-based approach to attract private investment. This fundamental change of course came about, and was possible, for a number of reasons:

- The Treasury and the State Planning Organization (SPO; after 2011 the Ministry of Development) had become increasingly reluctant to consider Treasury guarantees for BOT and BOO projects in view of the contingent liabilities;
- There had been allegations of irregularities in the BOT contracting process. The shift from negotiated BOT contracts based on unsolicited proposals to competitively bid BOO contracts on priority projects helped address these concerns but did not eliminate allegations about the past BOT contracts.
- As economic growth started to decline in the late 1990s, electricity demand growth decelerated and, with the already-contracted BOT and BOO power plants' projected generation, supply/demand balances started to ease. The electricity supply security argument for providing Treasury guarantees became irrelevant and was replaced by the risk of a surplus of expensive take-or-pay<sup>3</sup> electricity in the medium term.



- The EU's first electricity directive in 1996, and electricity reforms in Europe, inspired the government to consider market-based approaches. A working group was established to review available options and prepare a new way forward. The group brought together officials from the Ministry, TEAŞ, TEDAŞ, SPO, and Treasury. This preparation effort enabled Turkey to move forward when the time was right.

### 2.1.2 Phase 2: Market-Based Reforms Since 2001

As is often the case with fundamental reforms, a crisis provided the impetus for implementing the planned energy reforms. In this case, the crisis was exceptionally deep and left Turkey with no choice but to implement exceptionally strong measures. The following section presents the accomplishments and lessons from the competitive electricity and gas market model Turkey set out to implement in 2001. The focus of the discussion is on the electric power sector; progress in the gas sector has been more limited and is accordingly covered in more detail in Section 2.2, which focuses on energy reform challenges.

#### *The 2000 - 01 Crisis*

Turkey is known for its boom-to-bust economic cycles. In the 1990s, GDP growth varied from a high of 9.3% to a low (contraction) of -5.5%. A slowdown began in the late 1990s, with growth declining from 7.5% in 1997 to 2.5% in 1998. Slowing growth in Turkey, combined with financial crises in East Asia and Russia, reduced foreign investors' confidence in Turkey and capital inflows declined. A major earthquake hit Turkey in 1999. Inflation was high and the economy contracted by 3.6%. A disinflation and macroeconomic stabilization program supported under an IMF standby arrangement was launched in 1999, but concerns about the health of the banking sector remained and increased. Financial crises erupted in November 2000 and, after a period of calm, again in February 2001. A second, much larger IMF supported program followed.

Turkey's Savings Deposit Insurance Fund (SDIF) ended up taking over 18 banks for a program of mergers and closures and recapitalization of surviving banks at a cost that amounted to over 30% of Turkey's GDP. Funding to SDIF was provided from the budget with funds raised through bonds. The cost was very high – Turkey's public debt doubled – but market confidence was restored and growth returned. Recovery was spectacular: after a contraction of 5.7% in 2001, GDP grew by 6.2% in 2002 and averaged over 6% per year through 2007. The banking sector that emerged from the restructuring after the 2000–01 crisis provided most of the debt financing to the investors that responded to the energy sector liberalization launched as part of the government's response to the crisis.

#### *2001 Electricity and Natural Gas Market Laws*

In 2001 comprehensive reforms were launched and very strong measures were taken by the government in several sectors, perhaps most notably in the banking sector, as discussed above. Energy sector was not far behind banking: an Electricity Market Law (EML) and a Natural Gas Market Law (NGML) were both enacted in 2001. Conflicts between public authorities, corruption allegations, and court cases<sup>4</sup> about some of the contracts helped build public support for the reform including the passage of these laws in the Parliament. Both laws were ambitious and far-reaching. These laws provided for sectoral restructuring, the establishment of electricity and gas markets, market opening, electricity suppliers (traders), bilateral contracting, open access to networks, and the establishment of the Energy Market Regulatory Authority (EMRA).

##### **2.1.2.1 Electricity Market Development**

This section summarizes key features of the evolution of Turkey's electricity market that are explained in detail in the main report.

The ultimate target was to establish a competitive market environment capable of attracting private investment and promoting efficiency through competition. It required major changes in the administrative and regulatory framework, the restructuring and unbundling of state-owned



power companies, major changes in trading arrangements, the establishment of a competitive marketplace where multiple buyers and sellers could interact, and the establishment of an open-access regime for non-discriminatory access to transmission and distribution networks. It also required transition arrangements and sequencing of actions to move from a monopolistic single-buyer model to wholesale competition and eventually full retail competition (which will occur when all consumers are eligible. i.e. have the freedom to choose their electricity supplier).

#### **2.1.2.2 The Legal, Regulatory and Institutional Framework**

The 2001 EML provided the legal foundation. EMRA was established under the EML as an electricity market regulator and was soon renamed as the Energy Market Regulatory Authority as its functions were extended to cover the natural gas, liquefied petroleum gas (LPG), and petroleum markets. EMRA prepared the secondary legislation necessary for licensing, tariffs of regulated activities, transmission and distribution grid codes, market opening, market rules and procedures, and balancing and settlement. As the market evolved, both the EML and EMRA's regulations were improved through amendments, revisions, and new regulations as deemed necessary.

EMRA performs its duties and exercises its rights arising from the related laws through the Energy Market Regulatory Board, which is the representative and decision-making body of the Authority. It consists of nine members, including EMRA's President, each of whom is appointed to a six-year term by the Council of Ministers. To ensure EMRA's operational autonomy, the law mandates that board members cannot be dismissed before the expiry of their terms of office. The Law also provides for EMRA's financial autonomy from the government by empowering it to fund its activities through fees charged to the energy industry. Although there are increasing concerns about EMRA's autonomy and government intervention in its tariff-setting authority, market regulation and supervision authority has been largely transferred from the government to an independent regulator.

Turkey adopted a new Electricity Strategy in March 2004.<sup>5</sup> Its objectives included electricity distribution privatization with an end-2006 target completion date. Because the EML did not include targeted measures for renewable energy development or energy efficiency, separate Renewable Energy and Energy Efficiency Laws followed in 2005 and 2007, respectively.

#### **2.1.2.3 Restructuring the State-Owned Power Companies**

In 2001, in line with the principle of unbundling market activities, the Turkish Electricity Generation and Transmission Company (TEAŞ) was split into three parts:

- The Turkish Electricity Transmission Company (TEİAŞ) was established for carrying out electricity transmission, system and market operations;
- The Electricity Generation Company (EÜAŞ) was established for carrying out electricity generation; and
- The Turkish Electricity Trading and Contracting Company (TETAŞ) was established for carrying out electricity wholesale activities – including handling the long-term PPAs (with BOO, BOT, and TOOR companies) left over from the previous regime.

In addition, TEDAŞ was restructured in 2004–06 into a holding company and 20 regional subsidiaries for the implementation of distribution privatization in accordance with the 2004 Electricity Strategy.

#### **2.1.2.4 Transitional Measures**

- As a transitional measure, vesting contracts<sup>6</sup> were introduced in 2006 between (a) TETAŞ and EÜAŞ as wholesale electricity suppliers and (b) the TEDAŞ subsidiaries as purchasers (covering 85% of their retail supply). This measure was phased out in 2012

- A price-equalization mechanism (i.e., an interregional cross-subsidy) was introduced to balance the cost differences between distribution regions in order to implement the policy of uniform national retail tariffs for captive consumers; and
- 15 BOT project proposals were converted to market-based projects and were licensed by EMRA, providing about 1,300 MW of capacity to the emerging electricity market.

### 2.1.2.5 *Unbundling of Functions*

Turkey's legal and regulatory framework differentiates between market and regulated activities. Transmission and distribution are regulated by EMRA. Competitive market activities such as generation and supply are not regulated, except for retail sales to captive consumers<sup>7</sup> and TETAS' wholesale. The following unbundling measures can be highlighted:

- Transmission unbundling: With the establishment of TEIAS, the transmission network and system operation was separated from the supply business.
- Distribution unbundling: Separation of distribution from retail was realized in two phases. Until end-2012, distribution and retail were carried by the same regional distribution company via separate accounts ("account unbundling"). Each regional company had two licenses: a distribution license to operate the distribution system in its region and a retail sale license to supply electricity to non-eligible consumers in its region. As stipulated in amendments made in the EML in 2008 and the 2009 Strategy Paper, those activities are to be legally unbundled at the recommendation of Competition Authority. As of the end of 2012, the distribution companies were legally separated into distribution and "assigned supplier" companies.<sup>8</sup>
- From January 2013, distribution companies operate and maintain the distribution grid, carry out the necessary grid investments, and provide non-discriminatory electricity distribution and connection services to all system users, including eligible consumers connected and/or to be connected to the distribution system.
- From January 2013, assigned supplier companies can sell electricity and/or capacity both to captive consumers located in the authorized regions and to eligible consumers countrywide. They are also the last resort supplier of the consumers in their regions.
- Although distribution companies cannot engage in any other market activity, owners or shareholders of generation/supply companies can be (and generally are) owners of distribution companies and retail supply companies. There is no limitation for assigned supplier companies. This creates a potential concern with regard to implementing the open-access regime (see following section), which will require careful supervision by EMRA and the Competition Authority.

### 2.1.2.6 *Provisions for Open Access to Transmission and Distribution Grids*

Unbundling of grid activities is a prerequisite for open access to the grids, and it was carried out as described above. Effective third-party access (TPA) also requires a set of rules, procedures, and pricing arrangements for non-discriminatory access and use of the grids by third parties. These were introduced in the EML and secondary legislation. EMRA supervises the activities of the grid operators and the functioning of the market to ensure implementation. TEIAS and the distribution companies are obliged to provide non-discriminatory access to the grids according to TPA rules covering (a) connection to the grids and (b) the use of transmission and distribution systems regulated by standard connection and use-of-system agreements. Furthermore, the connection and use-of-system prices are regulated through connection charges and transmission/distribution tariffs.

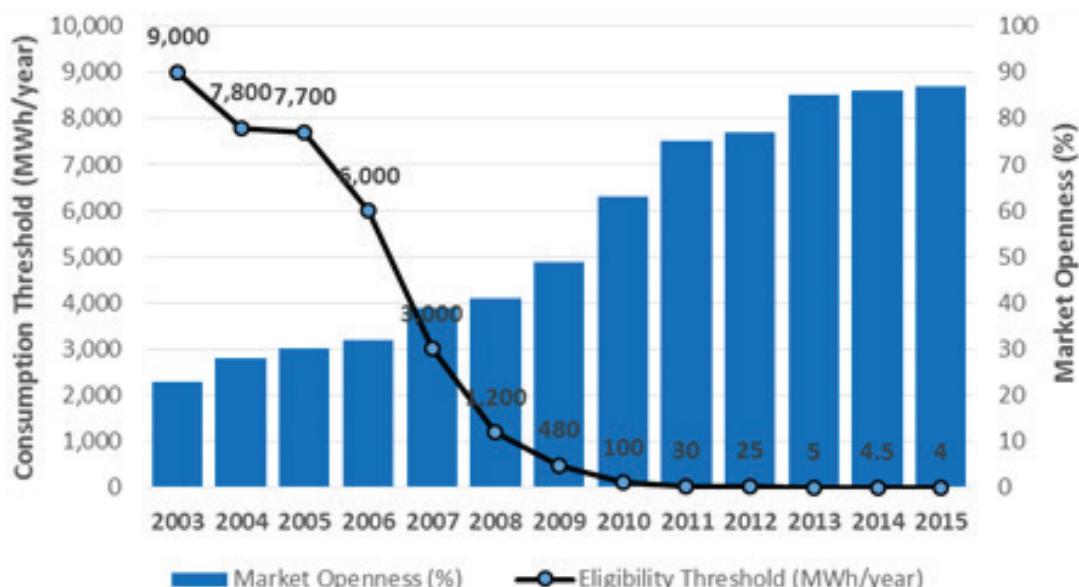
As a result, generators and other suppliers are able to access eligible consumers, and eligible consumers can reach potential suppliers – all thanks to market design and trading arrangements

that collectively represent a competitive, market-based mechanism for determining who has the right to use the grid to access their customers.

#### **2.1.2.7 Eligible Consumers and Market Opening**

The electricity market opened up in 2003, when large consumers became eligible to choose their electricity suppliers. In 2003 the consumption limit for eligibility was 9 GWh per year; this has gradually fallen to 4 MWh as of January 2015, as shown in Figure 1. In the same period the theoretical market opening ratio (a measure of market liberalization) reached 85%.

**Figure 1. Electricity Market Openness, 2003–15**

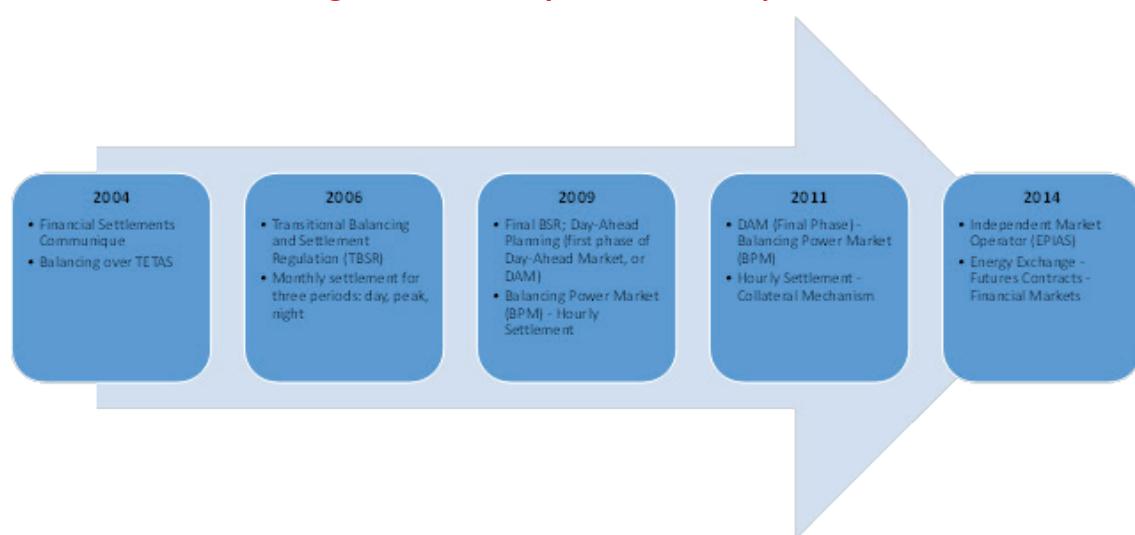


The number of eligible consumers exercising their right to choose their supplier remained very small until 2010. The number shows a noticeable increase since 2010 and has reached approximately one million. The suppliers of eligible consumers are mostly generators and wholesale companies (traders).

#### **2.1.2.8 Centralized Balancing, Settlement, and Trading Arrangements**

The development of a power exchange (i.e., a centralized platform for trading electricity) is a complex, multi-year undertaking. The steps involved, illustrated in Figure 2, are discussed below.

**Figure 2. Electricity Market Development**



Turkey's March 2004 Electricity Strategy envisioned developing Turkey's power exchange at a highly ambitious pace in two steps: (a) a temporary balancing and settlement mechanism by January 2005 and (b) a modern day-ahead market, with hourly prices, by July 2006. Time requirements were severely underestimated – the first step was accomplished in 2006 and the second in 2011 – but the results have been impressive from the very beginning. The Turkish abbreviation of the department with TEİAŞ that administers the balancing and settlement mechanism, the Electricity Market Financial Reconciliation Center, is PMUM. Turkey's power exchange continues to be known as PMUM even after the launch of the Day Ahead Market in 2011. The process of electricity market development will continue in 2015 as PMUM separates from TEİAŞ to become an independent Energy Market Operations Company, or EPIAŞ.

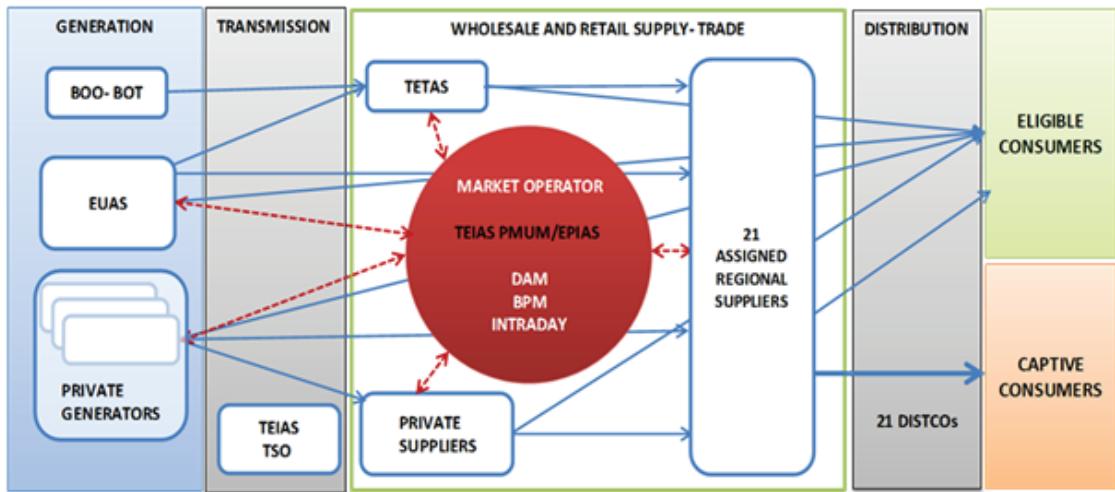
The intent of the temporary balancing and settlement mechanism was to help transmission system operator TEİAŞ with its real-time task of balancing demand for and supply of electricity. It did this through a mechanism that allowed TEİAŞ to prepare an indicative generation schedule one day ahead of actual system dispatch. In the absence of a comprehensive IT system (the development of which had just been launched), generators submitted their proposed programs and prices twice a month to PMUM, TEİAŞ prepared and submitted the demand forecasts, and PMUM prepared (and enabled TEİAŞ to disseminate) schedules for generators.

Prices at PMUM were not regulated but instead reflected demand and supply. PMUM provided an attractive centralized market place for private generators, including renewable energy developers. Wholesale prices in PMUM quickly exceeded the \$55/MWh level in the "safety mechanism" established for renewable energy,<sup>9</sup> and development activity in hydro accelerated and wind took off. However, the persistence of low, regulated tariffs discouraged eligible consumers from switching away from regulated tariffs, so they remained captive consumers (and many that had switched returned). Instead of pursuing bilateral contracts with eligible clients, generators sold on PMUM. Autoproducers (industries with power generation facilities originally built for their own electricity needs) exploited the same opportunity: They sold their generation on PMUM and bought electricity for their own use from distribution companies at the lower, government-controlled tariff. The result was PMUM's rapid development into a liquid wholesale market – instead of the originally intended, much more limited role of a temporary balancing and settlement mechanism.

### **2.1.2.9 Further Development of PMUM Trading Platforms**

The 2009 Electricity Strategy confirmed the main transitional steps and target dates for separating PMUM's energy trading and balancing markets. In line with this Strategy, (a) in 2009 a transitional day-ahead planning market was introduced and (b) in December 2011 modern day-ahead and balancing markets were launched by TEİAŞ in line with EMRA regulations. A new intra-day market, designed by PMUM, will be introduced by PMUM's successor, the forthcoming Energy Market Operations Company (EPIAŞ). The intraday market is expected to be particularly useful for intermittent renewable energy generators – it is much easier for them to forecast available generation intra-day than day-ahead and to use the intra-day 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 Operation Company (EPIAŞ)**

The operation of organized wholesale power markets, and the financial settlement of the transactions made in these markets, will be moved from TEİAŞ to an independent Energy Market Operations Company, EPIAŞ. TEİAŞ will continue to operate the balancing power and ancillary services markets. The government had signaled its intent to develop such a company in the 2009 Electricity Reform Strategy, and the new Electricity Market Law of 2013 provides for its establishment.

EPIAŞ will be responsible for the operation of organized wholesale markets (such as day-ahead and intraday) for electricity and later also for gas, effectively becoming an energy exchange. EMRA led the work on its establishment. TEİAŞ holds 30% of EPIAŞ, Borsa İstanbul holds about 30%, and the remaining 40% is widely shared among interested energy market participants. Financial trading and risk management instruments are to be developed and operated by Borsa İstanbul. Market participants have widely welcomed the prospect of an independent energy market operator, and 97 companies have responded to EMRA's invitation to become shareholders in EPIAŞ.

#### **2.1.2.11 TETAŞ as the Manager of Sovereign-guaranteed Power Purchase Agreements and Sales to Uncreditworthy Electricity Distribution Companies**

Another noteworthy feature in the design of Turkey's electricity reform is the establishment of TETAŞ for managing the BOT/BOO contracts of the 1990s and its coexistence as a centralized purchaser of contracted and sovereign-guaranteed BOT/BOO power with market-based bilateral contracts and PMUM as the centralized market platform for market-based electricity. This dual structure proved indispensable when the planned privatization of TEDAŞ' electricity distribution subsidiaries by end-2006 proved infeasible and ultimately slipped by several years. Market-based generation could not have developed as it did at the time by selling to PMUM if generators had been faced with only the TEDAŞ DistCos or industrial companies enjoying low government-controlled tariffs as potential clients. TETAŞ honored Turkey's obligations to BOT/BOO generators and pooled the more-expensive BOT/BOO power with the less-expensive EUAŞ power. TETAŞ supplied TEDAŞ DistCos when most of them were unviable and uncreditworthy due to the low retail tariffs. TETAŞ continues to supply the DistCos, now all privatized, including with electricity purchased on PMUM in its portfolio. The government continues to rely on TETAŞ to operate the price equalization mechanism to implement its policy of uniform national retail tariffs.

### **2.1.2.12 Tariffs and Impact on Investments and Electricity Market Development**

According to the EML:

- All regulated tariffs must be cost reflective;
- The price of energy (excluding regulated end-user tariffs) is to be determined by the market under competition; and
- If there is a need to protect some consumers, subsidies shall not be provided through tariffs, but rather through a direct subsidy mechanism.

Actual implementation has not always been possible according to those principles – most notably in 2003–07, as discussed below. Prospects for sufficient generation investment and distribution privatization were undermined by government policy directing EMRA to keep electricity retail tariffs constant from 2003 through 2007. Constant retail electricity prices, despite a significant increase in imported gas prices and generation costs from 2005, caused a severe deterioration in the financial viability of the sector. This had the effect of limiting available funding for new public investments, discouraging private investors, and sending incorrect price signals to energy consumers about the use and conservation of energy. Supply security again became the primary and a rapidly increasing concern.

A partial blackout in 2006 helped accelerate the implementation of a temporary balancing and settlement mechanism (which quickly developed into an effective wholesale trading platform, as discussed below) but pricing decisions were still deferred. Pressure built up. The government was forced to choose between (a) allowing EMRA to introduce significant tariff adjustments and (b) subjecting the country to the increasing risk of electricity shortages – potentially leading to load shedding, economic slowdown, and protests from citizens. Recognizing the increasing risk of shortage, a new, cost-based energy-pricing mechanism was approved in March 2008 and significant price adjustments were implemented in 2008–09, as discussed below.

Due to the low retail tariffs, TEDAŞ distribution companies were unable to make timely payments to their suppliers (EÜAŞ, PMUM, and TETAŞ). This, in turn, caused PMUM to accumulate arrears to the sellers on PMUM (private generators, TETAŞ, and EÜAŞ); TETAŞ to BOTs/BOOs; and EÜAŞ to its gas supplier, BOTAŞ. To avoid discouraging private generators, PMUM assigned priority to making payments first to private generators and then to TETAŞ and EÜAŞ, as the public generator was paid last. Arrears continued to increase until the 2008 tariff reform and implementation of the cost-based energy pricing mechanism (discussed below) and were then gradually paid off and finally eliminated in 2011.

#### ***Cost-based Energy Pricing Mechanism***

In March 2008, prompted by the rapidly increasing risk of electricity shortages due to insufficient investment and high demand growth, the High Planning Council (a committee of ministers chaired by the Prime Minister) approved a new cost-based energy pricing mechanism. Launched by EMRA in July 2008, the mechanism provided for quarterly adjustments of electricity prices to cover the (justified) increases in costs incurred by the Turkish Lignite Company, TETAŞ, EÜAŞ, TEDAŞ, and BOTAŞ, including the costs of electricity obtained on the wholesale market, through mandatory tariff filings by companies and necessary (justified) tariff adjustments by EMRA.

BOTAŞ was able to operate the mechanism for its gas sales only up to 2009 – an issue that even today continues to impede the development of the natural gas market, as discussed below. In electricity, EMRA has applied the pricing mechanism since 2008, with the following impressive results:

- Tariffs were brought to cost-recovery level by January 2009 with a series of significant tariff adjustments totaling about 60%.
- Collections started to improve despite the tariff adjustments, especially after distribution privatization.



- With cost-reflective tariffs and improved bill collection, financial recovery was achieved in the power sector.
- Financial recovery allowed TETAŞ and PMUM to pay current bills and eliminate arrears to private sector generators by 2010.
- The remaining cross-payables and receivables between public sector companies were offset through special legislation enacted by the Parliament in February 2011.

#### **2.1.2.13 Investor Response and Results**

The private sector's response to these legal, regulatory, and PMUM trading platform development measures has been spectacular. Some 31,000 MW in new generation capacity has been developed without sovereign guarantees since 2008. The Day Ahead Market operated by PMUM now covers about 30% of Turkey's electricity supply – and provides a price signal for electricity traded outside PMUM through bilateral contracts. The distribution privatization program was launched, carried out, and completed, as discussed in the following section. Finally, the number of market participants gradually increased and now exceeds 830, as shown in Figure 4. They are mostly private generators and wholesale/retail sale companies.

**Figure 4. Growth of Electricity Market Participants, 2003–14**

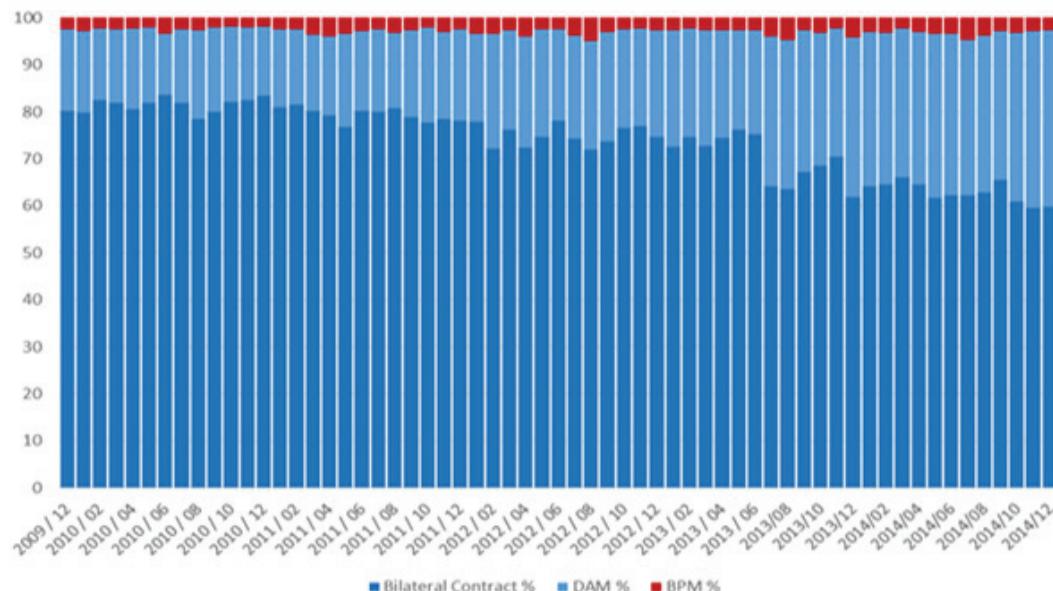


Source: TEİAŞ PMUM.

Approximately 70% of Turkey's electricity is currently traded through bilateral contracts. The remaining energy is traded mainly in the Day Ahead Market (DAM) and imbalances are resolved in the Balancing Power Market (BPM). Figure 5 shows the growth of the share of DAM in total electricity trading since the introduction of day-ahead trading.



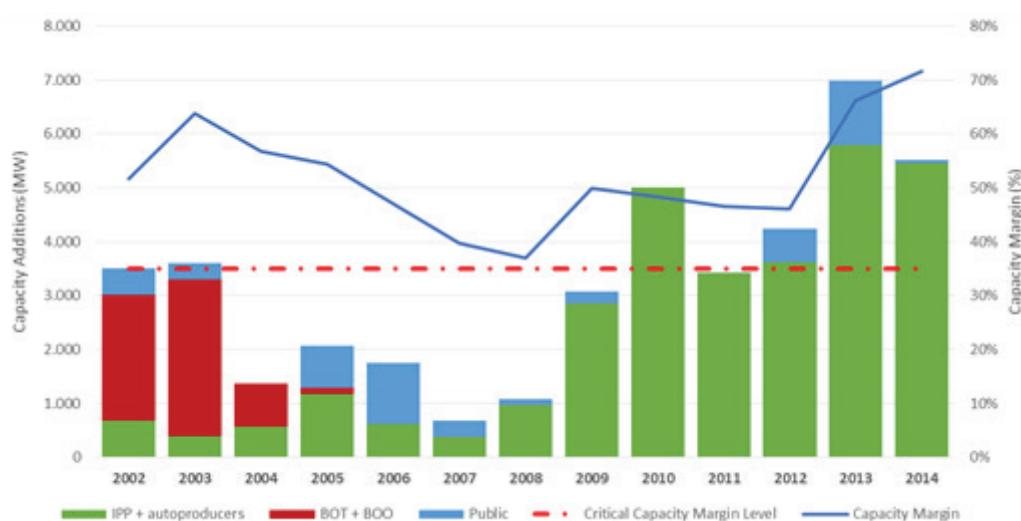
**Figure 5. Growth of Trading in the Day Ahead Market, 2009–14 (%)**



Source: TEİAŞ PMUM.

Figure 6 illustrates generation capacity additions and capacity margin from 2002 to 2014. (Capacity margin shows the percentage of total nominal generation capacity in excess of peak demand. It provides an indication of supply/demand balance but should not be confused with reserve margin, which reflects actual availability of generation capacity.) For Turkey, experience has shown that the capacity margin should not be less than 35% due to the high share of hydro and the low availability of EÜAŞ lignite plants. (This is shown in the chart as the “critical capacity margin level.”)

**Figure 6. Generation Capacity Additions and Capacity Margins, 2002–2014**



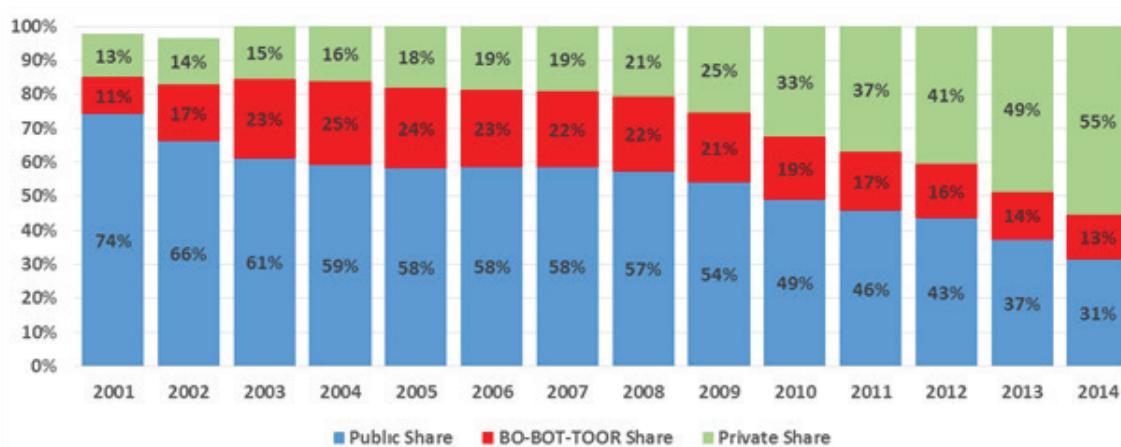


After the 2000–01 crisis, Turkey had embarked on a path of concerted reform which had yielded robust economic growth of over 6% per year from 2002 to 2007. Projections up to 2007 had shown the capacity margin falling well below the critical 35% level in 2009 and rapidly further thereafter. Figure 5 shows that margins actually increased. This is because in 2008 the global economic downturn hit Turkey's economy. Growth decelerated and GDP started falling in the 4th quarter of 2008. It brought the annual growth for the year 2008 down to 1.1% and to -4.8% for 2009. The economy then rebounded and registered a growth of 9 percent for 2010. Since 2010, economic growth has settled at a 3–4% annual level and electricity demand growth – at 4–5% per year – has settled well below the 6–7% annualized rates of the previous decade. Power generation investments have continued and capacity additions peaked in 2013. Generation capacity margin has reached 70%. The market would be over-supplied were it not for the severe drought that affected hydro generation in 2014.

In the late 1990s and early 2000s, the risk and cost of overcapacity was borne by the public sector – directly by TEAŞ and TETAŞ and indirectly by the Treasury as the guarantor of the BOT/BOO contracts. Now the risk and cost of overcapacity are borne primarily by the private sector as the owners and financiers of market-based generation companies. Competition in the electricity market has increased. Most affected are older, less-efficient gas-fired plants, which are finding it increasingly difficult to cover their cost of generation. Consolidation in the market is expected: some old plants have already been closed and others are expected to follow. However, unlike in 2000–01, the banking sector is expected to be able to withstand the impact of the financial difficulties of some of its clients. The challenge for the government is to persuade investors and their financiers to continue to invest so that supply security can be maintained after the current temporary surplus situation is over.

Figure 7 shows the fundamental shift from virtually 100% public sector generation toward market-based private sector power, which at 55% already accounts for the majority of the power supply – less than 14 years after the enactment of the EML in 2001. It should also be noted that BOO plants (which represent 10% of total capacity) could also be included in the private sector share since they are private generation investments that, unlike BOT plants, will not be transferred to the public.

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





### 2.1.2.14 Privatization

#### *Sequencing*

The 2004 Strategy Paper placed top priority on privatizing distribution. This “privatization of distribution first” approach aimed to create a reliable distribution sector that in turn would give confidence to prospective investors in generation privatizations and new capacity additions. TEDAŞ was not in a position to provide such confidence. If generation privatization had been attempted ahead of distribution, the generators’ main customer would have been TEDAŞ. The assessment was that generation privatizations were not likely to succeed as generators would not contract with TEDAŞ in the absence of state guarantees. Guarantees were not available – nor were they sought, as they would have marked a return to the pre-2001 privatization method, which was against the competitive market-based approach of the EML.

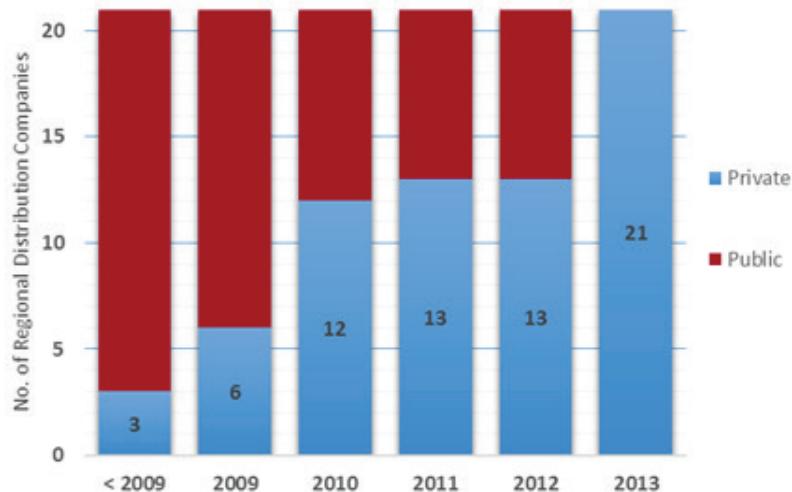
The second issue was the lack of the reliable metering, billing, and balancing-settlement functions required for effective wholesale competition; time and investment is needed to establish such an environment. The third issue was the desire to reduce loss and theft through efficient private sector management.

#### *Distribution Privatization*

Distribution privatization was adopted as the best available means to raise required investments and achieve a sustainable long-term solution to satisfactory bill collection and distribution network efficiency. The first privatization attempt in the 1990s was unsuccessful due to legal issues and regulatory uncertainties. By the time the second attempt was launched in 2008, these issues had been addressed: (a) legal issues had been resolved, in consultation with Danıştay, with a revised approach where the TOOR contract was executed between TEDAŞ and its subsidiaries and in the privatization the shares of these subsidiaries were offered for sale through a competitive bidding process carried out by the Privatization Administration (PA); and (b) regulatory uncertainties had been addressed through the enactment of the Electricity Market Law and EMRA regulations.

The approval of the cost-based energy pricing mechanism helped build private sector confidence to the extent that the government was able to launch the delayed implementation of the program to privatize electricity distribution. PA structured the sale in three phases – four tenders in 2008, three tenders in 2009 and eleven tenders in 2010 – eventually determining winning bidders for all 18 DistCos included in the program. However, seven of the 2010 tenders could not be completed and were eventually cancelled, then rebid in 2012–13. This time all seven were sold and the privatization program was completed in 2013, raising a total of about \$12.7 billion, as shown in Figure 8.

**Figure 8. Development of Privatization of Distribution Regions**



Source: PA

#### *Generation Privatization*

It was assumed that generation privatization could succeed only once there were commercial buyers (such as private distribution companies and wholesalers) in the market capable of contracting the output from the newly privatized generators and a developed centralized electricity market. Therefore, generation privatization commenced only after some progress was made in distribution privatization and after wholesale-retail trading mechanisms were introduced.

In line with this strategy, the government decided to privatize all thermal and some hydro plants of EÜAŞ. In addition to several small hydro plants, 10 large thermal plants have so far been tendered (5,758 MW) and transferred to their new private owners. The government plans to privatize the remaining plants gradually.

#### **2.1.2.15 Success Factors and Emerging Challenges**

As summarized in Figure 9, Turkey has substantially accomplished the targets it set out to achieve back in 2001. A combination of several factors, including the cooperation of several agencies, underpins the remarkable success of Turkey's electricity market development and distribution privatization programs in a period of crisis and turmoil in local and international financial markets. The government was perceived to be fully committed to market liberalization and market-based investment and privatization. The government decisively and repeatedly assured current and prospective investors that there would be no return to the sovereign guarantees of the 1990s, and that generation investors and the new private owners of privatized electricity companies would have the government's full backing.

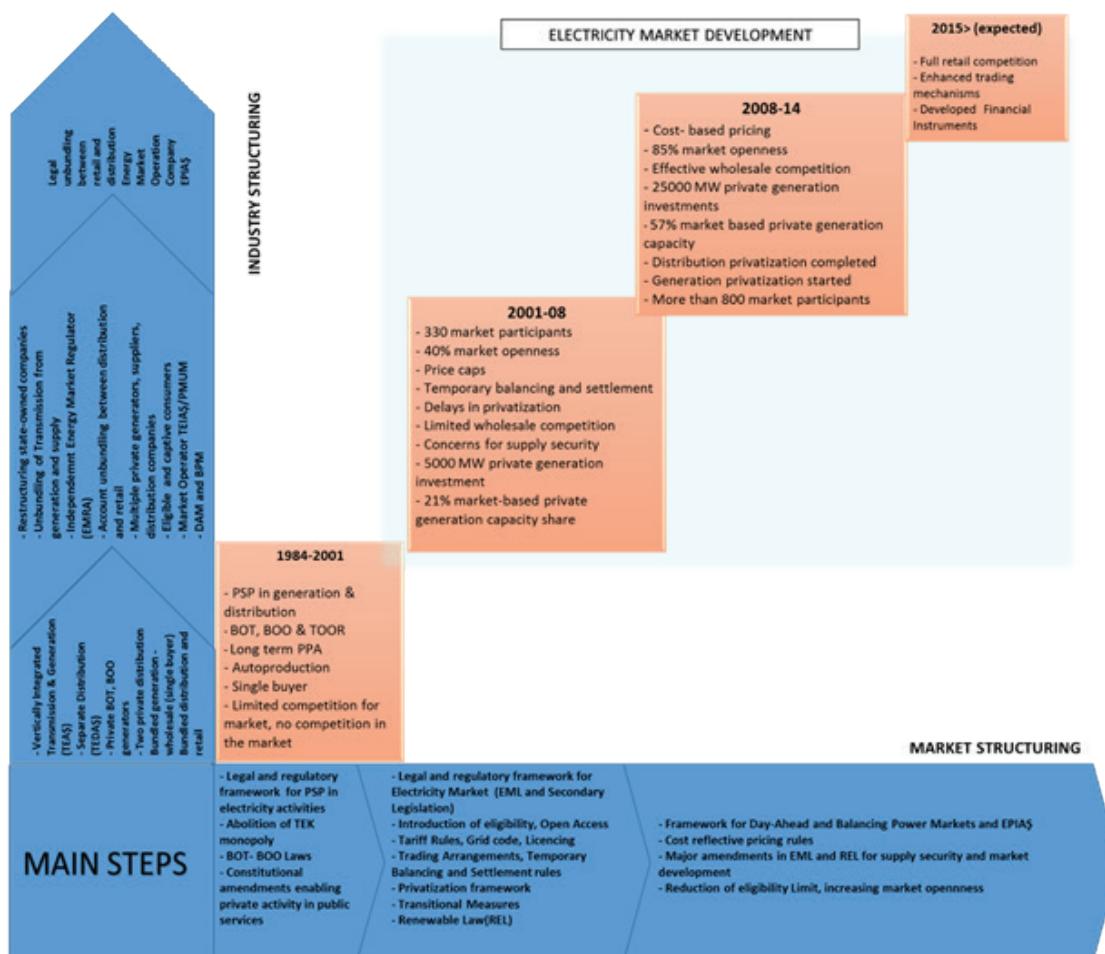
The private sector's strong response demonstrated the credibility of the government's commitment and the strength of the overall legal and regulatory framework. Turkey's legal and regulatory framework facilitated private investment and privatization and the administrators – the Ministry of Energy and Resources and the energy regulator (EMRA) on the energy side and the Ministry of Finance and the PA and its privatization advisors on the privatization transaction side – worked together effectively to implement the privatization program.

Finally, Turkey's overall favorable long-term growth prospects helped attract and encourage investors. The Competition Authority's contribution to the market design and implementation is also noteworthy. Its proposals for unbundling of distribution and retail supply, and its decisions on market share during privatization, helped increase the competitiveness of the electricity market.



## Turkey's Energy Transition - Milestones and Challenges

**Figure 9. Turkey's Measures on Industry and Market Structures and Electricity Market Development**



It is too early – detailed information is not yet available – to assess the performance of the privatized distribution companies. Discussions with some of the private companies and their industry associations indicate that a few companies are struggling and might not be able to meet EMRA's performance targets in system losses and/or bill collection. The cost-based tariff mechanism provides for sustainable operations as long as the companies meet or exceed EMRA's performance targets. But should companies fall below these targets, their finances would come under increasing pressure. TEDAŞ' system was divided into 20 companies to make it possible for local companies to participate in the privatization process and to increase competition. These goals were achieved and in fact competition was intense, even for the two companies in South Eastern Turkey – Vangolu and Dicle – with unusually high loss/theft rates. Views have been expressed suggesting that (a) EMRA's performance targets might be too aggressive for some of the 20 companies that were offered for sale; and (b) some bidders might have been too aggressive in their bid calculations and over-optimistic in their assessments of their ability to deal with loss and theft issues.

Although there is probably little that the government and EMRA can do about over-optimistic bid strategies, consideration could be given to adjusting EMRA's performance targets should objective assessments show them to have been too aggressive and/or based on inaccurate baseline information. Continuous and careful supervision by EMRA and coordination with the Competition Authority will be vital for the successful implementation of retail competition and the expansion of unlicensed generation in distribution systems.



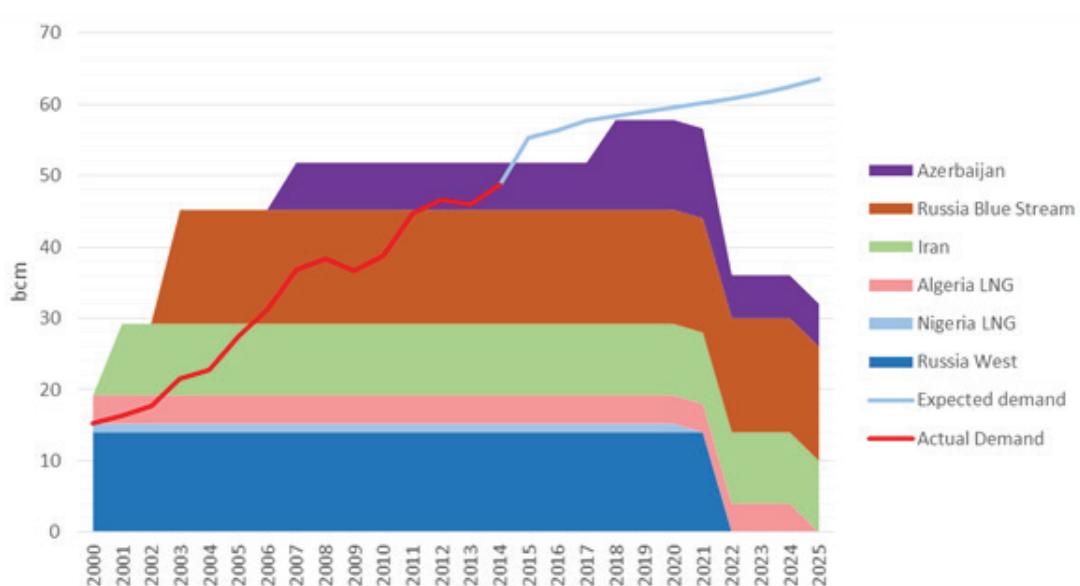
### 2.1.3 Gas Market Development

In sharp contrast to the electricity sector, progress in the development of the natural gas market has been markedly slow. The government has chosen to proceed cautiously with several key aspects of gas market reform envisioned in the 2001 Natural Gas Market Law. In line with power sector restructuring principles, the Natural Gas Market Law provided for the restructuring of BOTAS to separate its trading and infrastructure activities, but the actual unbundling has still not been carried out. The Law formally abolished BOTAS' monopoly rights on natural gas import, distribution, sales and pricing. BOTAS relinquished its effective monopoly in Turkey's gas imports by a tender in 2005 with the release of 4 billion cubic meters (bcm), and another 6 bcm was started to be imported by private sector companies in 2012. Despite strong efforts of the Government, BOTAS remains the major gas importer, with a market share of almost 80%. Seven private companies account for the balance.

The delay in unbundling BOTAS, and BOTAS not consistently applying the pricing mechanism, have enabled the government to moderate the impact of gas price increases in the international market. These practices have enabled Turkey to offer industries the second-lowest gas price in Europe – only Romanian industries have enjoyed lower prices, based on control of domestic gas producer prices. But these practices cause major distortions and undermine the development of a competitive gas market. The private sector has also expressed concern about the conflict of interest in BOTAS being both the major trader and the owner and operator of the gas transmission system.

As illustrated in Figure 10, existing long-term gas purchase contracts are not sufficient to cover the projected demand increase. Large-scale additional imports, including spot LNG, will be required. If not done by BOTAS these imports will require further liberalization of imports and hence amendment of the Natural Gas Market Law. Because of insufficient gas storage capacity, supply cannot meet the daily consumption in cold seasons. Furthermore, there are bottlenecks in BOTAS' gas network that constrain not only the flow of gas but also the trading of gas by its prospective competitors. Gas supply security will be at risk until these issues have been addressed.

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



Source: Prepared using BOTAS and EMRA data.

The 2001 Law proved more effective in helping Turkey attract private sector participation in gas distribution. EMRA organized highly successful and competitive tenders for licenses to build new city distribution networks and provide distribution and retail supply services. Currently 70 of Turkey's 81 cities enjoy gas service; private companies provide the service in all but one of the 70 cities. Competition for the distribution licenses was intense. Most of the winning companies in EMRA's tenders for licenses propose very low distribution charges, in some case no charges other than initial connection charges, for the first eight-year tariff period. EMRA is currently processing tariffs for the second tariff period. Distribution charges will inevitably have to be adjusted to better reflect the cost of distribution service, as EMRA has already done in electricity distribution.

### 2.1.4 Support for Renewable Energy

Turkey's support schemes, although conservative in the European context, have proven effective in promoting private sector renewable energy development. It is remarkable that Turkish companies have invested in wind generation selling to the electricity market or under a support scheme which pays them less than half of what Bulgaria and Romania offered to attract private companies under similar wind conditions. The overcompensation and politically sensitive, legally challenging (and possibly costly) reversals experienced in Bulgaria and Romania have so far been avoided. However there is a concern that if the subsidized solar capacity is not capped, solar support at \$133/MWh might lead to large-scale deployment and become a financial burden to electricity consumers in the future. Taking into account the continuing reduction in the investment cost of solar facilities, it might become possible in the medium term to develop Turkey's rich solar potential with support prices not higher than the market price.

#### 2.1.4.1 Market-based Invitation to Renewable Energy

Turkish private companies were invited to participate in market-based hydro development in 2004. They entered hydro – and, later, other renewable energy – development primarily because of the electricity market, that is, based on their expectation to be able to sell their output profitably at market prices to large consumers and traders. This was unlike the approach used in several European countries where the government encouraged private investment with highly attractive support schemes offering prices well above prevailing wholesale prices in their countries' electricity markets. There was initial hesitation in Turkish banks about renewable energy financing. The pioneering work by the Turkish Industrial Development Bank (TSKB) and Turkish Development Bank (TKB) showed the way, however, and larger banks soon followed. As a second step in efforts to attract the private sector into renewable energy development, the government prepared a Renewable Energy Law in 2005 to put in place a back-up safety mechanism for renewable energy. It provided for the purchase of renewable energy at \$55/MWh should the renewable generators not be able to achieve a higher price in the market.

#### 2.1.4.2 Conservative Support Mechanism

The private sector had been attracted to renewable energy development primarily on the strength and promise of the electricity market, backstopped with a conservative floor-price guarantee should market prices fall. Well-aware of the much more generous support schemes elsewhere, the government amended the Renewable Energy Law for more support also in Turkey. The Parliament in December 2010 approved an amendment providing enhanced support, including (a) technology-based feed-in tariffs and (b) a support mechanism (a renewable energy pool) that provides firm off-take arrangements. The approved feed-in tariffs for hydro and wind (\$73/MWh) were comparable to PMUM prices. The tariffs for geothermal power (\$105/MWh) and biomass and solar electricity (\$133/MWh), though significantly higher than PMUM prices, were nevertheless lower than some investors had sought, especially for solar. Instead, the amendment provides additional support through local content incentives. The government established these prices based on the assessment and expectation that prices of renewable energy technologies would continue to come down and therefore higher support prices should and could be avoided.



Turkey's mechanism provides for renewable generators to choose for a 12-month period, in October of each year, whether they wish to use the support mechanism for the following 12-month period or sell to the market. Initially in 2012 and 2013 investors chose the market by a wide margin. In view of the current uncertainties many investors opted to move to the support mechanism for 2015, with the result that about one-half of eligible renewable capacity will now fall under the support mechanism and one-half will sell to the market. The 2013 Electricity Market Law removed licensing requirement from small (less than 1 MW) renewable energy plants and obligates distribution companies of the areas where such plants are located to buy electricity from such plants (with compensation from PMUM as this is a national scheme). These special arrangements for small renewable generators are expected to accelerate solar development in particular.

As a result of electricity market development and support mechanisms described above, about 16,000 MW of new generating capacity using renewable sources was commissioned in 2002-2014.

#### ***2.1.4.3 Environmental and Social Dimensions of Renewable Energy Development***

Renewable energy enjoys wide support compared to thermal power generation. However, large-scale renewable energy development, even small and medium-size projects, inevitably comes with significant environmental and social impacts of its own. Turkey is no exception. The environmental impact assessment and project clearance process has at times been overwhelmed by the number of applications. Developers have complained about complicated procedures, delays, and lack of transparency. Environmentalists and citizens have expressed concern about inconsistent application of environmental permitting and licensing procedures/guidelines and the adequacy of public information provided for decisions made.

In various parts of the country, renewable energy projects (especially hydro) have caused some public reaction, mainly due to (a) the lack of adequate public consultation prior to licensing and the decision-making stages of the projects and (b) the expedited expropriation procedures used during such projects. While depending on the size of the projects and the environmental category, consultation may be required during the EIA preparation, meaningful and accessible consultation with the communities before, during, and after the project construction is often lacking. As a result, the courts remain the main venue to which people resort in order for their grievances to be addressed. The process is not optimal for managing public reactions and social risks.

Assessment of the cumulative impacts of renewable development has proven particularly challenging. The environmental impact assessment and project clearance process is focused on individual projects by different developers at different times, rather than on a series of projects along a river or a group of wind projects. Planning at the river basin scale is now being adopted by the government. However, it will take 5–10 years to prepare integrated plans for all 25 river basins and many more hydropower plants will be built by then. Solutions to wind development now applied in Turkey include an annual licensing cycle and competitive bidding by TEİAŞ for access to the grid. Time will tell if and how well these approaches address the issues.

Associations of developers emphasize that the whole sector suffers from the mistakes of a few inexperienced developers. They agree that people affected by such mistakes should be compensated but the whole sector should not be questioned. All parties seem to agree that there is need for more consultation and more transparency in the process and for explicit justification of decisions (whether approvals or rejections). They also express the need for shortening the lengthy review process and standardizing rules and procedures.



### 2.1.5 The Leading Role of Turkish Investors and their Mostly Turkish Financiers

Turkey's electric power reform program has attracted large investments from several foreign companies. Two of them – CEZ from the Czech Republic and E.ON from Germany (taking over from Verbund from Austria) – got involved in electricity distribution following the privatization program, both as partners with well-established local companies. In addition to CEZ and E.ON, six other foreign companies are generating electricity in Turkey: 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 them as partners with well-established local companies and all without long-term contracts. (In addition, Tata from India is developing a hydro project in Georgia for export into the Turkish market.)

Foreign banks that have provided project financing include BNP Paribas, BPCE, Deutsche Bank, Erste Group, MUFG, Raiffeisen, Société Générale, and Unicredit. The European Bank for Reconstruction and Development (EBRD), European Investment Bank (EIB) and International Finance Corporation (IFC) have also made significant financial commitments. Yet although this is an impressive list of companies and banks, foreign investors and foreign financing have played a relatively minor direct role in Turkey's energy sector – especially in the power sector, where the bulk of private investment has been placed. Foreign investment and external financing also support Turkey's energy sector indirectly, through Borsa İstanbul (the Istanbul Stock Exchange) and local banks. It is expected that foreign companies will increase their involvement in the future through acquisitions of stakes in generation and possibly also some of the distribution companies.

A leading private sector role has been played by Turkish investors and their mostly Turkish financiers. The “secret” of the success of Turkey's energy reforms has been the three-way collaboration and risk-taking between (a) successive governments, (b) public institutions and state-owned energy companies, and (c) Turkish investors and their mostly Turkish financiers. The collaboration flourished following passage of the 2001 electricity and natural gas market laws that launched the process of energy market liberalization. Turkish investors took the risk of investing in power generation without sovereign guarantees on the strength and promise of the market at the time when the market existed only on paper in the 2001 Electricity Market Law. They continued to invest year after year without waiting for an established market. Their desire for a centralized market was evident – they rushed sell to PMUM when it was launched in 2006 – but the occasional calls for long-term contracts come not from them but from financiers. They continue to trade increasing volumes on PMUM. More than a hundred have applied to become shareholders in the “new PMUM,” the Energy Market Operations Company (EPIAŞ).

The 2005 Renewable Energy Law increased attention of private investment in renewable energy. The response from the private sector, mostly Turkish companies, exceeded all expectations. The first wave of investments went to hydro, then wind, and now solar is starting. The remark “If you do not have a 20-megawatt hydro plant, you are nothing” reflects the enthusiasm of Turkish investors. Not only experienced Turkish construction firms but also other Turkish companies with little or no prior energy experience have invested in medium-size hydro development, more recently in wind, and presumably soon in solar.

Following the deep restructuring of the banking sector after the 2000–01 crisis, Turkey has a banking sector capable of providing large volumes of financing to Turkish investors. They have provided most of the debt financing to the energy investors. Although Turkish banks have shown substantial willingness to take energy risk, they have required investors to carry primary risk. They have required equity, which is normal, and they have also preferred corporate finance instead of project finance. Many Turkish companies diversifying into energy have obtained a part of the debt finance for their energy projects based on the strength of their balance sheets. The use of the capital market, through initial public offerings (IPOs) and bond issues, has been limited and offers substantial potential for financing a part of the future energy investment



needs. Many companies, even large companies that diversified into energy are family-owned and could consider IPOs. The government owns several energy companies which would be good candidates for IPOs. Availability of financing is not expected to become a constraint to energy investment as long as electricity and gas markets function and prices are allowed to be set in the market.

### **2.1.6 Turkey's Nuclear Program**

Turkey has a long-standing interest in nuclear power. The Atomic Energy Commission was established in 1956. The Commission was restructured as the Turkish Atomic Energy Authority (TAEK) in 1982. The first feasibility study on a nuclear power project was done in 1970. Proposals and attempts to initiate projects were also made in 1973, 1976, 1980, and 1992. Nuclear power was included in Turkey's development plan in 1993 and a formal bidding process for a 2,000 MW plant was launched in 1996. After a series of delays and postponements, that effort was finally abandoned in 2000 as the economic situation continued to deteriorate. After the recovery from the economic crisis, the nuclear effort was restarted once again in 2006.

In 2007 a new Law on the Construction and Operation of Nuclear Power Plants and Energy Sale (Law 5710) was enacted and in 2008 companies were invited to submit bids to build and operate a nuclear power plant in Akkuyu (a small town on the Mediterranean coast) on a BOO basis. Treasury guarantee was not offered; however, TETAŞ would be the off taker. Only one company, a consortium led by the Russian state-owned nuclear vendor Atomstroyexport, submitted a bid, and finally the tender was cancelled. After several unsuccessful competitive tendering attempts, the government decided to pursue direct negotiations with the Russian government. Following intergovernmental negotiations, an intergovernmental agreement between the two countries was signed by the Turkish Prime Minister and the Russian President in May 2010 for the construction of a 4,800 MW plant (four units of 1,200 MW) in Akkuyu. The Turkish and Russian parliaments ratified the agreement later that year.

These developments "re-energized" some of the prospective suppliers that had not bid in the first process, and various proposals were subsequently received. The government carried out discussions and negotiations with several groups and their governments. A second contract was concluded in 2013 with a French-Japanese consortium for a 4,480 MW plant (four units of 1,120 MW). The second plant will be located in Sinop on the Black Sea coast. Intergovernmental Agreement was ratified by Turkish Grand Assembly (TBMM) in April 2015. According to the Intergovernmental Agreement, the years of commissioning of the four units are 2023 for unit I, 2024 for unit II, 2027 for unit III, and 2028 for unit IV. Additional contracts are expected.

TETAŞ will buy 70% of the output of Akkuyu units 1&2 and 30% of units 3&4 for the first 15 years of commercial operation of each unit at an average prices of \$123.5/MWh. The remainder of the plant output is to be sold by the Akkuyu Company on the electricity market. The government, either directly or through state companies, is not taking an initial equity share. The Akkuyu company starts with 100% Russian ownership, but plans to reduce Russian ownership to as low as 51% have been reported. Turkish companies (public and private) may therefore become shareholders later during construction and/or operation. After 15 years of operation – by which time the debt portion of the financing of the plant will have been paid off – the Akkuyu Company is to pay 20% of its profits to the Turkish government. TETAŞ will buy 100% of the output of the Sinop plant an average prices of \$108.3/MWh (excluding fuel). EÜAŞ is taking a 49% equity share in the project. With equity participation by EÜAŞ and the purchasing of 100% of the Sinop plant's electricity by TETAŞ, the exposure of public companies is higher than to the Akkuyu plant.

At \$123.5/MWh the electricity from Akkuyu and \$108.3/MWh (excluding fuel) the electricity from the Sinop plant will be well above the market price for base-load power in the Turkish market. The government is widely expected to put in place arrangements to ensure pass-through of the cost to electricity consumers in one way or another, arguing along the lines of the UK government<sup>10</sup> that the benefits in terms of security of supply, diversification, and climate change



mitigation justify such arrangements. Guaranteed off-take arrangements, whether for nuclear or renewable energy, inevitably reduce the size of the competitive market (that is, the market that is available for private companies to contest).

The government's energy strategy envisions a series of nuclear projects. If the economy continues to grow at 3–4% average annual rates, electricity demand will continue to grow at 4–5% average annual rates. Though the growth rates are lower than in the previous decade, the system is larger and continued large capacity additions will be needed. Turkey's strategy calls for an increasingly diversified fuel mix in electricity generation: reduced share of gas, increased share of renewables, full utilization of remaining lignite resources, and introduction of nuclear energy as a major source of base-load power. The preparations for the first two nuclear projects that are planned to go into construction in the next few years have faced opposition from the local population and the civil society. For the future implementation of nuclear program, the government could consider increasing (a) information dissemination about the role of nuclear energy and need for continued power generation expansion, (b) consultations regarding site selection, (c) transparency about waste management and emergency plans; and (d) the separation of TAEK's regulatory functions into an independent nuclear regulatory authority. A new Nuclear Energy Law is under preparation and reportedly covers areas (b)–(d).

### 2.1.7 Political Developments and the Authorizing Environment for Energy Reform

Turkey experienced major political changes during the period covered in this review. The 1980s started with a military coup in September 1980. The governments that followed the short period of military rule typically proved unstable and short-lived. Economic performance varied from year to year. Deficits increased and the economy slowed down toward the end of the 20<sup>th</sup> century. The 21<sup>st</sup> century started with a deep crisis in Turkey. This seemingly never-ending cycle of political turbulence and turmoil provided a challenging political context and an unstable authorizing environment for implementing energy reforms in the 1980s and 1990s. The 2001 economic crisis finally gave energy reformers an opportunity to put forward and secure approval of a highly ambitious legislative package for electricity and gas reform.

In sharp contrast to the 1980s and 1990s, Turkey has had a stable government in 2002–2015. After the 2002 Elections, a new government “inherited” the 2001 energy reform package and decided to support and continue to implement it. However, the initial pace of reform implementation was slower than reformers had hoped for. Petroleum prices were liberalized in 2005 but caution was highly visible in electricity pricing: constant prices were maintained for five years in 2003–07.

After returning to office in the 2007 parliamentary elections, the government responded to the emerging electricity-supply security risk in an impressive manner. Energy reforms accelerated from 2008 and yielded spectacular results in the power sector, including renewable energy development, as discussed previously.

The government has proceeded more cautiously with gas sector reforms. In contrast to the 2001 Electricity Market Law, the government delayed the implementation of key measures in the 2001 Natural Gas Market Law, and BOTAS has not been able to consistently implement the 2008 cost-based energy pricing mechanism. As discussed previously, the reform of the gas sector remains unfinished.

Although the government has left “regular” energy contracts and investments largely to the private sector, it continues to play an active role in BOTAS gas imports and nuclear power development/contracting. Sovereign guarantees have not been provided but, with BOTAS as the main purchaser of gas and TETAŞ as the primary purchaser of nuclear power from these contracts, the government is committing the public sector to large, long-term obligations.



## 2.1.8 Energy Pricing and Subsidies

Price reform is an essential part of successful energy reform where prices are below cost-recovery levels and government ability to provide subsidies is limited. This seemingly obvious fact is easy to state but difficult to turn into action, and price reform has proven elusive to implement in many countries. Although Turkey has made remarkable progress in energy price reform, challenges remain, especially in the natural gas sector.

### 2.1.8.1 Petroleum

Petroleum price reform and liberalization was the first to be attempted and also the first to be accomplished. The process took place over decades. Liberalization process effectively started in 1983 with the restructuring of TP. Price liberalization followed in 1989 with a law that allowed private companies the right to set prices. The initial impact was limited, however, as state companies continued to dominate the sector and private companies' effective pricing freedom was limited.

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

The 2003 Petroleum Market Law put EMRA in charge of the petroleum market, along with electricity and gas markets it had been established to develop in 2001. In accordance with the 2003 Law, petroleum prices were fully liberalized in 2005. EMRA continued to monitor the functioning of the market and has intervened in cases of suspected price collusion. Retail prices of gasoline and petroleum are high due to high excise taxes. Targeted tax breaks have been provided to public transport and agriculture.

### 2.1.8.2 Electricity and Natural Gas

Electricity and natural gas prices were administered by the government (via the Energy Ministry) until EMRA's establishment in 2001. However, while price regulation was transferred to EMRA under the 2001 electricity and natural gas market laws, in practice the government influence continues today. The 2008 cost-based energy pricing mechanism was designed to remove government control. The mechanism has been effective in electricity, where EMRA has applied the pricing mechanism since 2008 – with impressive results, as discussed above. BOTAS has not been able to consistently operate the mechanism – an issue which still today holds back the development of the natural gas market and indirectly affects the electricity market. Through BOTAS the government effectively controls the wholesale price of gas, leaving EMRA to regulate gas distribution and supply services.

### 2.1.8.3 Public Acceptance

Undoubtedly Turkish drivers do not appreciate the fact that the gasoline and diesel prices they pay at the pump are among the highest in Europe. Petroleum, electricity, and gas price adjustments have nevertheless been accepted by the consumers. Acceptance of the high petroleum prices and the significant electricity price adjustments of 2008–09 have been facilitated by Turkey's economic growth since 2002 and the accompanying growth in household incomes which has eased the burden caused by higher prices.

There are at least 22 governmental social support mechanisms. The only targeted energy subsidy is the provision of free coal 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. Because households account for a small share (about 20%) of electricity consumption and an even smaller share of gas consumption (directly or through electricity), direct subsidy to low-income households would be less expensive than the current across-the-board subsidy on the wholesale price of natural gas. Residential electricity prices currently include a higher electrical-energy price component than the prices paid by non-residential consumers – a factor that should encourage these consumers to switch suppliers when they become eligible to do so.

Instead of the impact of energy price increases on households, the government's primary economic concern is the impact of energy price increases on the economy through their effect on inflation and the competitiveness of Turkish industries. The political economy assessment seems to be that energy price adjustments can continue as long as they do not jeopardize economic growth and the growth of household incomes. It appears that energy price adjustments have been accepted as an inevitable cost of development. However, acceptance does not mean that all households can comfortably afford to pay their energy bills, and social support and energy efficiency programs targeted at low-income consumers could be considered.

### 2.1.9 The Bottom Line: the Results of Turkey's Energy Reforms

Energy reforms have ensured the security of the energy supply required to meet the demand stemming from Turkey's rapidly growing economy as well as a fast-growing population with rapidly increasing incomes.

Key lessons from Turkey's energy reforms are summarized in Table 1 at the end of this section. These lessons are drawn, and Turkey's accomplishments are discussed, in the preceding Part I of this overview, which presents Turkey's transformation toward the competitive electricity and gas market model it set out to implement in 2001. The focus of the discussion is on the electric power sector; progress in the gas sector has been more limited and is accordingly covered in more detail in Section 2.2, which focuses on energy reform challenges.

Energy security has been achieved through large investments. Since 2001 the bulk of investments have been provided by private investors, based on the strength of the electricity and gas markets, without sovereign guarantees. This has helped Turkey's efforts to maintain fiscal and external balances.

Energy security has been achieved by diversifying Turkey's primary energy mix, as facilitated by energy reforms:

- The transport sector remains dependent on petroleum products, but the use of oil in power generation has been virtually eliminated, and its industrial use has been reduced;
- Natural gas went from zero in 1987 to a major source of energy two decades later, most notably in power generation (to a share of almost 50%);
- Private sector investment was attracted to complement EÜAŞ' hydroelectric generation and take the lead in other renewable energy development following the enactment of the Renewable Energy Law in 2005; and
- The next major diversification step has been launched with the signing of contracts to implement two very large nuclear power projects for commissioning in the next decade.

Energy security has been supported through more efficient use of energy, facilitated by energy reforms including largely market-based and cost-reflective energy prices. Improved energy efficiency helped contain demand growth and improve not only energy security but also Turkey's overall competitiveness.

The "secret" of Turkey's success in reform implementation is the three-way collaboration and risk-taking between (a) successive governments, (b) public institutions and state-owned energy companies, and (c) Turkish investors and their mostly Turkish financiers.

**Table 1. Key Lessons from Turkey's Energy Reforms**

Reform Features	Application in Turkey	Applicability in other Countries
Legal framework	Electricity and Natural Gas Market Laws, Renewable Energy Law	Functioning legal system and an independent judiciary.
Regulatory framework	EMRA	Independence and professionalism require government commitment and support and capable professionals.
Centralized electricity market	PMUM, soon EPIAŞ	Multitude of sellers and buyers required. For smaller countries/systems this may be achievable through regional market solutions.
Starting a market	State companies and existing private companies with generation, including industrial self-generators (autoproducers)	Willingness to allow state companies to sell to a market. Existence of captive or other private generation capacity.
Dealing with existing long-term contracts	TETAŞ in parallel with PMUM (contracts and market in parallel).	Availability and capacity of transition vehicles.
Sequencing of reform actions	Initial generation investment preceded distribution privatization, large-scale generation investment in parallel with distribution privatization, generation privatization at a later stage. Parallel centralized platforms, PMUM for market-based generators and TETAŞ for guaranteed IPPs.	Credibility of the government commitment to implement reform legislation and strategy. Availability and capacity of transition vehicles.
Availability of new long-term contracts	Contracts beyond one-year duration are not available yet. Borsa İstanbul is to offer financial instruments.	Strength of the market to attract investors and financiers without long-term contracts
Wholesale market price	Set at PMUM based on supply and demand. TETAŞ in parallel.	Willingness to accept market prices instead of price controls.
Mitigation against gaming/price manipulation by market participants	The government has and will retain through TETAŞ and EÜAŞ sizeable presence in the wholesale market. EMRA and Competition Authority can investigate alleged manipulation.	Strength of public institutions, market share of public generators/suppliers.
Retail market price	Cost-based pricing mechanism, operated by EMRA, as a transition mechanism. Continued EMRA regulation of network services.	Willingness to accept cost recovery, including pass-through of wholesale prices.
Renewable energy development	Based primarily on a functioning centralized electricity market; technology-specific feed-in tariffs provide supplementary comfort. Intra-day market to facilitate large-scale inflow of renewables.	Functioning wholesale market required.
Distribution privatization	Legal and regulatory framework and institutions. Privatization Administration, EMRA, Daniştay.	Government commitment essential but solid legal and regulatory framework and institutions also required.
Business environment	Well-established local companies and new prospective local entrants with high risk appetite. Foreign companies present but energy sector not dependent on foreign participation.	Existence, size, and risk appetite of local businesses.
Banking sector	Strong local banking sector (after deep banking sector reform). Foreign banks present, primarily through local banks.	Existence, size, and risk appetite of local banks.
Capital market	Borsa İstanbul (large stock exchange), local and foreign investors.	Existence, size, and risk appetite of investors.
Economic growth	Successive governments managing economy for sustained growth, for the welfare of citizens and for continued success at the polls.	Political stability, ability of governments to look beyond the immediate future and current issues.
Energy security for economic growth and welfare of citizens	Rapid economic growth after successful recovery from the 2001 economic crisis, growing demand for energy.	Is energy security at risk, now/in-the-near term or in the medium-to-long term?
Fiscal balance	Determination to limit contingent liabilities.	Fiscal situation. Ability of government budget to carry contingent liabilities.
Current account	High energy import dependency. Need to contain energy import bill to moderate current account deficits.	Domestic energy resource endowment. Share of energy in the country's import bill.
European Union	Accession prospect is an anchor for Turkey's own modernization process.	Existence of influential external reform drivers.
Regional integration	Potential to become a regional energy hub for improved energy security for Turkey and to contribute to energy security in the region and in Europe (especially in gas).	Geographical and geopolitical feasibility of integration.
Public acceptance of energy price adjustments	Adjustments accepted as inevitable part of economic growth and development. Increases in household incomes have preceded electricity and gas price adjustments. No targeted social support for low-income consumers.	Economic and household income growth prospects. Existence of effective social support mechanisms for low-income consumers.

## 2.2 Overview Part 2: Energy Reform Challenges

Past success may help to show the way forward, but it does not guarantee future success. Turkey's economy continues to grow. The demand for energy, especially electrical energy, continues to grow. The energy sector will have to meet this growing challenge to secure the energy supply required for Turkey's growth and development and the welfare of its citizens. Some of the issues facing the government now may prove as challenging to deal with as the issues of the past decade. Turkish investors and their mostly Turkish financiers have invested a lot and learned a lot, but their enthusiasm has waned. As their capacity to take risks has increased, their understanding of the risks has as well. They expect energy market liberalization to continue and they expect governance and transparency in the energy sector to continue to improve and increase.

The situation is most critical in the gas sector, where the progress of reform is well behind that of the electricity sector and supply security is at risk. However, with natural gas having the highest share in power generation, issues in the gas sector affect the electricity sector directly – even if, in terms of nominal generation, the electricity market is currently over-supplied. Governance issues in EMRA, state-owned energy enterprises, and the Ministry of Energy cut across the whole energy sector.

Turkey's economic growth for 2014 is estimated at 2.9%. The World Bank projects Turkey's economy to continue to grow at an average annual rate in the 3.0-3.5% range in 2015–17, noting downside risks from uncertain global conditions including continued slow growth in Europe and geopolitical tensions. The decline in oil prices since mid-2014 and the ongoing decline in gas import prices may boost growth and ease the current account deficit and inflation in 2015.

However, domestic and foreign investors are deterred by concerns over the unpredictable business climate and the strength of key economic institutions in Turkey. These concerns include the business climate 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 in the three-way collaboration explaining the success of Turkey's energy reforms – are concerned about the continuation of energy market development and the operational autonomy and transparency at EMRA, state-owned energy enterprises, and the Ministry of Energy. Notwithstanding the remarkable accomplishments summarized in the first part of this overview, reform in the energy sector must continue if Turkey is to secure its electricity and gas supplies without having to return to large-scale – and, in the long run, unsustainable – government 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.

The following sections will discuss each of these in turn.

### 2.2.1 Natural Gas Market Reform

After a brief period of over-supply in the gas market – with BOTAS being over-contracted – demand is catching up with contracted import volumes. Current gas demand, at about 47 bcm per year, is already close to the total contracted supply of about 52 bcm per year. Gas demand exceeds available supply during cold winter days, resulting in supply curtailments. With government support, BOTAS recently contracted additional supply from Azerbaijan, which will add about 6 bcm per year to Turkey's contracted import volume by 2018. Negotiations with Russia are underway on gas prices, new pipelines and purchase of additional gas. LNG imports will be required, including spot imports to deal with short-term shortages. Additional supplies including from new sources and new supply routes will be required as existing contracts expire.



In contrast to the remarkable progress in gas distribution privatization and gasification program, gas market development is well behind electricity. A comprehensive set of measures is needed for medium-to-long supply security, starting with an amendment of the 2001 Natural Gas Market Law and including the unbundling of the national gas company BOTAS and consistent application by BOTAS of the cost-based energy pricing mechanism. These measures are needed to increase the share of the private sector in gas imports, to enable Turkey to realize its ambition to become a regional energy hub, and to improve and maintain gas supply security.

A package of five broad measures would advance the development of the gas market:

1. Facilitating gas imports by the private sector;
2. Restructuring BOTAS;
3. Cost-reflective and transparent wholesale gas pricing by BOTAS;
4. Developing a centralized gas trading platform and mandating BOTAS to progressively trade its gas through the 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 proposed amendment to the Natural Gas Market Law to the Parliament. However, although the draft includes some of the five reform measures, their formulation raises considerable uncertainties:

- The draft amendment would eliminate gas import restrictions on companies other than BOTAS; these restrictions currently forbid imports from countries with which BOTAS has signed gas purchase agreements. This modification has been sought by the private sector for a long time. However, (a) the modification comes with the requirement that prospective importers must obtain the Energy Ministry's approval (not even spot LNG imports are excluded) and (b) BOTAS can continue to enter into new pipeline gas import contracts (with the approval of the Council of Ministers) in case gas supply security is endangered or for the purpose of export. These provisions may deter private initiatives, especially by companies not affiliated with gas producers in Turkey's long-standing import countries, Russia and Azerbaijan.
- The draft amendment retains the target included in the 2001 Law to reduce BOTAS' share of gas imports to 20%. Although the 2001 Law set 2009 as the deadline for reaching this target, actual progress by 2009 was marginal and BOTAS' market share remains almost 80%. The amendment contains no deadline.
- The draft amendment provides for the separation from BOTAS of its gas transmission, storage, and LNG activities into two separate companies, one for the gas transmission network and operations and one for gas storage and LNG terminals. The private sector has long sought such a restructuring. According to the amendment, this unbundling process is to be finalised within one year after the enactment of the law.
- The draft amendment provides for the forthcoming Energy Market Operations Company, EPIAS, to expand its operations beyond electricity and also become a gas market operator. EPIAS is currently being established, as provided for under the 2013 Electricity Market Law. However, the draft amendment contains no deadlines for expansion of its operations into the gas market.

Notwithstanding these observations, the proposed NGML amendments will be an important step toward establishing a competitive natural gas market.

### **2.2.1.2 BOTAS**

BOTAS will remain the largest gas importer for the foreseeable future. Over time its market share will progressively decline if it does not sign new purchase agreements as the demand for gas in Turkey increases and BOTAS' existing import contracts expire. The effective unbundling of BOTAS should help ease private companies' concern about BOTAS enhancing its market position through its control of the network. The private sector will closely watch the progress of the gas law amendment, the unbundling of BOTAS, and EPIAS' progress in developing a gas trading platform (and preparatory steps by EMRA and BOTAS ahead of EPIAS' gas market operations) for signs of the government's intent and commitment. BOTAS could also be obligated to trade an increasing share of its gas imports through the new EPIAS platform to (a) help develop liquidity and (b) reduce both its role in bilateral wholesale gas supply contracting and the scope for cross-subsidies.

### **2.2.1.3 Wholesale Gas Pricing**

Even if the 2001 Law is amended as proposed and the above measures are implemented, reform of the gas market will remain incomplete without cost-reflective and transparent wholesale gas pricing by BOTAS. An effective gas market cannot be established without removing price distortions to create a more level playing field for BOTAS and its competitors. The ongoing decline in gas import prices provides an opportunity to reform BOTAS' wholesale gas pricing in 2015 without having to significantly raise prices charged to BOTAS' market-based customers. Negotiations with Gazprom continue and so does the arbitration case with Iran on gas prices. The government and BOTAS expect significant price reductions from both. LNG prices might fall even more than pipeline gas prices in 2015. The burden of possible price increases stemming from subsidy reductions would be borne by users, not taxpayers, through foregone oil import tax revenue. A social subsidy targeted at low-income consumers could be considered.

### **2.2.1.4 Transmission System Bottlenecks and Gas Storage**

Requiring BOTAS and its successor gas transmission network company to eliminate network bottlenecks would be the easiest part of the natural gas market reform. Feedback on network investment plans and proposals for the most pressing priority projects could be sought from market participants. BOTAS has demonstrated its capacity to develop and implement gas transmission network projects. This capacity would be transferred and would be available in the unbundled gas transmission network company. The new gas transmission system operator will also have an important opportunity to promote gas market development by improving the transparency of BOTAS' congestion management practices.

A significant increase in gas storage capacity would also be required, not only to support the functioning of the gas market but also to secure the supply. This is because, at about 2.6 bcm, Turkey's existing storage capacity represents only about 5% of annual gas consumption. In comparison, other large European gas-importing countries have storage capacities representing 20–30 percent of their annual consumption. The 1.0 bcm Tuz Gölü gas storage project is under construction and large potential for further storage development exists. The draft amendment of the Natural Gas Market Law provides for the separation from BOTAS of its transmission system and gas storage and LNG terminals into two separate companies. The transfer of TP's existing gas storage facilities and ongoing storage investments into the new storage and LNG terminals company should be examined as it would help create a stronger storage company from the beginning.

### **2.2.1.5 Developing Turkey into an Energy Hub: Gas**

Turkey has the vision and the potential to become a regional gas hub. Turkey has a nationwide gas transmission network of connecting pipelines bringing its gas imports from Russia, Azerbaijan, and Iran. Turkey has two LNG terminals in operation and suitable locations for additional terminals. Gas storage capacity is still low, but a major storage project is under construction and large potential for further storage development exists. Turkey has the potential to further



diversify its pipeline gas sources including the neighboring Iraq, Israel (through an undersea pipeline system) and Turkmenistan. In addition, Europe is currently seeking to diversify its gas supply sources and routes through “the Southern Corridor” – with Turkey in between Europe and the potential gas sources in the Caspian and Middle East regions. The first major Southern Corridor development consists of a 16 bcm-per-year gas production project in Azerbaijan and a gas transmission development consisting of the Trans-Anatolian Pipeline (TANAP) through Turkey and the Trans-Adriatic Pipeline (TAP) from Turkey’s Western border through Greece, Albania, and the Adriatic Sea to Italy. BOTAS has contracted 6 bcm per year and TANAP and TAP will transit the remaining 10 bcm per year to Italy.

Once these pipelines are built, Turkey will for the first time have significant pipeline capacity beyond its own gas needs – a basis prerequisite for a gas hub – and the TANAP and TAP pipelines can be expanded to accommodate additional volumes. Furthermore, TAP allows from the start of operation up to 80% reverse flows.

Reform of the natural gas market is required for the government to achieve its vision for Turkey to become an energy hub. As demonstrated by the experience of the United States, and by Europe’s experience in the United Kingdom and continental Europe, developing a functional gas hubs requires – beyond adequate capacity for inflows, storage, and outflows – a multitude of suppliers and a multitude of supply sources and routes that are not in the control of any one market participant. Recent experience in continental Europe shows how gas hubs have helped new suppliers enter the European gas market, facilitated competition, and brought market pressure to bear on even the largest and best-established European gas companies and their foreign gas suppliers.

## **2.2.2 Electricity Market Development**

As discussed in preceding sections of this overview, Turkey has established step-by-step over the past decade a well-functioning electricity market. Since 2001 the legal, regulatory, and institutional framework has attracted and enabled market-based private sector investment resulting in over 31,000 MW of capacity, of which over 25,000 since 2008. The state companies’ share of the wholesale power supply (as a generator or purchaser under long-term power purchase agreements) has fallen below 50%. The centralized wholesale electricity market now has over 800 market participants. The electricity market is competitive and over-supplied – (and would in fact be over-supplied were Turkey not experienced a severe drought that has led to a fall in hydro generation in 2014 also). Yet the market development effort needs to continue to persuade currently hesitant private investors to resume investment activity in time to avoid a risk of electricity shortages well before the end of the decade.

A package of four broad measures would advance the development of the electricity market:

1. The reform of the natural gas market;
2. The establishment of EPIAŞ and the development of financial trading and risk management instruments;
3. The operational and financial strengthening of TEİAŞ; and
4. Transparency regarding EMRA decisions, TEİAŞ congestion management, TETAŞ and EÜAŞ market operations, and the government’s operational and financial goals for TETAŞ and EÜAŞ.

### **2.2.2.1 Natural Gas Market**

Reforming the natural gas market is a key element also in the efforts to develop Turkey’s electricity market, in view of the important role of gas in the fuel mix in the power sector. Prospective investors in new gas-fired power generation capacity and their financiers look for increased predictability and transparency. Natural gas accounts for almost 50% of electricity generation.

Gas-fired plants set the price in the electricity market. A well-functioning gas market would boost investor confidence across the electric power sector. It is expected that predictability and transparency will increase after the amendments in the Natural Gas Market Law and launching of a centralized gas trading platform by EPIAŞ.

### 2.2.2.2 EPIAŞ

The new 2013 Electricity Market Law provides for the establishment of a new Energy Market Operations Company, EPIAŞ, to take over TEİAŞ' electricity market operations. Market participants widely welcomed the prospect of an independent energy market operator: in response to EMRA's invitation, 97 companies became shareholders in EPIAŞ. It is expected that EPIAŞ will be a major step toward more-transparent market operation and the establishment of an effective energy exchange for both electricity and gas. The introduction of an intraday market is expected in 2015. Introducing new methodologies such as market splitting and demand-side participation would support more-effective market operation. Financial trading and risk management instruments are to be developed and operated by Borsa İstanbul.

### 2.2.2.3 TEİAŞ

TEİAŞ, the backbone of the power system, is under severe and increasing pressure to respond to the demands of private generators and load changes. Over the past 10 years it has faced a real challenge in increasing the transmission capacity in time to respond to the new connection applications of hundreds of new generation facilities, most of them in rural areas, amounting to more than 35,000 MW of capacity. Including those licensed but not yet built, TEİAŞ has managed to provide connection permits representing more than 100,000 MW of capacity, and is trying to expand the grid to match the implementation progress of new generation projects.

The share of private generation is projected to continue to increase and the distribution side is fully privatized, leaving TEİAŞ in an increasingly challenging position in the middle. The build-up and increasing share of wind generation and emerging solar generation pose major integration and operational challenges to TEİAŞ. Wind and solar generation are decentralized and have short construction periods – in sharp contrast to centralized (large-scale) thermal plants with longer construction periods, which allow TEİAŞ much more time to respond. The intermittent nature of wind and solar adds greatly to the complexity and challenge of reliable system operations.

Bottlenecks in TEİAŞ' transmission system can cause congestion, increase costs, and raise concerns about the exercise of market powers by some generators. These issues are most striking at times of gas shortage, when congestion in the electricity transmission system leads to the forced use of lower-efficiency gas plants and gas supply restrictions to the highest-efficiency plants. Increased transparency is needed in TEİAŞ' network congestion management practices.

TEİAŞ' current institutional set-up may not be sustainable in the medium-to-long term. There is broad agreement on the diagnosis of TEİAŞ' constraints in such areas as finance, procurement, decision-making, transparency, and staff recruiting and retention. Measures to increasing TEİAŞ' operational capacity and financial strength may require enacting a special law to provide TEİAŞ with sufficient autonomy if progress in the overall reform in the governance of state-owned enterprises is not expected.

### 2.2.2.4 Developing Turkey into an Energy Hub: Electricity

Western and North European countries from France to Finland have integrated their electricity markets. Integration is governed by a project called Price Coupling of Regions (PCR) and is regulated in a Multi-Regional Coupling (MRC) agreement. (Price Coupling of Regions (PCR), is the initiative of seven European Power Exchanges, to develop a single price coupling solution to be used to calculate electricity prices across Europe, and allocate cross border capacity on a day-ahead basis). Romania, Hungary, the Czech Republic, and Slovakia have coupled their own markets and intend to join the Western and North European market coupling. Bulgaria's



new market operator, the Independent Bulgarian Energy Exchange (IBEX), intends to join the European market coupling. Through EPIAŞ applying the PCR algorithm – and subject to adequate interconnections with the European power system – Turkey will have the potential to join the emerging Europe-wide electricity market. This is a significant opportunity for Turkey.

So far integration has focused on interconnection and has fallen primarily on TEİAŞ (apart from power generation plant control upgrades) as required for the synchronization with the European power system administered by the European Network of Transmission System Operators for Electricity (ENTSO-E). Since the process has been completed and TEİAŞ has become an associate member of ENTSO-E, the existing interconnection can be brought up to full utilization. Further reinforcement of the Turkey–ENTSO-E interconnection would help Turkey take increased advantage of trading opportunities with the European market. The utilization of Turkey's current interconnection with Georgia is constrained by transmission system limitations in TEİAŞ' system in the northeastern part of the country. TEİAŞ' system interconnections with other neighbors are currently limited-capacity links, in island-operation mode, or are not in operation. (Realization of the potential to upgrade these connections and increase trade is also dependent on geopolitical developments.)

### **2.2.2.5 TETAŞ and EÜAŞ**

Electricity market development and liberalization will benefit from the continuing decline in the share of electricity generated by the public sector, directly by EÜAŞ from its own plants and indirectly by TETAŞ from the BOT/BOO generators. TETAŞ' contracts with BOT/BOO generators will expire progressively in 2017–21. They will be “replaced” by power purchases from nuclear power projects, which are expected to be commissioned unit-by-unit at an average pace of about 1,000 MW per year in the 2020s.

However, the bulk of new generation in Turkey will continue to come from market-based private projects. Generation by EÜAŞ will decline in line with the government program to privatize its thermal generation capacity and smaller hydro plants – a total of about 16,000 MW is to be privatized, of which over 4,000 MW has so far been completed. EÜAŞ will retain its large hydro plants, and may become a shareholder in strategic public-private partnership (PPP) projects such as the Sinop Nuclear power plant project, and power plant projects aiming at utilization of local lignite sources. The government has used both EÜAŞ and especially TETAŞ as major vehicles in support of power sector reform and electricity market development, and they will continue to be available to the government for interventions in the electricity market, including for mitigation against gaming/price manipulation by market participants. Increased transparency in the government's operational and financial goals for TETAŞ and EÜAŞ would provide predictability and help ease market concerns about the way 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**

EMRA was established in 2001 as an independent, administratively and financially autonomous public institution. EMRA performs its duties and exercises its rights arising from the law through the Energy Market Regulatory Board, which is the representative and decision-making body of the Authority. It consists of nine members, including EMRA's President, each of whom is appointed to a six-year term by the Council of Ministers. To ensure EMRA's operational autonomy, the Law mandates that they cannot be dismissed before the expiry of their terms of office. The Law also provides for EMRA's financial autonomy from the government by empowering it to fund its activities through fees charged to the energy industry. However, although these arrangements are international best practice, there is a concern that appointments and EMRA's autonomy having been occasionally compromised in practice. The government could address the issue by appointing highly experienced energy and financial sector professionals enjoying wide-spread recognition and market confidence.

Even though the regulated tariffs are determined by EMRA and the cost-based pricing mechanism is used to determine the prices for TETAŞ, EÜAŞ, and distribution companies; the perception in the market is that the government is effectively in charge of energy pricing instead of the EMRA. This perception is reinforced every time the government announces energy price adjustments or delays in price adjustments even while acknowledging BOTAŞ' financial difficulties.

The provision in the 2013 Electricity Market Law transferring the responsibility for auditing the performance of electricity distribution companies from EMRA to the Energy Ministry has contributed to the concern and perception about EMRA's diminishing role. Even though the audit reports will be sent EMRA and EMRA will be final decision making body, this is a highly unusual arrangement, especially as it comes more than a decade after EMRA's establishment.

The government's privatization program transferred the entire distribution system to private companies. The system includes areas with a combination of a pre-existing environment of low payment rates and socioeconomic disadvantages. Even the two companies with unusually high loss/theft rates, Vangolu Elektrik Dagitim and Dicle Elektrik Dagitim, attracted several bidders. It is not surprising that private distribution companies are experiencing major challenges in such areas. The government is committed to making the privatization program a long-term success. During privatization the government decisively and repeatedly assured investors that the new private owners of privatized electricity companies will have the government's full backing. The government has a legitimate responsibility to find sustainable solutions to issues which go well beyond electricity into areas of law and order and socioeconomic development. However, undermining EMRA's ability to regulate distribution companies should not be part of such government support. If the government is concerned about EMRA's operational capacity, the expected measure would be to reinforce EMRA's powers and capacities instead of taking over EMRA's functions. The new auditing department that has been set up in the Ministry to audit the distribution companies could be moved to EMRA.

### **2.2.3.2 EMRA-Competition Authority Collaboration in Retail Competition**

To increase retail competition, distribution companies should allow eligible consumers to switch to suppliers other than assigned supply companies (which are owned by the same group as the distribution company) without creating artificial difficulties. Similarly, in order to expand unlicensed generation facilities, non-discriminatory third-party access to distribution grids is necessary. From the applications of independent suppliers and consumers to the Competition Authority, it can be seen that there is a concern about some distribution companies' abusing their market power to prevent switching and being unwilling to allow connections. Although retail and distribution activities are legally unbundled, there is no ownership unbundling. Therefore careful supervision by EMRA and strong coordination between EMRA and the Competition Authority will be useful to monitor the activities of assigned retail companies and distribution companies to prevent such behavior. Furthermore, close cooperation between EMRA and consumer associations will be useful for increasing consumer awareness about the potential benefits of switching.

### **2.2.3.3 Subsidies for Low-income Consumers**

Most Turkish energy consumers have accepted energy price adjustments as an inevitable cost of development. However, acceptance does not mean that all households can comfortably afford to pay their energy bills. A recent impact assessment across Turkey found that most households in Turkey can afford to pay their electricity bills despite price increases – but that households with non-salaried incomes, rural households, and those consumers whose livelihoods may necessitate electricity (such as farmers using electric water pumps for irrigation and small urban businesses) are vulnerable to increases in electricity prices. Social support and energy efficiency programs targeted at low-income consumers would support the overall electricity and gas market liberalization and could be considered as part of the government's planned review of social assistance mechanisms.



Targeted social support and energy efficiency programs to low-income consumers could be an integral part of the solution to the challenges currently faced by some of the privatized electricity distribution companies. Social support is not a substitute for flexible and innovative measures by the companies themselves. There are reports about companies experimenting with forgiveness of past debt, fixed monthly payments, paying in installments, etc. However, there have also been reports about “wholesale” disconnection of electricity services for some neighborhoods and villages, making people who pay their bills in these places less inclined to pay.

Targeted social support would also facilitate the forthcoming transition to more “regular” tariffs in gas distribution. Most of the winning companies in EMRA’s highly competitive tenders for distribution licenses had bid very low distribution charges, in some case no charges other than initial connection charges, for the first eight-year tariff period. EMRA is currently processing tariffs for the second tariff period and distribution charges will now inevitably have to be increased to reflect the cost of distribution service.

#### **2.2.3.4 Transparency**

Large-scale renewable energy development, even small and medium-size renewable energy projects, inevitably comes with significant environmental and social impacts of its own. The environmental impact assessment and project clearance process has at times been overwhelmed by the number of applications. Developers have complained about complicated procedures, delays, and lack of transparency. Environmentalists and citizens have expressed concern about inconsistent application of environmental permitting and licensing procedures/guidelines and the adequacy of public information provided for decisions made. There is need for more transparency in the process and for better justification of decisions (whether approvals or rejections). In the case of nuclear, the additional dimension of nuclear safety and waste disposal are areas where the public demand for information has not been adequately met.

Turkey’s growing economy and growing population will continue to require more energy. Complex reforms and measures are required to secure requirement of investments from Turkish investors and their mostly Turkish financiers. They are also looking for increased transparency in market operation (PMUM/EPIAŞ) and electricity and gas transmission system operations including balancing, dispatch, congestion management, and supply curtailment (TEİAŞ and BOTAS). Securing public support for the reforms and for the investments that the reforms are designed to attract is in principle simpler, but perhaps just as challenging in practice. It will require information-sharing, education, consultation, engagement, and transparency – continuously, relentlessly, with no exceptions; otherwise continued public support will be undermined. Improving statistical data collection and dissemination will help to improve transparency and confidence of both market participants and the public.

#### **2.2.3.5 State-owned Energy Enterprises**

The role of state-owned enterprises (SOEs) in the energy sector has declined significantly since 2001 and will continue to fall as most new investments are carried out by the private sector and as the EÜAŞ thermal generation plant privatization program progresses to completion. However, although their market share has declined, the role of energy SOEs remains critical to the functioning of the electricity and gas markets. Electricity transmission system operator TEİAŞ and the forthcoming gas transmission system operator and gas storage/LNG terminal company provide the backbone of the energy system. BOTAS will remain the largest gas importer and supplier into the foreseeable future. EÜAŞ will continue to own and operate the largest hydro plants in the country and as such will be a major player in the electricity market. PPAs signed in the 1990s will expire one by one, but electricity trading company TETAS will remain a major buyer and seller of electricity through its involvement in Turkey’s nuclear energy program. EÜAŞ will be a minority shareholder in at least one of the nuclear power companies and, along with TETAS, will be selling large volumes of electricity in the market.



Further modernization of the governance of energy SOEs and the listing of key energy enterprises are important policy priorities. Though established as companies, BOTAS, EÜAŞ, TEİAŞ and TETAŞ still face substantial challenges in the conversion into modern, autonomous, and professionally-run SOEs. Management autonomy is currently undermined by Decree Law No. 233 on State Economic Enterprises; the Law on the Turkish Court of Accounts (Sayıştay); the Public Procurement Law; and a series of controls by the Energy Ministry, the Ministry of Development, and the Treasury. In accordance with the legislation, the boards of energy SOEs consist of the CEO (General Manager) and two (usually the most senior) deputy General Managers of the company, two senior officials (usually Deputy Undersecretaries) from the Energy Ministry, and a Treasury appointee. Investment proposals have to be approved by the Board, the Energy Ministry, and the Ministry of Development. The government retains approval power even of the network investments of BOTAS and TEİAŞ, although they are fully regulated by EMRA. Instead of commercial auditors, SOEs are audited by Sayıştay (Court of Accounts), an institution responsible for auditing on behalf of the Grand National Assembly (i.e., the Parliament) the revenues, expenditures, and property of central and local governments. Instead of commercial procurement practices, SOEs are required to apply the Public Procurement Law.

The OECD Guidelines on Corporate Governance on State-Owned Enterprises<sup>11</sup> serve as a global benchmark for SOE governance reforms:

- Governments are expected to develop and issue an ownership policy that defines the objectives of state ownership, the state's role in corporate governance of SOEs, and how the state will implement its ownership policy.
- Governments should not be involved in the day-to-day management of SOEs. They should instead allow SOEs full operational autonomy to achieve their defined objectives and hold their boards and management accountable for performance.

Naturally, energy SOEs would continue to carry out their activities in line with the government's energy policies and in accordance with the country's laws and regulations. The professionalization of the boards and management of energy SOEs would help ensure that the energy SOEs have boards and management capable to directing and running the companies without day-to-day government involvement.

In recent years the listing of key energy SOEs through initial public offerings (IPOs) on the Istanbul Stock Exchange has been discussed – for example in October 2014 by the Finance Minister in an interview on the government's plans for privatizations and public offerings. Potential exists for a program of IPOs to support a number of key policy objectives, namely, to (a) help improve the governance of energy SOEs, as new investors would be expected to support the professionalization of the boards and management of energy SOEs; (b) support electricity and gas market liberalization directly by improving SOE performance and indirectly by increasing overall investor confidence; and (c) raise proceeds for the government – and, subsequently, investment resources for each company depending on its investment needs and debt/equity position.

The IPO program could start with TEİAŞ and the shares of the new gas transmission system company (after the expected unbundling of BOTAS). BOTAS, EÜAŞ, and TETAŞ could follow later. The new gas storage/LNG terminals company may need some time to establish its operations and finances to become more attractive for an IPO. TP, in the petroleum sector, is another prime candidate for listing. Secondary offerings could follow later in a progressive, step-by-step program of ownership diversification and commercialization.

The reform of Turkish Airlines is an excellent local reference point for the public listing route: the government holds a substantial share (49.12%) and the company is run on a commercial basis outside the controls of the Decree Law No. 233, the Court of Accounts, and the Public Procurement Law. In the energy sector, the Italian experience is a relevant reference for Turkey:



while earlier unthinkable, oil and gas company ENI, electricity generator and supplier Enel, and transmission system operator Terna have all been listed in local and international exchanges (with well-defined governance policies) and the Italian state has reduced its ownership to well below 50%.

#### 2.2.4 Next Steps in Energy Reform

Notwithstanding Turkey's remarkable accomplishments since 2001, reform in the energy sector needs to continue if the country is to secure its electricity and gas supplies without returning to large-scale – and in the long run, unsustainable – government support mechanisms. This review of challenges concludes that a package of reform measures is needed to further develop the electricity and gas markets and improve the governance and functioning of EMRA and key energy SOEs.

The government is updating the 2009 energy strategy. The strategy update is an excellent vehicle for the government to reiterate its energy vision with updated milestones and timelines while engaging existing market participants and prospective investors in the continued development and liberalization of Turkey's electricity and gas markets.

Comprehensive reforms will not happen overnight and market participants and their financiers do not expect everything to happen overnight. Upfront "confidence building measures" could nevertheless be implemented during the next 12 months to continue developing the electricity and gas markets and to reassure market participants that the liberalization continues and the governance and transparency of public institutions and energy SOEs will improve. These measures could include the following:

- The amendment of the Natural Gas Market Law could be enacted.
- Taking advantage of declining gas import prices, the government could bring BOTAŞ back into the Cost-Based Pricing Mechanism and allow cost-reflective and transparent wholesale gas price adjustments by BOTAŞ.
- The development of a social safety mechanism for low-income energy consumers would take some time (even if added to one of the existing subsidy mechanisms funded from the budget) but the government could announce that it has decided to establish such a mechanism.
- The development of EPIAŞ could be accelerated so that EPIAŞ could be fully operational within 2015.
- The Energy Ministry, BOTAŞ, and TEİAŞ could disclose and explain to market participants their gas supply curtailment and electricity congestion management mechanisms before these mechanisms are applied during the 2015–16 winter and whenever they are being used.
- The government could announce that it has decided to list the shares of TEİAŞ, parts of BOTAŞ (after unbundling), EÜAŞ, TETAŞ, and TP through a program of initial public offerings on the Borsa İstanbul.

Some of the issues facing the government now may prove as challenging as the issues of the past 14 years. Turkish investors and their mostly Turkish financiers have invested – and learned – a great deal, and their enthusiasm has waned. Although their capacity to take risks has increased, their understanding of the risks has also increased. They are looking for signs of the government's intent to address difficult issues. They expect energy market liberalization to continue and they expect governance and transparency in the energy sector to continue to improve and increase.



## Turkey's Energy Transition - Milestones and Challenges

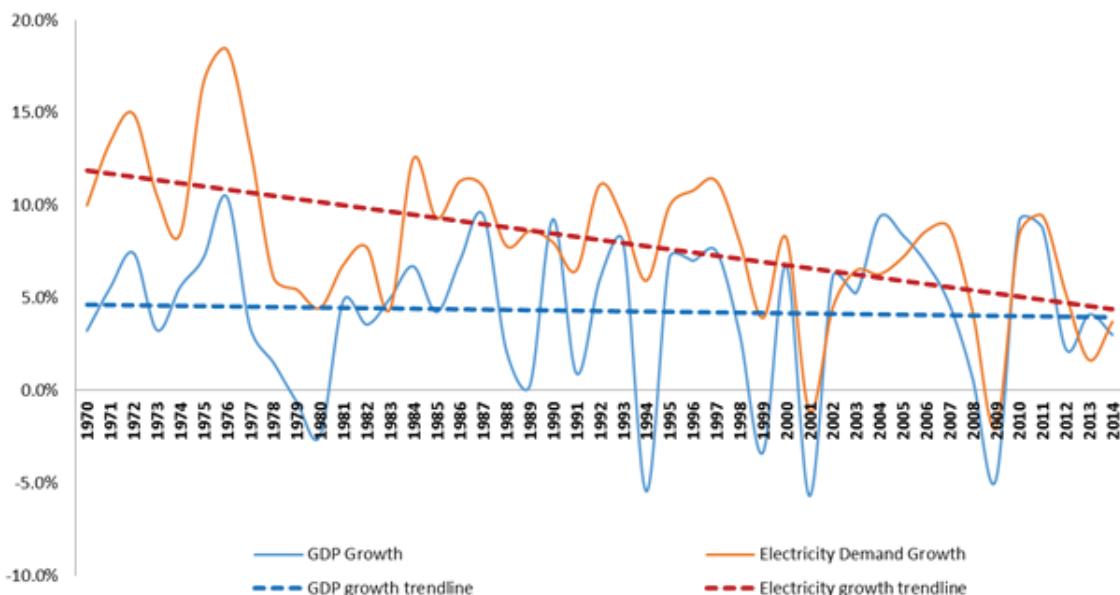
# Main Report

## Main Report

The Republic of Turkey is located between southeast Europe and Asia and borders the Mediterranean, Aegean, and Black Seas. Its neighboring countries are Armenia, Azerbaijan, Bulgaria, Georgia, Greece, Iran, Iraq, and Syria. The population was 77,695,904 as of the end of 2014 and the total surface area is 780,580 km<sup>2</sup>.<sup>12</sup>

The economy of Turkey is defined as an emerging market economy and is largely developed, making Turkey one of the world's newly industrialized countries. Despite enduring multiple serious recessions and erratic growth, Turkey's average GDP growth rate over the past 45 years is 4.3%. In line with the growing economy, the Turkish electricity market is one of the fastest-growing markets in the world. The annual average consumption increase was 8.3% since 1970, as shown in Figure 11.

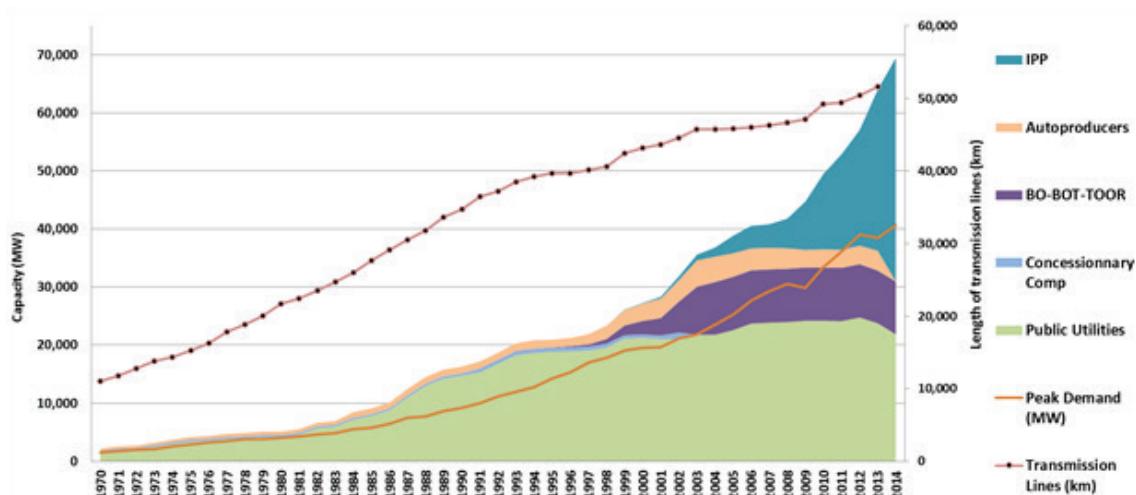
**Figure 11. GDP and Electricity Demand Growth Rates, 1970–2014**



Source: TUIK and TEİAŞ.

To support Turkey's economic growth and cope with increased electricity demand, substantial investments have been necessary in the generation, transmission, and distribution segments of the electric industry. In order to increase the generation capacity, different investment models have been implemented since the late 1960s. As a result, the composition of ownership of the generation capacity changed drastically during this period. The development in generation capacity according to ownership is shown in Figure 12.

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



Source: TEIAS statistics.

Since 1970 Turkey's generation capacity has increased more than 30-fold, reaching 69,500 MW in 2014. The fragmented transmission system was substantially developed and a meshed countrywide transmission grid was eventually built. Through ambitious urban and rural electrification programs, the distribution system was also expanded and the target of "providing electricity services for all citizens" was achieved.

To understand the main drivers of the reforms leading to the opening of the power sector to the private sector, it is useful to summarize the situation in Turkey in the early 1980s.

### 3.1 Summary of the Power Sector before 1984

#### 3.1.1 Before the Turkish Electricity Authority: 1913–70

Although electricity generation started in Turkey in the early 1900s with a 2 kW small hydro turbine, the country's first commercial generation facility was the Silahtaraga coal-fired power plant, which was commissioned in 1913. From then until 1935 the electricity sector was dominated almost entirely by private initiatives. When the Turkish Republic was founded in 1923, the total installed power was 32 MW and consumption per capita was only 3.3 kWh. The year 1935 saw the founding of Etibank, a state-owned development bank, and the Electrical Power Resources Survey and Development Administration (EIE), and the electricity business was nationalized.

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

Until the 1970s the system was fragmented. Except for some regional networks, the transmission and distribution systems were not interconnected; instead they were owned and operated by different public administrations, and all electrification programs were carried by different public entities. Municipalities and private concessionary companies had their own rights and responsibilities with respect to electricity generation, transmission, distribution, and sales. Although there were several public organizations dealing with electricity generation, transmission, and distribution, there was no central planning. Table 2. shows selected indicators for Turkey's power sector in 1970.

**Table 2. Selected Indicators for Turkey's Power Sector in 1970**

1970	Public	Private						Total
		Conc. Companies	BOT	BO	TOOR	Auto-producer	IPP	
Generation capacity (MW)	1,994	194	0	0	0	(360)*	0	194 2,188
Generation capacity ownership (%)	91.1%	8.9%	0.0%	0.0%	0.0%	0.0%	0.0%	8.9%
Transmission lines (km)				11,000				
Transmission transformer number/capacity (MVA)				N/A				
Rural electrification (%)				6				

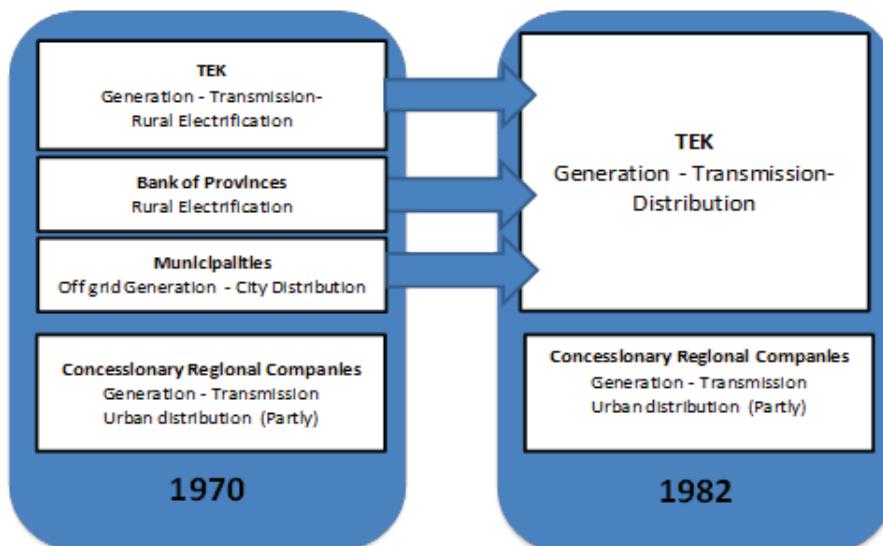
Source: TEIAS statistics.

\* Used mostly in publicly owned sugar factories; thus considered in "public ownership".

### 3.1.2 The TEK Period

The establishment in 1970 of the vertically integrated Turkish Electricity Authority (TEK) – and the consolidation of all electricity activities within it, except for municipality-owned and -operated city distribution systems and two regional private companies – was one of the major steps in the sector's restructuring. The main priority was the electrification of Turkey, and TEK's focus was on urban and rural electrification together with development of an interconnected, strongly meshed transmission network. The TEK's establishment was in line with the preferred economic development policy (development through a planned economy under the leadership of the state) at those times. The consolidation of all electric sector activities was completed after transferring the urban distribution activities from municipalities to TEK in 1982. In fact, the initial intention was to have municipalities carry out distribution and retail activities. However, because the municipalities' performance was poor and they were not paying their bills to TEK, it was at last decided to transfer these distribution facilities and service obligations to TEK. Private sector participation (PSP) was very limited, and there were only two vertically integrated regional concessionary companies and only one concessionary distribution company operating in a small region. Public companies were also shareholders of these concessionary companies. The sector structure is summarized in Figure 13.

The DSI and General Directorate of Electric Power Resources Survey and Development Administration (EIE) were responsible for developing hydroelectric capacity during this period.

**Figure 13. Power Sector Structure before 1984**

In the late 1970s Turkey entered an economic recession. Its GDP growth rate decreased sharply, and the economy actually contracted in 1979 and 1980. The worldwide energy crisis due to increased petroleum prices was one of the reasons for this decline. Roughly 30% of the country's installed capacity depended on petroleum imports, and limitations on imports led to electricity disruptions and rationing during 1978–1980.

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

- Consolidation of sector activities under a strong state-owned monopoly;
- Centrally planned public investments for generation and transmission, and distribution investments in parallel with an electrification program; and
- Difficulties due to economic problems that limited investment and even operation and maintenance (O&M) budgets – resulting in insufficient supply, especially after 1977.

### 3.2 Electricity Sector Reform

Emerging from a severe economic crisis in the late 1970s, a military coup in 1980, and political turmoil in the early 1980s, Turkey changed course in 1983 and embarked on a path to move from state-controlled, import-substitution industrialization – featuring heavy state ownership and control – toward a liberal market economy, in both domestic markets and international trade.

The electricity sector was also influenced by these developments, and Turkey began reforming its electricity industry. The need for power sector financing, along with a desire to increase economic efficiency, led Turkey to seek private sector involvement in electricity supply systems. Private sector involvement was desired not only to secure financing, but also to access market-oriented skills, the latest technology, and usually quicker implementation than would be the case under public sector management.

The reform and restructuring process started in the first half of 1980s with the opening of the operational components of the power industry – generation, transmission, and distribution – to private sector participation. It can be divided into two distinct phases:

- First Phase: 1984–2001.
- Second Phase: The period after the Electricity Market Law was enacted in 2001. This phase can be further divided into 2001–07 and 2008–present, the second of which has featured accelerated reform implementation triggered by a new energy-pricing mechanism and the development of wholesale market mechanisms.

#### 3.2.1 First Phase: 1984–2001

The first phase, from 1984 to 2001, featured the legal and structural changes that (a) demolished the public monopoly in electricity generation and distribution and (b) enabled private sector participation in the electricity sector. Table 3 shows key power sector indicators at the beginning of this phase.

**Table 3. Selected Indicators for Turkey's Power Sector in 1984**

1984	Public	Private							Total
		Conc. Companies	BOT	BO	TOOR	Auto-producer	IPP	Total Private	
Generation capacity (MW)	7,190	324	0	0	0	948	0	1,272	8,462
Generation capacity ownership (%)	85.0%	3.8%	0.0%	0.0%	0.0%	11.2%	0.0%	15.0%	
Transmission lines (km)					25,975				
Transmission transformer number/capacity (MVA)				682	/17,206				
Rural electrification (%)				65					

Source: TEIAŞ statistics



In December 1984, Law No. 3096 was enacted to enable private sector participation in the power industry. This law in effect ended TEK's monopoly in generation, by introducing private generation investment models such as **build-operate-transfer (BOT)**, **transfer of operational rights (TOOR)**, and **autoproduction**. In the same year, TEK's legal status was changed and it became a state economic enterprise.

The first phase also included intermediate stages. Due to the uncertainties surrounding, and unsatisfactory progress of, the BOT model and gradually tightening of the supply/demand balance, a specific law for BOT implementation (Law No. 3996) was issued in 1994. Later, the **build-own-operate (BOO) model** was introduced in 1997 to enhance private generation investments.

Also, state-owned companies were restructured and the industry structure was changed in this period. The details of implementation of the PSP models and restructuring are discussed in subsequent sections.

### **3.2.1.1 Industry Structure in 1984–2001**

The period from 1984 to 1993 can be considered as a “TEK plus private participation” period. As Figure 14 illustrates, in 1993 TEK was restructured and two state-owned companies were established: TEAŞ (the Turkish Electricity Generation and Transmission Company) and TEDAŞ (the Turkish Electricity Distribution Company). This was an important step toward the unbundling and corporatization of state entities. The unbundling of distribution and retail activities from generation and transmission, and the establishment of new state-owned companies, were attempts to increase public sector efficiency and to enable private sector participation, and can thus be considered as first steps toward privatization.

**Figure 14. The TEK Restructuring**

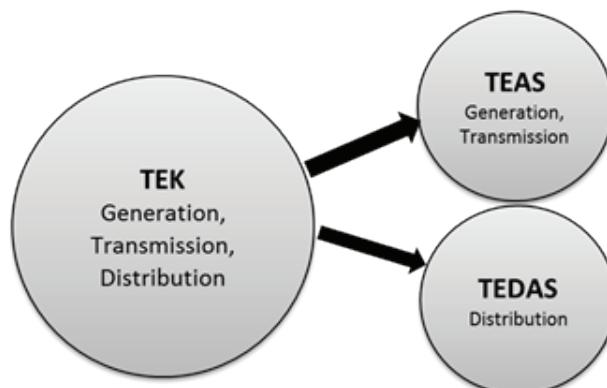
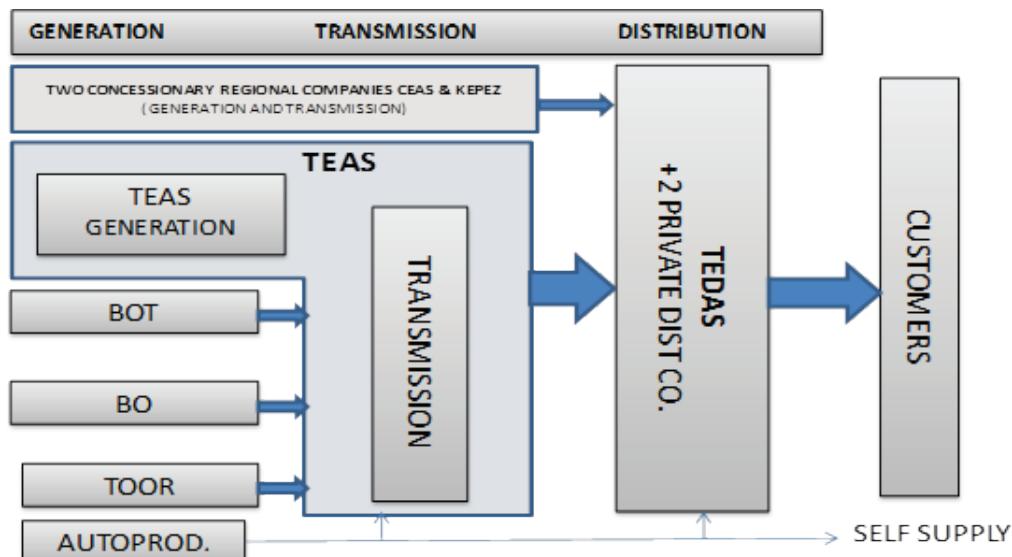


Figure 15 shows the industry structure at the end of this period.

**Figure 15. Industry Structure in 2000**



In this period, TEAŞ was the single buyer and seller of electricity from BOT, BOO, and TOOR power plants under long-term PPAs that included take-or-pay commitments guaranteed by the Treasury. Industrial companies were allowed to generate electricity for their own use under the autoproduction model.

### 3.2.1.2 Private Sector Participation in Generation

Enacted in 1984, Law 3096 allowed for PSP in electricity generation through the BOT, TOOR, and auto-production models. The secondary legislation related to the implementation of this law was enacted in September 1985. The main aim was to enable PSP in generation, transmission, and distribution activities based on private law through assignment contracts – as opposed to the concession concept used for only two regional transmission/generation and one distribution activity by that time. However, as a result of both general public opinion and the decisions of judicial authorities at that time, Law No. 3096 was also forced to be implemented in the form of a concession, subject to administrative jurisdiction by the *Danıştay* (the Council of State, the nation's highest administrative court). An exception was the autoproduction model, which was implemented successfully without necessitating the concession concept.

#### *The BOT Model*

Under the BOT model, companies were allowed to build and operate power plants, selling their generation to the public utility (TEK and later TEAŞ and TEDAŞ) through a combination of long-term power purchase agreements (PPAs) and “assignment” or concession contracts between the Ministry of Energy and Natural Resources (MENR) and the company. At the end of each contract, the plant was transferred to public ownership. The terms and PPA price were determined in the main contract and TEAŞ had to sign the PPA according to the main contract. The implementation of the BOT model is described in detail in Appendix 1.

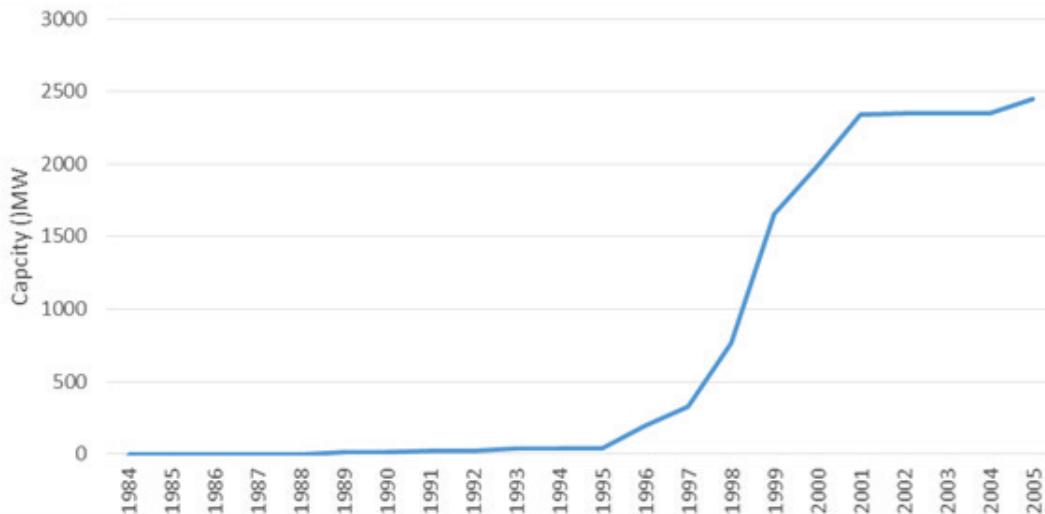
The 1994 BOT Law helped Turkey attract a massive response from prospective foreign and local investors in the form of hundreds of unsolicited project proposals which were not envisaged in the optimum generation expansion plans. However, MENR and TEAŞ were not equipped to handle this unexpected influx of unsolicited proposals.

**As a result of BOT model implementation, 24 power plants were commissioned between 1984 and 2001: 18 hydro, 2 wind, and 4 natural gas CCGT<sup>13</sup> As shown in Figure 16, in 1994 BOT installed power was only 35 MW; most of these plants were contracted and commissioned**



after 1994; and the total installed power of these BOT plants reached 2,450 MW. Compared with the country's energy needs, as well as the government's continuous efforts and ambitious expectations, this outcome cannot be considered as satisfactory.

**Figure 16. Development of BOT Plant Capacity, 1984–2005**



Source: TEIAŞ statistics.

The main reasons for this inadequate outcome were uncertainties in the legal and administrative framework and implementation problems which are discussed in more detail in Appendix 1. However, the BOT experience proved that without a clear and transparent legal and administrative framework, a consensus on main legal framework and principles, and a transparent implementation, no model can be successful. Given careful and planned project sequencing, competitive selection, and Treasury guarantees, this model could have been used to increase generation capacity. However, it would also have increased contingent liabilities and delayed the establishment of a competitive market mechanism.

#### *The TOOR Model (Generation Privatization)*

**The TOOR model** involves transferring the operational rights of state-owned power plants to private companies. The ownership of the assets remains with the state. Again there was an assignment contract with the Ministry and a PPA with public utility. The TOOR model was used to privatize state-owned power plants between 1984 and 2001. One hydroelectric power plant (HPP) was transferred in 1996, and in 1997 the tendering process was begun for 16 thermal power plants representing a total installed power of 9,576 MW. However, although six contracts were signed as a result of the tender, the contracts had to be cancelled due to Danıştay decisions.

Hence, the result of the TOOR implementation was highly unsatisfactory. In the end, except for one HPP (a 30 MW plant transferred in 1996) and one lignite plant (Çayırhan, a 620 MW concession contract transferred in 2000 and 2001),<sup>14</sup> all the other contracts could not be implemented.

Although the Danıştay decisions were the main reason, there were other reasons for this unsuccessful implementation, as discussed in Appendix 1.

#### *The BOO Model*

Due to the insufficient realization of BOT plants by 1997 – and instead of trying to review and compare hundreds of unsolicited proposals – the government decided to focus on priority projects of its own choice and to select investors for these projects through competitive bidding in order to secure more reasonable prices and conditions. It therefore introduced the **BOO model** in Law 4283 in 1997. The implementation of this model is described in Appendix 1.



When compared with the BOT model, the BOO model was implemented successfully and in a relatively short period. As a result of the tendering process, contracts for four natural gas CCGTs and one imported hard-coal power plant were signed in 1998 and 1999. The total installed power of these plants was 6,100 MW and all were commissioned in 2002–04.

However, the implementation of the BOO model has also had some negative implications. The Law did not allow the use of domestic sources such as lignite and hydro because the use of natural resources would necessitate concession contracts. Therefore, only natural gas and imported coal could be used. (Even if it was not so, however, there was an urgent need for additional capacity and only natural gas plants could be commissioned in such a short time.) After 4800 MW in BOO gas plants were built, this caused an overdependence on imported natural gas for electricity generation. Furthermore, as with the BOT plants, the electricity generated by BOO plants crowded out competition in the electricity market due to the take-or-pay obligations.

### *The Autoproducer Model*

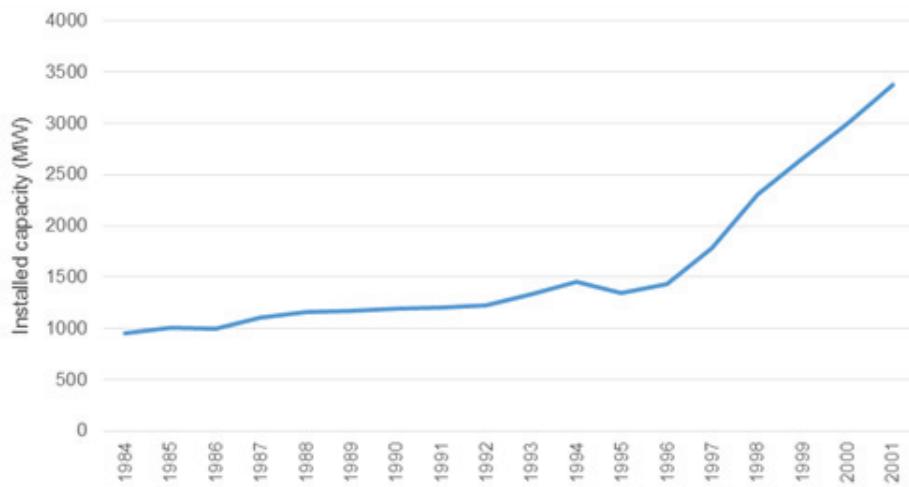
The **autoproducer** (self-generation) **model** involves the ownership and operation of power plants by industrial companies, mainly for their own electricity needs. In Turkey, plants built using this model have generally been cogeneration plants<sup>15</sup> and their excess power has been sold to TEDAŞ. Although there had been autoproducer plants before 1984, they were mostly cogeneration plants used in state-owned sugar factories and were governed through special regulations. Law 3096 provided for the widespread use of autoproduction.

At first, the autoproducer plants were built mainly to generate heat for use in industrial processes, and electricity production was not the main aim. However, due to the tightening supply/demand balance, MENR decided to incentivize the autoproducer plants and increased the tariff cap for their sales to TEDAŞ. This led to new autoproducer plants being built mainly to generate electricity – plants with lower thermal efficiency than those established for cogeneration purposes.

Furthermore, the “autoproducer group” concept was introduced. According to this concept, industrial companies could come together to establish a generation company that in return supplied their electricity needs like an autoproducer. Both autoproducers and autoproducer groups could sell their surplus energy to TEAŞ or TEDAŞ (with a cap) without considering time of generation and time of consumption.

Of the four models covered in this section, the best results were achieved using the autoproducer model. In this period several autoproduction facilities, with a total installed power of roughly 2300 MW, were commissioned. In addition, there were several plants under construction in 2001. As shown in Figure 17, the implementation gained pace after 1997.

**Figure 17. Growth of Autoproducer Plant Installed Capacity, 1984–2001 (MW)**



Source: TEAŞ Statistics



The autoproducer group implementation may be considered the first step toward independent generation. However, it was also a misuse of the autoproduction concept in that a very small share (about 1%) of the many shareholders came together and built new power plants mainly to sell electricity to TEAŞ and TEDAŞ, rather than producing for their own needs. (After 2008 the plants established only for electricity generation were converted to generation companies and were treated as independent power producers, or IPPs).

#### *PSP in Distribution - Privatization using the TOOR Model*

From 1984 to 2001 two types of contract were used to privatize electricity distribution under the TOOR model. Under the first model, used in two distribution regions (Aktas and Kayseri), the energy supply company (TEAŞ) assumed all risk and the distribution company was guaranteed a predetermined profit. (Profit was determined as “a reasonable return on equity.”)

The second model employed a tender process. The main difference between this and the first model was that this model left some risks to the company and removed the reconciliation process.<sup>16</sup> According to the second model, the distribution regions could be transferred to private companies for operation for a limited time. The ownership of assets remained with the state. The companies had exclusive rights to operate the distribution network in the region and to supply energy to all consumers in the region (except the industrial companies, which were supplied by autoproducers).

**Although Turkey auctioned off almost all the distribution regions in 1996, it did not successfully transfer the operational rights of the regions because the Daniştay annulled the authorizations of most of the companies. Thus, as described in Appendix 1, except for two regions, this process could not be finalized.**

#### **3.2.1.3 Summary of the 1984–2001 Period**

This period thus featured the legal and structural changes that (a) demolished the public monopoly in electricity generation and distribution and (b) enabled private sector participation in the electricity sector. At the beginning, the Turkish Electricity Authority (TEK) was the vertically integrated monopoly for generation, transmission, distribution, and trade activities. In 1984, the passage of Law No. 3096 allowed the private sector to participate in the power industry. This law in effect ended TEK's generation monopoly by introducing private generation investment models such as BOT, TOOR, BOO, and autoproduction.

However, the first steps lacked a solid legal footing. Rather than resulting from a long-term restructuring plan, the liberalization of the electricity industry stemmed from high demand growth and a correspondingly urgent need for investment. The overall outcome of the first phase of reform efforts can be summarized as comprising a moderate level of private capital inflow into the generation segment. Because regulatory uncertainty and country risk hampered the investment climate, new investment in generation required high risk premiums, which pushed up energy costs. In addition, most of the risks were allocated to the buyer (public companies) in the contracts.

The process was full of interruptions and reversals due to:

- Lack of consensus between legal authorities and governments on the main principles for PSP in electricity activities, which caused considerable delays and hesitations because of:
  - Prolonged arguments on legal framework and Judiciary decisions against the principles set forth in Laws 3096 and 3996;
- Lack of consensus between public entities on the implementation of the BOT and TOOR models – which caused the State Planning Organization (SPO), Treasury, and TEAŞ to resist MENR's implementation of the BOT and TOOR models;
- Unsuccessful efforts to privatize generation and distribution activities;

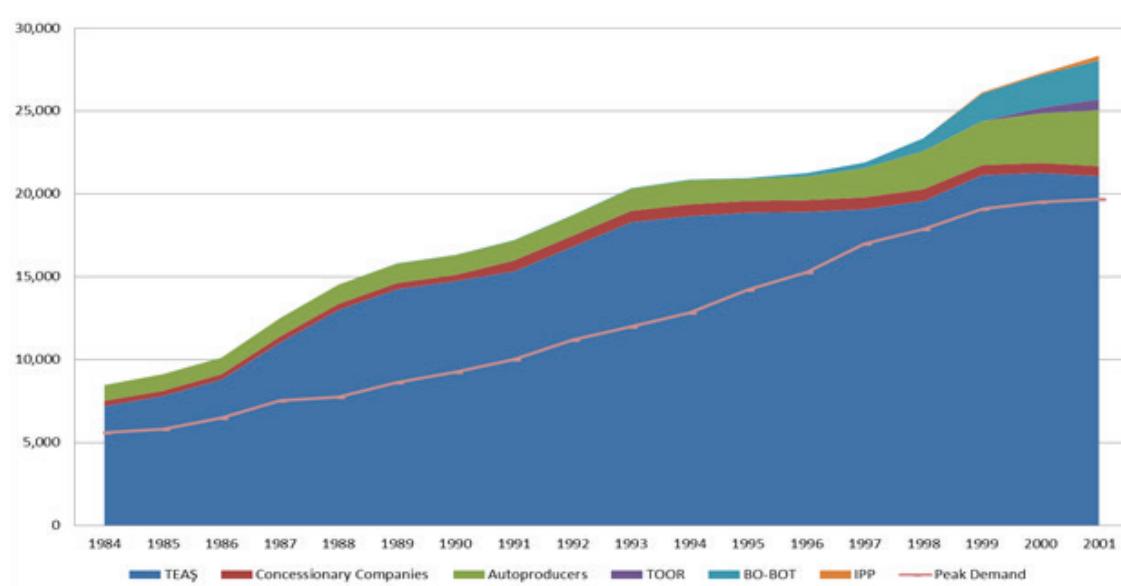


## Turkey's Energy Transition - Milestones and Challenges

- Worsening supply security due to insufficient generation investments; and
- Lack of commitment, frequently changing governments, corruption accusations, and frequent bureaucratic changes.

Including BOO, BO, and autoproducer plants under construction in 2001, a total of about 11,000 MW of capacity was commissioned under the legal framework introduced in this period. However, as shown in Figure 18, because public investment slowed down due to BOT investment expectations and delays in implementation, the capacity margin (the difference between installed power and peak demand) fell sharply after 1994, and supply security worsened towards 2000.

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



Source: TEIAŞ Statistics

To overcome the urgent regional supply problems, the so-called “mobile plants” concept was introduced. According to this model, small plants (initially 25 MW each) were built by private firms and their capacities were “hired” by TEAŞ for five years beginning in 1999. Later this concept was used to solve the worsening supply deficit, and both the number of plants and their unit power ratings increased (to 100 MW each). Although demand sharply declined in 2001, the construction of the plants continued due to their existing contracts; as a result, a total of 795 MW of capacity was commissioned by the private sector in 1999–2003. They were mainly fuel-oil or diesel-oil plants (stacked combustion engines), and although some were dismantled after their contracts expired, some continue as IPPs.

There was no competition in the market and limited competition for the market. In other words, there was some competition among the companies to have the right or concession for building, operating, and selling the energy produced in the power plants (“competition for the market”). However, except for the autoproducer (self-generation) model, every consumer had to buy energy from the distribution company, and the sole supplier to the distribution companies was TEAŞ. There was no market and no legislative basis for competition among the suppliers.



Table 4 below provides a summary of some power sector indicators at the end of this phase.

**Table 4. Turkey's Power Sector: Selected Indicators, 2001**

2001	Public	Private							Total
		Conc. Companies	BOT	BO	TOOR	Auto-producer	IPP	Total Private	
Generation capacity (MW)	21,063	610	2,338	0	650	3,374	297	7,269	28,332
Generation capacity ownership (%)	74.3%	2.2%	8.3%	0.0%	2.3%	11.9%	1.0%	25.7%	
Transmission lines (km)				43654					
Transmission transformer number/capacity (MVA)				1,090 / 62,015					
Rural electrification (%)				100					

Note: Mobile plants are considered independent power producers (IPPs).

Source: TEIAŞ statistics.

### 3.2.2 Second Phase: Establishment of Competitive Electricity Market

#### 3.2.2.1 Main Motivations and Key Elements

In the late 1990s, based on the lessons learned during the previous liberalization attempts, a more carefully structured transformation process was initiated with the objective of improving the economic efficiency of, and attracting private investment into, the energy sector. Although there had been a PSP model to attract private investment since the early 1980s (as described earlier), that model required take-or-pay guarantees and created contingent liabilities over the public institutions while leaving almost all of the market risks to the buyer.

The problems encountered in the previous period (the high-cost generation of BOT plants and the contingent liabilities of the state due to Treasury guarantees) showed the need for a different model to attract private investment. An investment environment – that is, a market – was needed that would attract private investors without state or state-owned buyer guarantees; instead, **the market itself should attract new generation investments.**

Hence, the main objective was to create a competitive market structure with the expectation of attracting investment, increasing efficiency, and enhancing the reliability and quality of supply. However, competition requires multiple buyers, multiple sellers, and an open access (OA) regime. To satisfy these requirements it was necessary to restructure the industry, establish a regulatory framework for pricing and supervision of monopolistic activities, remove barriers for entry, and introduce trading mechanisms.

The issuance of the first EU Electricity Directive in 1996 was also an important milestone for the Turkish electricity sector because it coincided with Turkey's aspiration to join the EU. In January 1997, with funding from the World Bank, Turkey's Ministry of Energy and Natural Resources (MENR) began the studies necessary to prepare the legal framework for a competitive electricity market that would comply with the conditions of the EU's directive. A group was formed within MENR to draft an Electricity Market Law (EML). With the support of the World Bank and European Commission, a draft law was prepared. In parallel, a different group began drafting of a Natural Gas Market Law (NGML). The aim of these studies was the eventual transformation of the energy sector from a vertically integrated, monopolistic system to a market structure featuring full retail competition.

Due to the deep economic crisis in 2000 and 2001, the government launched comprehensive reforms in several sectors, including the energy sector. In a way, the crisis provided the impetus to put the above-mentioned designs into implementation. Furthermore, conflicts between public authorities, combined with court cases regarding previous implementations, boosted public support for the reforms.

### 3.2.2.2 Main Principles and Key Elements of the 2001 Electricity Market Law

The Electricity Market Law No. 4628 ("the EML") was issued in March 2001. It was amended several times in subsequent years; finally, after several revisions, a new EML numbered 6446 ("the new EML") was enacted on 30 March 2013.

The EML's purpose was determined as

*Ensuring the development of a financially sound and transparent electricity market operating in a competitive environment under provisions of civil law and the delivery of sufficient, good quality, low cost and environment-friendly electricity to consumers and to ensure the autonomous regulation and supervision of this market.*

The 2001 EML set the legal framework for the sector; defined the institutional structure, the market activities, and the roles and responsibilities of market players; and established the Energy Market Regulatory Authority (EMRA) to ensure the independent regulation and supervision of this market. More specifically, the EML introduced the following principles for the creation a competitive market, which are also preserved in the new 2013 EML:

- A licensing framework for market entry;
- Legal unbundling of transmission system and market operation from generation and supply businesses;
- To implement the unbundling requirement, the establishment of three state companies from TEAŞ: EÜAŞ for generation, TEİAŞ for transmission and market operation, and TETAŞ for trading (discussed below);
- Account separation for distribution and retail business until these activities are legally unbundled by the end of 2012;
- Non-discriminatory pricing and tariff mechanisms;
- Regulated third-party access to transmission and distribution grids, in a non-discriminatory manner;
- Non-discriminatory access of generation companies and suppliers to eligible consumers in distribution areas;
- Eligible consumer concept in which all consumers (eventually) have the freedom to choose their electricity suppliers (have access to competing suppliers);
- The legal basis for establishing a competitive bilateral contracts and balancing markets;
- Privatization of generation and distribution assets; and
- Implementation of a transitional period until full liberalization.

The market activities fall under two categories. Regulated market activities comprise (a) transmission, (b) distribution, (c) retail sales and retail sale services to non-eligible consumers, and (d) TETAŞ' wholesale.

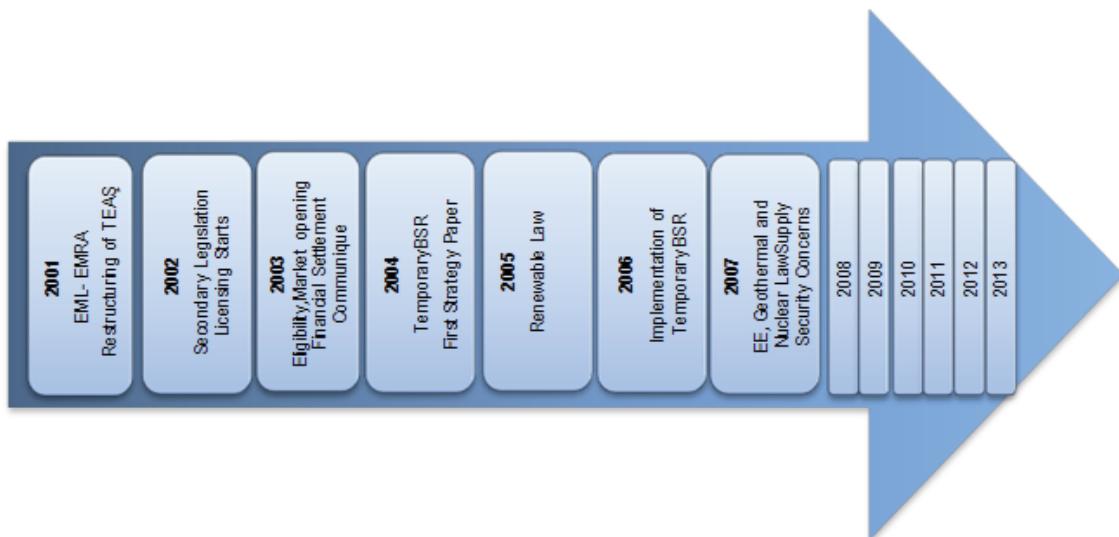
Competitive market activities comprise (a) generation, (b) wholesale (except TETAŞ' bilateral contracts or transitional contracts that are regulated), and (c) retail sale to eligible consumers.

(Wholesale and retail sale activities are called "supply activity" in the new EML).

### 3.2.2.3 Major Implementation Steps between 2001 and 2007

Turkey has been carrying out a comprehensive reform in all segments of the energy sector since 2001. Although the legal and regulatory framework and industry and market structures evolved step-by-step over time, the process can divided into two main phases. Between 2001 and 2007 the basic legal and regulatory arrangements were developed (see Figure 19) and the market structure was changed – but at the same time transitional problems were experienced. In the second phase, after 2008, the reforms were accelerated and a competitive market developed. In the following sections, the major steps taken in this process will be discussed.

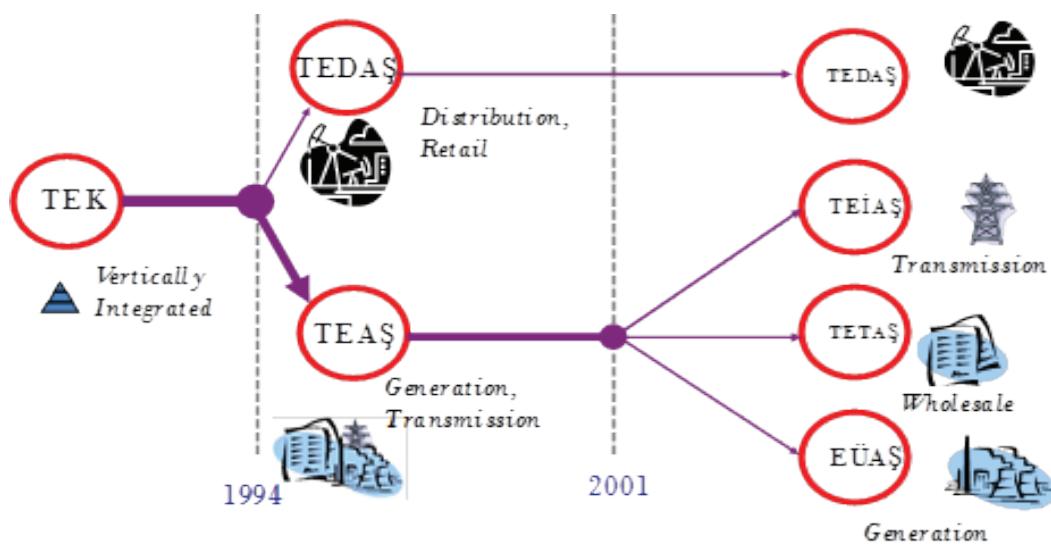
**Figure 19. Major Implementation Steps in 2001–07**



### 3.2.2.4 Restructuring of Public Companies

One of the first steps was to restructure the public electricity companies. In line with the principle of unbundling market activities, state-owned TEAŞ was split into three new companies responsible for transmission, generation, and wholesale, as shown in Figure 20. One of the main reasons for this was to create a transmission company that would act as an independent system and market operator, which is necessary for a competitive market structure.<sup>17</sup>

**Figure 20. Restructuring of Public Companies**



TEAŞ was restructured to form three state-owned enterprises:

- **Turkish Electricity Transmission Company (TEİAŞ)**, established for carrying out electricity transmission activities as well as system and the market operation;
- **Electricity Generation Company (EÜAŞ)**, established for carrying out electricity generation activities;



- **Turkish Electricity Trading and Contracting Company (TETAŞ)**, established for carrying out electricity wholesale activities, including the handling of existing long-term PPAs with BOO, BOT, and TOOR companies. TETAŞ purchases energy from BOO, BOT, and TOOR companies and also purchases low-cost energy generated by EÜAŞ' large-capacity hydro power plants and sells it to distribution companies at regulated prices.

These three companies, together with **TEDAŞ**, are the state-owned players in the market. **TEDAŞ**, as will be discussed later, was restructured in 2005 for privatization carried out in 2008–13.

### **3.2.2.5 Establishment of Energy Market Regulatory Authority (EMRA)**

One of the major steps in the reform process was the establishment of EMRA to ensure the autonomous regulation and supervision of this market. Originally called the Electricity Market Regulatory Authority when it was established by the EML, it was immediately afterwards renamed the Energy Market Regulatory Authority as per the provisions of Natural Gas Market Law No. 4646 issued on April 2001. With the enactment of Petroleum Market Law No. 5015 and Liquefied Petroleum Gas (LPG) Market Law No. 5307, EMRA has also been authorized to regulate and supervise the petroleum and LPG markets. EMRA's first board members assumed duty on November 19, 2001, on which date EMRA became operational.

The necessary secondary legislation was prepared by EMRA during the Preparatory Period, which ended on 3 September 2002. The initial draft market rules (the Electricity Market Implementation Manual, followed by the Transitional Balancing and Settlement Regulation, or TBSR) were developed in 2002–03 at a time when there was an ample generation reserve margin. Licensing activities started in September 2002, and the market was opened to eligible consumers in March 2003. At the beginning, the consumption limit for eligibility was 9 GWh per year (this limit was gradually reduced over time by EMRA, as will be discussed in subsequent sections).

Some of the important secondary legislation prepared by EMRA during 2002–03 is as follows:

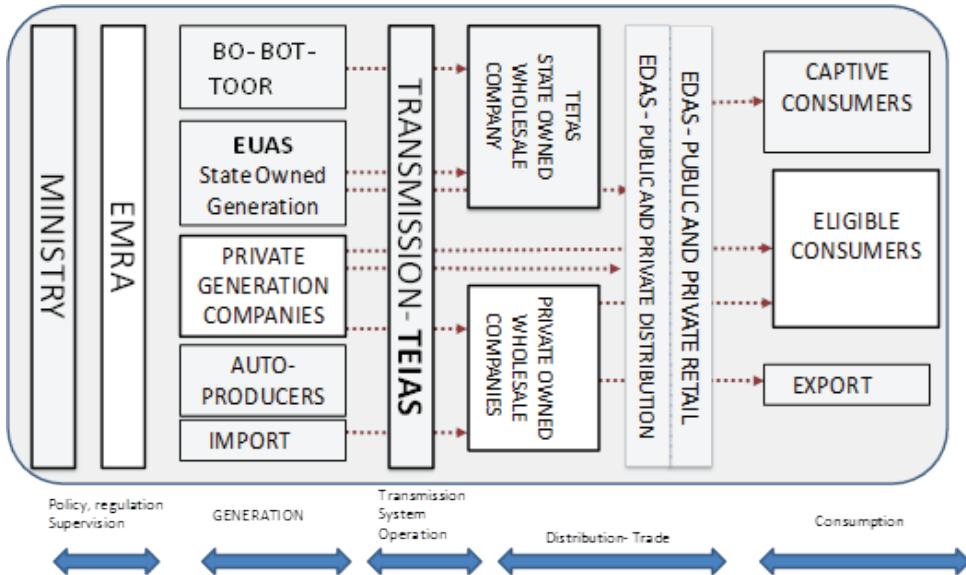
- Licensing Regulation (LR)
- Grid Code
- Electricity Market Distribution Regulation (EMDR)
- Transitional Balancing and Settlement Regulation (BSR)
- Ancillary Services Regulation
- Tariff Regulation

Another important step was the attempts to convert the unfinished BOT projects, which have valid existing contracts but are not implemented yet. In the Licensing Regulation it was declared that, if those project owners waive their contractual rights, they will be entitled to a license without fulfilling the licensing conditions stipulated in the Regulation. (The EML was later amended to include a similar clause.) There were 31 such projects, for a total capacity of 2,855 MW. Of these, the contracts of 15 (representing a total installed power of 1300 MW) were cancelled by mutual agreement and all of the companies obtained generation licenses, eventually built plants, and became market players.<sup>18</sup> In fact they were among the first players in the market together with existing autoproduction companies. It was an amicable solution and a smooth transition.

### **3.2.2.6 Market Structure**

The aforementioned restructuring, unbundling, and introduction of new private participants made for a substantial restructuring of the Turkish electricity market. Figure 21 illustrates the structure of the electricity industry after the EML.

**Figure 21. Industry Structure after the EML**



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

It should be noted that this structure changed when the new EML was enacted in 2013, as will be discussed later.

### 3.2.2.7 2004 Strategy Paper

The market design envisaged that the market would be operating within a short time and that rapid progress would be made in privatizing the distribution companies (DistCos). Those two steps would have laid the groundwork for a transparent and predictable electricity market price to emerge; allowed investors to develop some confidence in the operation of the balancing and settlement rules (BSR); and enabled credit-worthy eligible buyers to support the financing and implementation of new generation projects.

Although the EML established the main principles, there was a need to prepare a roadmap for the evolution of the market – especially the balancing and settlement mechanism, the steps for privatizing distribution and generation assets, and transitional measures for tariff implementation, for trading of state-owned generation. However, although the government was committed to the goals of the reform program – specifically, the goals of implementing a competitive market and privatizing distribution and generation – progress in actual implementation was limited. Implementation targets and implementation steps were agreed, but action was not taken. There was a lack of effective coordination of the reform effort and, perhaps more importantly, a lack of consensus on the transition approaches. While there was broad-based consensus on achieving a competitive market structure with the privatization of distribution and generation, there were fundamental questions being raised by MENR and the Ministry of Finance on the transition arrangements/requirements – specifically regarding the need for:

- Initial (vesting) contracts between generation and distribution companies, to ensure smooth startup of the market and facilitate privatization;
- Shifting to a cost-reflective pricing regime at the retail level before privatization; and
- Targeted subsidies to manage the impact of price increases on low-income consumers.

Hence, with the support of international experts (a World Bank–funded Expert Panel), a strategy paper titled “Electricity Sector Reform and Privatization Strategy Paper” was prepared jointly



## Turkey's Energy Transition - Milestones and Challenges

by MENR, EMRA, Treasury, and SPO<sup>19</sup> and the Privatization Administration; and issued as the decision of the Cabinet-level High Planning Council, chaired by the Prime Minister, on 17 March 2004. Its main decisions were as follows:

- **Privatization:**

In order to create financially strong and viable retail sector which would help attract new generation investments into the power sector, it is decided that privatization will start from the distribution sector. 20 regional distribution companies shall be established in 21 distribution regions [one was already private].

Generation privatization will start after distribution privatization and after establishment of a functioning wholesale market. Excluding some hydroelectric power plants that will not be privatized, the state-owned generation assets shall be grouped and portfolio generation companies shall be established.

The timeframe for the activities for the establishment of regional distribution companies, determination of their licensing process, their tariff structures, etc. is also set out in the strategy paper.

It was envisaged that, the preparatory work for and the necessary legal and regulatory changes would be completed by mid-2005 and distribution privatization would be completed by 2007.

- **Transitional Implementation:**

It was decided that EÜAŞ and TETAŞ would sell their energy to distribution companies through transitional (vesting) contracts, covering 85% of their regional demand of non-eligible consumers. Except for TETAŞ contracts, the duration of these contracts would be five years. In order to implement a uniform national selling price to the customers, it was decided to implement a price equalization mechanism (a cross-subsidy between regions). In this context, each distribution company transfers the excess money collected to TETAŞ if the national tariff is higher than its cost reflective tariff, and this excess money is transferred to the distribution companies, whose cost-reflective tariffs are higher than the national tariff. The national tariff is set at a level sufficient to enable this transfer.

- **Market Development:**

A Temporary Balancing and Settlement mechanism will be prepared and implemented. Before actual implementation, a virtual trial period (without cash requirements) was envisaged for the training of market participants.

The final BSR will be prepared and a wholesale trading platform with hourly settlement will be established.

The 2004 Strategy Paper also included measures for securing supply and strengthening TEİAŞ. Since the implementation of some of the provisions in the strategy paper would require amendments to the EML and related legislation, a roadmap for the amendments was also envisaged in the Strategy Paper. The preparatory work and changes in the legislation were to be carried under the coordination of MENR.

### ***3.2.2.8 Implementation of the 2004 Strategy Paper***

#### Privatization

The preparatory work for the restructuring of distribution companies, determination of their revenue requirements, loss and illicit use ratios, account separation, and determination of EÜAŞ portfolio groups was completed in 2004–05, with some delay compared to the timeframe envisaged in the Strategy Paper. Meanwhile, TEDAŞ was transferred to PA management and 20 regional distribution companies were established and licensed.



However, even though the preparations were completed by the last quarter of 2006, distribution privatization was delayed by the government unexpectedly just before the tendering stage. The reason for this decision was explained in the Privatization Section of this report.

#### Transitional Measures

The necessary legal and regulatory changes and amendments in the EML were realized in 2006, and the legal basis was established for national tariff implementation, a price equalization mechanism, and transitional contracts.

#### Market Development (Implementation of the BSR) in 2004–07

The Market Rules were first designed in 2003 and the legislative framework (i.e., the “Transitional” Balancing and Settlement Regulation, or TBSR) was completed in November 2004, PMUM (the market operation center within TEIAS) was established, and virtual (non-cash based) implementation began. However, the actual operation could only be started in August 2006 because TEDAŞ’s reluctance to participate even in the virtual implementation had also influenced the decision makers. Because it was unable to assess regional demands accurately, TEDAŞ was concerned that (a) an additional burden would occur in the balancing market due to imbalances and (b) that this additional cost would increase their already large losses since there was no intention of implementing a cost-reflective tariff at that time.

After a regional blackout caused both by a fault in one big thermal plant and by insufficient balancing capacity, MENR decided urgently to implement balancing and settlement regulation. After the TBSR was implemented, PMUM provided a trading platform for the market participants. However, suppressed regulated tariffs (discussed in more detail below) discouraged eligible consumers from switching away from regulated tariffs, and they remained captive consumers (some who had made the switch even chose to switch back to the DistCos). As a result, private generators had to sell most of their generation to PMUM, and hence the balancing market became a sort of pool. This, in turn, created another difficulty. DistCos (mostly state-owned at that time) topped up their energy needs (on top of the energy which were provided by TETAŞ and EÜAŞ) and imbalance power from PMUM – but had to sell it with a non-cost-reflected tariff to captive consumers. Eventually, this caused delays in the payments of TEDAŞ DistCos to suppliers.

Nevertheless, despite the problematic implementation, the introduction of the balancing and settlement market was one of the major steps in the reform and initiated new generation investments.

The 2004 Strategy paper provided a roadmap for the reform process and aimed to increase the confidence of market participants, especially private parties who could potentially invest in Turkey. In fact, initially the strategy paper was generally welcomed by the participants. However, hesitation and delays on the creation of a marketplace (balancing and day-ahead markets) and the decision to delay distribution privatization caused a loss of confidence. In addition, the intervention to control the end-user prices (keeping them below cost) further decreased the confidence of market players. This, in turn, had a negative impact on supply security due to insufficient generation investments.

Even though its implementation was delayed, the 2004 Strategy paper was an important step in the reform process. The decisions and the principles stated in the paper became the basis for privatization, transitional measures, and establishment of the wholesale market.

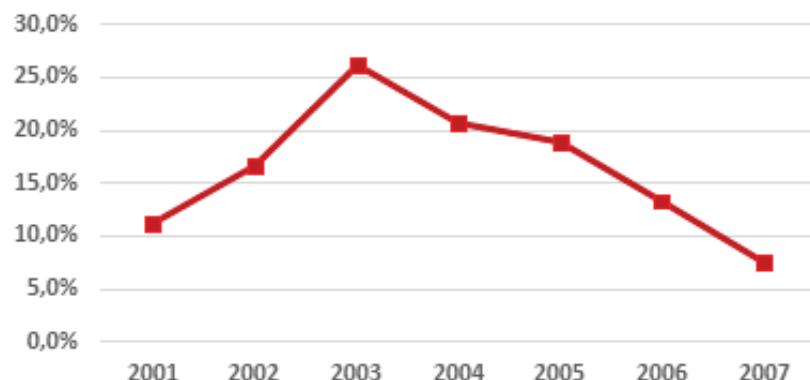
#### **3.2.2.9 The Supply/Demand Balance in 2001–07**

##### Insufficient Generation Investment: Alarming Security of Supply Situation

The average annual demand increase in 2002–07 was about 7%. Due to a sharp decrease in demand in 2001 and the commissioning of BOO plants in 2002 and 2003, the reserve margin<sup>20</sup> was at first sufficiently high. However, as shown in Figure 22, after 2003 the reserve margin declined sharply.

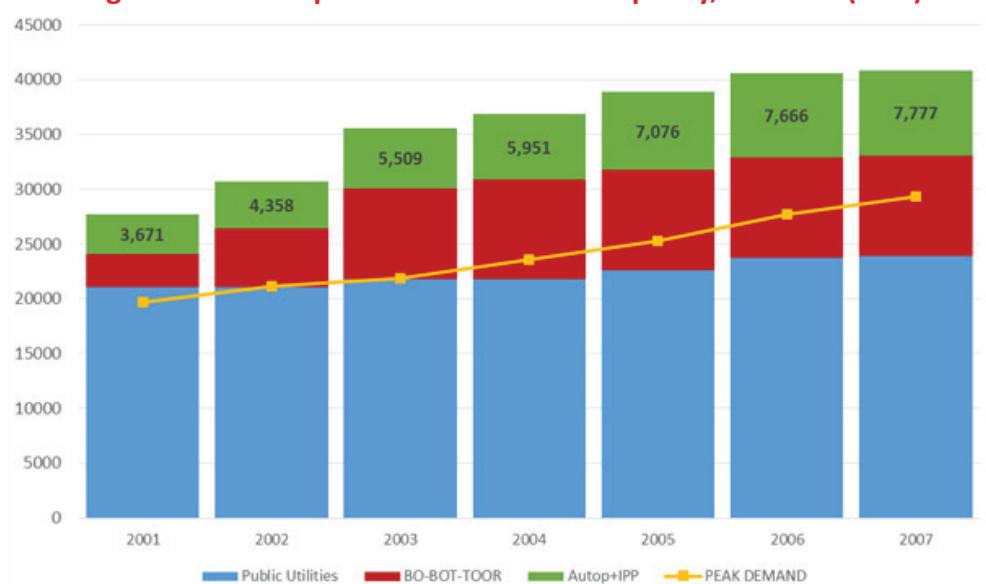


**Figure 22. Reserve Margin, 2001–07**



Studies conducted in 2006 indicated that, if demand continued to increase as projected, there would be a supply crisis from 2008 onward. The main reason for this was insufficient generation investments. Except for the hydro plants built by DSI, there was no public investment. Previous models, such as BOO and BOT, were no longer used. As shown in Figure 23, only 4,000 MW of private sector investment was created in seven years (mostly autoproducer facilities and old, unfinished BOT projects that were converted to IPPs, including investments initiated before 2001). Furthermore, the utilization rates of hydro plants were decreasing due to gradually worsening hydrological conditions.

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



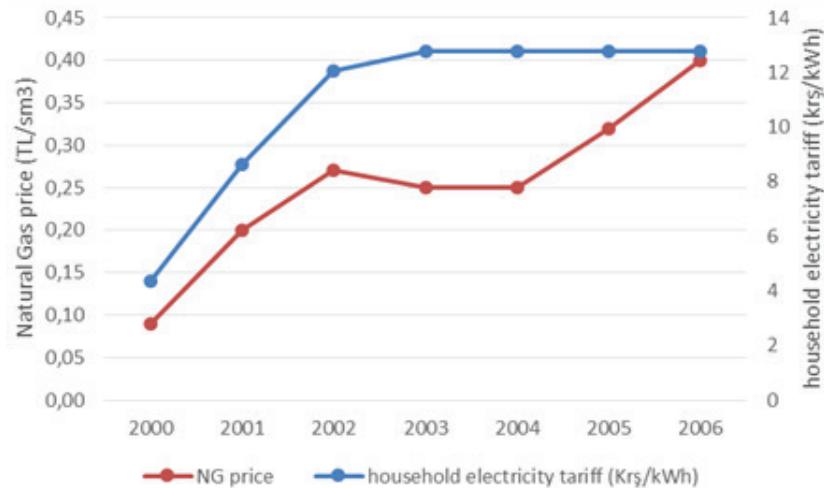
Source: TEIAS.

There were several reasons for the private sector's reluctance to invest in generation:

- Electricity prices had remained unchanged for the last five years while fuel prices and other costs increased, as shown in Figure 24.. Although there was no need for tariff increases up to 2005, due to abundant hydro generation and relatively lower natural gas prices, starting from 2005 the tariffs should have been increased to achieve cost recovery. Even though there were eligible customers, the low capped retail tariff discouraged switching and was not sufficient to recover the generation costs of private (mostly natural gas-fired plants). Hence the eligible consumers preferred to buy their energy from distribution companies with regulated prices. The regulated tariff structure did not incentivize the distribution companies (the DistCos) to contract for energy at a price that would give new-entrant generation sufficient revenue to pay for the investment.



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



Sources: BOTAS and TEDAS.

Note: Mid-year prices are used. Old Turkish lira converted to new Turkish lira.

- There was no mechanism to indicate long-term price signals. Even though the balancing and settlement regulation (TBSR) was in place, it was not implemented until late 2006. That is, there was practically no market place for trading energy until 2006, as discussed in the previous section.
- The market concept was new to Turkey. There was no track record. Public generation and sales by TETAS covered the energy demand of distribution companies up to 2005.
- Even after the implementation of TBSR in 2006, there was no possibility for bilateral contracting due to the following reasons:

TEDAS' past payment performance was not encouraging for prospective investors considering entering into possible long-term bilateral agreements. Distribution privatization was planned to be completed by 2007, and its postponement weakened confidence. The uncertain future status of the distribution sector led to unwillingness to contract for the long term and reduced incentives for new generation investment.

Due to demand increase and imbalances, distribution companies had to procure energy in addition to transitional contract amounts. However, since there was uncertainty, both suppliers and distribution companies did not prefer the new contracts and instead bought from the balancing market at imbalance prices. As explained in the previous section, the market structure for IPPs thus temporarily changed from a bilateral contracts market model to a central pool.

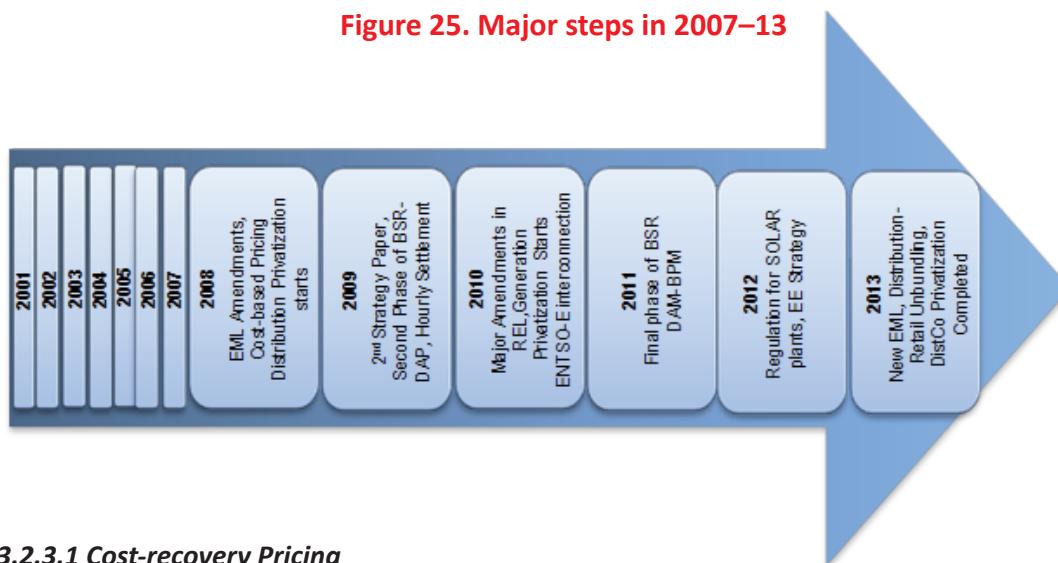
The commencement of implementation of TBSR (though it was not functioning as intended and was not sufficient for long-term confidence) did act as an incentive for new investments in that the number of new generation licenses increased after 2006. However, the main increase in investments occurred only after the implementation of cost-recovery pricing, the start of distribution privatization in 2008, and the introduction of well-functioning market platforms in 2009 and 2011.

The supply/demand balance worsened due to a high demand increase in 2007 and the first half of 2008. However, in the second half of 2008, electricity demand began to fall as a result of the global economic crisis. If not for this crisis and the resulting decline in demand, electricity rationing would have been inevitable from 2009.

### 3.2.3 Since 2008: New Steps toward a Competitive Market

*"Learning from past experience"*

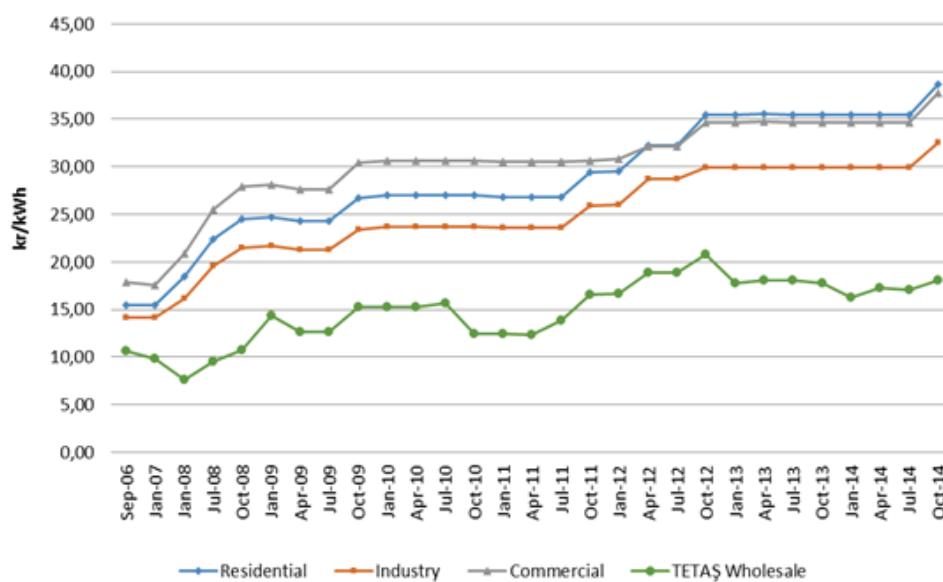
Figure 25. Major steps in 2007–13



#### 3.2.3.1 Cost-recovery Pricing

The risk of looming power shortages from 2009 onward and the unsustainable financial performance of state-owned companies prompted the Turkish government to take serious action by the beginning of 2008. For the first time since 2003, the regulated electricity tariff substantially increased in January 2008. After a gap of about five years, three substantial tariff increases were implemented (January 2008, July 2008, and October 2008), raising the average retail tariff by about 50%, thereby achieving full cost-recovery levels. This significantly improved the financial viability of the sector, encouraged more-efficient consumption patterns, and attracted private investment into the sector. **A cost-based, or "Automatic" Pricing Mechanism (APM)** was introduced for maintaining full cost recovery. Under APM, the prices of the Turkish Coal Enterprise (TKI), BOTAS, EÜAŞ, TETAŞ, and the distribution companies were to be adjusted quarterly using the formulas given in the APM, the first three by the companies/the government and the last by EMRA<sup>21</sup>. The average household, commercial, and industrial captive consumer tariffs (including taxes) and regulated TETAŞ tariff are shown in Figure 26.<sup>22</sup>

Figure 26. Household and Industrial Tariffs since 2006



Source: EMRA and TEDAŞ Statistics.

Note: kr= kuruş. (The Turkish lira is subdivided into 100 kuruş.)

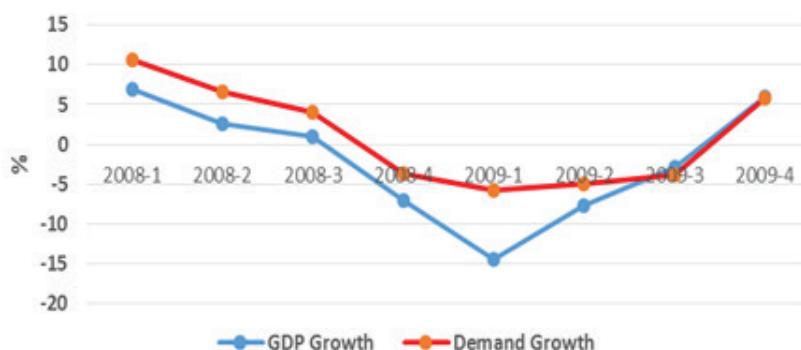


### 3.2.3.2 Supply Security Measures and Amendments in the EML

In 2006, with support from the World Bank, MENR began a series studies to assess the supply security situation.<sup>23</sup> The main question was whether the market design and implementation had any drawbacks and, if so, what the possible remedial measures should be. The studies showed that even if the implementation mistakes (discussed above) were corrected, there should also be a clear definition of responsibilities of the relevant organizations, a monitoring mechanism, and possibly also some new market mechanisms (such as capacity mechanisms, auctions, obligations to procure sufficient capacity) in order to enhance the security of supply. These recommendations for long-term structural change became the basis of the 2008 amendments to the EML and the 2009 Strategy Paper (see next section).

The slowdown of electricity demand growth and actual decline in demand in late 2008 and early 2009 (Figure 27) gave Turkey extra time – a window of opportunity to attract greater investment in generation capacity and electricity efficiency. Although the supply/demand balance improved due to the demand decrease, several short- and long-term measures were determined for the improvement of long-term supply security. The EML was amended in 2008 to allow for measures to better monitor and evaluate the electricity supply security. However, plans for long-term measures such as the Capacity Mechanism lost their sense of urgency and have not been implemented.

**Figure 27. Quarterly Changes in GDP and Demand, 2008–09**



### 3.2.3.3 2009 Electricity Market and Supply Security Strategy Paper

A new strategy paper was prepared in 2008 and published in May 2009 following its approval by the High Planning Council. Entitled “Electricity Market and Supply Security Strategy Paper,”<sup>24</sup> this document defined the steps necessary for market opening and for ensuring supply security and set out targets for domestic resources to be used in electricity supply in the medium and long terms. The Strategy Paper covered the following main topics:

- **Market implementation steps:** It reiterated the government’s commitment to establish a competitive electricity market and defined a road map for implementing wholesale market mechanisms such as the Day Ahead and Balancing Power Markets. It also envisaged an independent market operator to run an electricity exchange. It aimed at full market opening by 2015.
- **Privatization:** The Strategy Paper recognized that distribution and generation privatizations are important instruments for the establishment of a competitive market structure. It further stated that the basic goal in privatization was to establish competition in the sector, increase efficiency in the generation and distribution sectors, and ensure security of supply.
- **Supply security:** The electricity strategy called for close monitoring of the projected supply/demand balance by the Ministry of Energy and Natural Resources, with periodic



reports to the government on these projections and on the measures recommended for ensuring supply security. If, despite the measures taken, public sector investments in new generation capacity are recommended, these would need to be discussed as part of the government budget process. It also envisaged the consideration of further mechanisms in order to enhance supply security, such as a capacity mechanism and electricity/capacity auctions.

- **Future targets for domestic and renewable sources:** Since Turkey's over-dependency (over 40%) on imported high-cost natural gas for electricity generation was creating problems for the current account and concerns for energy security, the Strategy Paper declared Turkey's intention to increase the shares of domestic sources such as lignite and hydro in electricity generation and targets to utilize them fully by 2023. Furthermore, the Strategy Paper aimed to increase the share of renewable sources in electricity generation over 30% by 2023.
- It also set out the principles for establishing interconnections with neighbors, including the steps for interconnection with the Union of Coordination of Transmission of Electricity (UCTE), which on 1 July 2009 changed its name to the European Network of Transmission System Operators for Electricity (ENTSO-E).

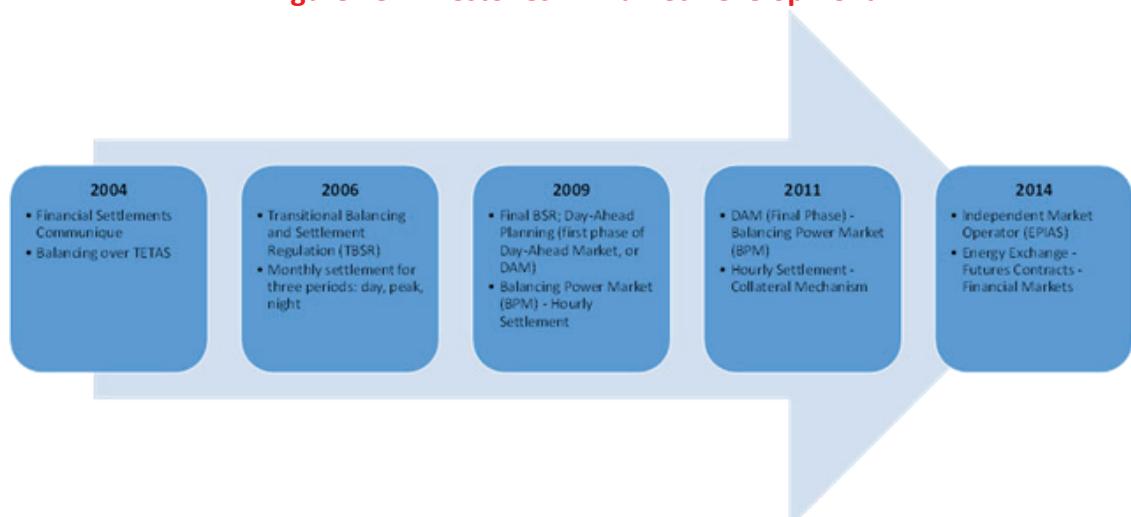
### *Implementation of the 2009 Strategy Paper*

The imminent threat of shortages due to low levels of private investment, the losses due to pricing policies, and the worsening performance of public distribution companies proved that the previous policies were not sustainable. Actions were delayed until it was no longer possible to delay further. Therefore, unlike the 2004 strategy, the decisions related to the wholesale market and privatizations were implemented without a major delay, as will be described in the following sections.

#### **3.2.3.4 Development of the Wholesale and Retail Markets: Trading Mechanisms**

The market structure being implemented in Turkey is based on bilateral contracting between buyers and sellers, complemented by a centralized day-ahead market and a residual balancing and settlement regime. In order to introduce wholesale competition and implement a marketplace, it was necessary to design and implement the rules and procedures for settling imbalances, scheduling, and dispatch. The implementation of the Balancing and Settlement Regime was one of the major steps. Since operating a wholesale market requires a developed metering and IT infrastructure and well-organized market participants, the market rules have been implemented gradually. The milestones of the market implementation can be seen in Figure 28.

**Figure 28. Milestones in Market Development**





The Market Rules were first designed in 2003 and the legislative framework – the first Balancing and Settlement Regulation (called the Transitional Balancing and Settlement Regulation, or “TBSR”) – was completed in November 2004. However, the operation could only be started in a transitional (pilot) mode in August 2006 due to reasons explained in previous sections. Until 2006 a simple balancing and settlement regime was used, in which the balancing power of private generators was supplied by TETAŞ at regulated buying and selling prices. After TBSR was implemented, it provided a trading platform for the market participants. However, as explained previously, due to suppressed regulated tariffs it became a pool.

This, in turn, created another difficulty. The DistCos (mostly state-owned at that time) topped up their energy needs (on top of the energy provided by TETAŞ and EÜAŞ) and imbalance power from PMUM. However, due to the higher prices in PMUM and suppressed tariffs, the DistCos found it difficult to pay TETAŞ, EÜAŞ, and even PMUM. This delayed PMUM’s own payments to the private sector. In addition, the arrears of the DistCos (TEDAŞ) to TETAŞ and EÜAŞ accumulated, as did the arrears of TETAŞ and EÜAŞ to BOTAŞ. This deadlock situation eased only after the cost-recovery tariffs were implemented and the eligible consumers switched back to other suppliers.

The mechanism implemented from 2006 until 2009 was sometimes called the “day-ahead balancing market.” In fact it was a “day-ahead scheduling mechanism (DAS).” Twice a month (not every day) the generators would submit their hourly generation programs and the prices if they were being used in day-ahead and real-time balancing (prices would be requested to load and de-load their plants) for the next 15 days. The daily demands were determined by TEİAŞ’ national load dispatch center for every hour of the next day and the system was balanced according to the physical capacity nominations of generators. The marginal price at the supply/demand crossing point were determined according to bids and offers. Therefore the system was balanced by TEİAŞ one day before. Generation scheduling was carried by TEİAŞ and disseminated to generators. Furthermore, the real-time balancing during the day was done by TEİAŞ on the basis of the generators’ prices. The settlement was also different, since the metering and IT systems were not completed: there were three settlement periods, namely, day (11 hours), peak (5 hours) and night (8 hours). It was a measure to have a balanced system for the next day in order to have a more manageable real-time balancing.

Together with infrastructure development, the detailed rules of the second phase of BSR were developed, which almost completely changed the original BSR. Phase 2 came into force in April 2009 and started in December 2009. This phase was a more complicated DAS mechanism. Instead of submitting twice a month, bids and offers were now submitted daily for each hour of the following day. Marginal prices were calculated and announced one day ahead. Still, the demand for the next day was determined by TEİAŞ. Instead of day, peak, and night settlement periods, the only settlement period was now one hour.

And finally, the final phase of BSR was started in December 2011. The balancing market evolved into a real Day Ahead Market (DAM), which is a voluntary power exchange in which supply and demand are balanced by the bids and offers of suppliers and consumers. TEİAŞ no longer balances the system one day before according to its demand estimations. It became a marketplace where supply, demand, and prices are determined according to participants’ bids and offers. Real-time balancing is carried out by TEİAŞ, in the real-time Balancing Power Market (BPM), based on load and de-load prices submitted by the participants one day before.

Studies for the establishment of an “intraday market” are at an advanced stage and it is expected that an intraday market will be in operation in 2015.

There were substantial delays in the implementation of both the TBSR and the final BSR (DAM and BPM). Today’s point could have been reached earlier. As stated in the previous sections, delays in cost-recovery pricing and distribution privatization had postponed the implementation. However, even if there had been no delays, a gradual pace of progress featuring step-by-step implementation would have been inevitable. Neither the technical infrastructure nor the



experience of market players could be built in a very short time. This is why a simple methodology was used by 2006; after which transitional methods (as defined in TBSR) were introduced, starting with a virtual (non-cash-based) implementation; and finally a wholesale DAM and BPM were established.

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

The introduction of trading and balancing mechanisms were major steps in sector reform. As currently operated, the markets can be defined as follows:

- **Bilateral Contract Market:** in which long-term contracts for volumes of energy are decided between buyers and sellers at a bilaterally agreed price. Price occurrence depends on bilateral contracts. Bilateral contracts provide a tool for hedging against volume and price risk for both the buying and selling sides.
- **Day Ahead Market (DAM):** in which buyers and sellers nominate hourly bids and offers for sale with settlement at a market clearing price. Price occurrence depends on day-ahead supply and demand (marginal pricing). The DAM acts as a market where uncontracted generation can be bought and sold in a bid-based scheme
- **Balancing Power Market (BPM):** in which participants are balance-responsible parties (they may join together to form balancing groups). Generators submit bids (to buy energy if the system is long) and offers (to sell energy if the system is short) for each hour of the day ahead once the DAM has closed and production and demand schedules have been finalized. Price occurrence depends on real-time supply/demand balance.

In addition to wholesale market mechanisms described above, Ancillary Services may provide additional revenue for the generators. These services are used for a reliable power system operation and are provided through ancillary service agreement with TEİAŞ.<sup>25</sup>

### *Energy Markets Operation Company (EPIAŞ)*

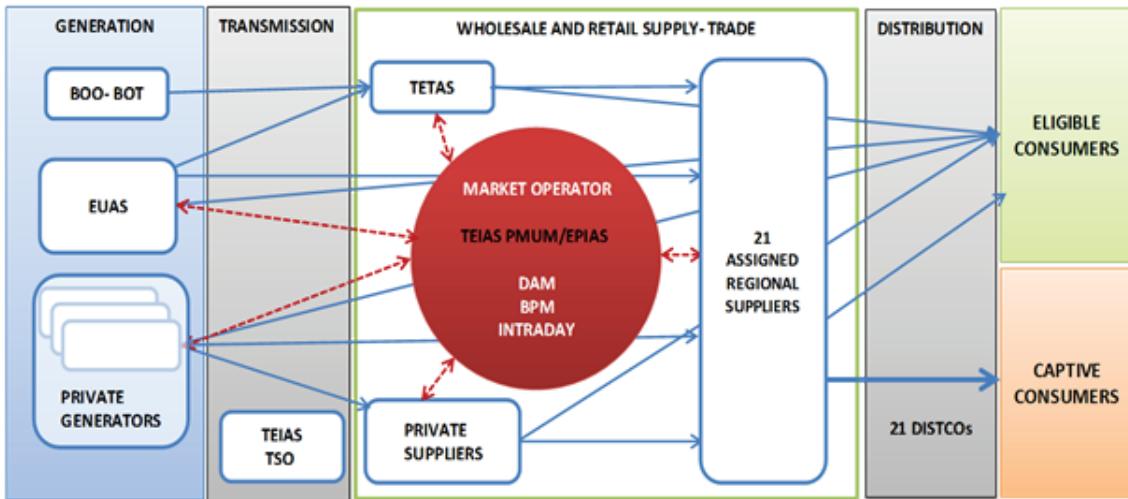
Until the new EML, which was enacted in 2013 (Law No. 6446, replacing Law No. 4628), market operation was carried by TEİAŞ though a separate department (PMUM). After the new EML, market operation activity was defined as “the operation of organized wholesale power markets and the financial settlement of the transactions made in these markets.” This activity, which will be carried out under a Market Operation License, will be separated from TEİAŞ and carried out by an independent company named as EPIAŞ. However, TEİAŞ will continue to operate the balancing power and ancillary services markets.

EPIAŞ will be responsible for operating the organized wholesale markets (such as DAM and Intraday) and developing an Energy Exchange (this will also include gas). It will also operate the market for standardized electricity contracts (i.e., capital market instruments) as well as the derivative markets, where derivatives based on electricity and/or capacity are traded. EPIAŞ will also be a market operator for gas trading.

The shareholders of EPIAŞ are TEİAŞ and BOTAS (30%), Istanbul Stock Exchange (30%) and the private sector (40%). EPIAŞ became operational in 2015.<sup>26</sup>

The final market structure is shown in Figure 29. (NOTE: With the new EML, autoproducer licenses are converted to generation licenses).

**Figure 29. Final Market Structure**

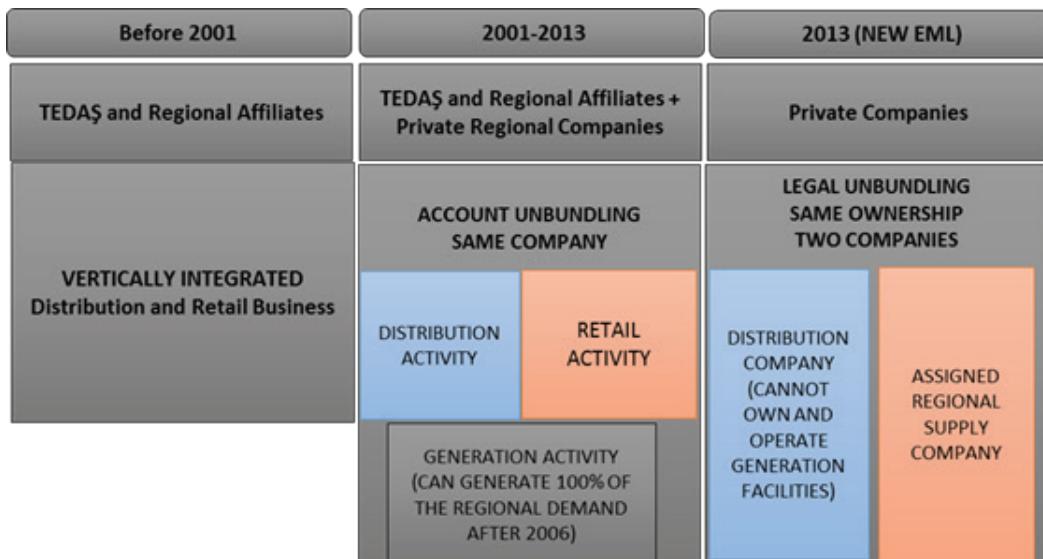


### 3.2.3.5 Legal Unbundling of Distribution and Retail Activities

Until January 2013, the distribution and retail businesses were carried by the same regional distribution companies (DistCos) using account separation (i.e., account unbundling). They had two licenses: distribution licenses for operating the distribution system in their regions, and retail sale licenses for supplying electricity to non-eligible consumers in their regions. As stipulated in second Strategy Paper and amendments made in the EML, those activities are now legally unbundled. As of the end of 2012, DistCos were legally separated into DistCos and “assigned supplier” companies.<sup>27</sup> However, legislation allowed assigned supplier companies to carry out their duties under DistCos during the first half of 2013.

The transformation process from a single vertically integrated structure to the legally unbundled regional company structure is shown schematically in Figure 30.

**Figure 30. Unbundling of Distribution**



The DistCos operate and maintain the distribution grid, and carry out the necessary grid investments, to provide non-discriminatory electricity distribution and connection services to all system users – including eligible consumers connected and/or to be connected to the distribution system, as specified by provisions of their licenses and the Electricity Market Distribution Regulation. The distribution licensees must also prepare regional demand projections and distribution investment plans for required distribution facilities to be built in the regions specified in their licenses.

The DistCos are obliged to purchase electrical energy and feed it into the distribution grid to make up for energy lost as a result of technical or non-technical losses. They must also read the meters of all distribution system users – including eligible consumers supplied by another supplier – and keep their records. They are obliged to provide non-discriminatory distribution services to all parties. According to the new EML, a distribution company cannot engage in any activity other than distribution or be a direct shareholder of a legal entity engaged in any other market activity. The new EML has prohibited only direct ownership; so indirect ownership of a DistCo by a generation company (GenCo) is still possible.

According to the new EML, an assigned supplier can sell electricity and/or capacity to captive consumers located in its authorized region and to eligible consumers countrywide. They are also the last-resort supplier of the consumers in their regions.

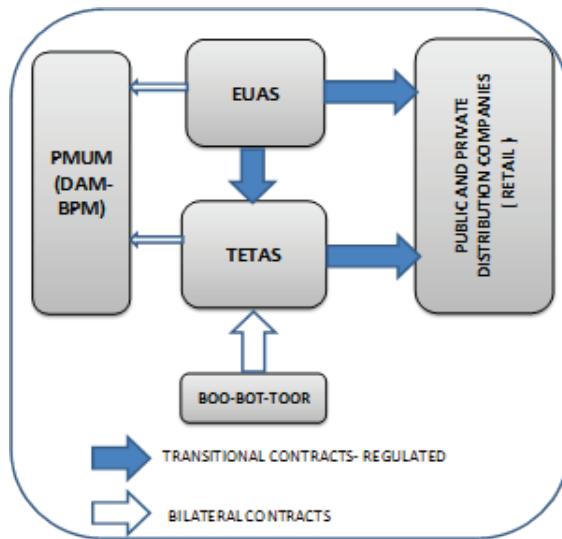
### ***3.2.3.6 The Role of EÜAŞ and TETAŞ***

Before the new EML of 2013, the roles of EÜAŞ and TETAŞ were restricted. EÜAŞ, because it owned and operated state-owned power plants, was not allowed to make new generation investments except for reasons of supply security. EÜAŞ could only take over the hydroelectric power plants built by the State Hydraulic Works (DSİ). Through the transitional contracts, its total generation was allocated to TETAŞ and distribution companies. Additionally, it can participate in the DAM for the un-contracted part of its generation, and in the BPM for balancing purposes.

The EML defined TETAŞ' role as a public wholesale company responsible for executing the “existing contracts” of the former TEAŞ (the BOO-BOT-TOOR contracts and import contracts signed before 2001). TETAŞ could sign new import contracts only with the authorization of Council of Ministers. After the first Strategy Paper, a part of EÜAŞ’ hydroelectric generation was allocated to TETAŞ to decrease the overall cost of the existing high-cost contracts. TETAŞ could sell its energy to distribution companies only through transitional contracts, and the prices of these contracts were regulated by EMRA.

The roles of EÜAŞ and TETAŞ prior to the 2013 EML are shown in Figure 31. It can be said that the market design did not initially assume any significant role for TETAŞ and EÜAŞ after the transitional period. Due to the hydro power plants that will remain in EÜAŞ portfolio, EÜAŞ would have a restricted role in the market after privatization. TETAŞ, on the other hand, was considered a “temporary” institution whose role would gradually decrease and eventually end following the expiration of “existing contracts.” However, as will be explained in Nuclear Section, TETAŞ is authorized to sign PPAs with a prospective Nuclear Power Plant Company that is expected to be commissioned by 2023. Hence TETAŞ will continue to exist after existing contracts are terminated.

**Figure 31. Role of EÜAŞ and TETAŞ before the 2013 EML**



The existence of a state-owned wholesale company (TETAŞ) provided a smooth transition from the single-buyer model to a competitive market. On one hand, it has been used to fulfill the obligations of State against old BOO-BOT plants; on the other hand, it became the main supplier to uncreditworthy state-owned distribution companies before privatization. The transitional contracts also provided a means to supply electricity to privatized DistCos during the long, gradual privatization process.

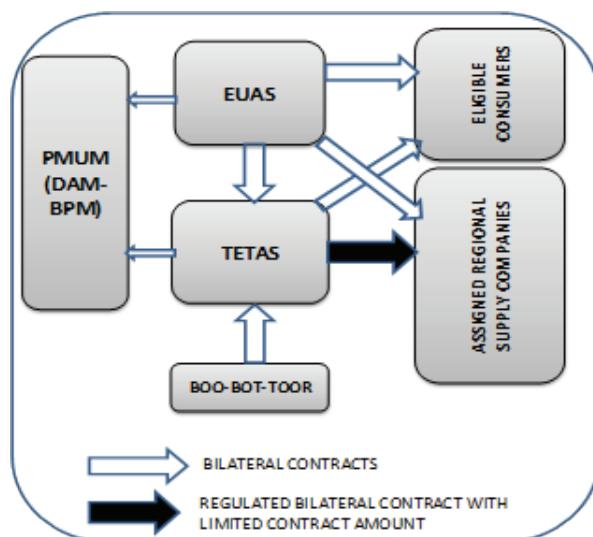
With the new EML, EÜAŞ and TETAŞ can be considered active players in the market. According to the new EML:

- There is no explicit restriction on, or condition for, new EÜAŞ generation investment.
- EÜAŞ has equal rights and responsibilities with the private generation licensees in the market.
- EÜAŞ can be a shareholder in private generation companies established to build and operate new generation facilities (especially strategic generation investments like nuclear power plants and thermal power plants using domestic lignite).
- TETAŞ' rights and responsibilities are equal to those of any private wholesale company in the market (however, its prices for its sales to DistCos will still be regulated).
- Distribution companies must buy energy from TETAŞ to compensate for loss, theft, and lightning in their region.
- The assigned regional supply companies – which are at the same time “supplier of last resort” in their distribution regions – shall buy a part of their needs in this context from TETAŞ. The amount will be determined by EMRA.



Hence the roles of EÜAŞ and TEDAŞ have changed and they are now active market players, as shown in Figure 32.

**Figure 32. Role of EÜAŞ and TEDAŞ after the 2013 EML**



### 3.2.3.7 Privatization

#### General Approach

Previous attempts in the Turkish electricity sector to privatize facilities have always caused legal challenges. In order to overcome such problems the Privatization Administration ('PA') received a legal interpretation from the *Danıştay* on the applicable privatization methods before determining the model for electricity generation and distribution privatizations.

According to the *Danıştay*'s interpretation, generation facilities built on a primary source can neither be owned by, nor sold to, private parties because the land under the facility has a river on it and is therefore a public asset. Therefore, hydroelectric power plants and similar facilities, like geothermal power plants, can be privatized only through the transfer-of-operating-rights (TOOR) model, leaving the title of assets with the public.

By contrast, thermal power plants are not built on a fuel source that is public property, and so the title of assets of coal, lignite, and CCGT power plants can be sold. However, coal mines feeding the lignite plants can be transferred to the private sector only through TOOR model.

Similarly, the *Danıştay*'s interpretation for distribution facilities was that the only allowable privatization method was the TOOR model because the sale of distribution assets means the sale of the immovable land under them, which is usually public property.

Methods of privatization are determined accordingly by the PA. Along with the electricity market reform implementation, a privatization program was started in 2006. According to the suggestion in the first Strategy Paper, priority was given to privatizing distribution first – the point being to create a reliable distribution sector, thus giving confidence to potential private generation companies. TEDAŞ, by any measure, was not inspiring that confidence. If generation privatization had started before distribution, the generators' main customer would have been TEDAŞ, and without state guarantees generators would not have contracted with TEDAŞ. This would have created an approach similar to the pre-2001 privatization method, which was not a competitive market approach.

The second issue is the lack of reliable metering, billing, and balancing/settlement functions. Time and investment is needed to establish such an environment. The third issue is the desire to reduce loss and theft under an efficient management of private sector.



### *Distribution Privatization*

The First Strategy Paper envisaged starting distribution privatizations in March 2005 and finishing them by the end of 2006. Preparations could only be completed in November 2006. However, even though the preparations were completed, distribution privatization was delayed by the government just before the tendering stage. The government's reasoning was as follows:

- The distribution system needs huge investments.
- If those investments are not made following privatization, service quality will deteriorate.
- Hence, these investments will be completed by TEDAŞ and the privatization process will continue afterwards.

Because one of the reasons for privatization was to remove the burden of investment cost from public companies, this contradicted the privatization distribution decision. Although it was not clearly announced, the real reason for the government's decision might be as follows:

- Estimates showed that, in order to finance the necessary investments, the electricity tariffs should be increased substantially.
- To cover O&M costs, including the effects of loss and theft, the O&M component of the tariff should also be increased.
- Such a tariff increase was a politically sensitive issue (see the section on pricing policy in 2002–07).

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

The distribution companies were privatized using a TOOR-backed share-sale model. According to this model, the investor is the sole owner of the shares of the distribution company – but with no ownership of distribution network assets or other items that are essential for the operation of distribution assets. The ownership of these distribution assets remains with TEDAŞ.

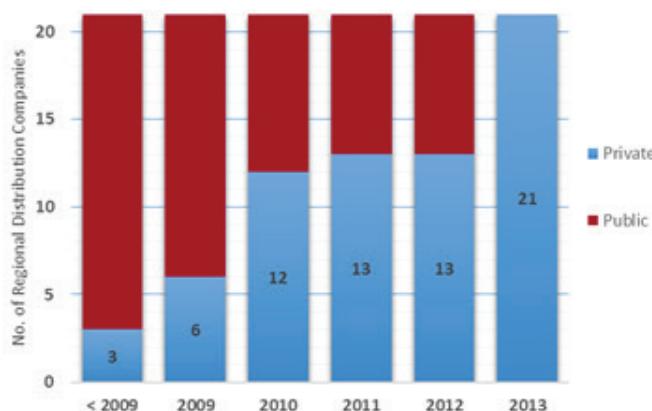
As a first step, the operational rights of distribution regions were transferred to regional public distribution companies (TEDAŞ affiliates). Then the shares of these companies were sold by PA. Each investor, through its shares in the distribution company, was granted the right to operate the distribution assets pursuant to the company's TOOR agreement with TEDAŞ and its share sales agreement with PA.

Under the envisaged market structure, the privatized electricity distribution companies will operate as monopolies (as distribution service providers, not retailers) in their regional areas, with distribution licenses granted by EMRA. Under the agreement, the operators must fulfill investment obligations to both replace and expand the network assets.

In addition to three regions that were privatized under the previous privatization model, distribution privatization has been realized through consecutive tenders. As shown in Figure 33, the number of privatized regions gradually increased from 2009 to 2013; as of November 2013, all distribution regions had been privatized.



**Figure 33. Development of Privatization of Distribution Regions**



Source: Privatization Administration.

However, the distribution privatization process was not as smooth as had been planned. For the reasons explained below, the process slowed down in 2010–12.

This first package, tendered in 2008, comprised four regional companies; transfers were completed for three of them in 2009 (the transfer of one was delayed until 2013 due to a legal challenge). The second package of seven companies started in October 2009 and the successful companies took over the regions in 2010.

Although additional tenders for the remaining seven regions were launched in 2010; tenders of five regional distribution companies were eventually cancelled as bidders could not fulfill their obligations. Tenders of two regional companies were cancelled by the Privatization High Council.

One of the reasons for the initial privatization failure in the third and final phase of the tenders was the very high bid prices, which were based on unrealistic and optimistic expectations about the tariff parameters to be used in the second tariff implementation period. The bidders later realized that those amounts were not realistic when related parameters (such as gross profit margin) were determined by EMRA in 2010, making the regions less profitable than expected.

Another reason for delay in the process was the Competition Board's decision on market share limits. According to the decision, one group of companies can acquire only those distribution companies whose total electricity distribution is less than 30 percent of the total electricity distributed in Turkey. Because of this decision, which was taken after privatization auctions were completed, some groups of companies had to give up taking over the shares of the DistCos for which they had bid the highest amounts. Furthermore, although the U.S. dollar/Turkish lira exchange rate was around 1.5 during the tendering period, it rose to 1.8 in the third quarter of 2011 (bids were in U.S. dollars).<sup>28</sup> Hence, they could not take over the regions and the Privatization Administration had to renew the tenders.



Currently, all DistCos have been transferred to private parties. The DistCos, transfer dates, and privatization revenues are listed in Table 5.

**Table 5. Result of Privatization Tenders**

DistCo	Successful Bidder	Transfer Date	Transfer Value (Million US\$)
Baskent	Enerjisa-Verbund	2009	1225
Sakarya	Akenerji-Chez	2009	600
Meram	Alarko	2009	440
Osmangazi	Eti Gumus	2010	485
Yesilirmak	Calik Enerji	2010	441,5
Coruh	Aksa	2010	227
Uludag	Limak, Kolin and Cengiz	2010	940
Camlibel	Limak, Kolin and Cengiz	2010	258,5
Firat	Aksa	2010	230,25
Trakya	IC İctas	2011	575
Bogazici	Limak, Kolin and Cengiz	2013	1960
Akdeniz	Limak, Kolin and Cengiz	2013	546
Gediz	Elsan-Tumas-Karacay	2013	1231
Dicle	Iskaya - Dogu	2013	387
Aras	Kiler	2013	128,5
Ayedas	EnerjiSa - EON	2013	1227
Toroslar	EnerjiSa - EON	2013	1725
Vangolu	Turkerler	2013	118
<b>TOTAL PRIVATIZATION REVENUE</b>			<b>12745</b>

Source: Privatization Administration.

The Turkish government gained about \$12.75 billion in revenue from the privatization of distribution companies. However, as stated in the first and second Strategy Papers, the purpose of privatization was not to support the budget. Its main purpose was to improve the performance of the distribution companies, reduce both losses and costs through efficient operation and investment, and reflect the gains to consumers by reducing electricity prices. Although considerable revenue was obtained, the high transfer fees have created and are still creating difficulties for the new owners; this will be discussed in subsequent sections.

#### *Operational Performance of Privatized Distribution Companies*

Because the privatization of distribution was delayed until 2009, and as a result of the gradual transfer process in 2009–13, it is so far impossible to accurately assess the gains and/or shortcomings of the privatization. However, the following observations can be made:

##### Collection Rate and Payments to the Suppliers:

According to the information received from DistCos, excluding some regions in Eastern and Southeastern Turkey, the collection rate in the privatized regions is over 95%. This shows that the low collection rate has mainly been a result of the weakness of public companies rather than high prices.

Until 2012, transitional contracts were in place<sup>29</sup> and the main suppliers of the DistCos were EÜAŞ and TETAŞ. In 2008, before privatization, TEDAŞ' total accumulated debt to EÜAŞ and TETAŞ had reached roughly TL 10 billion. Since EÜAŞ could not collect its receivables, it could not pay gas and coal companies. It was a deadlock situation that could be resolved only by enacting a law allowing reconciliation between state-owned energy companies in 2011.

Since privatization this problem has been mitigated to a certain extent. Most of the privatized DistCos are now paying fully – with the exception of (a) one region that defaulted on its payments in 2012 and 2013 (it diverted funds out of the company) and (b) three regions with high loss and theft ratios and low collection rates, where the companies have had difficulty collecting enough revenue to pay energy costs and distribution fees.<sup>30</sup> It is expected that companies in those regions will have difficulty continuing at the existing tariff level.

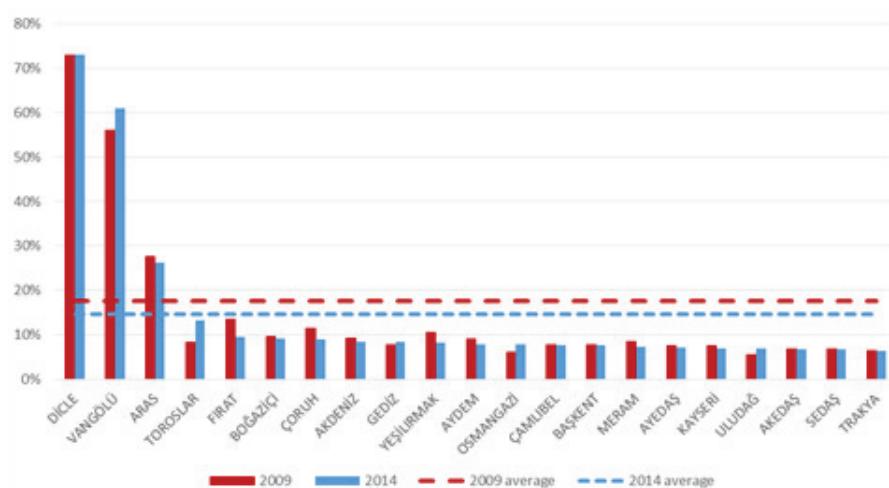
#### Loss Reduction:

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

Essentially, the most desired gain at the first stage is bringing theft under control by having the private operators implement necessary measures. Tariffs are determined according to loss and theft targets. To create an incentive for private DistCos, if they perform better and reduce the loss and theft below the determined target level, additional revenues will remain with DistCo. On the other hand, if a DistCo cannot meet its reduction targets, it is not allowed to reflect the additional cost to the tariffs. In other words, reducing the loss and illicit utilization in their regions is one of the primary duties of the DistCos. Otherwise, these companies will absorb all the revenue losses.

The loss and theft ratios in the distribution regions for 2009 and 2014 are shown in Figure 34.

**Figure 34. Loss and Theft Ratios of the Distribution Regions, 2009 and 2014**



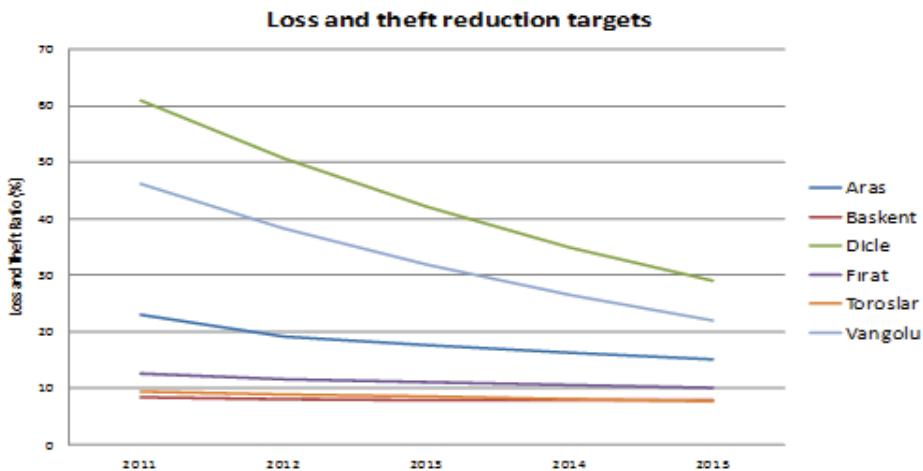
Source: EMRA.

Loss and theft rates vary considerably among the regional distribution companies. This big difference was the main reason for implementing the nationwide price equalization mechanism, which allows for cross-subsidization between regions.

The average ratio was 17.7% in 2009 and reduced to 16% in 2013 and to 14.56% in 2014. Excluding the three high-loss regions, Turkey's average loss and theft was 9% in 2011 and is reduced to 8.1% in 2014<sup>31</sup>.

Because the privatization program was considerably delayed, the reduction targets set for the first tariff implementation period (2006–10) could not be met, so EMRA set new targets for 2011–15. The targets for some of the distribution regions are shown in Figure 35.

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



Source: EMRA.

In 2012, technical losses in the distribution sector amounted to 8.2%, and non-technical losses were above the OECD average.<sup>32</sup> The main losses/theft occurred in the poorer distribution regions to the east of Turkey. The country average is almost 14.5%. As mentioned previously, in certain high-loss regions, especially Dicle and Vangolu, reduction targets could not be met. For this reason, the loss and theft targets of Aras, Dicle, Toroslar, and Vangolu were revised upwards to ensure financial sustainability in 2013. However, for Dicle, Vangolu, and Aras regions, problems persist due to high illicit use and their targets will be revised again. According to EMRA's evaluation, targets generally met by DistCos except three high-loss regions. EMRA will determine new loss targets for 2016-2020 tariff implementation period.

#### Service Quality

There is no reliable published official data to determine whether the service quality has improved or not. Moreover, since privatization was completed only after 2008 and most companies were transferred only in 2013, it is too early to evaluate the performance of these companies. The collection and performance-based evaluation will be possible only after the full implementation of the Electricity Supply Security and Quality Regulation (ESCQR).

#### Problems in Implementation

In both the first (2006–10) and second (2011–15) tariff implementation periods, there were no investment-program-based regional demand forecasts. Although there is a national demand forecast, it cannot be said that reliable regional demand forecasts exist that can serve as the basis for investment planning. Hence, it is highly possible for over- or under-investment to result at the end of the tariff period.

In 2006 EMRA approved 5-year distribution tariffs in line with the distribution companies' assumed investment programs. However, after privatization, the now-private distribution companies claimed that the assumed investment programs were insufficient to meet the needs of the actual system expansion. Therefore the distribution companies asked for their investment programs to be revised (thereby effectively requesting a tariff increase) and this caused problems. The suppressed investment programs and the revenue requirement based on them also led the companies to force third parties to invest in order to be connected or to be supplied. The underlying reason for the insufficient investment programs was the government's effort to keep the prices low. However, the investment allocations for the second implementation period were increased, as reflected in the distribution tariff. In fact, the distribution tariff, including loss and theft, has been increased substantially since 2008. Even though the total increase in the residential tariff in 2008–14 was 73%, the distribution and loss and theft component rose more than 200%, whereas the energy component rose only 43%.



Before 2006 the DistCos were allowed to engage in the generation business – provided that they obtain a generation license and that the amount of the annual electricity they generated did not exceed 20 percent of the total amount of electricity supplied for consumption in their region within the previous year. However, with the amendment of the EML in 2006, the 20% limit was removed. From then until the new EML was enacted, the DistCos could have generation licenses and could become self-suppliers. Also, the DistCos could procure energy from bilateral contracts signed with affiliate generation companies. The EML allowed generation companies to enter into affiliation with distribution companies provided that such affiliation did not confer exercising “control” on these companies as defined under the Law. Most of the privatized distribution companies were acquired by investors that also had positions on the generation side. The ownership of a DistCo by a generation company offers opportunities for vertical integration. This created concerns about the provision of nondiscriminatory distribution system access and operation principles.

The new EML removed this possibility. Following their legal unbundling, DistCos are no longer allowed to carry out generation activities. However, there is no restriction for regional retail companies (i.e., the assigned regional suppliers owned by the same group owning the DistCo). If the owner of the regional company also owns generation plants, “self-supply” or “self-dealing” might be possible.

Although distribution and retail activities were unbundled in the beginning of 2013, it was not an ownership unbundling, so ownership of regional distribution and assigned retail companies remained with the same owners. Furthermore, it is known that most of the shareholders of the DistCos and regional supply companies’ owners are also owners/shareholders of generation companies. As openly declared by some of the generation companies, they aim to supply most of the electricity demand in the distribution regions from their generation portfolios. Even though this was one of the main motivations for them to invest in generation, EMRA should carefully supervise this behavior to ensure fair retail competition.

Depending on financing conditions, high transfer fees and pre-determined loss-reduction targets created problems and companies asked for a tariff increase. For distribution companies (i.e., the “wire” business) the main revenues are determined according to a revenue cap methodology. The distribution tariff is set at a level that will cover O&M expenditures, investment programs, and loss and theft figures. The DistCos have a fair return on equity for their investment expenditures (a 10-year repayment period and 10.49% interest). However, the DistCos must finance the investment, and repayment through the tariff will be proportional to actual investment. For loss and theft, if they can manage to reduce losses below the target figure, they will benefit. For O&M expenditures, if they can manage this activity efficiently, they can cover their expenditures. Therefore, they need to be careful in meeting the targets and should not cause a cost overrun in their expenditures.

It should be noted that previous loss and theft targets were based on the information provided by TEDAŞ. Even for most of the regional companies that were not privatized in 2009, the new targets were again determined according to TEDAŞ. Since privatization, some of the new companies have claimed that these loss and theft figures do not reflect the actual loss and theft ratios and that the actual figures are higher. Furthermore as mentioned in the previous section, the loss and theft targets could not be met and actual losses have increased for four regions. However, one of the reasons for this increase is political turmoil in southeastern neighbors of Turkey and demand increase due to having more than a million refugees from those countries to Turkey. Some companies – especially those in regions with high loss and theft rates – are finding it difficult to reduce losses and are unable to increase their collection rates.

The regional assigned suppliers (i.e., the unbundled retail arms of the DistCos) can sell electricity and/or capacity to captive consumers with a regulated tariff located in the authorized region



and to eligible consumers countrywide. Each supplier also acts as the last-resort supplier of the consumers in its region.

The retail tariff is determined according to “price cap methodology.” The price cap is determined using the following formula:

$$\text{Sales price/kWh} = 1.0349 \times \text{buying price/kWh}$$

That is for their sales to non-eligible consumers, for which they can have a 3.49% profit. This profit margin, previously 2.27%, was increased at the distribution companies’ request. They can buy from TETAS (at the regulated price), from the BPM and DAM, and from other suppliers through bilateral contracts. The buying price is determined according to respective shares of overall supply, and they are allowed to reflect DAM prices for the portion supplied by DAM and other suppliers. Their sales to eligible consumers are not regulated and prices are determined competitively. Therefore, except for revenues from eligible consumers, their main income comes from the 3.49% margin.

To be able to cover their operational and financing costs for approved investments, pay their debts for the transfer fee,<sup>33</sup> and pay the cost of energy to suppliers, the regional distribution and retail supply companies should be efficient, experienced, and financially strong – and their collection rates should be high. In fact, the rational for the privatization depended precisely exactly depending on these issues.

However, during privatization, technical capability and management ability was not sought after. The main determining factor was the transfer fee in the tendering process. As mentioned earlier in this report, high transfer-fee bids in the tender caused either (a) delays in the privatization process or (b) continuous attempts to increase both tariffs and targets for loss and theft.

Another problem is the monitoring and auditing of realized investments. Each year, the DistCos submit the following year’s investment program in accordance with their approved budgets; this includes the realization of any distribution components commissioned during the year. Although it seems possible to audit investment with this methodology, considering the huge amount of investments in the 21 DistCos,<sup>34</sup> it is in fact very hard to audit the physical realization of each component.

According to the first EML, the supervision and auditing of DistCos was one of the duties of EMRA. However, the new EML stipulates that the inspection of DistCos is to be carried by MENR. MENR will audit the DistCos and send its reports to EMRA, and EMRA will decide according to the reports prepared by MENR. Although the final decision-making authority seems to be EMRA, transferring such an authority to MENR is not compatible with the “independent supervision” principle, which is one of the main virtues of having an independent regulatory body.

#### *Generation Privatization*

It was assumed from the beginning that generation privatization would be viable only once there were (a) commercial buyers (such as private DistCos and wholesalers) in the market capable of contracting the output from the newly privatized generators (b) and a developed market place. Therefore, in the First Strategy Paper, it was decided that generation privatization would not commence until there was some progress in distribution privatization and wholesale-retail trading mechanisms were introduced.

Originally, the strategy was as follows:

- All thermal power plants (TPP) would be privatized.
- Except for some reservoir-type hydroelectric power plants (HEPPs), which are mostly located on border-crossing river basins, all hydroelectric plants would also be privatized.

- To privatize generation facilities, the operational rights of hydroelectric power plants would be transferred, but the assets of thermal power plants (TPPs) would be sold. If a lignite or coal power plant were privatized, the operational rights of related coal or lignite mines would be transferred.
- The EÜAŞ plants to be privatized would be grouped under several “portfolio generation companies,” and those portfolio companies would be privatized.

However, even though the preparation for the establishment of portfolio groups was completed, the portfolio companies were not established; instead, the EÜAŞ portfolio groups continued to operate under EÜAŞ. Although the Privatization Administration (PA) later re-grouped the plants and rearranged the portfolios, the public generation portfolio companies have not been announced officially. Instead, PA decided to privatize thermal power plants as single facilities, and hydroelectric power plants as portfolio generators, depending on their location. On the other hand, some TPPs using the same lignite mine, such as Kemerkoyp and Yenikoy, were privatized together.

Generation privatization started with TOOR tenders by the Privatization Administration for small, run-of-river-type HEPPs that were not included in portfolios. After three auctions, 59 power plants (310 MW) were privatized as follows:

1. Generation privatization started in 2008 with the privatization of seven small hydroelectric, one geothermal, and one small gas turbine (for a total installed power of 141 MW) and all plants were transferred.
2. In 2010, 56 run-of-river small-hydroelectric plants (with a total installed power of 140 MW) were tendered; of these, 28 were transferred (100 MW) and the remainder were cancelled.
3. Thirdly, in 2012, three old BOT HEPPs (which had been transferred back to EÜAŞ in 2010–11 because their contracts had expired) and 14 run-of-river HEPPs, with a total installed power of 64 MW, were tendered and transferred. Finally in 2014, 5 small HEPPs (5.54 MW) were tendered and transferred.

As a second stage, several thermal power plants are being tendered and privatized as stand-alone power plants. As of July 2015, the situation is as follows:

- 1200 MW Hamitabad Natural Gas CCPP has been transferred on Aug. 1, 2013 at a price of USD 105 Million to Limak Natural Gas Generation Company.
- 600 MW Seyitömer Lignite Fired TPP has been transferred on June 17, 2013 at a price of USD 2,248 Million to Çelikler Seyitömer Electricity Generation Company.
- 457 MW Kangal Lignite Fired TPP has been transferred on Aug. 14, 2013 at a price of USD 985 Million to Kangal Electricity Generation Company (Konya Şeker).
- 300 MW Çatalağzı Hard Coal Fired TPP has been transferred on Dec. 22, 2014 at a price of USD 350 Million to Elsan Electric Appliances Industry and Trading Company (Bereket Energy).
- 3x210 MW Yatağan Lignite Fired TPP has been transferred on Dec. 01, 2014 at a price of USD 1,091 Million to Elsan Electric Appliances Industry and Trading Company (Bereket Energy).
- 2x210 MW Yeniköy Lignite Fired TPP together with 3x210 MW Kemerköy Lignite Fired TPP and port facilities have been transferred on Dec. 23, 2014 at a price of USD 2,671 Million to IC İçtaş Energy Production & Trading Company.
- 210 MW Orhaneli Lignite Fired TPP together with 365 MW Tunçbilek Lignite Fired TPP have been transferred on June 22, 2015 at a price of USD 521 Million to Çelikler Orhaneli, Tunçbilek Electricity Generation Company.
- 990 MW Soma B Lignite Fired TPP has been transferred on June 22, 2015 at a price of USD 685,5 Million to Soma Electricity Generation Trading Company (Konya Şeker).

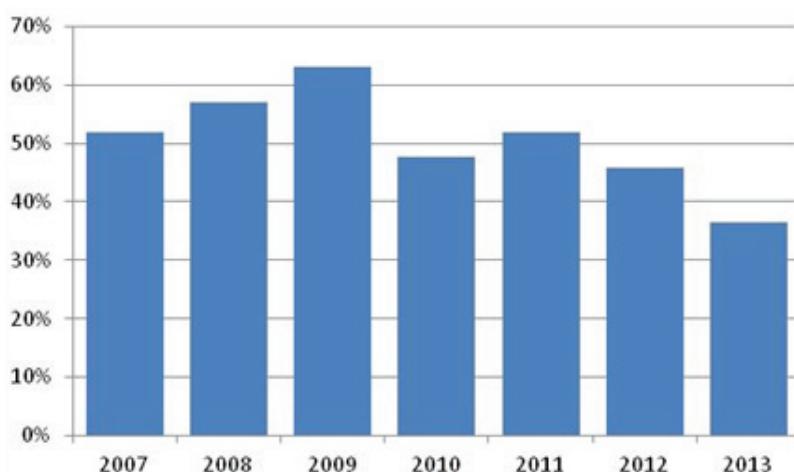


- Six RoR-type plants with a total capacity of 5.54 MW were tendered on 22 March 2014 and the highest bid was \$6.6 million. The decision from the Privatization High Council was obtained on 7 August; payment has not yet been made.
- An additional five RoR-type plants with a total capacity of 2.84 MW were tendered on 30 May 2014 and the highest bid was \$8.85 million. (Not yet transferred)

#### Generation Privatization Implications.

The utilization factor of the EÜAŞ thermal power plants, especially the lignite-fired ones, are because of their age, poor performance, and poor operational efficiency. The capacity factor<sup>35</sup> of EÜAŞ lignite plants from 2007 to 2013 is shown in Figure 36.

**Figure 36. Capacity Factor of EÜAŞ Lignite-fired Power Plants, 2007–13**



Source: TEİAŞ Statistics.

Normally, given the low cost of local lignite, these plants should always have a competitive advantage as base-load plants and their dispatch rates should be high, resulting in high utilization (i.e., a high capacity factor). The privatization of EÜAŞ thermal power plants will eventually improve their operational efficiency, thus contributing to supply security by helping to decrease the country's imports of natural gas. However, to improve their operational performance most of those plants will have to be rehabilitated. Due to rehabilitation investments, the cost of generation may increase – unless compensated for by cost reductions resulting from efficiency gains.

This is also true for EÜAŞ' privatized natural gas (NG) plants. Except for the Bursa CCGT power plant, the plants are old and have such low efficiency (below 50%) that rehabilitation should in fact include replacing the gas turbines with more efficient ones. Otherwise the existing NG plants will not be able to compete with the new ones, which have much higher efficiency (58–60%).

The privatization of EÜAŞ' reservoir-type hydroelectric plants will also affect market prices. EÜAŞ' prices are currently driven by the average cost of its combined thermal and hydro portfolios, and most of EÜAŞ' generation is sold to TETAŞ a price that represents this average cost plus a profit margin. However, after privatization private companies will seek to maximize revenues by concentrating deliveries at high-demand or peak-consumption periods during which the DAM or BPM prices are determined by high-cost NG plants. That is, those plants will no longer be priced according to their costs but rather according to market marginal prices, which are determined mostly by natural gas plants.



### 3.2.3.8 The Competition Authority's Role in Market Reform

According to Article 167 of the Turkish Constitution, the State shall take all actions necessary to prevent monopolization and cartelization in the markets that may arise de facto or as a result of agreements. The State responded to this mandate first in 1994 by adopting Act No. 4054 on the Protection of Competition, then in 1997 by establishing the Competition Authority (CA) to enforce the Act.

The main goals of the Competition Act are the prohibition of cartels and other restrictions on competition, the prevention of abuse by a firm that is dominant in a certain market, and the prevention of the creation of new monopolies by monitoring some merger and acquisition transactions. CA has contributed to the reform process, through its decisions and official opinions, during the market design and privatization process. In this context, before distribution privatization, CA determined **the legal separation of distribution and retail activities** as a prerequisite of privatization. In fact, this condition came into force by amending the EML and implemented in 2013.

CA also monitored the distribution privatization tenders and did not allow some transfers since the new owner would have had more than a 30% share of the total retail business.

CA also carries investigates claims against assigned retail and distribution companies by eligible consumers and suppliers. There are claims that the distribution companies do not treat all suppliers equally – that is, that they discriminate against the assigned supplier (which is owned by the same owner of the DistCo). Similarly, CA also deals with claims that the DistCos do not treat applications equally by creating difficulties for the connection of unlicensed generation facilities to the distribution grid. According to CA's evaluation, such behavior indicates the abuse of market power; and according to CA's decision, EMRA should also take necessary measures.

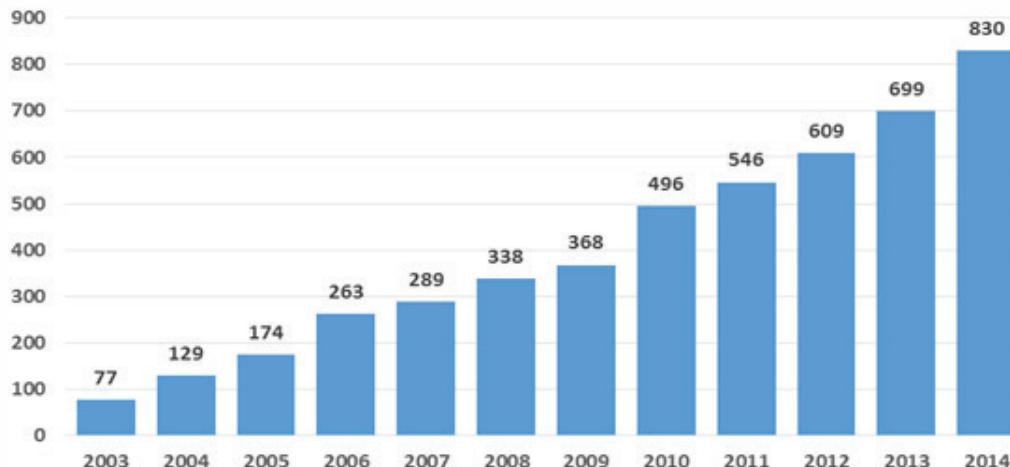
CA also helps develop market competition by publishing detailed reports on the electricity, gas, and petroleum sectors to determine the problems and challenges in each. CA's role is vital for the effective implementation of competition in the electricity and gas markets.

### 3.2.4 Achievements

#### 3.2.4.1 Market Activity

Since 2003 the number of participants registered with PMUM (the Electricity Market Financial Reconciliation Center within TEİAŞ) has increased steadily, as shown in Figure 37.

**Figure 37. Number of Participants in PMUM, 2003–14**

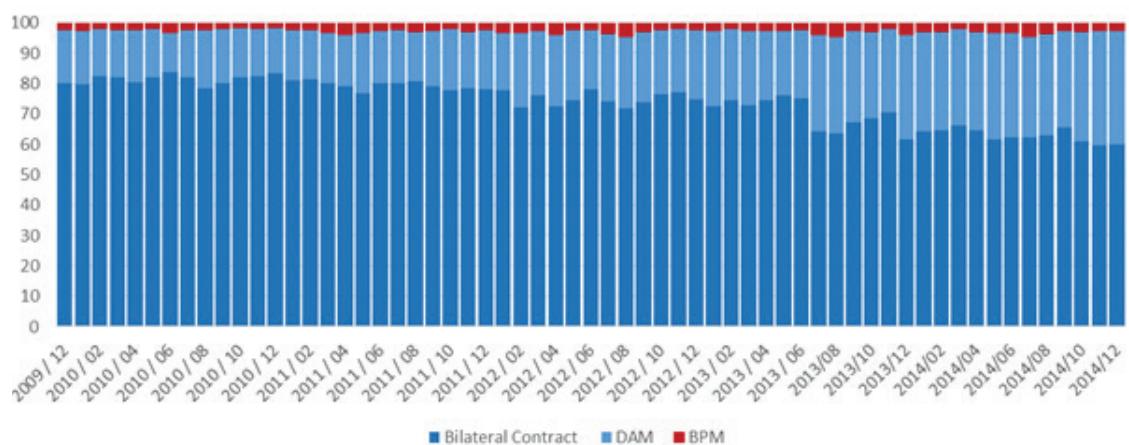


Source: TEİAŞ/PMUM.



- The number of private generators has increased considerably, indicating the attractiveness of Turkey's electricity market to private sector investment. The number of the wholesale licenses increased especially after functioning balancing and day-ahead market trading platforms were introduced.
- Roughly 70% of electricity in Turkey is traded through bilateral contracts. The remaining energy is traded mainly in the DAM and imbalances are resolved in the BPM. The shares of traded energy in DAM, BPM and bilateral contracts since the introduction of day-ahead trading are shown in Figure 38.

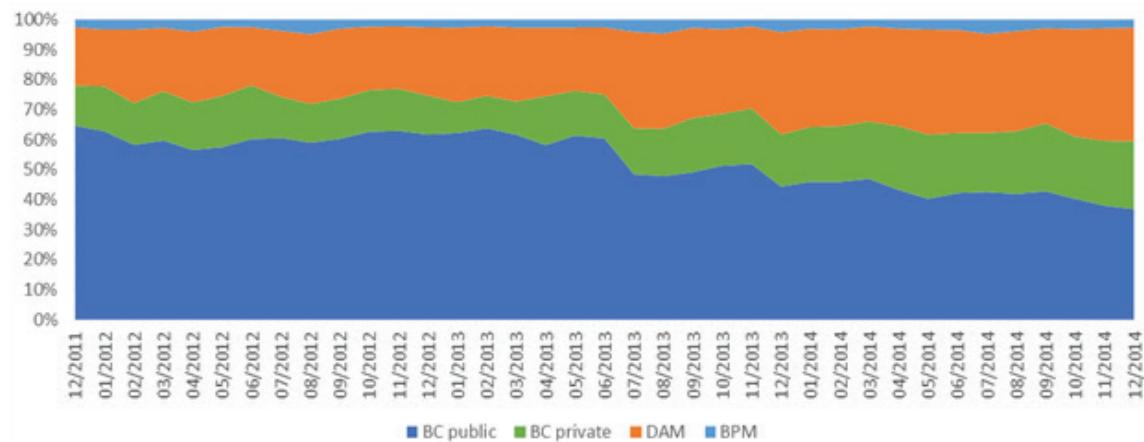
**Figure 38. Shares of Volumes Traded via Bilateral Contracts, DAM, and BPM, 2009–14 (%)**



Source: TEİAŞ/PMUM.

On the other hand, as shown in Figure 39, the share of bilateral contracts between consumers and public suppliers has decreased since 2013 as public generation has been privatized. However, the share of private supplier's bilateral contracts is not increasing by the same amount. This indicates that, at least for the time being, private suppliers prefer to sell their energy in the DAM rather than by bilateral contracts. The bilateral contracts generally have a one-year term.

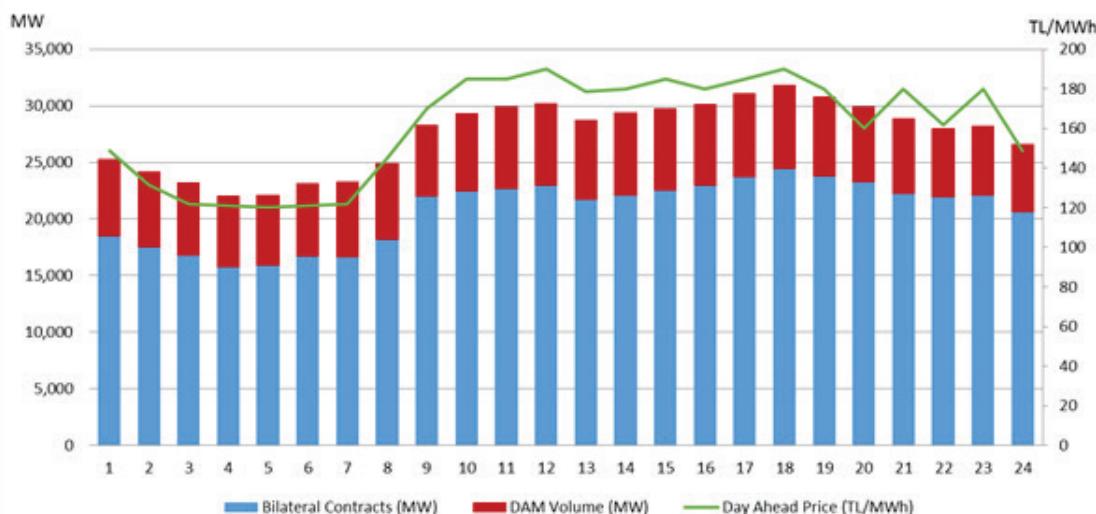
**Figure 39. Shares of Energy Traded in DAM, BPM, and using Bilateral Contracts, 2011-14**



Source: TEİAŞ/PMUM.

The prices in DAM generally depend on the supply/demand balance. As an example, Figure 40 shows the hourly demand, volume traded by bilateral contracts and in DAM, and also hourly marginal clearing prices in DAM on 13 November 2013.

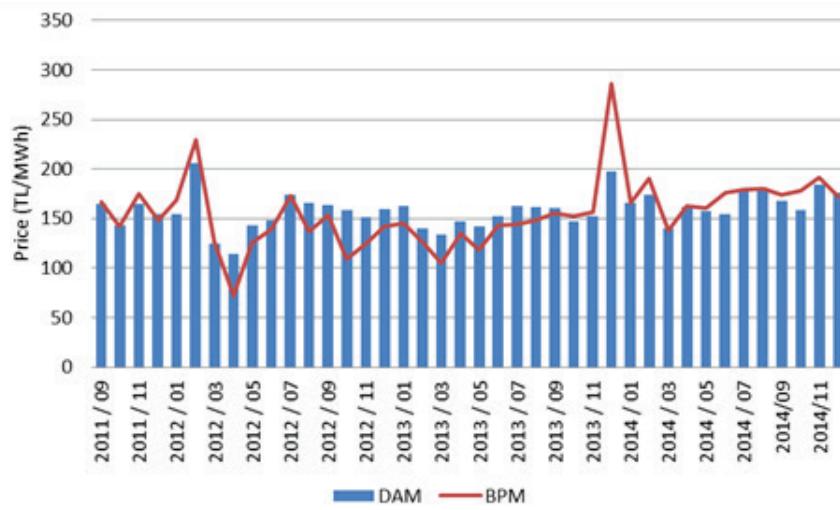
**Figure 40. DAM Volume and Marginal Prices, 13 November 2013**



Source: TEİAŞ/PMUM.

As shown in Figure 41, the DAM market clearing price and BPM marginal prices generally follow seasonal variations in supply and demand. The peaks in February 2012 and December 2013 reflect supply shortages resulting from natural gas supply limitations. The relatively low prices in March and April 2012 reflect the increase in run-of-river hydro power plant generation, during which water inflows increase. Similarly, the increasing prices in summer 2014 indicate the increase of thermal generation (mostly natural gas) due to a dry year and insufficient water inflow in 2014. This also shows the dependency of generation prices on hydrological conditions.

**Figure 41. Variation of Wholesale Market Prices since the Introduction of DAM and BPM**



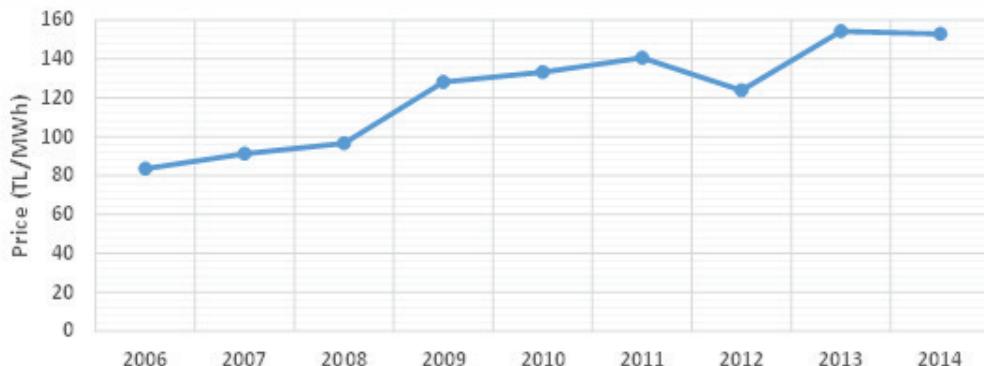
Source: TEİAŞ/PMUM.

Wholesale activity is not regulated and has no tariff (except for TETAŞ). The wholesale electricity price level depends on bilateral contract prices and on the price occurrence in DAM and BPM. However, as mentioned previously, the share of bilateral contracts is about 70% and, for most of those contracts, suppliers are public companies (EÜAŞ and TETAŞ) for the time being. Existing contracts (between TETAŞ and BOO and BOT companies) represented around 24% of total generation in 2013, and their prices are pre-determined in the contracts. Although the share of public companies in total generation is falling, the government can still affect market prices through the sales of EÜAŞ and TETAŞ.



The Turkish Average Wholesale Electricity Price (TAWEP) is an indication of average wholesale energy price changes. Determined and announced by EMRA each year, Figure 42 shows the variation of TAWEP from 2006 to 2014.

**Figure 42. Turkish Average Wholesale Electricity Price (TAWEP), 2006–14**

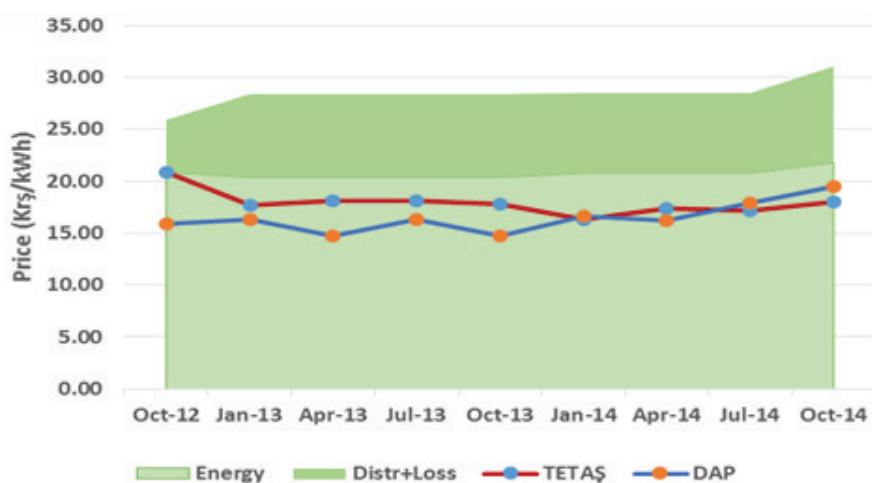


Source: EMRA.

Wholesale market price depends mostly on the price of electricity generated by natural gas-fired power plants (since they are the marginal plants in the merit order), and natural gas imports are priced in U.S. dollars. Although the Turkish lira lost roughly 25% of its value in 2013-14, this change was not totally reflected to wholesale prices. As will be discussed in Natural Gas Section, the main reasons are the constant natural gas price (in TL) in this period and increasing competition in the market.

On the other hand, as shown in Figure 43, the regulated wholesale tariff of TETAŞ fell in 2012–2014. TETAŞ buys electricity from EÜAŞ, BOT and BOO plants. TETAŞ' cost depends on EÜAŞ prices and also gas-fired BOO and BOT generation, which is denominated in U.S. dollars. The decrease in TETAŞ price under these unfavourable conditions can only be explained with (1) a possible reduction of EÜAŞ price to TETAŞ even though in 2014 the cheaper hydroelectric generation of EÜAŞ fell drastically due to dry season and (2) a reduction in revenue and profit targets of EÜAŞ and TETAŞ, which is set by the government in each fiscal year.

**Figure 43. Wholesale prices and end-user residential tariffs, 2012–14**



Source: TETAŞ/TEİAŞ/EMRA.



Hence constant end-user prices can be explained by (a) the government's natural gas pricing policy, which will be discussed in 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, the end-user tariffs were kept constant for 22 months in 2013-14 before increasing by 9% in October 2014.

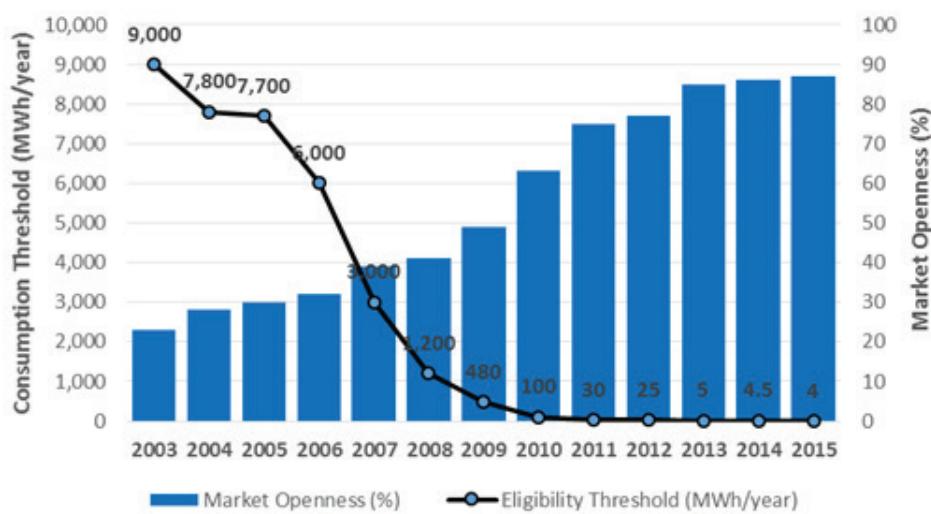
Unlike the physical markets mentioned above, Turkey's financial markets are not developed sufficiently yet. A futures market was recently established in Izmir and there is also an OTC market, but these markets are very shallow and progressing rather slowly.

Although the transition from a single buyer system to full competition is not completed yet, the development of wholesale market in Turkey is an important accomplishment. Both Government and private sector participants have learned a lot and gained experience. Remaining problems will be solved and the need for government intervention will disappear as the market develops. The establishment of EPIAŞ will improve electricity trade volumes and instruments.

### **3.2.4.2 Eligibility: Theoretical and Actual Market Openness**

In 2003 the consumption limit for eligibility was 9 GWh per year. It has been gradually decreased to 4 MWh as of January 2015, as shown in Figure 44. In the same period the theoretical market opening ratio<sup>36</sup> reached over 85%.

**Figure 44. Development of Eligibility Limits and Market Openness, 2003–15**

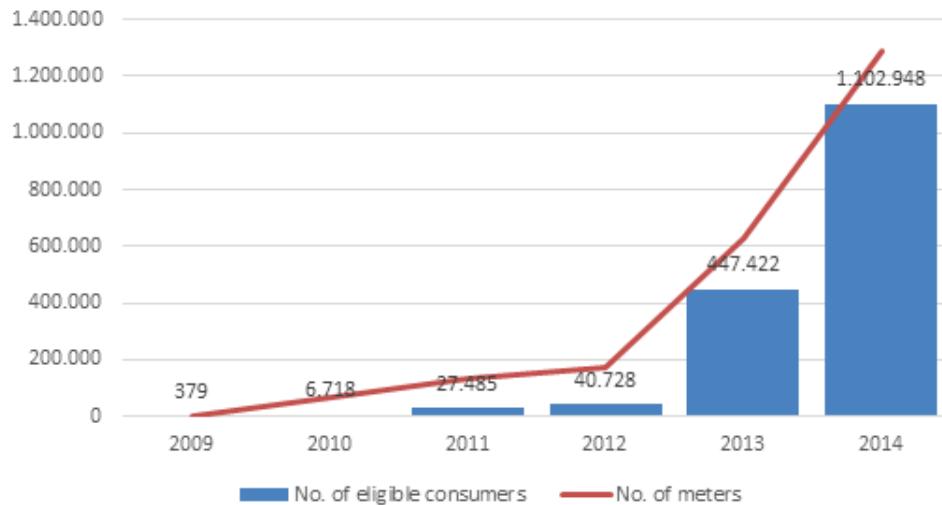


Source: TEİAŞ/PMUM.

However, until 2010 the number of eligible consumers exercising their right to choose their supplier remained very small. As shown in Figure 45, the number of eligible consumers has noticeably increased since early 2010. This is due mainly to the reduction in the limit and to favorable market prices. The big increase in 2013 is due to the removal of collective eligibility<sup>37</sup> by the new EML; eligible consumers must now register individually.



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



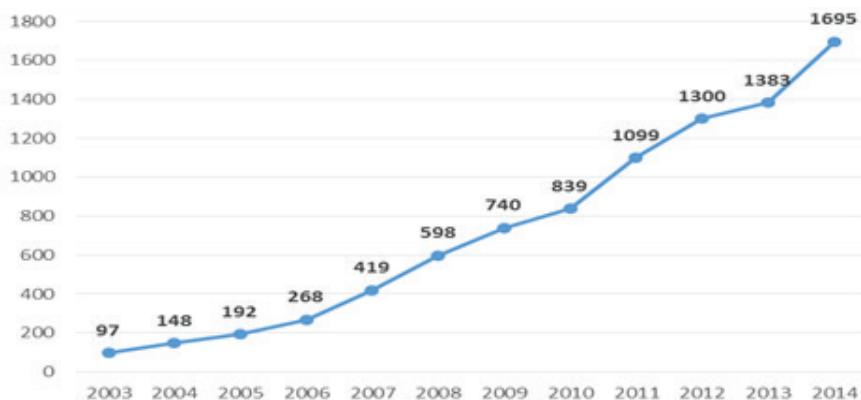
Source: TEİAŞ/PMUM.

The suppliers of eligible consumers are mostly generators retail and wholesale companies (i.e., suppliers and, traders). Wholesale companies purchase power under bilateral contracts and in the DAM. They are also responsible for balancing their customers' consumption including through the balancing market. In order to exercise the eligibility right, it is important to have metering systems that can measure hourly consumer demand. The number of registered meters recently reached 1,463,000. It was only around 2,000 in 2009.

### 3.2.4.3 Generation Investments

According to the EML, the generation investments will be carried out by the private sector. Unless there is a determined supply security problem, the public generation company EÜAŞ is not allowed to invest in a new generation facility. The exception to this principle is the big reservoir-type hydroelectric power projects (HEPP) that were planned and/or under construction before the EML. Although there have been some supply/demand balance problems in the last 10 years, this policy has been consistently followed. As a result of the gradual evolution of the new market structure, private sector generation investments have increased considerably. The growth in the number of generation licenses is shown in Figure 46.<sup>38</sup>

**Figure 46. Development of Generation Licenses, 2003–14**



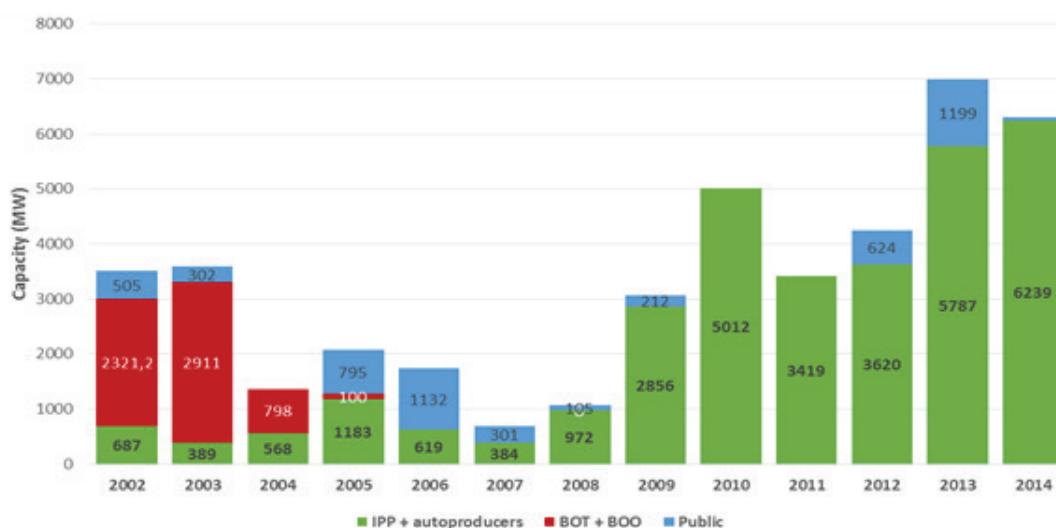
Source: EMRA, Activity Report 2014



## Turkey's Energy Transition - Milestones and Challenges

From 2002 to 2015, 43,100 MW in new power plant capacity was commissioned. 74% of this new capacity (31,735 MW) was due to private sector investments (IPPs and autoproducers). Figure 47 shows the capacity and ownership of power plants commissioned in 2002–14.<sup>39</sup>

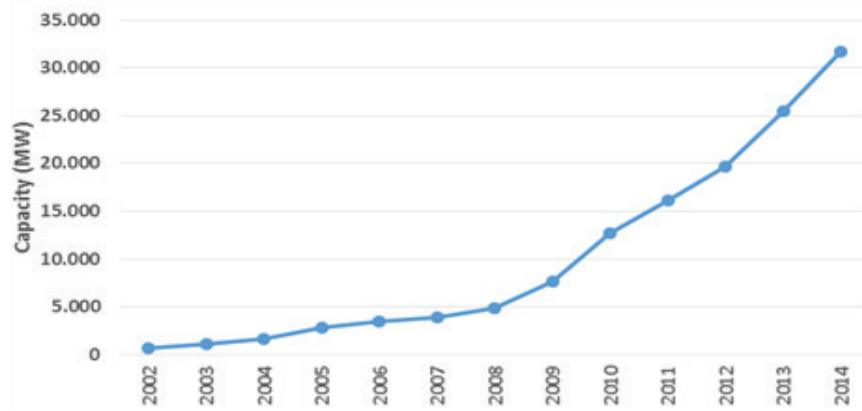
**Figure 47. Capacity and Ownership of Power Plants Commissioned, 2002–14**



Source: MENR.

Excluding the BOO and BOT plants commissioned during 2002–04, the installed power of new power plants realized by private firms was about 32,000 MW in 12 years. As shown in Figure 48, private investment gained pace after 2007 and 88% of this capacity was realized in 2007–14. The reform process has attracted large generation investments by many private companies, with an annual average investment of roughly \$4 billion in 2008–14 (excluding those under construction). Most of the generation investment has been by Turkish companies; although there have also been a number of foreign investors, most are partners of local companies. Both Turkish and foreign banks have financed the investments. International financial institution (IFIs) have also made significant contributions, especially for renewable generation investments.

**Figure 48. New Power Plant Capacity Realized by Private Companies, 2002–14 (MW)**

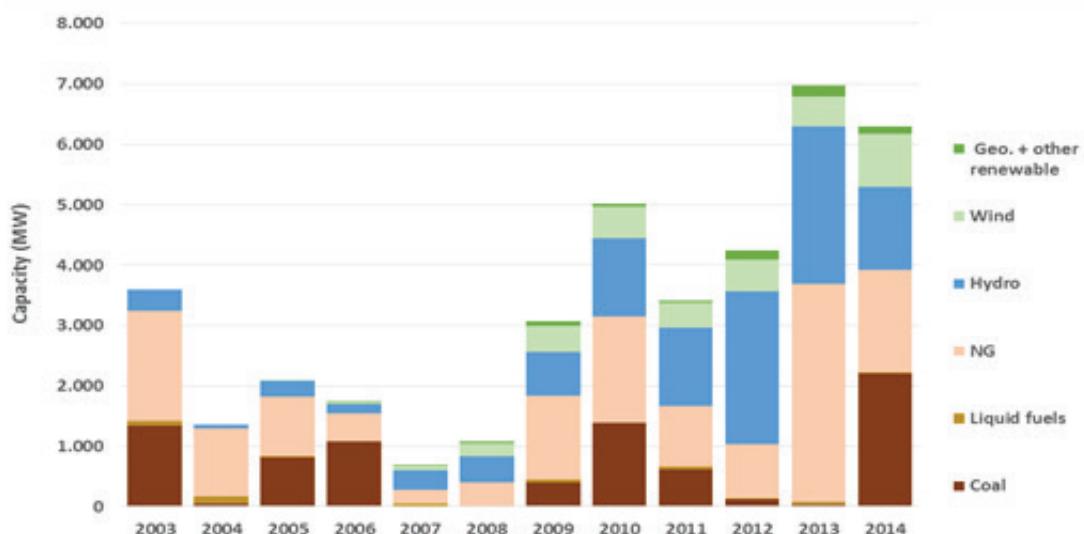


Source: MENR and TEİAŞ.



The breakdown of the new investments by fuel is shown in Figure 49. It should be noted that, except for the renewable energy feed-in tariffs (which are relatively low when compared with feed-in tariff levels in most countries), the investments have been made under competitive market conditions without any take-or-pay guarantees from the government, in contrast to the previous private investments made under the BOO or BOT models. (As will be discussed in Renewable Energy Section, because most renewable generation is also traded in the market due to favorable market prices, it can be said that investments in renewable energy have also taken place under competitive market conditions.)

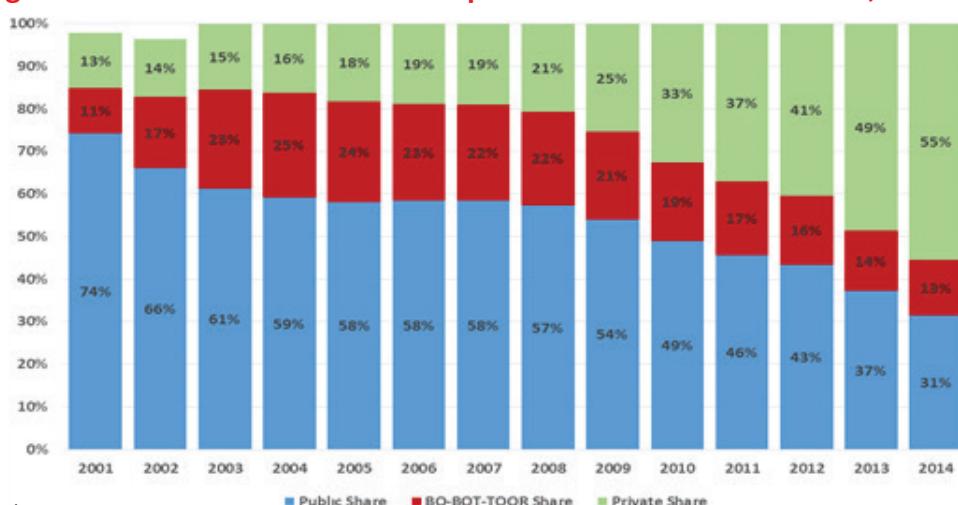
**Figure 49. Breakdown of Generation Investments by Fuel, 2003–14 (MW)**



Source: TEİAŞ- MENR.

As shown in Figure 50, the share of market-based private sector capacity in the total installed power had reached 55% – meaning that market-based power accounted for the majority of Turkey's power supply less than 14 years after the enactment of the EML in 2001. With the projected investments and privatization, this share will increase further. It should also be noted that BOO plants (10% of total capacity) can also be included in the private share since they are private generation investments. This shows the fundamental shift from virtually 100% share of public sector generation up to the mid-1990s.

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

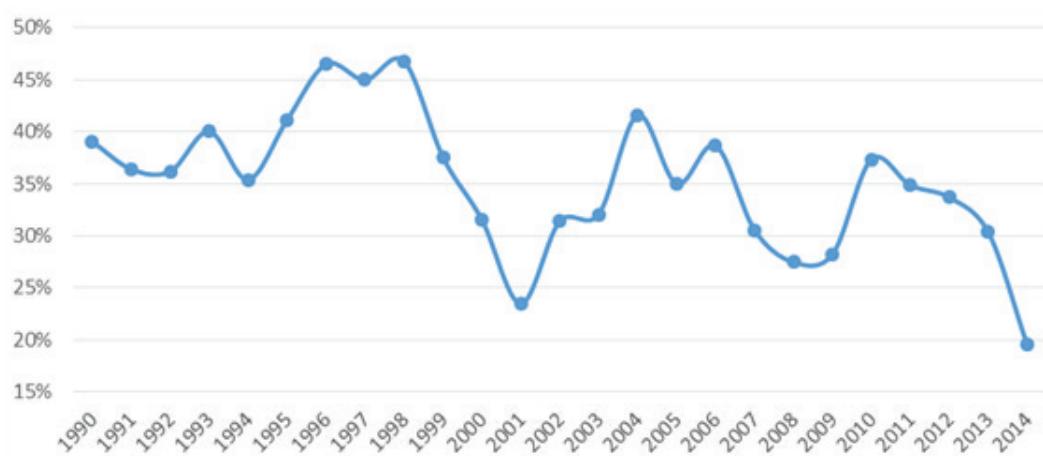


Source: TEİAŞ- MENR.

### *Generation Investments and Security of Supply*

As explained previously, Turkey has experienced several supply and demand problems over the past 40 years. Due to insufficient generation investments and variable hydrological conditions, the installed capacity margin has shown big variations. Despite higher capacity reserves, very tight supply/demand balance periods have been observed in the past. The reasons for this are the installed power generation capacity mix and low availability of the existing thermal power plants. The variability of historical generation data shows that hydrological conditions in the big river basins are unstable. The historical average utilization factor of HEPPs averages around 37% and varies between 50% and 25%, as shown in Figure 51.

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



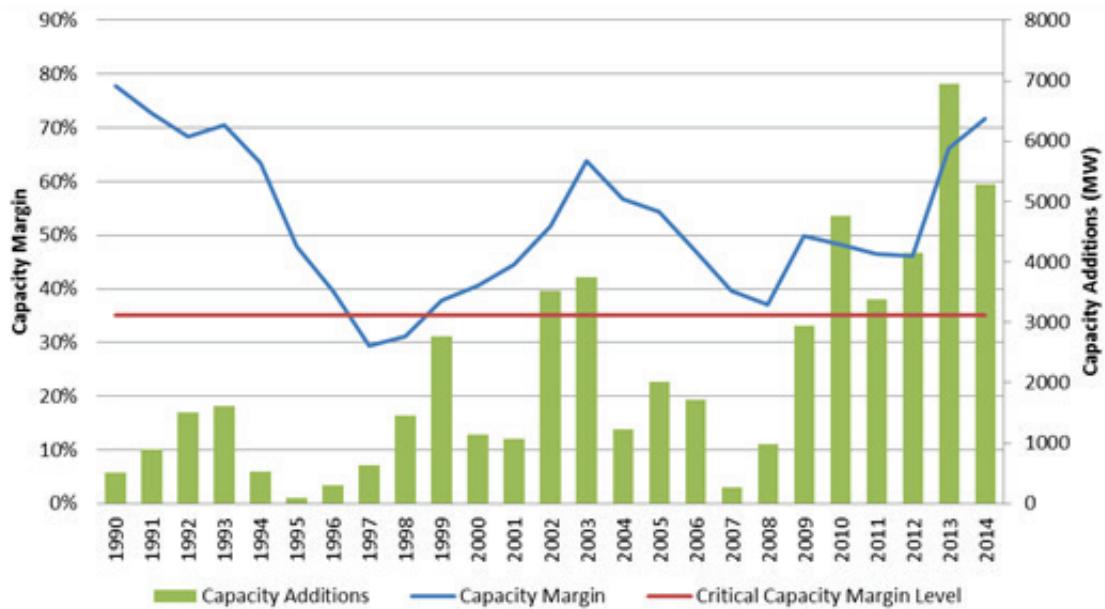
Source: TEİAŞ Statistics.

On the other hand, in addition to substantial hydroelectric capacity, the shares of other intermittent renewable energy sources have begun started to increase in the recent years. Due to variations in hydrological conditions, the shares of hydro and renewables in total generation present considerable variations.

At the moment, the capacity margin is around 70%. However, this high capacity margin is not a reliable indication of the adequacy and reliability of the Turkish power system. Past experience has proved that, whenever the capacity margin is smaller than 35%, it is impossible to provide a reliable energy supply due to the low availability of hydroelectric and other renewable power plants, especially during dry years/periods and when the availability of old thermal power plants is low (see Figure 52). Therefore, in order to have an adequate reserve margin (i.e., the margin between available power generation capacity and peak demand) in unfavorable hydrologic conditions, the installed capacity should be at least 35% over than peak demand, provided the operational performance of old thermal power plants is improved (by rehabilitation and efficient management).



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



Source: Calculated from TEİAŞ statistics.

As the previous figure shows, there are big fluctuations in capacity margin. In the early 1990s state investments began to decrease on the assumption that new private investment would increase through the BOT model. However, because of the insufficient legal and administrative structure at the time, private generation investment was insufficient and capacity margin decreased drastically. The subsequent BOO attempt was late when considering the long construction period of those big thermal power plants; the BOO plants were commissioned in 2000–02, when the government had already decided to move to a different regime for the power market. In 2001, although a new market regime was adopted, there was a long transition period because of insufficient implementation. Private investments gained pace only after the introduction of wholesale market mechanisms in 2006, cost-based pricing in 2008, and the starting of distribution privatizations.

As stipulated in the 2009 Strategy paper, increasing the share of domestic sources in electricity generation will improve the security of supply. The development of renewable energy, which is discussed in the Renewable Energy Section, is an important achievement.

Similarly, Turkey is trying to increase the share of its most important domestic source – lignite – in total power generation. Some lignite mines have been opened to private companies with a view to using the lignite for power generation, and the government is supporting investment in lignite-fired power plants. Although the outcome has not been as outstanding as it has been for renewables, the number and capacity of private sector lignite plants are increasing.

As the share of renewable sources and lignite in total power generation increases, it is expected that the share of imported sources, such as natural gas and imported coal, will decrease. This will enhance supply security while also helping to improve the current account balance.

### 3.2.5 Electricity Interconnections and Regional Electricity Trade

#### 3.2.5.1 Overview of Interconnections

Since the 1970s, Turkey has established interconnections with all of its neighboring countries and participated in regional system integration initiatives. It has done this to:

- Contribute to supply/demand balance,
- Reduce investments through reserve and capacity sharing,

- Improve the quality of energy, and
- Facilitate electricity trade.

Table 6 shows the interconnection list together with voltage level and operation mode.

**Table 6. Interconnections with Neighboring Countries**

Interconnection	Voltage (kV)	Mode
Georgia I	220	Asynchronous - Island
Georgia II	400	DC back-to-back
Armenia	220	Not operated
Azerbaijan (Nahcivan)	154	Asynchronous - Island
Iran-1	154	Asynchronous - Island
Iran-2	400	Asynchronous - Island
Iraq	400	Asynchronous - Island
Syria	400	Asynchronous - Island
Bulgaria-1	400	Synchronous
Bulgaria-2	400	Synchronous
Greece	400	Synchronous

As can be seen, most of the tie lines are operated in island mode. That is, Turkey's importing regional grids are synchronized with that of the exporting country, but isolated from the rest of the Turkish grid. The island mode of operation is inefficient and undesirable. Exceptions to this are the DC back-to-back connection with Georgia and synchronous connections to the European grid (through Bulgaria and Greece). Except for the European connection, the interconnections with other countries are asynchronous.<sup>40</sup>

Turkey looks for synchronization with neighboring countries and is cooperating with various international forums to establish large and regional interconnected systems. Since the mid-1990s Turkey has wanted to be a part of an interconnected European network. Upon Turkey's formal application in 2000, UCTE<sup>41</sup> decided to activate preparations for the synchronous connection. In order to comply with the UCTE requirements, Turkey has made extensive changes to allow its power system to operate in a parallel and synchronous manner with the European transmission network. It has also made substantial investments to improve the control systems of some important power plants to facilitate frequency regulation. Due to Turkey's robust 400 kV system, which was designed and built in accordance with international standards, there was no major investment in transmission infrastructure, control, and protection systems.

In September 2010, after implementing two major projects as part of a joint Turkey-UCTE group, and after successfully completing isolated tests, Turkey synchronously connected to the ENTSO-E grid via two Bulgarian and one Greek interconnection lines, and trial operation started. During trial operation the commercial export and import capacities are limited. Although initially a one-year trial operation was envisaged with a limited import capacity of 400 MW and export capacity of 300 MW, the duration was extended and import and capacities were increased to 550 MW and 400 MW, respectively, in 2013. Finally, in April 2014 the ENTSO-E Committees<sup>42</sup> decided to allow the permanent synchronous operation of the Turkish electricity transmission systems with the Continental Europe system. After completing the necessary formalities, TEİAŞ became an associate member of ENTSO-E and import and export capacities can now be increased to the technical limits of the interconnection lines (around 3,000 MW), provided the internal power systems have no other limitations.

ENTSO-E rules do not allow a country operating synchronously with its system to (a) interconnect with third countries other than via a DC connection or (b) connect with a voltage level equal to or less than 110 kV.<sup>43</sup> Also, a technical study for these connection methods should be performed and the permission of ENTSO-E should be received. This means that, except for the ENTSO-E



connection (the two Bulgarian and one Greek connections), all the other connections will be asynchronous, and all interfaces should be through DC back-to-back facilities. In this context, a new interconnection line between Turkey and Georgia was completed and became operational in 2014.

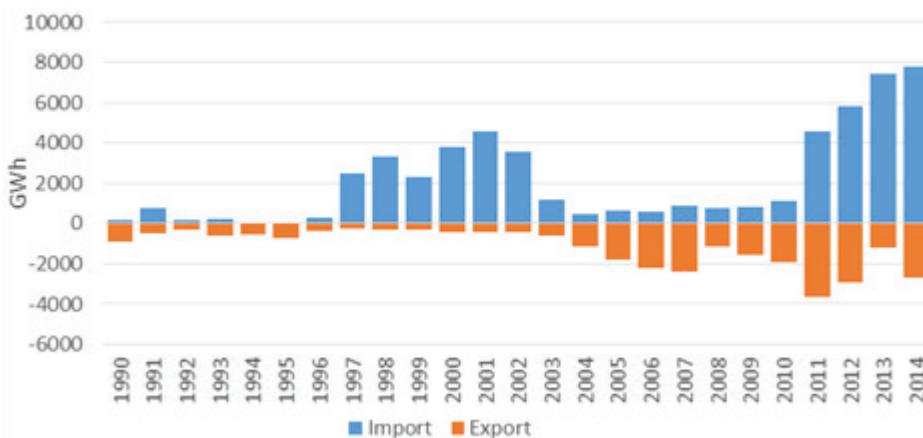
Turkey is also continuing investments to develop energy trading possibilities with its neighbors. For example, TEİAŞ has started building a second 400 kV line to Iraq and is studying the feasibility of building back-to-back stations for the Iran and Syria connections.

According to Turkey's Import-Export Regulation, import and export are subject to available capacity, the consent of MENR, and the approval of EMRA. To import or export electricity a company must have a supplier license and must pay "system use" and "system operation" tariffs as well as a "market operation fee." Available transmission capacity is allocated by the "explicit auction" method in case of scarce capacity. The eligible market participants are TETAŞ, wholesale companies, retail sale companies (import only) and assigned retail suppliers (import only). These arrangements will have to be modified to provide for the coupling of the Turkey's electricity market to the European market as discussed below.

### **3.2.5.2 Cross-border Electricity Trade**

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

**Figure 53. Electricity Imports and Exports, 1990–2014**



Source: TEİAŞ Statistics.

Until recently, the main driving force was to balance demand and supply, with supply generally depending on hydrological conditions and the sufficiency of local generation capacity. During the 1970s and 1980s, electricity imports from Bulgaria played an important role in meeting Turkey's domestic demand due to the chronic shortage of electricity investments. Trading was not the main aim. Before 2003, all imports and exports were carried out through intergovernmental agreements and bilateral contracts between state-owned electricity utilities. The "island" mode, or unit directing mode,<sup>44</sup> of operation limited energy exchanges.

Especially since the ENTSO-E connection, commercial transactions have increased – imports mainly coming from Bulgaria, Iran, and Georgia and exports going mainly to Syria, Iraq, and Greece. After ENTSO-E removes the capacity limitations, and after the new 400 kV DC connection with Georgia is commissioned, it is expected that import and export volumes will further increase. Facilitation of high volumes of commercial energy exchanges will also foster the competition in the market and will have a positive impact on prices, in addition to conventional reserve-sharing and investment-reduction benefits. For the time being, market prices in Turkey are relatively high (because the price-setting generators are natural gas plants) so imports are attractive.

Except for the European market, Turkey's neighbors do not have competitive, liberal markets and energy trade is mostly under government control. Therefore, at least for the time being, instead of a fully competitive regional electricity market, the more realistic option is for the main utilities (and possibly a few exporters of neighboring countries) to sell/trade in the Turkish market. Furthermore, electricity generated with heavily subsidized gas prices in Eastern and Southern countries may be a problem for local generators and investors if the interconnection capacities with those countries increase.

Once the ENTSO-E synchronization and membership have been achieved, the next step will be market coupling with the European internal market. In the longer term, the Turkey-ENTSO-E connection will facilitate other regional cooperation initiatives, including the Mediterranean Electricity Ring (MED-RING), because Turkey's ENTSO-E connection completes a key part of the path from the Middle East to Europe. As the markets develop around it and as cross-border capacities increase, Turkey – thanks to its geographical position and relatively well-developed internal electricity market – may have a pivotal role to play in regional electricity trading as an energy hub.

Western and North European countries from France to Finland have integrated their electricity markets. Integration is governed by a project called Price Coupling of Regions (PCR) and is regulated in a Multi-Regional Coupling (MRC) agreement. Romania, Hungary, the Czech Republic, and Slovakia have integrated and coupled their own markets and intend to join the Western and North European through market coupling. Bulgaria's new market operator, the Independent Bulgarian Energy Exchange (IBEX), intends to join the European market coupling. Through EPIAŞ applying the PCR algorithm (the algorithm is called EUPHEMIA) Turkey will have the potential to join the emerging Europe-wide power electricity market. This is a significant opportunity for Turkey but its realization will require major efforts by EPIAŞ and related regulatory adjustments.

Market coupling is the coupling of day-ahead markets, using the EUPHEMIA algorithm. EPIAŞ would have to apply the algorithm and a part of Turkey's cross-border transmission capacity with Europe would have to be allocated to the market coupling. Currently TEİAŞ explicitly auctions cross-border capacity. Part of the transmission capacity on the European border would have to be allocated to the coupling for implicit auctioning as part of day-ahead electricity trading in the market coupling. Implicit trading is the most sophisticated but also the most efficient trading mechanism – this is the model implemented as part of the PCR. It is also the most transparent – the higher the share of cross-border capacity allocation to the market coupling, the higher the transparency in cross-border trading. In the Nordic region the TSOs have allocated all available cross-border capacity to their jointly-owned regional day-ahead market, Nord Pool Spot. EPIAŞ need not develop the full range of market coupling operational capability in-house but could instead contract with a PCR service provider. This is the option chosen by IBEX to avoid the costly and time-consuming capacity development effort and to accomplish the market coupling much earlier than on its own.

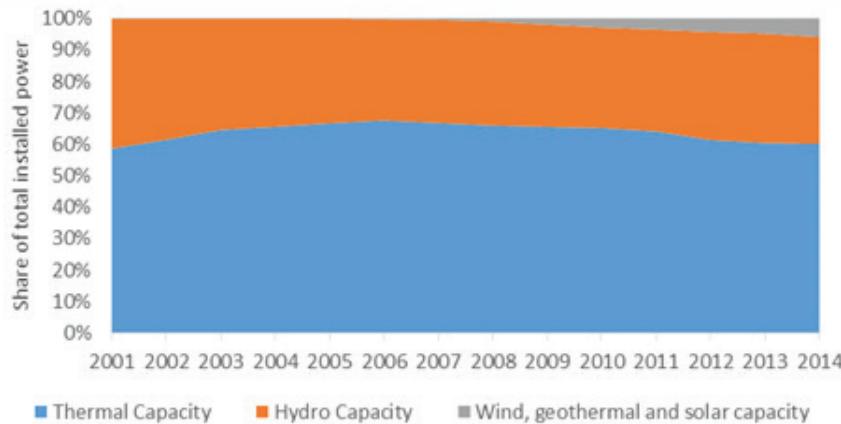
### 3.3 Renewable Energy (in Electricity Production)

An important achievement in Turkey's electricity sector reform process is the promotion of renewable sources in electricity generation. Turkey has substantial renewable energy sources and they are the second largest domestic energy source after coal. The main renewable energy resources in Turkey are hydro, biomass, wind, biogas, geothermal, and solar. However, at around 11%, the share of renewable sources in the country's primary energy supply is still low.<sup>45</sup>

As of December 2014, the total installed capacity of power plants using renewable sources was 27,700 MW. As shown in Figure 54, the share of renewable plants in total installed power has been roughly 40% for the last 13 years. (88% of renewable capacity remains hydro, despite the recent development of other wind, geothermal, and solar.) However, considering the fact that the total installed power increased more than twofold in this period, it can be concluded that the growth in renewable capacity has been substantial. In this period about 16,000 MW of new generating capacity using renewable sources was commissioned.



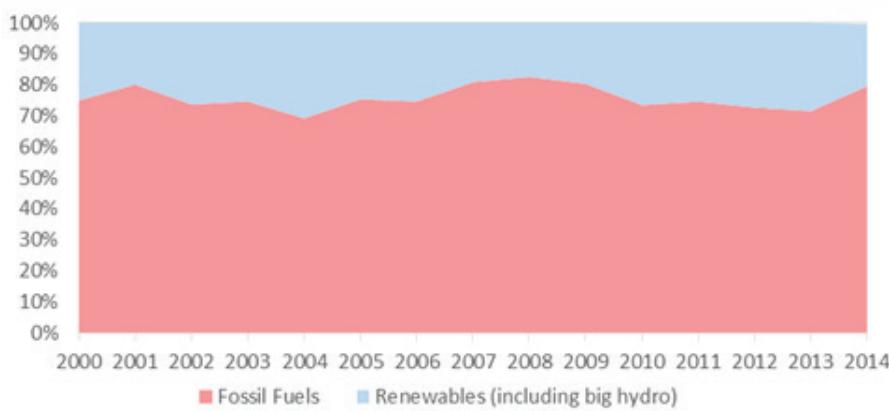
**Figure 54. Renewable Sources: Shares of Installed Power, 2001–2014**



Source: TEİAŞ.

On the other hand, as shown in Figure 55, due to the considerable share of hydroelectricity generation, the share of renewable sources in total electricity generation varies between 17 and 30%, depending on hydrological conditions.

**Figure 55. Share of Renewable Sources in Electricity Generation, 2001–2014**



Source: TEİAŞ.

The utilization of domestic renewable energy sources is of vital importance to Turkey's efforts to reduce its dependence on imported energy supplies, secure its energy supply, and prevent its greenhouse gas emissions from increasing. Turkey's energy policy seeks to increase the current share of renewable energy in electricity generation to 30%. When compared with the existing share (the average over the past ten years is 24%), this may at first appear to be a moderate target. However, considering the annual demand increase, which is more than 5%, to achieve a 30% share by 2023 the amount of electricity generated with renewables will have to double in nine years.

Even though Turkey has made considerable progress in both legislation and implementation, there are also problems in implementation.

### 3.3.1 Historical Background

Except for hydroelectric sources, the use of renewables for electricity generation was not on the agenda in Turkey until the mid-1980s. Studies regarding the development of hydroelectric sources had, however, begun as early as 1935, after the establishment of EIEI, which was authorized to study the country's hydroelectric potential and develop projects. After the establishment of the State Hydraulic Works (DSİ) in 1954, the pace of hydroelectric development increased. The first

geothermal power plant was commissioned in 1984 (17.5 MW) and EIEI began studying wind energy in the mid-1980s. However, there was no distinct framework for renewable energy until 2005. Although there were some attempts to develop small hydro and wind projects under the BOT model, only 18.9 MW in wind plant capacity and 220 MW in small hydro capacity had been developed by 2001.

Following the enactment of the Electricity Market Law (EML) in March 2001, the development of renewable capacity began, and the process gained pace, after the enactment of a renewable energy law; this is discussed in the next section.

### 3.3.2 Legislation and Developments

The main law related to the use of renewable resources to generate electricity is the Law on Utilization of Renewables in Electricity Generation (No. 5346), known as the Renewable Energy Law (REL). Enacted on May 18, 2005, it has been amended twice. The rest of the legal framework derives from the EML (new and old), other sector-related laws shown in Table 7, and related secondary legislation (regulations, communiqués, etc.).

**Table 7. Primary Legislation Related to Renewables**

Year	Legislation
2001	Electricity Market Law (EML) (No 4628)
2005	Law on Utilization of Renewables in Electricity Generation (REL) (No 5346)
2007	Energy Efficiency Law (EEL) (No 5627)
2007	Geothermal Law (GL)(No 5686)
2008	Significant Amendments to the Electricity Market Law (No 5784)
2011	Amended Law on Utilization of Renewables in Electricity Generation
2013	New Electricity Market Law (new EML) ( No 6446)

MENR is the main body to prepare the legislation and determine policies/strategies for the promotion of renewable energy. The EML gave also EMRA the responsibility for promoting renewable energy sources in the electricity market. Specifically, the Electricity Market Licensing Regulation (LR) stipulates that EMRA must (a) take the measures necessary to encourage the use of renewable and domestic energy resources and (b) initiate actions with relevant agencies to develop and implement incentives in this field.

Although the EML enabled private companies to build HEPPs, there was no regulation defining (a) the rights and obligations of the parties concerned to use the water or (b) the procedures for obtaining an HEPP license. An important step in the development of renewable energy in Turkey was the issuance of the **“Regulation about the Rules and Procedures for Acquiring Water Use Rights for Electricity Generation”** in 2003.<sup>46</sup>

This regulation only defined the procedures, but also allowed private companies to invest in the projects being developed by DSI and EIEI. EIEI since 1935 and DSI since 1953 had been working on river basins to determine hydroelectric capacity and preparing feasibility reports and plans for the candidate HEPP projects on several river basins. However, DSI was interested only in building big dams, and the private sector could build and operate HEPPs only under the BOT model before 2001. Hence this regulation was an important step for hydro development (especially small-size) by the private sector.

#### 3.3.2.1 Renewable Energy Law (REL)

The REL introduced certain advantages with respect to floor price and priority dispatch. Its aim is to assure the use of renewable energy resources in a safe, economic, and qualified manner in order to increase the diversification of energy resources, reduce greenhouse gas emissions, and protect the environment – and to develop a related manufacturing sector to realize these objectives.



According to the REL, renewable sources are hydro, wind, solar, geothermal, biomass, biogas, wave, stream, tidal energy resources. Although all kinds of hydro, including large dams, are deemed “renewable,” only run-of river (RoR) or diversion-type HEPPs and HEPPs with a reservoir area of less than fifteen square kilometers are included in support mechanisms for renewables.

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

The REL has been amended at various times, and the most recent comprehensive amendment became effective on 8 January 2011, after prolonged discussion among all stakeholders. According to the REL and related regulations, a “renewable pool” (the Renewable Energy Resources Support Mechanism, or YEKDEM) was introduced. Renewable generation facilities are supported by distributing the total cost of the electricity supplied to the pool, among all the suppliers selling energy to final consumers, rather than on the direct purchaser of energy generated by each facility.

Under the previous legislation, only retail sale licensees were obliged to purchase renewable energy. In the new support mechanism, all suppliers are now obliged to share the cost of renewable generation in the pool (details of this support scheme are explained in Appendix 2). The companies producing electricity from renewable resources can choose either to be in the support mechanism or to sell their energy in the market. However, they must declare their preference for the following year by October, and once they are in the pool, they cannot trade in the market in the current year.

One of the important changes was rearranging the tariffs according to sources, as shown in Table 8. The tariff is applied for 10 years from the first operation date if the commissioning date is between 18 May 2005 and 31 December 2015. The Council of Ministers is authorized to extend this deadline for the feed-in-tariffs, which in any case will not be higher than the feed-in-tariff for the first period. The deadline is extended in 2013 with the same tariff level.

**Table 8. Renewable Feed-in Tariffs**

Type	US\$ cents/kWh
Hydroelectric PP	7.30
Wind PP	7.30
Geothermal PP	10.50
Biomass PP	13.30
Solar PP	13.30

At this point, it is necessary to discuss the reasons for setting feed-in-tariff levels that are lower than project sponsors expect, especially for wind and solar. One of the reasons for setting the feed-in tariff at this level for wind was to promote the development of efficient plants first. It was thought that, as the investment costs declined, the projects with moderate efficiency would also become profitable in time. Considering the transmission connection problems and system reliability and energy quality threats due to intermittency of wind plant generation, a gradual development was deemed necessary.

Similarly, when determining feed-in-tariff level for solar, the expectation was for a gradual decrease in solar power investment cost over time. In fact this expectation became a reality, and as the cost decreases, 13.3 U.S. cents has become attractive for the solar plants due to high solar radiation and the high number of sunny days in Turkey, when compared with many European countries that are providing higher tariffs.

The law also includes additional incentive mechanism for the domestically manufactured mechanical and/or electro-mechanical equipment used in plants as shown in Table 9.<sup>47</sup>



**Table 9. Additional Premium for Local Production**

Type	Max. local production premium (U.S. cents/kWh)	Max. possible tariff (U.S. cents/kWh)
Hydroelectric PP	2.3	9.6
Wind PP	3.7	11
Geothermal PP	2.7	13.2
Biomass	5.6	18.9
Solar PV	6.7	20
Concentrated Solar	9.2	22.5

The law assigns specific premiums to different types of equipment. This will enable investors to receive premiums for electromechanical parts of the plant, although only if local content is over 55%. Hence it is not realistic for project owners to obtain maximum local production premiums in the medium term.

Other critical provisions of the legislation are as follows:

- For solar and wind license applications, site measurements are required.
- Solar and wind license applications may be submitted only on the dates determined according to the Electricity Market Licensing Regulation.

The following are other notable incentives for renewables, grouped according to legislative origin:

- In the REL:
  - 85% discount in easement, permit or lease fees for the first 10 years of operation;
  - Use of natural reserves and national/natural parks with necessary permits;<sup>48</sup> and
  - Exemption from the compulsory 1% turnover payment for operating business on immovable assets of the Treasury.
- In the Licensing Regulation (LR):
  - 90% exemption from licensing fee and exemption from annual license fees for the first eight years of operation; and
  - Priority in system connection.
- In Tax Incentives within the Cabinet Decree on State Aid for Investments:
  - VAT exemption for domestic equipment for Investment Support Certificate holders; and
  - VAT, Customs Tax, and Resource Support Utilization Fund payment exemptions in imports for Investment Support Certificate holders.
- In the Law Regarding the Support of Research and Development Activities:
  - Research and development (R&D) expenditures deduction from Corporate Tax base at a rate of 100%;
  - Income Tax exemption (80% of salary income for eligible R&D and support personnel);
  - Social Security Premium support for five years; and
  - Stamp Tax exemption.



All renewable energy (RE) generators can benefit from these incentives whether they are participating YEKDEM or not.

On the other hand, the government has a renewable energy target of at least 30% in electricity generation by 2023 and, in this context, Turkey intends to utilize:

- All economically available hydroelectric potential,
- A wind-based installed capacity of 20,000 MW,
- All geothermal potential (which is currently established as 1,000 MW) by 2023, and
- A biomass based installed capacity of 1,000 MW

Also:

- It is targeted to generalize the use of solar energy for generating energy, ensuring maximum utilization of country potential. Regarding the use of solar energy for electricity generation, technological advances will be closely followed and implemented. MENR is targeting 3,000 MW in 2019 and at least 5,000 MW in 2023. Generation Plans will take into account potential changes in utilization potentials of other renewable energy resources based on technological and legislative developments. Should the use of such resources increase, the share of fossil fuels – and particularly of imported resources – will be reduced accordingly in the plans.

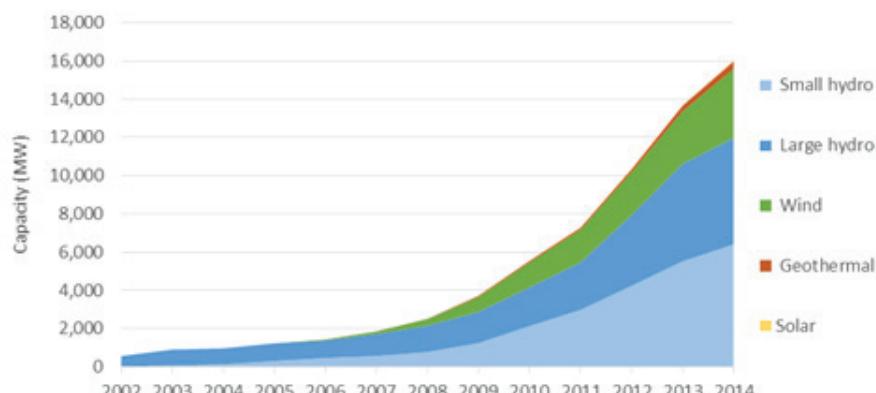
Another important milestone for the development of renewable energy in Turkey is unlicensed generation (or distributed generation), a concept introduced in 2007 in the Energy Efficiency Law. According to this law, power generation facilities using renewable sources and below 200 kW could be built and operated by private persons or entities without a license from EMRA. Amendments to the Renewable Law in 2010 raised this limit to 500 kW while allowing producers to sell their excess generation to assigned regional suppliers; and finally the limit was increased to 1 MW in the new EML (2013). As will be discussed later, although progress in this regard remains limited, the new legislation has opened the path to develop mini-hydro, wind, and especially roof-type solar photovoltaic (PV) installations, all of which will help substantially to increase the share of solar energy in the overall energy mix.

### **3.3.3 Progress**

Except for hydroelectric sources, the share of renewable sources for electricity generation was negligible until 2006. When the REL was enacted in 2005, the installed power of Turkey's wind plants was only 20 MW (17.4 MW of capacity was built under the BOT model in 1998–2001, and 2.7 MW under the autoproducer model) and the installed capacity of the geothermal plant was only 15 MW. Although the EML provided some incentives for renewables, the lack of a support mechanism limited private sector interest in hydro and wind projects – which were mainly old BOT projects that had given up their rights (purchase guarantees and the Treasury Guarantee for payments) in their existing contracts and had correspondingly become licensees in the free market for their projects.

As will be discussed in subsequent sections, the regulatory framework for renewables and the development of electricity market facilitated generation investment and there had been a substantial growth in generation capacity based on renewable sources, especially after 2007, as shown in Figure 56.

**Figure 56. Development of New-build Renewable Capacity since 2002**



Source: TEİAŞ Statistics.

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

- The support mechanism and feed-in tariff level stipulated in the REL guarantees the possibility of sale with at least a feed-in tariff (although not a very high tariff when compared with other countries). This has facilitated financing from local and foreign lenders. The support mechanism provides for long-term certainty and decreases investment risk. Sufficient or not, it provides a certain revenue stream for the project. The lenders generally see this as guaranteed revenue and high market prices as a bonus.
- The World Bank's support via loans for renewables (\$200 million and subsequently \$500 million) was an important initiative. At first local banks hesitated because they lacked experience with financing energy projects. However, starting with TKB and TSKB (the recipients of the World Bank loans), the banks' project evaluation teams learned the process and critical issues; this then encouraged other local banks to provide loans. With the first \$200 million World Bank loan, projects representing roughly 700 MW of capacity have been commissioned.
- The establishment of wholesale trading mechanisms such as the BPM and the DAM, with an average price level of 8–9 U.S. cents/kWh (until mid-2014; this varies with the exchange rate), attracted investment. Since the market prices were sufficient for a fair return, most of the companies preferred to sell in the market, rather than joining the renewable pool (support mechanism). Although the wind plants' intermittent generation may cause imbalances, the wholesale companies hedge the imbalance risk by thermal-hydro-wind plant portfolios and buy wind generation. However, after the Turkish lira fell in value versus the U.S. dollar in 2013, the pool became more attractive and many plants now prefer to sell to the renewable pool, which offers a feed-in tariff without any imbalance risk. The feed-in tariff and especially wholesale prices are sufficient for a fair return for efficient wind and hydro plants.

The potential and development of generation capacity is summarized below for each source; Appendix 2 provides a more detailed analysis.

### 3.3.3.1 Hydro

The annual hydroelectric generation potential of Turkey is reported as 140,000 GWh (considering the historical average utilization factor, Turkey can be assumed to have roughly 40,000 MW of potential).<sup>49</sup>

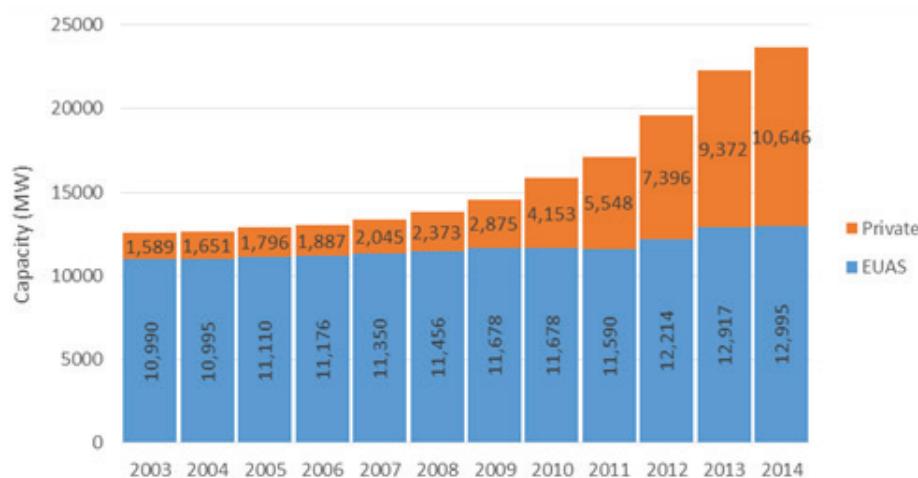
In 2001 total hydro installed power was **11,673 MW**, including 870 MW under BOT schemes. The number of hydroelectric plants increased substantially after the “Regulation about the Rules and



**Procedures for Acquiring Water Use Rights for Electricity Generation**” of 2003, which opened the door to private sector use of hydroelectric sources, and especially after the REL.

As of January 2015 the total capacity of 521 HEPPs in operation was 23,643 MW. Of these plants, 444 (7,036 MW) are run-of-river-type (RoR) and the remainder are reservoir-type. The capacity of private HEPPs is 10,646 MW. It should be noted that, although all HEPPs are considered renewable energy facilities, only RoR types and reservoir types with a lake area smaller than 15 km<sup>2</sup> are eligible to use the support mechanism. The development of hydro capacity in 2003–14 is shown in Figure 57.

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



Source: TEİAŞ statistics.

According to EMRA project progress reports, in addition to the existing plant capacity, 365 licensed private HEPP projects, with a total capacity of 13,300 MW, are under construction.<sup>50</sup> If these are realized, nearly 85% of Turkey’s total hydroelectric capacity will be utilized.

However, the private sector’s development of this hydroelectric potential has not been without its problems. The main issues are:

- The need to integrate huge number of HEPPs into the transmission grid,
- Environmental sustainability,
- Unfeasible projects developed by inexperienced or incapable developers,
- The developer’s selection process in cases where there is more than one applicant,
- High bid prices for some projects in auctions,
- Lack of river-basin development and operation plans,
- A lengthy administrative process during the development and construction phases, and
- Insufficient inspection of construction.

Each of these problems and challenges is discussed in detail in Appendix 2.

**The existing and future challenges and problems would cause suboptimal use of total usable potential or at least delay full utilization. Still, the achievement is substantial and can be considered a major success.**

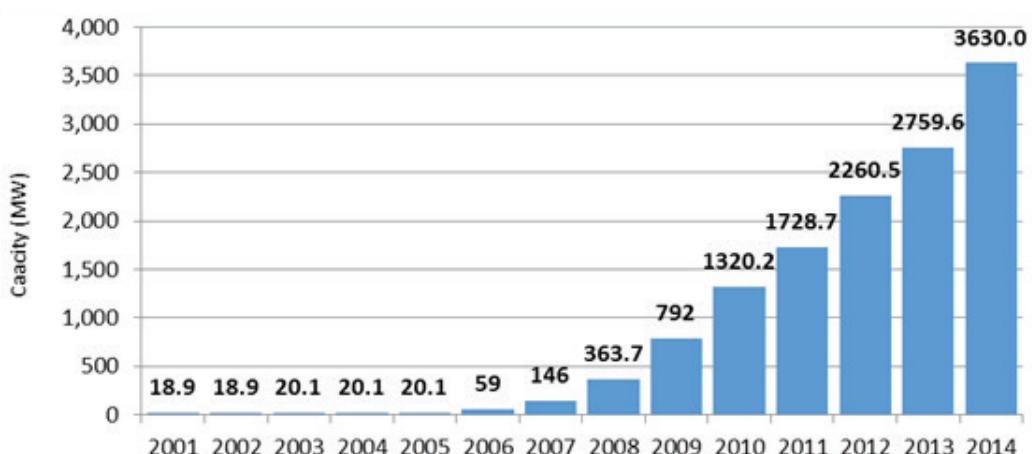


### 3.3.3.2 Wind

Turkey has a considerable wind potential waiting to be utilized. REPA<sup>51</sup> study showed that high-efficiency wind energy potential in Turkey is nearly 19,000 MW and the technically feasible installed capacity potential of regions with a wind speed between 7.5 and 8 m/sec is 29,259 MW. That is, Turkey has the potential for 48,000 MW in mid-to-high-efficiency wind energy generation in areas with an annual average wind speed of 7.5 m/sec or higher. High-potential fields exist in Turkey's Aegean and Marmara regions as well as in the coastal part of its Eastern Mediterranean regions.

Turkey's first wind power plant (WPP) was commissioned in 1998 and had an installed capacity of 8.7 MW. In 2001 the total WPP capacity was only 18.9 MW, all of it built under the BOT model. By the end of 2014, however, this had grown to 90 wind plants in operation, with a total installed capacity of 3,630 MW. The development of wind capacity since 2001 is shown in Figure 58.

**Figure 58. Wind Power Plant Capacity, 2001–14 (MW)**



Source: TEİAŞ.

The development of wind power in Turkey did not go smoothly. It was full of reversals and delays. The problems related to integration of huge number of plants into the grid, the lack of a selection process in case of multiple applications to the same transmission capacity, and/or overlapping project sites. Wind capacity started to grow after 2006, gaining pace only after the introduction of a more comprehensive administrative framework in 2009. The detailed description of this progress, together with problems and challenges, is given in Appendix 2.

As of January 2015, in addition to existing WPPs, there exist 182 licensed projects with a total installed power of 6,013 MW.<sup>52</sup> Although licensed mostly before 2011, only 27 of the plants (837 MW) are more than 30% completed. However, the chaotic process of the past has provided valuable lessons for the administration as well as investors, and progress should now be more smooth and gradual.

In order to increase the share of wind in total electricity generation, the capacity of the transmission system operator, TEİAŞ, to integrate increasing volumes of wind and other intermittent renewable sources into the Turkish power system needs to be strengthened. Furthermore, environmental challenges related to ambitious wind power development should be resolved.

Although the 2009 Strategy Paper assumes 20,000 MW in wind plant capacity in 2023, unless specific measures are taken it will be very difficult to install roughly 16,000 MW in eight years and achieve this target. Similarly it will be a challenge to reach the 10,000 MW target set in MENR's 2015–19 strategic plan.



The projects are financed mostly by export credit agencies and international financial institutions such as the World Bank and EBRD (working through local banks), and also through some contributions via voluntary carbon trading mechanisms. Still, financing remains an important bottleneck.

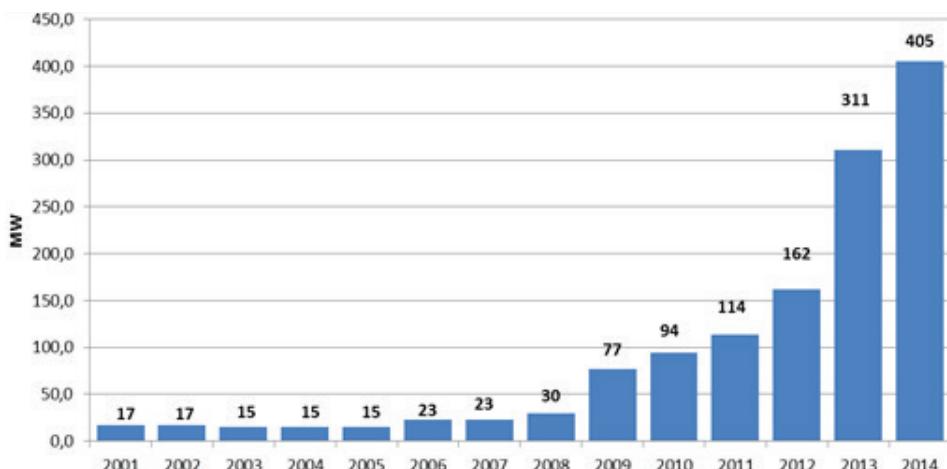
### 3.3.3.3 Geothermal

The theoretical thermal potential of Turkey's geothermal sources is determined as 31,500 megawatts (MWt). According to General Directorate of Mineral Research & Exploration (MTA)<sup>53</sup> Turkey's heat capacity (including natural springs) reached the 14,000 MWt level.<sup>54</sup> Geothermal energy is used for central heating, thermal tourism, greenhouse heating, industrial applications, and electricity generation. The number of geothermal sites which can be used for electricity production is 25, with 1,000 MW capacity.<sup>55</sup>

One important step for the development of geothermal energy is the Law on Geothermal Sources and Mineral Waters, which was issued in 2007. The aim of the law is to regulate exploration, protection, and use of geothermal sources.

The first geothermal plant, with an installed capacity of 17.5 MW, was commissioned in 1985. Following the passage of the Geothermal and Renewable Laws, most of the geothermal sites deemed suitable for electricity generation have been transferred via auction, and private firms are allowed to carry out exploration and development of the new sites under the inspection and control of the State. (The existing geothermal plant was privatized in 2008.) Since 2006 new plants have been built and commissioned by private companies, as shown in Figure 59.

**Figure 59. Geothermal Power Plant Capacity, 2001–14**



Source: TEİAŞ.

Although Turkey's geothermal capacity is much smaller than its wind and hydro capacity, it has developed quickly and nearly a third of the country's total potential is already utilized. In addition to the plants in operation, there are additional licensed projects (327 MW) and the total licensed capacity has reached 732 MW. It can be said that the target declared in the strategy paper will easily be achieved.

One of the reasons for this substantial progress is the sufficiently high feed-in tariff level of 10.5 U.S. cents/kWh. This price is attractive and, unlike wind and hydro, geothermal IPPs prefer to stay in the renewable pool (i.e., the support mechanism) instead of selling their production in the wholesale market. Since their capacity factors are high (around 80%), they are considered a reliable source – unlike wind and hydro, which have intermittency or seasonality in their generation pattern.

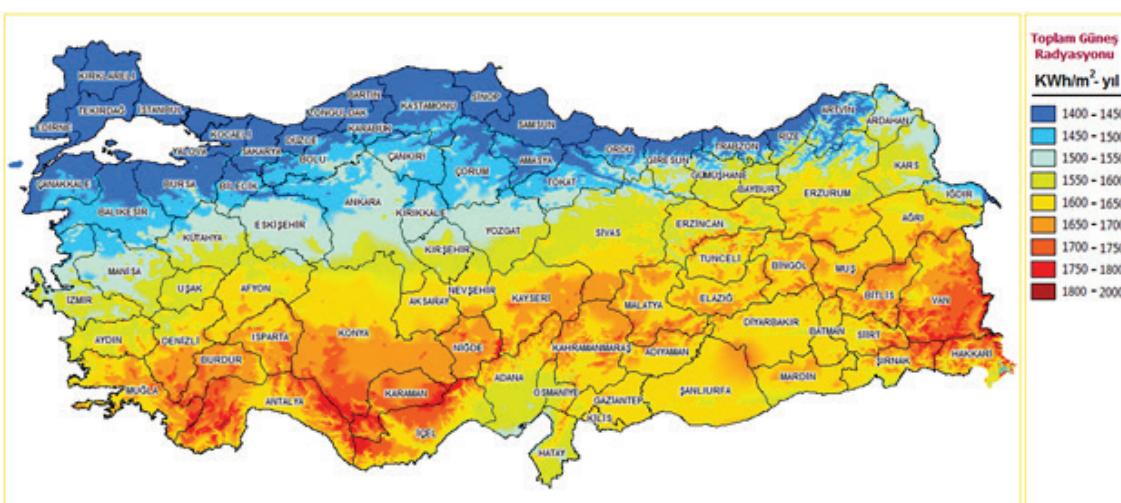
### 3.3.3.4 Solar

Thanks to Turkey's favorable geographic location, its solar energy potential is substantial. The following is the solar energy potential evaluation made by EIEI, based the data measured by the State Meteorological Services.<sup>56</sup>

- The annual average total insolation duration as 2,640 hours (7.2 hours/day). This duration changes between 1,996 hours and 3016 hours depending on the location. Average annual solar radiation as 1521 kWh/m<sup>2</sup>-year (average: 3.6, minimum 1.5, maximum 3.7 kWh/m<sup>2</sup> per day). Based on these values, the theoretical potential of solar energy in Turkey is equivalent to 376 TWh.
- According to a 2009 World Energy Council/Turkish National Committee Report, depending on technical and economic developments, annual electricity generation from solar may reach up to 50 TWh.<sup>57</sup>

The map in Figure 60 shows the solar radiation distribution in Turkey.

**Figure 60. Solar Radiation Map (GEPA)**



Sources: MENR, General Directorate of Renewable Energy.

Note: GEPA = Solar Energy Potential Atlas.

The main users of solar energy in Turkey are the flat-plate collectors in domestic hot-water systems. Turkey is one of the leading countries in the world in this regard, with a total collector area of more than 10 million square meters. The systems are mostly used in the Aegean and Mediterranean regions. Total energy production is 768,000 toe (tonnes of oil equivalent), which represents about 0.6% of the country's primary energy supply.<sup>58</sup> The industry is well developed, with high-quality manufacturing and export capacity. The number of companies is around 100. Annual manufacturing capacity is 750,000 m<sup>2</sup>.

However, despite the high utilization of solar energy for other purposes – Turkey is the world's second-largest user of solar energy for water heating –, for the time being electricity production by using solar is an undeveloped area in Turkey. Because of the high unit cost of electricity generation, it was impossible to produce electricity commercially without incentive mechanisms.

The feed-in-tariff price envisaged in the first version of Law on Renewable Energy was 0.055 Euro cents), which investors did not consider high enough to invest in solar power plants. Therefore, until recently there were no applications for solar plant investments. The capacity of solar plants



was negligible (except for experimental facilities at some universities and isolated PV plants such as telecommunication facilities, forest-fire watch towers, etc.), and there was no commercial application.

However, after the amendments made to the REL in 2010 and the preparation of related regulations in 2011–13, the picture changed. In the 2010 version of the Law, feed-in-tariff prices increased to \$0.133 (13.3 U.S. cents). This tariff was still low when compared to incentive prices offered in the EU at that time. However, due to higher radiation intensity and higher duration of sunny days, the utilization factor of solar generation facilities in Turkey is also much higher than in most EU countries.

A regulatory roadmap for solar power licensing has been determined. By law, the total solar power capacity that will be connected to the network by the end of 2013 cannot exceed 600 MW (unlicensed roof-type solar is not included). The Council of Ministers is authorized to determine the capacity of grid-connected solar electricity plant capacity. According to the Electricity Market Licensing Regulation, the installed capacity of each solar power project cannot exceed 50 MW, and each project must be connected to the nearest electrical substation.<sup>59</sup>

EMRA has issued the regulation for the procedures to be followed and TEİAŞ has announced the electrical substations to which the solar power plants may be connected, as well as the available interconnection capacity. Before applying to EMRA applicants must prepare technical documentation, including solar radiation measurements. The applications are evaluated by MENR's General Directorate of Renewable Energy (YEGM) and then sent to TEİAŞ. Applications representing 600 MW of capacity were accepted in June 2013 and the total capacity of applications has since reached nearly 9,000 MW.

According to the legislation, if there is more than one application for the same connection capacity, the capacity will be distributed after an auction. Two auctions have been made in May 2014 and January 2015. The auctions will be completed in 2015.

There was no definite target in the 2009 Strategy Paper. In 2015 MENR set a target of 3,000 MW by 2019<sup>60</sup> and is currently aiming at 5,000 MW by 2023. Considering the high potential, and the downward trend in installation costs, this target can be reached. In fact, the high number of applications for the allocation of 600 MW is an indication of investor appetite.

Furthermore, it is expected that, due to the “unlicensed generation” possibility, roof-type PV implementation will possibly boost overall solar generation capacity.

While it was practically zero in 2013, by the end of 2014 solar capacity had reached 40.2 MW,<sup>61</sup> mostly due to roof-type PV installations (unlicensed generation facilities) and some projects aiming to energize irrigation pumps in Southeast Turkey.

Taking into account the continuing decline in the investment cost of solar facilities, it might become possible in the medium term to develop Turkey's rich solar potential with support prices not higher than market price.

### **3.3.3.5 Biomass**

Biomass represents around 3% of Turkey's total primary energy supply. It is a conventional source of energy because it uses animal and agricultural waste, mostly for heating purposes. However, the biomass/biogas plants' share of the country's total installed power is negligible (0.3%). In 2006 total capacity was only 41 MW. As of end 2014, 58 plants were in operation, with a total capacity of 289 MW. Most were built following the amendments made to the REL and the increase in the feed-in tariff, and most use municipal waste or landfill gas.

In addition to existing plants there are 10 plant projects (39 MW).<sup>62</sup> Especially for landfill gas, investors depend on municipal administrations because they have authority over the landfills. The administrations' waste management problems should further encourage the development of the biomass sector.

The expected increase in the use of biomass use to generate electricity is due especially to the “unlicensed generation” legislation (see following section), which may possibly attract investments to rural projects in rural areas that utilize agricultural and forestry waste. This will also facilitate investment in rural areas and will provide socioeconomic benefits to the population

### 3.3.4 Unlicensed Generation

Another important milestone for the development of renewable energy in Turkey was the potential for “unlicensed generation” (or distributed generation) introduced in 2007 by the Energy Efficiency Law. According to this law, power generation facilities that use renewable sources and are below 200 kW can be built and operated by private persons or entities without a license from EMRA. This limit was subsequently raised to 500 kW and finally to 1 MW in the new EML (2013).

By introducing unlicensed electricity production, it is aimed to promote generation from both cogeneration plants and renewable sources in order to (a) increase the share of renewable sources, (b) decrease grid losses by facilitating distributed generation, and (c) increase efficiency.

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

- Isolated facilities and emergency generators,
- Micro-cogeneration facilities (i.e., cogeneration plants smaller than 50 kW), and
- Power plants up to 1,000 kW using renewable sources. (The Council of Ministers has the authority to increase this limit up to five times for each source, depending on the capacity of transmission and distribution grid and supply security considerations.)

In other words, private individuals can establish such facilities at homes, farms, dwellings, and the like for their own electricity needs – and are also allowed to sell their excess energy to the distribution system, to which they are connected through the renewable support system. Private persons or legal bodies in the same region can aggregate their consumptions for the purpose of establishing generation plants collectively. Typical examples of such renewable generation facilities include solar PV applications on rooftops, micro-hydroelectric plants, small wind turbines, and biomass plants.

The generation facilities under this scope can be connected only to the distribution grid. Distribution companies are obliged to connect these if there is sufficient capacity of the grid at the corresponding voltage level (LV or HV).<sup>63</sup> They can reject or limit connections only in accordance with the conditions stipulated in the relevant regulation.<sup>64</sup> This regulation defines the technical and administrative rules and procedures for connection, operation, metering, and payment. The technical limits for the connection points are also defined in the regulation. The excess energy generated from these facilities is supplied to the distribution grid, and assigned regional supplier companies cannot reject the energy supplied. At each connection point, there is a metering system to measure the energy supplied from and to the grid. In case of collective use, the difference between the aggregated consumption and generation is determined. The price of the energy supplied is priced according to the feed-in tariffs established in the REL. At each distribution region, the total energy from these suppliers is assumed to be supplied by the distribution company to the “renewable pool,” and the total cost of procured energy in this pool is paid to the distribution company in accordance with the procedures described in the REL and related secondary legislation.

This application was defined in the Energy Efficiency Law of 2007 and incorporated into the EML in 2008 as well as the REL in 2011. However, due to the technical and administrative issues that must be sorted out before implementing such a new concept, the secondary legislation was finalized only in 2011 and amended in 2013.



The conventional distribution system design and operational procedures are for transferring energy from generation sources to passive consumption points (passive loads). However, the implementation of the new regulation brings out a new philosophy: The consumption points might not be passive loads anymore, and there would be reverse flows from these points to the distribution system. Therefore, together with strengthening the medium- and low-voltage network, new protection and measurement methods and new operational procedures should be introduced. Further studies and developments on “smart grid” will be necessary to implement this concept more smoothly.

Because the regulations were issued only recently, implementation did not gain pace until 2013. However, there is great interest from the public. Table 10 shows the breakdown of applications as of July 2015.

**Table 10. Unlicensed Generation Projects**

Source	Project Applications		Approved Applications		In Operation	
	Number	Capacity (MW)	Number	Capacity (MW)	Number	Capacity (MW)
Wind	149	108,0	54,0	36,1	2,0	0,5
Solar	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: TEDAŞ

The high number of projects demonstrates the high level of public acceptance and interest. It is expected that unlicensed generation implementation – especially solar PV – will increase the share of renewable sources in the overall energy mix, as experienced in many countries.

### **3.3.4.1 The Influence of Support for Renewables on Wholesale Market Prices and Supply Security**

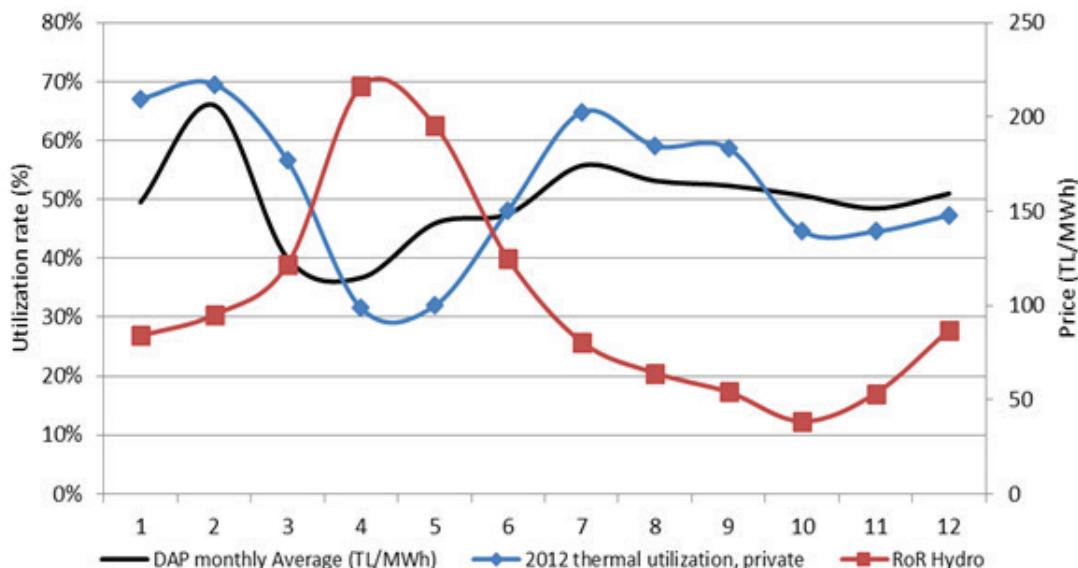
One of the reasons for supporting the development of renewable energy is to decrease import dependency and enhance security of supply. In fact, together with other benefits such as reduction of GHG emissions, the achievements to date have proved that support mechanisms (the renewable pool, priority dispatch, and feed-in tariff) have attracted substantial private generation investment and therefore helped to cope with increasing electricity demand. Although the share of small hydro, wind and solar in total electricity generation is currently small, it is expected to increase considerably.

Electricity generation from small hydro, wind, and solar plants is considered “must-run” generation and those plants are dispatched without a competitive selection mechanism in the wholesale market. That is, they are always in the lower end of the merit order curve. Normally, their available capacity is lower than that of thermal plants, and demand is met only with base-load plants such as coal and efficient natural gas plants, and finally at peak times by less efficient/expensive natural gas plants and liquid fuel-fired plants. Therefore the marginal price in the day ahead market is set mostly by natural gas-fired plants.

As a natural consequence, if the available capacity of renewables is high, their share of overall consumed electricity increases, the share of thermal generation falls, and the marginal cost in the wholesale market decreases. The relation between renewable generation and the day-ahead market average price in 2012 is shown in Figure 61.



**Figure 61. Monthly Utilization of Renewable and Thermal Plants and Day-ahead Price**



Sources: TEIAS electricity statistics and PMUM.

Note: RoR = run of river; DAP = day-ahead price.

It can be seen that, during the wet period (March–May), the capacity factor of run-of-river type hydro plants increases, whereas that of thermal generation decreases, resulting a decrease in wholesale market prices. Hence, at first glance it can be concluded that another benefit of renewables is decreasing electricity prices. However, this would be correct only if the decrease in the wholesale prices were fully reflected in consumer prices. In fact, there is a cost for renewables and it is paid for by consumers through renewable support mechanisms. Therefore, the decrease in wholesale prices is not full passed on to consumers.

This phenomenon will not be a challenge to thermal plant owners, as far as the share of renewables is small. However, as the renewables' share increases, especially in wet years, most of the hourly demand can be supplied by hydro, wind, and especially solar during daylight hours. Naturally, the generation will not be continuous, but will rather occur during sunny days, windy periods, and/or wet years. However, inevitably it will affect the operation time of the fossil-fired plants. The average utilization factor of the thermal plants may be lower than anticipated.<sup>65</sup> For example, due to very high share of solar in Germany, on some days the solar generation reaches so high a level that some base-load plants must reduce or even cease their own generation. At such times, daily market prices naturally decrease and sometimes fall to zero. Hence, the high share of renewables is a challenge for plants using fossil fuels.

It can be said that this is a natural consequence and a desirable result. However, there are challenges also:

- Since the availabilities of most of the renewables are low, there should be sufficient available spare thermal capacity in order not to endanger supply security and system reliability. There is a cost of keeping spare capacity.
- Turkey needs new base-load generation capacity to cope with increasing demand. However, the investment decision depends on revenue calculations that are based on future market prices and the amount of future production in "energy-only" markets.
- The long-term marginal prices in the wholesale market must be at a level that provides a sufficient revenue to cover investment and operational expenses at a fair profit. Otherwise it may not be feasible to invest in big base-load plants that generally do not have enough flexibility to work like a peaking plant. However, as discussed previously, during periods of abundant, out-of-market renewable production, wholesale prices will



fall. If because of this effect the utilization factor of those base load plants declines, and if revenue can be obtained only from the wholesale energy market, investment would not be feasible,

- Since it will not be possible, at least in medium term, to meet the demand and peak consumption, and have a reliable supply with renewables only; while the country benefits from increased renewable generation, the investments for base-load plants should also continue. Any decrease in investor appetite would have very crucial effects on Turkey's electricity security.
- Therefore, in addition to today's energy market, there should be new mechanisms to secure investments and attract investors. A possible solution would be to introduce a capacity mechanism that will secure a fair return for investment. However, unlike the old BOO/BOT models this mechanism should be market-based.
- It also highlights the necessity of reinforcing interconnections and enhancing regional trading, since different time zones and different peak periods will cause more efficient utilization of the generation portfolio.

Depending the amount of price support, another impact of renewables, especially of unlicensed solar generation facilities, will probably be on the end-user electricity tariffs. When unlicensed generation was introduced in 2007, the main aim was to facilitate micro-distributed generation facilities, mainly for the owners' own consumption. However, later regulatory amendments imposed no self-consumption limit. Hence any applicant can build a generation facility with a generating capacity of less than 1 MW irrespective of his own consumption, and distribution companies must buy the generated electricity during the first ten years of operation, at a price determined in the law. If there is no obligation for self-use, project developers may aim to trade, and the share of solar generation that is priced well above market prices may increase. As a consequence, the end-user prices will increase due to the support mechanism. As observed in other countries, the high support prices have become a burden and some governments have had to adjust them. This is not an urgent issue for Turkey since the capacity of high-priced solar generation is still small. However, considering the high potential, it can be a problem for Turkey also. To address this, the support tariff can be adjusted periodically according to the investment cost (which is decreasing), and a self-consumption percentage limit can be imposed.

### 3.4 Nuclear Energy

For over 40 years, Turkey has sought to build nuclear power plants (NPP) in order to diversify its electricity supply sources to meet growing demand in a reliable manner. The goal is to increase the share of nuclear power plants in electricity generation to 10 percent by 2023, and then to continue to increase it in the long term. In 1956, the General Secretariat of the Atomic Energy Commission was established in Ankara, as an organization affiliated with the Prime Minister's office. One year later, Turkey became one of the founding members of the International Atomic Energy Agency. In 1982, the Commission was restructured as the Turkish Atomic Energy Authority (by Law No. 2690). In the 1960s two research reactors (one in the Çekmece nuclear research center and the other in İstanbul Technical University) were commissioned in Turkey.

Since 1967 Turkey has tried to build a nuclear power plant through competitive tendering; altogether it has conducted three tenders. In all three, the plant was planned as a state investment, with the state being the owner or at least shareholder of the plant. However those tenders could not be finalized successfully for several reasons.

In 2007 a new Law on Construction and Operation of NPPs was enacted, and in 2008 companies were invited to bid for building and operating a nuclear power plant in Akkuyu, a small town on the Mediterranean coast. For the first time, the model was not a state investment but rather a BOO. Although there was no Treasury guarantee, TETAŞ would be the off-taker. No company submitted a bid, except for a consortium led by the Russian state-owned nuclear vendor Atomstroyexport, and finally this tender was also cancelled.

After several unsuccessful attempts to build the plant through competitive tendering, the government decided to include the plant in its generation capacity through direct intergovernmental negotiations. The sites of Akkuyu and Sinop were identified for the first two nuclear projects.

### Akkuyu

Following negotiations with Russian Federation, the “Agreement between the governments of the Republic of Turkey and of the Russian Federation for Cooperation on the Establishment and Operation of a Nuclear Power Plant at Akkuyu Site in the Republic of Turkey” was signed on 12 May 2010, for installing four VVER<sup>66</sup>-1200 type reactors, each with 1,200 MW of generation capacity, in Akkuyu. The Agreement was ratified by the Parliaments of both countries, on 21 July 2010 in Turkey and on 13 December 2010 in Russia.

As agreed, the Russian side registered a project company named Akkuyu Ngs Elektrik Üretim Anonim Şirketi (the “Akkuyu Project Company,” or APC) in Turkey on 13 December 2010.<sup>67</sup> The Company is responsible for designing, building, maintaining, operating, and decommissioning the plant for 60 years and TETAŞ will be the energy purchasing party for the first 15 years. TETAŞ will purchase 70% of the electricity generated by the first and second units and 30% of the electricity generated by the third and fourth units at an average price of 12.35 US cents/kWh (weighted average, excluding VAT). The remaining electricity is to be sold in the market by the company at the market price. It is the first NPP project to be implemented using the BOO model. The project also assumes the maximum possible involvement of Turkish companies, as well as companies from other countries, in construction and assembly activities. The plant’s total annual electricity generation capacity is expected to be 35 billion kWh when the four units are operational.

It was originally planned that the first unit would be in operation in 2019 and other units would be commissioned consecutively by 2023. The project company Akkuyu Nukleer Santral Elektrik Uretim had filed, in December 2011, an environmental impact assessment (EIA) report by the deadline and with a view to starting construction in 2013. The report was rejected twice, but the third report was approved in December 2014. APC is expected to submit a construction permit application to the Turkish Atomic Energy Authority (TAEK) in 2015. TAEK has procured technical support services from competent nuclear consultant companies in order to assess and review the construction license application. It is expected that the construction license will be granted in 2017, enabling full construction to start afterwards.

The company had expected to commission the first unit (1,200 MW) in 2020, followed by the other three 1,200 MW units in subsequent years. However, delays to date, combined with international experience in the construction/commissioning process of NPPs, indicate that the first unit may be commissioned later than planned.

### Sinop

In addition to the Akkuyu NPP, Turkey aims to build another NPP in the Sinop Area (in the Central North, on the Black Sea coast) through a company to be formed by EÜAŞ and a foreign nuclear power company. In this respect, there had been some negotiations with South Korea’s electrical utility, KEPCO, and a joint declaration was signed in 2010. However, during the negotiations, an agreement was not reached with South Korea and negotiations with Japan and several other candidate vendor countries have started.

An Intergovernmental Agreement between Turkey and Japan was signed in May 2013 and ratified in May 2015. According to the agreement, Turkey will be responsible for securing 49% of equity in the Project Company (EÜAŞ will hold 49%) while a consortium consisting of Mitsubishi Heavy Industries Ltd., Itochu Corporation (Japanese) and GDF Suez SA (France) will hold 51% of equity as long as the Power Purchase Agreement is in force.

The Sinop plant will comprise four units of ATMEA-1 type nuclear reactors,<sup>68</sup> each having an



installed capacity of 1,120 MW (total capacity is 4,480 MW). The project's estimated cost is \$22 billion. It is projected that the first unit will be commissioned in 2023 and the other units will be commissioned consecutively thereafter, with the fourth unit entering service by 2028.

Technical feasibility studies are ongoing and negotiations between EÜAŞ and the Japanese Consortium for establishing the Project Company have not yet been finalized.

#### *Turkish Atomic Energy Authority*

The Turkish Atomic Energy Authority (TAEK) is the authority responsible for establishing nuclear and radiation safety regulations and granting licenses for the site construction, and operation of nuclear power plants. At the same time, TAEK is affiliated to the Ministry of Energy and Natural Resources, which is responsible for promoting the usage of nuclear energy. Therefore, the Energy Ministry has prepared a draft nuclear energy law designed to separate the regulatory and other functions of TAEK and to establish a new independent nuclear regulatory authority

### **3.5 Future Expectations and Challenges in the Electricity Market**

#### **3.5.1 Supply/Demand Balance and Supply Security**

The annual increase in average consumption declined to 5.7% in 2002–13 (from an average of 8.3% over the last 40 years). However, due to expected economic and population growth, it is estimated that average consumption will continue to grow in the coming years, albeit at a slower pace. MENR projections assume roughly a 72% increase (5.6% annually) in the next 10 years.<sup>69</sup> As a rough estimate, if an average 4.5% annual GDP increase is assumed, with a smaller elasticity due to efficiency gains, an average 5% annual growth can be expected if demand-side management systems and conservation measures are implemented. Accordingly, peak demand will also increase. In order to cope with the increasing consumption, electricity generating capacity should be increased.<sup>70</sup>

Following the implementation of cost-recovery pricing, distribution privatization, and renewable energy support, and after the wholesale market was developed, generation investments gained pace. After the demand decrease in 2008–09 due to the economic downturn, and with the addition of new capacity in 2008–13, capacity margin has been increased to a level sufficient to ensure reliable operation (72% as of 2014).

However, it can be easily assessed that, taking into account past experience and potential future demand increases, Turkey needs to have new investments to preserve sufficient reserve margin for a reliable operation. Historical evidence indicates that capacity margin should not decrease below 35% in order to have an adequate available capacity. According to the latest EMRA progress report<sup>71</sup> and TEİAŞ Generation Capacity Projection Report (2013–17), at least an additional 15,000 MW of new capacity will be in operation by 2018 and the capacity margin will stay over 50%. Therefore, it can be said that there is no immediate supply security problem in the short term, provided sufficient gas is supplied. For the period after 2018, in order not to face new supply security problems, in addition to nuclear projects – and taking into account lead time and time required for construction – new generation investments should already be decided by developers.

However, the following facts should also be taken into consideration when evaluating previous investments:

- Previous investments occurred mainly in 2007–09, at a time when all estimates showed that Turkey needed new generation investment in the medium term to avoid a supply security problem. However, there is now an oversupply in the market that could persist until 2020, given slowing demand and the additions to renewable (especially solar and wind) capacity. (With economic growth above the anticipated 4-5 %, oversupply period would be shortened). In turn, this overcapacity will influence wholesale prices and reduce the utilization rate of new thermal plants.

- Due to economic and favorable financial conditions in global markets, financing was easier In 2007-2012.
- Political and regulatory risks were low and there was a strong belief in the consistent implementation of a liberal, competitive market.

Two of the most important factors for attracting investment are confidence in the country's legal and regulatory framework and consistency in implementing market rules. The legal, administrative, and regulatory framework has provided an attractive investment environment over the past eight years.

Regulatory predictability is a prerequisite to expanding and sustainable private sector participation. Turkey has chosen private sector participation – through new investment and privatization of existing facilities – as the best available means to achieve a sustainable long-term solution to energy security, competitiveness, and operational efficiency in the energy sector. Any doubts about a fair transparent and stable political/legal system would at least increase country and regulatory risk. Hence, in order to keep investor confidence high and attract investments under the existing global political and economic conditions and supply/demand situation, the reform process should be continued as planned.

In order to attract investments, long-term price signals and long-term bilateral contracts are useful. At the moment the share of bilateral contracts in the market is around 70%, but this is mostly public-to-private and not longer than one year. It is expected that long-term price signals will be provided by markets operated by EPIAŞ (trading of physical electricity) and Borsa İstanbul (financial instruments for trading and risk management). Otherwise the volatility of spot prices may be a risk for suppliers and retail companies.

Another important factor for supply security is the adequacy and quality of the transmission system. In this respect, transmission investments should continue in order to enable faster integration of renewable generation to the system. Although some problems occurred in the past due to lack of coordination with licensing process and timely transmission investments, the new EML provided such a coordinated approach. However, TEİAŞ should have the ability to plan and announce available capacity, complete the transmission investments on time, and operate the power system reliably. This will be possible only with sufficient institutional and technical capacity of TEİAŞ. This issue is related with governance of SOEs and will be elaborated further in the following sections.

More-efficient utilization of the existing thermal units will also help to increase supply. As mentioned in the section on generation privatization, the utilization factors of EÜAŞ' thermal, especially lignite-fired, power plants are low and have decreased in the recent years. Most of the EÜAŞ plants are aged. Rehabilitation or renewal of these plants will increase their efficiency and increase their availabilities. The additional supply from those plants will also contribute to supply security.

Implementation of more-effective efficiency programs and demand-side management measures will certainly be helpful in enhancing supply security, as well as in reducing the GHG emissions.

On the other hand, Turkey's over-dependency on imported natural gas for electricity generation creates temporary supply deficiencies. As will be discussed in the section on the natural gas market, the lack of sufficient storage and daily send-out capacity is an important risk for electricity supply security. Additionally, Turkish hydroelectric generation depends mostly on hydrological conditions and varies drastically. If a natural gas shortage occurs in a dry year or dry season, the effect becomes worse. Hence, diversification of natural gas sources and timely completion of storage facilities are necessary for supply security.

In addition to the measures for a reliable supply of natural gas, the measures for the reduction of the share of natural gas in electricity production will help to enhance security of supply. The



installed capacity of lignite plants in operation is around 8,500 MW. After commissioning of five projects under construction (total installed capacity of 2,000 MW), Turkey will be using roughly 50% of its total domestic lignite power generation capacity. As the share of lignite in total power generation increases, it is expected that the share of imported sources, such as natural gas and imported coal, will decrease. Since this will enhance supply security, additional supports (initiatives) may be provided for new lignite-fired power plants. However, this support should not be in the form of take-or-pay guarantees as in previous BOT implementation.

Another issue related with supply security is the need for new base-load thermal generation capacity and the possible negative effect of supported renewable energy generation on the investment decisions of the private sector for base-load thermal capacity, as was explained earlier in the section on renewable energy.

The oversupply period should also be used as an opportunity to study capacity mechanisms, which were on the agenda during the supply crises period in 2007–08.

### 3.5.2 Electricity Market Development

As discussed previously, Turkey has over the past decade established, step by step, a well-functioning electricity market. The legal, regulatory, and institutional framework attracted and enabled market-based private sector investment, the number of market participants and eligible consumers substantially increased, distribution privatizations were completed, and wholesale competition was achieved to a certain degree, yet the market development effort needs to continue.

The introduction of an intra-day market and the establishment of EPIAŞ are major steps. The new 2013 Electricity Market Law provided for the establishment of a new Energy Market Operations Company, EPIAŞ, to take over from PMUM/TEİAŞ the operation of the electricity market. EPIAŞ has been established, 97 private companies have become company shareholders, and it is expected that EPIAŞ will be fully functional in 2015. Financial trading instruments are to be operated by Borsa Istanbul. Therefore, both transparency and efficiency in market operations will be increased and EPIAŞ will serve as an energy exchange for Turkey – possibly as a first step toward a regional energy exchange.

There is a perception that wholesale electricity market prices are “regulated” through BOTAŞ, EÜAŞ, and TETAŞ prices for keeping end-user electricity tariffs constant (and for protecting the consumers against the “opportunistic behavior” of some private generators at the times when supply is short. The intervention to protect the consumers against price fluctuations and against opportunistic behavior may be considered as a legitimate behavior. However this aim can be better achieved through improvement of market rules and improvement in the transparency of market operations. If there is still a need to intervene, that should be done through an open and transparent way. Otherwise such interventions may create concern regarding the future of the market. Subsidies should be targeted to low-income households. Furthermore, interviews with market participants show that there are other issues such as transparency in TEİAŞ’ market operation and dispatch operations. In addition to improving market operation, EPIAŞ will help to solve the transparency issue. However, transparency in Balancing Power Market operations (which will be operated by TEİAŞ) and congestion management procedures should also be improved.

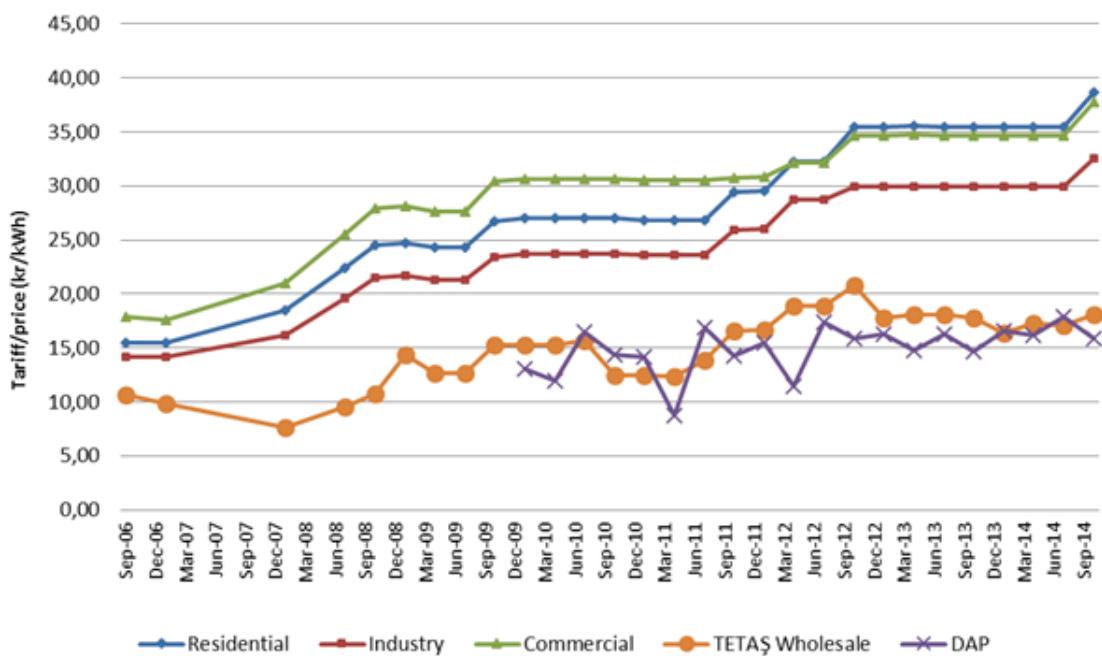
The latest strategy paper was prepared in 2008 and issued in 2009, six years ago, and most of the market implementation targets have been reached. However, further action is needed to promote market development. In fact, some next steps have already been indicated by EML amendments and EMRA-MENR decisions. Nevertheless, it will be useful to prepare and declare the strategies and implementation roadmap for future developments. It should cover the principles and implementation program for wholesale market development, and other issues as follows:

- Market Development:
  - Financial and derivative markets
  - Further steps for wholesale and retail competition
  - Phasing out the interregional price-equalization mechanism (national tariff)
  - Capacity mechanism implementation (if it will be used)
  - Coupling with other regional markets
- Other:
  - Protection plans for low-income consumers
  - Demand-side management
  - Renewable energy support policy
  - Energy efficiency
  - Utilization targets for domestic sources.

### 3.5.3 End-User Tariffs and Affordability

Figure 62 shows end-user electricity prices and wholesale market prices since 2006 and the day-ahead market price, or DAP, since 2009. Except for the last two years, end-user prices generally followed wholesale prices. (The explanation for the constant tariffs is discussed in Section 3.2.4.1.) Excluding 2006 and the first half of 2007, when the prices were suppressed, the residential tariff, including funds and tax, almost doubled and reached \$0.18 (18 U.S. cents).

Figure 62. Captive Consumer Tariffs (incl. Funds and Taxes) and Wholesale Prices (Excl. Taxes)

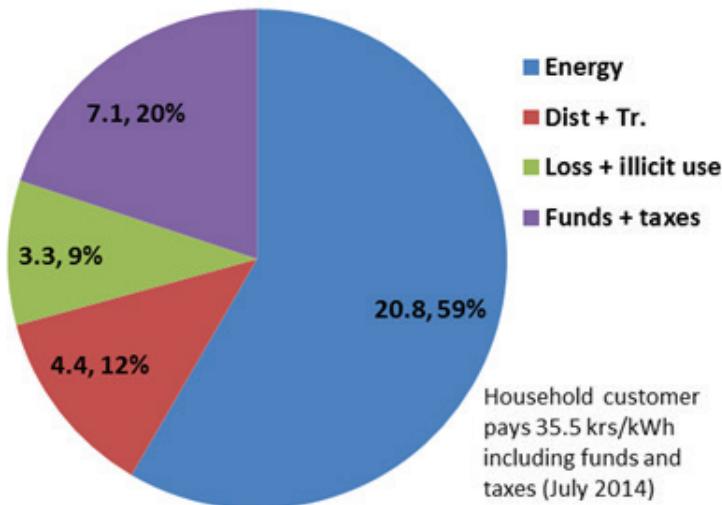


Source: based on TEDAŞ, EMRA, and TEİAŞ statistics.



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

**Figure 63. Components of the Household Tariff**



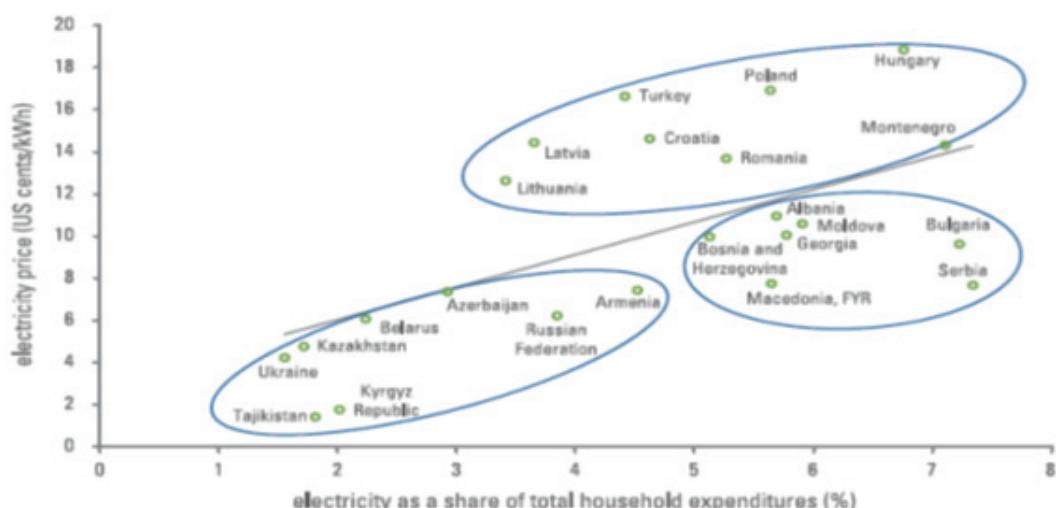
Source: Based on TEDAŞ statistics.

It should be reiterated here that, due to big differences between regions, a price-equalization mechanism remains in place<sup>72</sup> and an average national tariff is used in all regions. If this cross-subsidy between the regions is removed, there will be very high prices in high-loss regions.

As of 2013, electricity consumption per capita was 240 kWh/month (2,880 kWh/year) and the average consumption per household was around 150 kWh/month (1,800 kWh/year). That is, the average annual electricity expenditure of a household consumer was around TL 650. When compared with average annual equivalized household disposable income in Turkey, which is TL 13,250,<sup>73</sup> this represents roughly 5% of total household expenditures. Turkey's electricity price is relatively high when compared with prices in Eastern European and Central Asian countries, as shown in Figure 64.<sup>74</sup>

**Figure 64. Electricity Price and Electricity Share of Total Household Expenditures of Eastern Europe and Central Asia Countries**

#### Electricity Price and Electricity Share of Total Household Expenditures

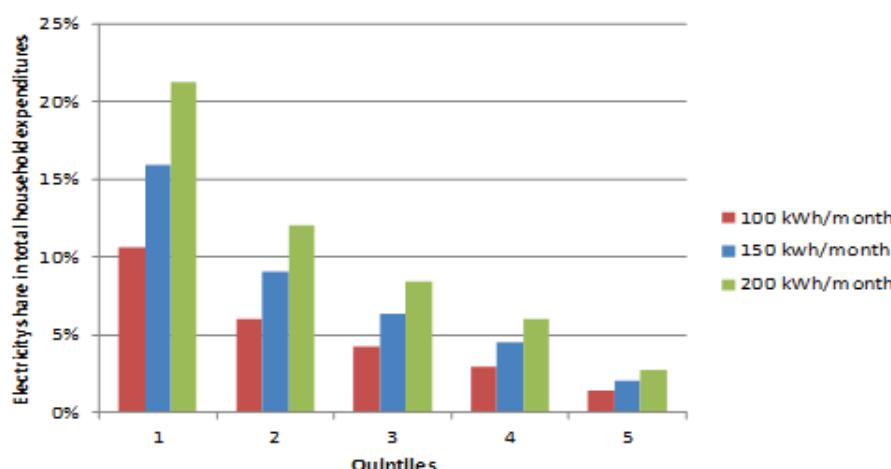


Source: The World Bank.

It can be observed that, for countries that have made progress in electricity sector reform, implemented cost-reflecting prices, and reduced subsidies, average household prices are higher.

On the other hand, if the share of household electricity expenditures is compared with annual household disposable incomes of quintiles,<sup>75</sup> the share of this expenditure changes drastically, as shown in Figure 65.

**Figure 65. Share of Electricity Expenditure in Annual Household Income for Different Income Groups and for Different Household Consumption Levels**



Source: Based on TEDAŞ and Turkstat data, 2014.

It can be observed that, even with moderate energy consumption (100 kWh/month), the electricity expenditure share is 11% for the lowest 20% income group. For 150 kWh/month consumption, this share is above 15% for the first quintile. The same share in 2008 was 12% and 18% for 100 and 150 kWh, respectively. It can be said that there has been a slight improvement since 2008 due to the improvement in income shares, but it can also be attributed to the suppressed electricity prices in the last two years.

The members of the lowest income group are spending more than 10% of their household disposable income on electricity only. If other energy spending, such as natural gas and/or heating spending, is included, this share will be far above 10% and they can be considered to be in energy poverty.

According to governmental targets, all consumers will be eligible by the end of 2015 (if it is not extended). When this point is reached, there will be no captive consumer and no regulated retail sale tariff. Instead, a “last resort” tariff will be used for those consumers who cannot obtain their electricity from a supplier using bilateral agreements. This tariff will also apply to those consumers who gain eligibility but prefer to buy electricity from their assigned supplier. The new EML foresees setting the last-resort tariff at a level sufficient to encourage consumers to search for a new supplier – while providing a reasonable profit to assigned retail companies. Therefore, the last-resort tariff is expected to be higher than the prices that can be obtained from the market. As the subsidies are removed from gas prices, and as EÜAŞ/TETAŞ’ share decreases, the market retail prices may be higher than today’s level.

With the removal of natural gas subsidies and the increase in electricity prices to cost-recovery levels, the energy spending for the first quintile, and even for second quintile, will further increase. A recent impact assessment across Turkey found that the majority of households in Turkey can afford to pay their electricity bills despite price increases, but that households with non-salaried incomes, rural households, and those households whose livelihoods depend on electricity, such as farmers using electric water pumps for irrigation and small urban businesses, are vulnerable to increases in the electricity prices.



To successfully implement reforms and attract investment, the prices should be set at least at cost-recovery level (and this level should also include internalized environmental costs) and price subsidies/interventions should be removed. A safety net should be introduced to protect low-income consumers. Universal subsidies through the tariff are an expensive way of protecting consumers. Therefore, an energy price for all income groups, as implemented today, is not a solution and also support individuals who do not need any support. **Existing pricing policies help not only the poor, but also higher-income groups that do not need such a subsidy.**

Therefore, in addition to the existing social support programs, for low-income consumers **a targeted price or subsidy policy** should be implemented and subsidies for higher-income groups should be removed. The cost of such a support mechanism may be lower than that of universal subsidy.

This will also help solve the problem of chronic illicit use and may encourage the efficient use of energy.

### 3.6 The Natural Gas Market

The natural gas sector is one of Turkey's most important strategic sectors. Although natural gas was introduced into the Turkish energy market just 27 years ago, today Turkey is a major natural gas consumer and among the four biggest importers in Europe (the other three are France, Germany, and Italy).

Natural gas plays an important role in Turkey's total primary energy supply (roughly 30%), and especially in electricity generation (average share for last 10 years is over 45%). Therefore, the issues related to the natural gas sector, such as supply and price, directly influence the electricity market and industry as a whole.

Furthermore, being an imported source, natural gas plays an important role in the foreign trade balance. The cost of Turkey's annual natural gas imports is of the order of \$18 billion<sup>76</sup> (2013), which constitutes a substantial share of the current account deficit.

In addition to its importance in the domestic market, due to Turkey's geographical position between the source regions (the Caspian Sea and the Middle East) and consuming regions (Europe), natural gas market and transit issues have a substantial impact on international gas trade. Hence the structure of, and developments in, Turkey's domestic natural gas market have an important influence on the realization of its aspiration to become an international energy hub.

Therefore, the development of Turkey'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

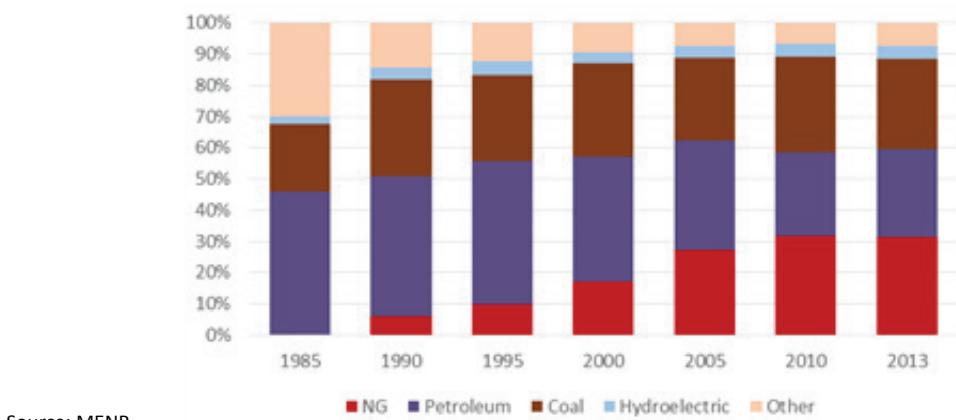
Natural gas is relatively new in Turkey. Although it was first discovered in 1970, meaningful consumption began in 1987 with the importing of natural gas from Russia in an effort to diversify electricity generation sources and prevent air pollution in the big cities, specifically Ankara, due to coal-dependent heating. The first important projects were the natural gas pipeline from Malkoçlar (on the Bulgarian border) to Ankara (1988), the Hamitabat CCGT Power Plant (1989), and natural gas delivery to Istanbul and Bursa (1992). The Marmara Ereğlisi LNG Terminal project also began in the same period as the second important investment in natural gas infrastructure, and the plant was commissioned in 1994.

As shown in Figure 66, the role of natural gas in Turkey's energy supply grew rapidly after 1985. According to MENR statistics, natural gas represented 31.3% of the total primary energy supply in 2013. Natural gas replaced petroleum-product usage in heating and electricity generation.



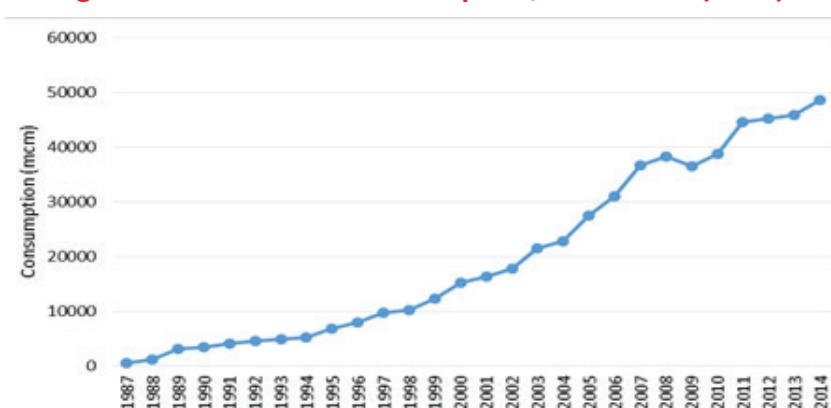
## Turkey's Energy Transition - Milestones and Challenges

**Figure 66. Sources of Turkey's Primary Energy Supply, 1985–2013**



Natural gas consumption reached 48.7 bcm in year 2014<sup>77</sup>. As shown in Figure 67, year-on-year gas demand growth in Turkey has been very high for the past two decades.

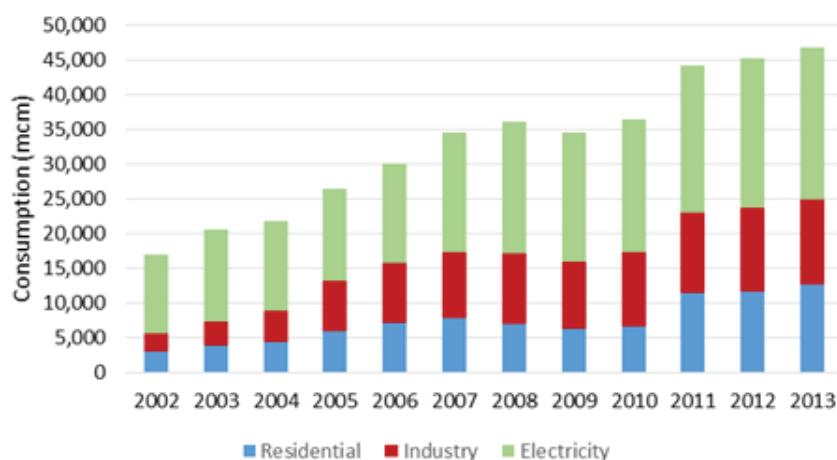
**Figure 67. Natural Gas Consumption, 1987–2014 (bcm)**



Source: EMRA, BOTAS.

The natural gas consumption by sector is shown in Figure 68. Even though the initial growth was led by the power sector, especially after the expansion of the natural gas transmission and distribution systems in the country, residential consumption also increased. In 2013 the power sector's share of total consumption was roughly 48%.

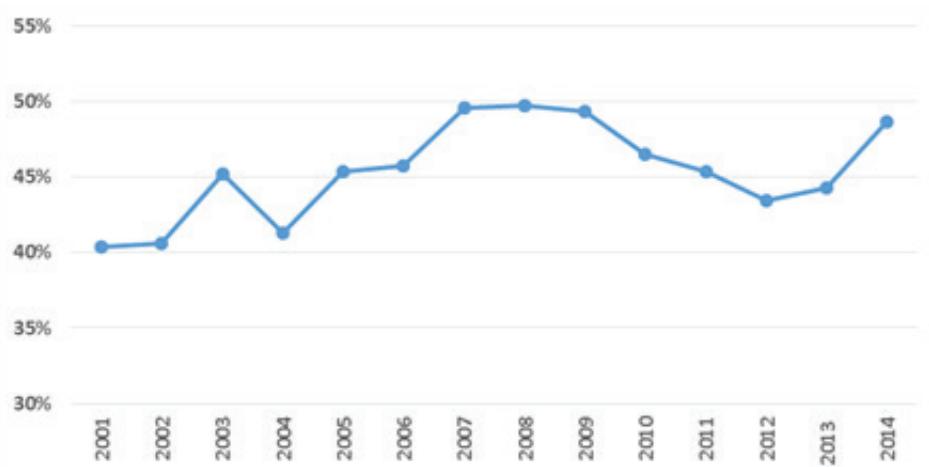
**Figure 68. Natural Gas Consumption by Sector, 2002–13 (bcm)**





Natural gas is now the major source for electricity generation in Turkey. As Figure 69 shows, depending on hydrological conditions and reserves in hydroelectric plants, the share of electricity generation from natural gas varies between 40% and 50%. As will be discussed in the following sections, this dependence on imported NG creates supply security concerns. Furthermore, due to insufficient storage capacity, seasonal electricity supply problems may occur during increases in residential consumption.

**Figure 69. Share of Natural Gas-fired Generation in Total Generation, 2001–14**



Source: TEİAŞ.

### 3.6.1.1 Supply

The market is import-dependent since domestic production is negligible (being less than 2 percent in overall consumption). The supply is mainly provided through BOTAS' long-term import contracts (pipeline gas and LNG), some of which have been transferred to the private sector. Table 11 shows the long-term agreements in force.

**Table 11. Existing Long-term Gas Contracts**

Contract	Quantity (*)	Contract Date	Starting Year
Russian Federation (West Route -BOTAS)( **)	4	14.02.1998	1998
<b>Algeria(LNG)</b>	<b>4.4</b>	<b>14.04.1988</b>	<b>1994</b>
Nigeria(LNG)	1.3	09.11.1995	1999
<b>Iran</b>	<b>9.6</b>	<b>08.08.1996</b>	<b>2001</b>
Russian Federation(Blue Stream)	16	15.12.1997	2003
Russian Federation (West Route- Private Sector)(***)	10		
Turkmenistan(****)	15.6	21.05.1999	Not in operation
<b>Azerbaijan (Phase I)</b>	<b>6.6</b>	<b>12.03.2001</b>	<b>2007</b>
Azerbaijan (Phase II)	6	25.10.2011	2017/18
<b>Azerbaijan (BOTAS International(BIL))</b>	<b>0.15</b>	<b>26.10.2011</b>	<b>2013</b>

Source: BOTAS.

\* Denotes the plateau amount in 9600 Kcal/m<sup>3</sup>.

\*\* Originally was eight bcm, four bcm is transferred to private importers.

\*\*\* 4 bcm contract transfer, 6 bcm from terminated west –route contract of BOTAS.. Import licenses were granted to four different sector companies following an announcement and application procedure as per NGML.

\*\*\*\* The Turkmenistan contract is not foreseen to be operational in the medium term.

In addition to gas imports through pipelines, LNG imports were liberalized through legal arrangements made in 2008, on a spot basis. BOTAS and private sector company EGEGAZ have been importing LNG since 2009. Table 12 shows imports in 2005–13. Although import sources are diversified, Russia's share is more than 50%.

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

Year	Russia	Iran	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.

Today, the total annual quantity of the long-term import contracts, excluding the Turkmenistan Contract, is approximately 52 bcm. To cope with the increasing demand, additional quantities must be supplied via spot LNG, short-term, and long-term new agreements.

Up to 0.75 bcm of natural gas is exported annually by BOTAS to Greece through exit points at Ipsala at the Turkish-Greek border.

### 3.6.1.2 Demand Projection

Historical gas demand rose slowly during the 1990s and more rapidly in the next decade. Demand is expected to continue to grow, though at a slightly slower pace than the last decade, as the market reaches saturation.

The extension of the gas network to distribution regions is almost completed, as is the licensing process for distribution regions. Of the original 81 cities, projects are ongoing in five, and these should be completed by 2016. They represent less than 2% of the total demand potential. On the other hand, infrastructure investments for city gas distribution have progressed very rapidly and over 90% of needed infrastructure for household supply is now in service; by 2016 this figure will have reached over 95%. Therefore, the residential consumption growth rate will slow down and growth will come from increasing penetration, industrial, and mainly power sector consumption. Therefore the future composition of electricity generation will be decisive for natural gas demand.

On the other hand, because of NG's high cost, and because the high levels of NG imports are a concern for energy supply security, the government aims to decrease NG's share of electricity generation to below 30% by 2023.<sup>78</sup> In the last five years there has been a slight decrease, mainly due to increasing renewable generation and a reduction in the electricity demand growth rate. (Assuming 400 TWh of electricity generation in 2023, reducing electricity production from NG to a 30% level by 2023 would mean limiting it to roughly 135 TWh; currently it is about 105 TWh.) Considering the slower-than-expected progress in local coal and renewable generation projects, and possible delays in nuclear power plant projects, it will be a challenging target. However, this target can be met with a certain delay of few years.

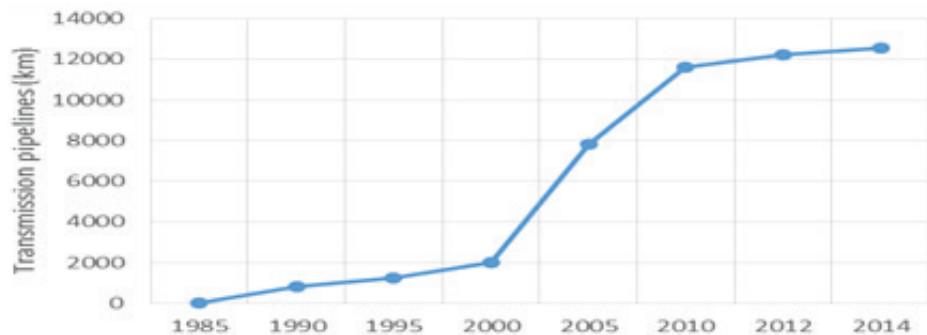
Therefore, the growth in natural gas demand may slow down. Still, the growth will continue and it is expected that consumption will reach 70 bcm by 2030.



### 3.6.1.3 Gas Transmission Network

The gas transmission network is owned and operated by BOTAS.<sup>79</sup> The development of the transmission system since 1985 is shown in Figure 70.

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



Source: BOTAS.

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

Gas is supplied to the main transmission network from four import entry points, two LNG terminals, one underground storage facility, and two domestic extraction sites. To increase gas dispatch capacity, future investments will focus on the construction of loop lines and installation of new compressor stations. In addition to the nine compressor stations currently in operation, the construction of a new compressor station at Eskişehir began in 2012 and it expected to be in service soon. Figure 71 shows the high pressure transmission lines and compressor stations of BOTAS.

**Figure 71. Natural Gas Transmission Map**



Source: BOTAS.

### **3.6.1.4 Distribution**

Whereas only six cities had access to natural gas in 2002, the number of gas distribution regions has now reached 69, covering 74 cities, through an EMRA tendering process that has been in place since 2004. This expansion is one of the main reasons for the increase of natural gas consumption in Turkey. This subject will be elaborated in the following sections.

### **3.6.1.5 LNG and Storage**

Currently there are two LNG terminals in Turkey:

- The Marmara Ereglisi LNG Terminal is owned by BOTAS and has a LNG storage capacity of 3 x 85,000 cubic meters. The annual regasification<sup>80</sup> capacity of this terminal is 6 bcm and a daily maximum 22.5 million cubic meters of regasified gas can be shipped to the transmission system.<sup>81</sup>
- The Aliaga LNG terminal, owned by private company EGEGAZ, has an LNG storage capacity of 2 x 140,000 cubic meters. Its annual regasification capacity is 6 bcm and its daily regasification capacity is 16 million cubic meters.

The only underground storage facility is Silivri Underground Facility, which consists of two depleted gas fields, owned and operated by TP.<sup>82</sup> The storage capacity is 2.661 bcm. A maximum of 20 million cubic meters of gas can be shipped to the system each day.

### **3.6.1.6 Investment Plans for LNG Terminals**

- BOTAS plans to increase the storage and regasification capacity of Marmara Ereğlisi LNG Terminal by installation of 4th LNG storage tank and additional send-out equipment such as High pressure pump, LNG Vaporizers, Pipeline Compressor and etc. Basic Design Engineering works for this Project has been completed.
- Licensing applications for four new LNG Plant investments have been submitted to EMRA. The locations are Aliağa and Çandarlı at the Aegean Coast and Yumurtalık at the Mediterranean Coast. The earliest date for any new LNG Terminal operation would be 2018.
- Discussions between the energy ministers of Turkey and Qatar relating to LNG Plant investment by Qatar in Turkey have been reported.

The new LNG terminals would have about 6–7 bcm regasification capacity each.

### **3.6.1.7 New Underground Storage Investments**

- Tuz Gölü (Salt Lake) Underground Storage Facility is being built by BOTAS. The salt caverns are being formed through leaching a salt formation with water brought by via a supply pipeline from Hirfanlı Dam. The project is planned to be completed in 2017 (first phase) and in 2020 (second phase) with a working gas capacity of 0.5 and 1 bcm, respectively, and eventually 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 its daily sendout capacity will rise to 40 mcm in 2015 during Phase 2. During Phase 3 TP plans to increase the storage capacity of the Silivri Facility 4.3 bcm and its daily reproduction capacity to 75 mcm by 2020.
- Two licenses have been granted by EMRA to private companies for new underground storage projects in the Tarsus region, with a target of 2-3 bcm in total storage capacity. MENR's 2015–19 Strategic Paper anticipates increasing the storage capacity to 10% of annual consumption in the medium term and to 20% in the long term.



### 3.6.2 Natural Gas Market Reform

Prior to the passage of the Natural Gas Market Law (NGML – Law No. 4646), BOTAŞ was the only company operating as main supplier, monopoly importer, and transmission company. In the distribution segment, only three cities were gasified and operated by municipalities (Ankara 1988, Istanbul 1993, İzmit 1994,) and two by BOTAŞ (Bursa 1993 and Eskişehir 1996)<sup>83</sup>.

In line with the policy of creating a market economy and inspired by EU's 1998 gas directive, the first studies for the liberalization of gas market started in the late 1990s and the NGML was adopted after the EML in April 2001.<sup>84</sup> The NGML aims to establish a legal framework for developing a fair, financially strong, transparent, and competitive natural gas market under the supervision of an independent regulator. The key features of the NGML can be summarized as aiming for a fully competitive market for wholesale gas supply and unbundling of BOTAŞ' main functions, thereby abolishing BOTAŞ' monopolistic position in the market.

The underlying strategic objective was to provide a secure supply of natural gas in a competitive domestic wholesale market, appropriately managing the medium-term potential supply overhang and minimizing the state's future contingent liabilities by shifting risk to the private sector.

The NGML's key provisions are:

- Independent regulation and supervision by Energy Market Regulatory Authority;
- Establishment of a licensing regime, regulated by EMRA for separate activities;
- Rules for competition, including unbundling of accounts and activities; avoidance of dominant positions (no supplier to sell more than 20% of annual gas consumption); provision of information and open access; and
- The “eligible consumer” concept.

Natural Gas Market Activities defined in the NGML are as follows:<sup>85</sup>

- Transmission
- Distribution
- Import
- Export
- Wholesale
- Storage (LNG terminals and underground storage facilities)
- The transport, distribution and trade of CNG (Compressed Natural Gas).

The law also introduced the following transitional measures and limitations.<sup>86</sup>

- BOTAŞ' share of the gas market was to be reduced to 20% by 2009;
- BOTAŞ should run tenders for contract or volume release of gas each year for at least 10% of the market;
- BOTAŞ shall not sign new import/purchase contracts (later in 2008 the law was amended and BOTAŞ and other private companies were allowed to buy spot LNG);
- No new gas import contracts may be signed with existing countries that already have contracts with BOTAŞ, except so that expiring contracts may be renewed;
- BOTAŞ should be fully unbundled by 2009 and the unbundled activities, apart from gas supply and transmission, should be privatized within two years.

The main reason for the first two transitional measures was to provide sufficient time to reduce BOTAŞ' share, and the third and forth items were designed to protect BOTAŞ because its existing

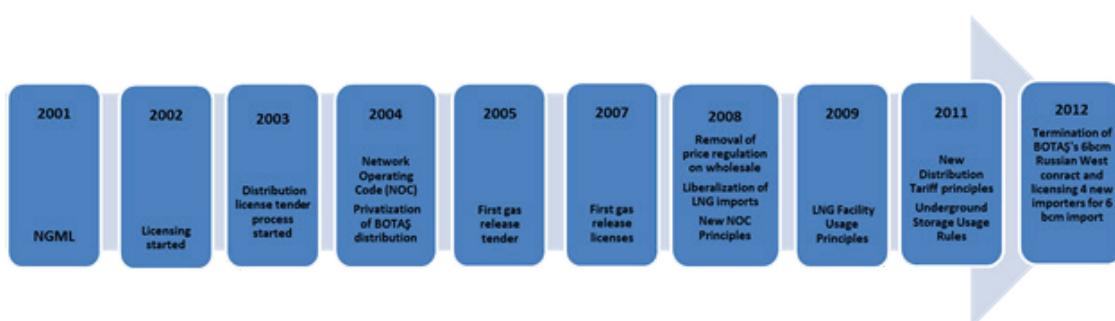


contracts include take-or-pay provisions. As will be discussed in subsequent sections, the far-reaching targets related to market share reduction could not be met and import limitations created supply security problems. Ownership-unbundling provisions were ambitious steps for that time. Such unbundling requirements have only been on the agenda in the EU through the 2009 Gas Directive.

### 3.6.2.1 Progress

Although implementation has been slower than in the electricity market, and although most of the original target dates were not met, there has been considerable progress toward a liberalized gas market. The major implementation steps are shown in Figure 72.

**Figure 72. Major Steps in Natural Gas Market Reform**



The outstanding achievements in the implementation of the NGML are as follows:

- The completion of the legal and regulatory framework;
- The privatization of BOTAS distribution;
- The expansion of the distribution system by private distribution companies through consecutive auctions held by EMRA;
- The development of wholesale activities and the abolition of BOTAS' monopoly by licensing new wholesale companies;
- The introduction of new suppliers and importers by transferring (via gas release tender) some BOTAS contracts to new private import companies, thus reducing BOTAS' share of the import and wholesale trade;
- The liberalization of LNG imports;
- The opening of the transport system to access by third parties; and
- The implementation of Network Operation Principles (NOP) defining the procedures and rules for the relations between shippers and transmission operator; and
- The implementation of an Electronic Bulletin Board (EBB) through which the nomination and capacity allocation processes with shippers are executed.



The existing market structure is shown in Figure 73.

**Figure 73. Natural Gas Market Structure**

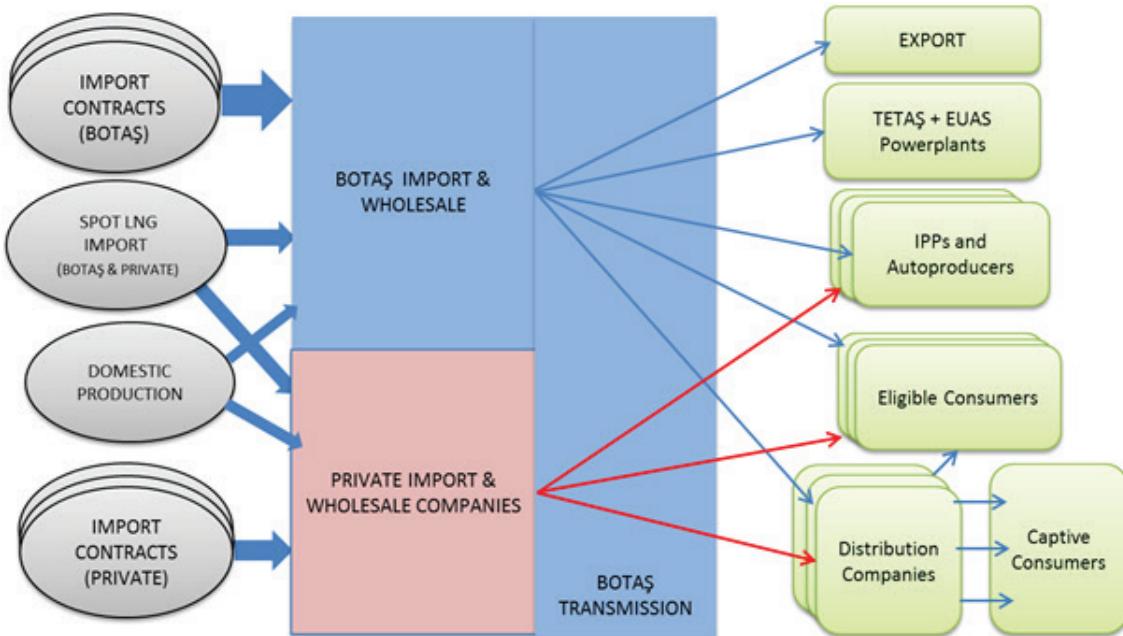


Table 13 shows the number of licenses for market players granted by EMRA as of January 2015.

**Table 13. Licenses in the Natural Gas Market**

Type of License	No. of Licenses	
Import*	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: EMRA Monthly NG Report, January 2015.

\* Because a separate license is required for each import, the number of import licenses does not represent the number of importers. BOTAŞ has six import licenses, and other private importers have eight licenses via pipelines (seven for contract releases and transfers and one for import from IRAQ).

\*\* CNG (compressed natural gas) licenses are required for the transport, distribution, and trade of CNG.

### 3.6.2.2 Transmission and Third-Party Access

Although all transmission activity (via pipelines) is carried out by a part of BOTAŞ, the legislation does not prohibit private parties from building and operating parts of natural gas transmission systems. For pipelines, the only transmission licensee is BOTAŞ; for LNG, 18 private companies have a LNG transmission license. License holders are permitted to carry out LNG filling, transport, and delivery activities; however, they are restricted to transporting LNG only in Turkish territorial waters and territory.

Nondiscriminatory third-party access (TPA) to the transmission network is an important factor for the introduction of competition in a gas market. To facilitate nondiscriminatory TPA, the Transmission System Operation Regulation was prepared and published by EMRA within the framework of the NGML. As a requirement of this regulation, all transmission licensees must publish the “Network Operation Principles” (i.e., the Turkish transmission grid network code) and the “Transportation Contract and Connection Agreement.”

In this context, Network Operation Principles (NOP) were prepared by BOTAS and approved by EMRA and published in September 2004. NOP has been amended as needed. Its main aspects are as follows:

- Capacity allocation is made for one year based on an entry-exit system.
- Transmission tariffs are determined by the revenue cap method.
- The users of the transmission system are called shippers. Shippers are therefore wholesalers or importers contracted to end users or exporters.
- Shippers book import capacity from the transporter.
- The balancing regime is daily at the ex-ante published imbalance price.
- BOTAS procures balancing services from shippers on month-ahead contracts; all transmission services provided from storage are procured via shippers.
- There are provisions for “difficult days” under which BOTAS can instruct shippers to provide balancing gas from specific storage facilities.

### **3.6.2.3 Distribution Activity and the Development of Gas Distribution**

Distribution licensees have a supply obligation as well as providing distribution services to suppliers and to eligible customers. In addition to supplying captive consumers, distribution licensees can supply eligible consumers in their regions. However, except for valid technical reasons, they cannot refuse to provide distribution services to eligible consumers supplied by other suppliers.

With the exception of the Istanbul distribution region, which is owned and operated by the municipality,<sup>87</sup> all previously existing distribution regions have been privatized. In addition, for provinces that previously had no natural gas distribution system, distribution licenses were granted following a series of tenders conducted by EMRA. (In these regions, the distribution licensees were obliged to first build the entire distribution network and then distribute and sell natural gas.) While there is competition for the distribution licenses, once awarded, there is no open access to the distribution networks and no competition for supply within the licensed area for non-eligible consumers. For the first five years eligibility threshold remained the same. However, in order to enhance retail competition EMRA decrease the eligibility limit as explained in Eligible Consumers section below.

The gas distribution tenders attracted considerable interest from local investors, and EMRA was highly successful in completing a number of tenders and licenses in a short space of time. Companies had to satisfy certain financial qualification and experience criteria to participate in the tenders. For the selection of the successful bidder, the main criterion was the distribution charge proposed by the bidding companies. (The distribution charge consists of unit service and depreciation charges, or USDC). The tenders were concluded by selecting the bidder offering the lowest distribution charges. For successful bidders, the distribution charge quoted is valid for eight years, after which it is determined by EMRA.

There were considerable differences among the prices bid for different regions. In some tenders the winning bidders in fact bid a zero charge (that is, the winning bidders did not request any distribution charge in anticipation that their sole income would be the one-time connection charge). These very low bids generated concerns about their success and the overall sustainability of the process – and thus its effectiveness in achieving long-term gasification objectives – and

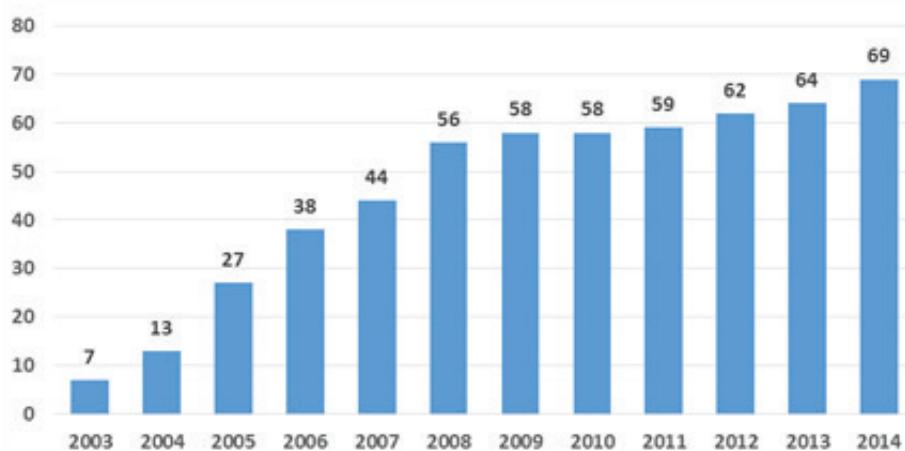


the methodology was criticized by many authorities. However, those concerns turned out to be unfounded.

Some companies have reached the end of the eight-year period. To determine subsequent distribution charges, EMRA established the Principles and Procedures of Tariff Calculation for Natural Gas Distribution Companies through a board decision in 2011.

As a result of the consecutive distribution tenders in 2003–14, the number of distribution regions reached 69, as shown in Figure 74.

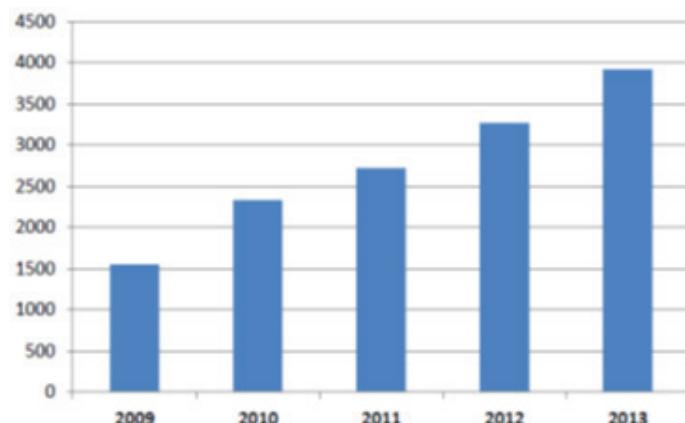
**Figure 74. Development of the Number of Gas Distribution Regions, 2003–14**



Source: EMRA.

In 2013 the government directed BOTAŞ to supply gas to the provinces that are outside the distribution regions. As a result of expanding the natural gas transmission network by BOTAŞ and construction of distribution network by distribution companies, the number of residential consumers in the 69 regions reached 9.5 million, and the number of eligible consumers increased to 372,000<sup>88</sup> in 2013.

The distribution companies that were licensed through distribution tenders have to invest in gas networks in their regions. By the end of 2013 the total investment realized by these companies had reached TL 3.9 billion, as shown in Figure 75. The existing distribution companies' investment for the regions which were not licensed through the tendering process reached TL 5.4 billion in the same period. The investments are inspected by the independent inspection companies certified by EMRA.

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

Source: EMRA 2013 NG Market Report (vertical axis: million TL).

According to the NGML, distribution companies cannot purchase more than 50% of their supply from the same supplier, and should certify that they are purchasing from the most economic source. However, these provisions could not be implemented due to BOTAS' dominance in the market.

#### **3.6.2.4 Unbundling**

The NGML includes unbundling provisions for BOTAS and other natural gas companies to enter the market. Pursuant to the NGML, accounting unbundling is to be applied in BOTAS and legal unbundling is envisaged until 2009. Accordingly, the Law provides that (a) import, transmission, storage, and distribution activities be undertaken by different legal entities and (b) ownership unbundling be carried out in BOTAS among its transmission, storage, import, and wholesale activities after 2009. However, this goal could not be attained and BOTAS has retained its legal status. Nevertheless, account unbundling in the activities did clear the way for third-party access to BOTAS' transmission grid and LNG terminal.

Distribution and retail operations are bundled for incumbent operators. The NGML requires account unbundling for the retail and distribution activities of distribution companies.

#### **3.6.2.5 Eligible Consumers**

According to the NGML, the following are deemed eligible and have the right to select their suppliers:

- Consumers with an annual consumption of more than 1 million cubic meters
- Electricity generation companies
- Cogeneration facilities
- Domestic natural gas producers

The NGML also authorizes EMRA to decrease the eligibility limit until all consumers became eligible. EMRA also has the authority to determine the eligibility limit for consumers in the new distribution regions. For the time being, the eligibility limit for these regions is 15 million cubic meters for the first five years of operation. (For some regions this period has already elapsed.) The recently privatized Baskentgaz distribution company in the Ankara region has a special limit of 800,000 cubic meters until August 2017.

Except for consumers that are in the newly tendered regions, the eligibility limit has been reduced gradually. In 2013 all consumers were deemed eligible except residential consumers. For residential consumers the eligibility limit has been reduced to 300,000 cubic meters. With this reduction the share of eligible consumers' consumption in the distribution regions reached



19%. However, only 11% of those consumers exercised their right.<sup>89</sup> As of 2013, the number of eligible consumers was roughly 372,000. In December 2014 the eligibility threshold was reduced to 75,000 cubic meters/year and the number of eligible consumers in distribution regions reached 435,786.<sup>90</sup> Furthermore the model agreements published by EMRA in 2013 for natural gas transportation and delivery services in distribution regions provides transparency in supplier switching.

In 2012, the consumption of eligible consumers supplied by distribution companies was roughly 3.8 bcm, whereas the consumption of eligible consumers supplied by other suppliers was roughly 18 bcm.<sup>91</sup> Not all the eligible consumer's consumption can be measured on a daily basis.

Naturally the growth in the number of eligible consumers will depend on the number of suppliers and level of competition in the market. The progressive reduction of eligibility threshold shows EMRA's commitment to increase retail competition.

### **3.6.2.6 Contract Releases**

Pursuant to the NGML,<sup>92</sup> the process of transferring BOTAS' purchase contracts to private companies was initiated in 2004. However, due to commercial and legal problems to do with contract transfer, the first tender was cancelled. After the amendment of Natural Gas Market Law in 2005, the approval of the selling party was made a pre-condition for participation in the auction. A second auction began in 2005 for 64 lots (250 mcm per lot) for purchase contracts with Algeria, Iran, Nigeria, and Russia. However, none but the Russian side provided their consent. As result, 16 lots (4 bcm) were released under a Natural Gas Sale and Purchase Contract dated 18 February 1998 between BOTAS and Gazprom Export LLC.

Another specific tender for the transfer of 6 bcm/year portion of the Natural Gas Sale and Purchase Contract dated 15 December 1997 between Gazprom export LLC and BOTAS was held in 2011, but the tender was canceled due to the lack of any eligible bids. The Western Line Contract of BOTAS dated 14 February 1986 for the import of 6 bcm/year was terminated by BOTAS and 4 private sector companies started to import 6 bcm/year of natural gas as of 2013 through Western Line. As a result of the 4 bcm gas contract release program and 6 bcm import license announcement procedure, seven companies are entitled to import 10 bcm (9,729 million standard cubic meters at 9,155 kcal per cubic meter) gas from Russia, as shown in Table 14.

**Table 14. Contract Transfers**

License Holder	Contract quantity (million cubic meters – 9000 kcal)	Contract quantity (million cubic meters – 9155 kcal)
Bati Hatti AŞ	1,000	983
Kibar Enerji AŞ	1,000	983
Bosphorus Gas Corporation AŞ	2,500	2,458
Akfel Enerji San. ve Tic. AŞ	2,250	2,212
Enerco	2,500	2,458
Shell	250	246
Avrasya Gaz	500	492

Source: EMRA.

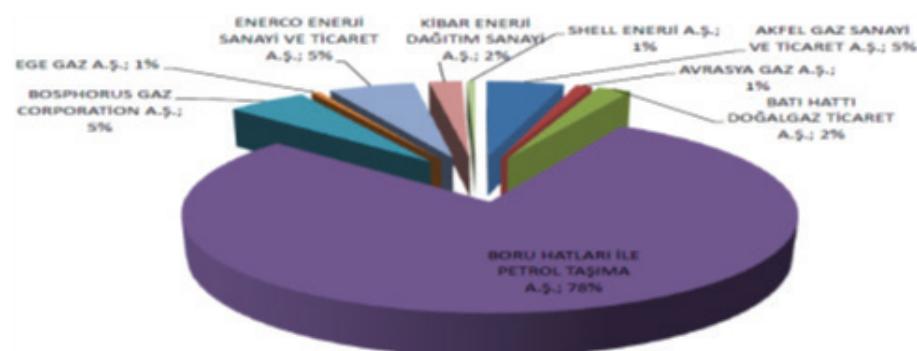
It should be noted that the main supplier, Gazprom, has shares in some of the import companies. For example, Gazprombank has a 40% share in Akfel and a 60% share in Avrasya, and Gazprom Germany has a 75% share in Bosphorus Gas.<sup>93</sup>

Therefore, the NGML's target (reducing BOTAS's share to 20% by 2009) has not been achieved. In fact, since its introduction, this target has been criticized as unnecessarily ambitious. It should be noted that even in more developed markets the proportion of supply controlled by the largest supplier can be much higher; in 2004 it ranged from about 50% in Germany and the UK to 75% in Italy and Spain and 90% in France.<sup>94</sup>

In 2005, following the first unsuccessful tender for contract transfer, amendments to the NGML introduced the possibility of “volume release” in cases where contract transfer is not successful. However, there have so far been no attempts at volume transfer. Perhaps the low profit margin is not attractive for new companies, and the lack of change in contract conditions (BOTAS retains the take-or-pay risk) is not attractive for BOTAS.

Figure 76 shows importers' shares in total NG imports for 2013. After the last contract release, BOTAS' share fell to 78%.

**Figure 76. Shares of Importers, 2013**



Source: EMRA 2013 Natural Gas Market Report.

### **3.6.2.7 Development of the Wholesale Market**

The liberalization of the wholesale market started only in 2007, after the first contract transfer in 2007 and liberalization of spot LNG imports in 2008. Even though the Network Operation Principles (NOP) Regulation was issued in 2004, BOTAS was the only player in the market until 2007. The 2008 NOP revision made possible natural gas exchange and title transfer in a virtual environment. Shippers (wholesalers and importers) can access the transmission network by signing Standard Transportation Contracts (STC) with BOTAS. The number of shippers increased from two in 2007 to 27 by 2013.

The shippers access the network according to the NOP Regulation (which also defines the rules and procedures for third-party access to the transmission network) and according to the STC. Shippers agree to NOP provisions when they sign the STC. The “Capacity Registration Certificate,” which certifies the capacities reserved by shippers, is an appendix of the STC. The duration of an STC can range from one month to one year.

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

The balancing period is set on a daily basis. The “balancing gas price” is determined on a monthly basis by taking the weighted average of the bids received prior to the month and the actual gas withdrawals during the month.<sup>95</sup> The transporter is responsible for ensuring the physical balance of the network, and no additional balancing service subject to a tariff has been defined under the concept of “Additional Service.”

The existing BOTAS Electronic Bulletin Board (EBB) is used to manage the network and publish the data that set the basis for most of the trade activity. Nomination processes with shippers are executed through the EBB, which is accessible via internet. All capacity requests and supply and consumption forecasts are provided by the shippers; and network constraints, balancing orders,



balancing prices, and capacities are announced by BOTAS, all through the EBB. Nomination processes are completed within a certain time period one day ahead, and requests for changes in schedule are not accepted, except in cases of force majeure.

However, according to private market participants, the market operation procedures and EBB have some deficiencies and are creating risks for shippers. Some of the points mentioned are security of the user and system data, the lack of intraday data, poor reporting, poor SCADA<sup>96</sup> communication, non-user-friendliness, and a significant amount of retroactive corrections.

It is reported by EMRA that, by January 2015, the revised version of the Electronic Bulletin Board for transmission activities came into effect in order to ensure more transparency to network operations. Moreover, another important step had been taken by EMRA paving way for introducing possible amendments to the Network Code by introducing the virtual implementation for the new market-based balancing regime for transmission. In this framework, virtual implementation legislation was issued by EMRA and the web module for virtual implementation was incorporated into the revised Electronic Bulletin Board for transmission activities in 2015. The implementation of the new market-based balancing regime for transmission is expected to begin in 2015.

Title transfers between shippers are carried out over virtual points called “Transfer Entry/Exit Points” defined at each entry point. On the other hand, the virtual “National Balancing Point,” which is defined for the whole network, is used for day-ahead gas exchanges between Shippers and for minimizing post-day imbalances.

The NOP allocation provisions allow related shippers to agree on quantities among themselves at all multiple entry and exit points, on the condition that the measured total quantity remains unchanged.

As of 2014, 42 wholesale licensees and importers were participating in the wholesale market. Private wholesale companies may purchase gas from BOTAS, from private importers, or from domestic producers (TP and private). They sell the gas to distribution companies, eligible consumers, and compressed natural gas (CNG) supply companies. Import companies also have the right to sell directly to distribution companies and eligible consumers. In this case, however, the distribution companies cannot be a legal entity of the importer. Production companies can sell their product directly, provided they obtain a wholesale license from EMRA.

### **3.6.2.8 Overview of Gas Pricing: Historical Trends and Current Prices**

BOTAS’ long-term pipeline and LNG import contracts are priced on formulae linked to international oil product prices. The price of spot LNG in Turkey is linked to the international spot market.

These factors determine BOTAS’ costs of buying gas together with the relative quantities taken on each contract, resulting in the weighted average cost of gas (WACOG). The costs of private importers depend on contracts between those companies and suppliers.

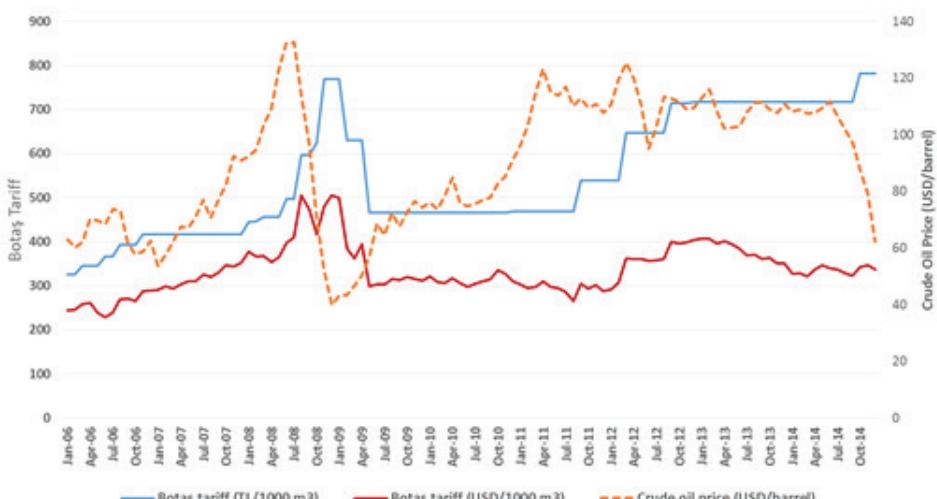
#### **Wholesale Prices and Subsidy**

Gas prices in Turkey are effectively controlled by BOTAS as it is still the dominant importer. Given the slow pace of the contract release program, BOTAS’ role is unlikely to change in the short-to-medium term.

Since WACOG is the main determinant of BOTAS’s costs, BOTAS should recover those costs from its sales and should reflect changes in its selling prices within a reasonable timeframe.

The government approved a cost-based, or “Automatic” Pricing Mechanism (APM) for state-owned enterprises in March 2008.<sup>97</sup> BOTAS was included in the APM to determine its wholesale prices for distribution companies and eligible consumers. The mechanism required BOTAS to update its tariff by factoring in variables such as import prices and the exchange rate between the Turkish lira and the U.S. dollar. The variation of BOTAS tariff (in TL and in USD) for eligible consumers and crude oil prices in 2006-14 are shown in the Figure 77.

**Figure 77. BOTAS Gas Price for eligible consumers and crude oil prices, 2006–14**



Sources: BOTAS, EMRA.

Following observations can be made:

- BOTAS tariff is adjusted according to the variation in international oil prices (with a time lag which depends on contract conditions).
- There had been no tariff adjustment in May 2009–October 2011, even the crude oil price is increased after mid-2010. In this period the tariff was in USD 300–350 / 1000 m<sup>3</sup> range.
- BOTAS prices to consumers were adjusted three times since October 2011 and cumulative increase in wholesale prices for household and industry has exceeded 48% since that time. In October 2012–October 2014, BOTAS kept its wholesale prices constant. Due to the depreciation of the Turkish lira since mid-2013 the tariff in USD is decreased to 350 \$/1000 m<sup>3</sup> again.
- Except for a short period after the APM implementation, the tariff is below USD 400/1000 m<sup>3</sup> for large eligible consumers.

As reported in Competition Authority and Sayistays' BOTAS reports<sup>98</sup> BOTAS tariffs for eligible consumers and distribution companies were set below the WACOG time to time since mid 2009 and in order to offset its losses, sale prices to EUAŞ, BOT and BOO power plants are set higher than prices to IPPs (effectively a cross subsidy). Court of Accounts (SAYIŞTAY) has also expressed concern about BOTAS' possible loss due to this pricing policy<sup>99</sup> in 2013. This price policy was a reflection of the government's policy of providing from the time to time a lower gas price to residential and industrial consumers including IPPs. The reduction of gas import prices following the reduction of international oil prices provides an opportunity to phase out this price difference.

Due to its dominant position in the market, BOTAS' selling prices are seen as a benchmark by the private wholesale companies. Therefore, BOTAS' pricing policy has not only affected its own financial position but at the same time is affecting wholesale competition. Unless the private importers' import prices and wholesale companies' costs are lower than BOTAS' price to its consumers in the market, they cannot compete with BOTAS' prices. Gazprom was selling gas to private importers (some of which are Gazprom shareholders) at a price as low as \$350 per 1,000 cubic meters, in order private suppliers to sell their gas in the market after the discount Gazprom granted in 2013.<sup>100</sup> In 2014 they got an additional temporary discount and for the first half of 2015 the price is reduced to 300 \$/1000m<sup>3</sup>. This price is nearly equal to BOTAS' eligible consumer tariff.



It is declared officially that the price negotiations between BOTAS and Gazprom are ongoing. In addition to the possible discount in the import price, the effect of reduction in the oil prices will be reflected to the import price of BOTAS. It is expected that after the reduction of import cost of BOTAS, the gap between cost reflecting and actual prices will be smaller and subsidy will be phased out. This would help further liberalization of imports and development of wholesale market.

### 3.6.3 Analysis of the 2001–14 Period

After issuing the NGML in 2001, it was expected that implementation of the Law would create a competitive, financially strong, and transparent natural gas market; secure the supply of gas; manage the potential medium-term supply overhang; and minimize the state's future contingent liabilities by shifting risk to the private sector. The law embodied a policy which had far-reaching intentions for creating a competitive gas market. However, this has not yet happened and a new draft law is under preparation.

Although the NGML was enacted in the same period together with the EML, progress in the natural gas market is far behind of that of electricity market. This slow progress may be attributed to several reasons such as:

- The strategic role of natural gas in economic development;
- Supply security concerns, due to a very high level of import dependency;
- Its role in international energy relations and energy policy;
- The role of Turkey as a transit country and its aspiration to be an energy hub for multiple producers and consumers;
- Unlike the electricity sector, there was practically no domestic experience for liberalization of the gas sector, and no liberal markets in gas supplier countries; and
- Until recently, the EU gas markets had also made only limited progress in liberalization.

Therefore, the policy developments toward introducing a competitive liberalized market have depended on geopolitical and international energy market conditions. All of the above-mentioned reasons created conflicting arguments as to whether to (a) continue with the sector reform as an EU candidate country, which requires full adaptation of the *Acquis Communautaire*,<sup>101</sup> or (b) become a major hub and energy corridor to Europe through a vertically integrated national champion (BOTAS), assuming liberalization would prevent Turkey from becoming a major energy player in the region and would endanger the supply security. As a result, unlike for the electricity market, for the natural gas market a clear strategy and roadmap for further liberalization, including the role of BOTAS in this structure, could not be determined.

The NGML aims to liberalize the gas market and decrease the government's share. However, BOTAS is still the dominant supplier in the market, cost-reflective pricing is not in place, and the functional unbundling of BOTAS could not be realized. Even though some of the targets set forth in the NGML could not be achieved in 13 years, as discussed in the previous section, there has been a considerable progress toward a liberalized gas market, as can be summarized in Table 15.

**Table 15. Progress toward a Liberalized Gas Market**

Regulatory Framework	
A new market entrance scheme: Licensing	
Regulated TPA regime	
Gasification Program- Distribution Tenders	
Market opening	
Gas release program- reducing BOTAS's share	
Unbundling of activities	
Efficiently working wholesale trading mechanism	
Abolishment of monopolies	
Cost Reflecting Pricing	

Insufficient progress in some areas, such as the Gas Release program and reducing BOTAS' market share to 20%, stems from the very ambitious targets set forth in the NGML. However, it is also clear that a fully functioning wholesale market and full competition are not yet in place.

### **3.6.4 Future Expectations and Challenges**

#### ***3.6.4.1 Amendment of the NGML***

Since some provisions related to import limitations, unbundling, contract release and market share have not been fulfilled in the timeframe set forth in the Law, the amendment of the NGML has been on the agenda for some time – since 2008, in fact – due to a lack of a consensus, especially about BOTAS's role and share in the market.

Finally, however, MENR prepared a revised version of the NGML and submitted it to Parliament in August 2014. The important provisions in the new draft are as follows:

- BOTAS will be restructured as three companies. It will remain an import and trading company, but two new companies will be established – one as a transmission system owner and operator, and the other for storage and LNG activities. Ownership unbundling shall be completed by in one year after the enactment.



- There will be no limitations for importers (other than BOTAS) that were not allowed to import gas from the countries that already have contracts with BOTAS.
- BOTAS cannot sign new pipeline gas contracts until its market share (import share) decreases to 20%. but can extend the duration of existing Although BOTAS is allowed to import LNG, it may enter into new pipeline gas import contracts only by decision of the Council of Ministers, in case supply security is endangered or for the purpose of export. However, although this provision is intended to reduce BOTAS's share in the market, unlike the existing law there is no timeframe for the reduction. Instead, the amended law prevents BOTAS from signing new gas sale contracts after 2015.
- Wholesale gas trading means shall be enhanced and EPIAS, which is being established in accordance with the new EML, will be a gas exchange platform as well.
- As a new item, a separate supply security provision is envisaged in the draft amendment. Ministry is responsible to take measures for security of natural gas supply.

There are also new provisions related to distribution companies, storage, transportation, etc. A firm timeline for the enactment of the amendment has not yet been established, but it is expected to become effective within 2015. The draft will be finalized in Parliament during the enactment process.

#### ***3.6.4.2 Improvement of Balancing and Settlement Mechanisms and Gas Trading Platform***

In the natural gas market, unlike in the electricity market, the mechanisms for balancing and settlement are not well developed. To improve market-based balancing and settlement efficiency, a balancing market should be established. As the system operator, BOTAS (the transmission company) will carry on real-time balancing. However, difficulties in collecting consumption data are hindering the management of system balancing. Improvements in metering, tele-information systems (SCADA), and existing Electronic Bulletin Board (EBB) are necessary. A day-ahead trading platform and more-developed markets should be established together with EPIAS. Establishment of an effective trade platform will also support the “energy hub” concept. Such a hub can determine the correct price structure based on market dynamics driven by supply and demand.

As mentioned earlier, the structure and developments in the domestic natural gas market in Turkey have an important influence on the realization of Turkey’s goal of becoming an energy hub. However, to achieve this goal it is necessary to establish a well-functioning natural gas market and trading platforms. Naturally, to establish such a market, the physical infrastructure should be sufficiently developed, the regulatory framework should be in place, and market and commercial frameworks should be improved. The current efforts to upgrade the EBB and the amendment of the Natural Gas Market Law are positive steps toward this goal.

Several studies are being carried by MENR and industry for establishment of a well-functioning gas market and an energy hub. In this context Turkish Gas Market Hub Project (Leonardo Da Vinci Programme) is ongoing. Partners of this project includes PETFORM (Turkish Petroleum Platform Association), EFET (European Federation of Energy Traders), ICIS (Independent Chemical Information Services) and Republic of Turkey Ministry of Energy and Natural Resources). Another Project funded from EU’s IPA program for Turkey for the establishment of an effective gas-trading platform and improvement of balancing-settlement system is carried by MENR in coordination with WB.

#### ***3.6.4.3 Cost Based Pricing and Subsidies***

The high cost of gas – due in part to Turkey’s overdependence on imported gas to generate electricity – directly influences both the competitiveness of Turkish industry and the living standards of citizens. For this reason, government price controls and the resulting cross-subsidization may be considered necessary (i.e., a valid excuse). It can be argued that further

liberalization and competition (which require cost-reflecting prices and minimum government intervention) would decrease the cost of gas for consumers. However, since the imported gas price is determined mainly by suppliers through existing contracts and is indexed to oil prices, competition in the domestic market will have only a marginal effect on the gas price as long as gas demand is met mainly through the existing contracts.

Gazprom's discounts to private importers can be taken as a sign of a possible price reduction through contract negotiation. However, real price reductions will be possible only by further diversifying the sources over time. Previously, due to medium-term overcontracting and take-or-pay risk, the liberalization of gas imports was a threat. However, as will be discussed later, the existing contracts are insufficient to meet growing demand and new sources should be found. This will also facilitate the realization of the aim of being an energy center.

In case BOTAS tariffs are set below the WACOG, liberalization of import cannot deliver full potential benefits since no new importer will be willing to enter the market other than the source countries' own companies, such as Gazprom's local affiliates.

It should be mentioned here that, Turkish consumers are among the ones using cheaper gas when compared with most of the European countries. However, even if subsidized, the consumer price (including any distribution tariff) is still high for low-income households. For this reason, a transparent subsidy mechanism targeting low-income groups should be implemented instead of subsidizing all consumers.

### 3.6.4.4 Infrastructure

The expansion of the natural gas transmission network to increase its transport capacity and building new storage facilities and LNG terminals are necessary to accommodate the increasing amounts of gas in the system. Importers, wholesale companies, and suppliers of last resort need access to sufficient storage capacity to meet their storage obligations for supply security purposes.

### 3.6.4.5 Supply/Demand Balance and Challenges

#### Long-term Supply - Demand Balance:

As mentioned previously, the existing supply contacts and domestic production are adequately balancing domestic consumption for the time being. However, to cope with increasing demand new sources will be necessary. Turkey's policy is to further diversify the sources while increasing imports from current suppliers. In this context the developments and opportunities are as follows:

- *Additional supply from Azerbaijan:* According to an Intergovernmental Agreement between Turkey and Azerbaijan, an additional 6 bcm per year from Azerbaijan (Shahdeniz Phase II) will be imported by BOTAS. (This is related to the Trans-Anatolian Pipeline Project (TANAP), which aims to transfer gas to Europe via Turkey.)
- *Additional supply from the Russian Federation:* Turkey is already negotiating with Russia for a capacity increase from the Blue Stream that is expected to provide 3 bcm in additional gas supplies annually. An additional 6 bcm supply from the newly announced Turk Stream (replacing the South Stream) has recently been added to the agenda.
- *Extension of the LNG contract with Algeria:* The term of the LNG Sales and Purchase Contract between BOTAS and Sonatrach for the import of LNG from Algeria has been extended.
- *Supply prospects from Iraq:* it can be assumed that 2 bcm can be imported from Iraq in 2016–18, gradually reaching a maximum value of 10 bcm by 2030.
- *East Mediterranean – Possible supply from Israel and Cyprus.*
- *Additional LNG imports and new LNG terminals.* New licenses and realization of new underground storage projects.



Provided that the supply prospects are realized and expiring contracts are renewed, it can be said that the supply/demand balance will be maintained in the long term. However, depending on the demand increase, there may be a supply deficit in 2015–17. The gap may be covered partly by increasing spot LNG imports.

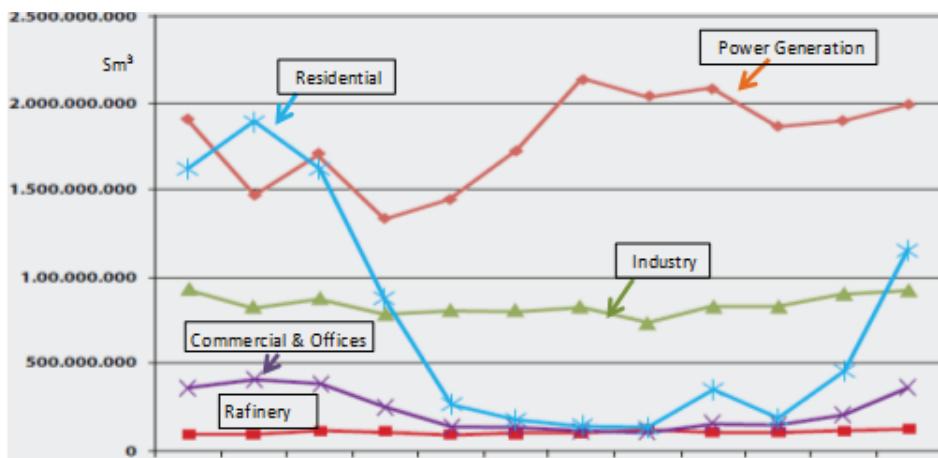
#### *Seasonal Supply Shortages*

The lack of sufficient storage facilities creates seasonal problems – especially during cold seasons, in which residential consumption increases. This is due to insufficient daily supply capacity.

The maximum daily supply is the sum of (a) daily contract quantities from pipeline import contracts, (b) the maximum send-outs from LNG terminals and underground storage facilities, and (c) local daily production. Currently, those figures are roughly 140, 36, 17 and 0.5 million cubic meters, respectively; in aggregate, 193.5 million cubic meters. However, this depends on the LNG and gas levels in the LNG terminals and underground storage.

On the other hand, the daily demand varies according to seasonal consumption. As Figure 78 shows, monthly residential demand varies drastically, and this seasonality in residential consumption will increase as household customer penetration increases. Hence the peak demand on very cold days reaches over 200 million cubic meters, and daily supply cannot meet the peak demand.

**Figure 78. Seasonal Consumption Trends of Different Consumer Groups (2013)**



Source: EMRA.

Problems experienced during peak demand periods also result from faults in the transmission infrastructure and insufficient capacity of compressor stations, especially for the transport of gas from Iran and Azerbaijan to high-consumption regions in Western Turkey.

Current storage capacity raises concerns for supply security and market stability.

Seasonal supply shortages will likely ease from 2017, when the upgrading of the TP Underground storage facility and the first phase of BOTAS' Tuz Golu Storage facility are completed and will ease further when new LNG facilities are installed and the second phase of Tuz Golu is completed in 2020.

It is interesting to note that, when the NGML was issued and until recently, one of the main problems was a medium-term supply overhang due to over-contracting and supply security was not an immediate concern. However, after a successful gasification program implementation and increased share of natural gas in electricity generation, the main challenge now is to meet the growing demand and secure the supply.

### 3.7 Petroleum Price and Subsidy Reform

Prior to reforms, the Turkish petroleum sector was dominated by state-owned, vertically integrated enterprises. Before 1990, the public distribution company Petrol Ofisi and the public refining company TÜPRAŞ were subsidiaries of TP, the national oil company. At that time, the industry was governed by public decrees under which prices of petroleum products were largely set by the government.

The petroleum sector reform started in the 1980s as part of broader economy-wide reforms moving toward a market-oriented economy. Before such reforms, the state exerted a dominant position in economic activities in terms of both (a) ownership of enterprises in critical industries, such as energy and petrochemicals, and (b) the allocation of financial resources, especially through state-owned banks.

The petroleum sector reform had several objectives, including improving the government's fiscal position and enhancing the sectoral efficiency. Under the 1989 law, importers, refining companies, distribution companies, and retailers were, in theory, to be allowed to set the prices of crude oil and petroleum products. The privatization of public refining and distribution companies started in 1990 and was fully completed in 2005. This did not, however, achieve a liberalization of prices in the 1990s. This was because the government maintained control of the state-owned enterprises that dominated the petroleum product market, which in practice set the prices of petroleum products – even though a liberal price regime was adopted legally.

In June 2013, in order to provide a competitive, transparent, reliable, and stable environment for petroleum and gas exploration and production activities, and also to regulate the rights and responsibilities of petroleum right holders and third parties according to measurable criteria, Turkey enacted the **Turkish Petroleum Law**. The Law introduced certain incentives to the sector. One is that all kinds of equipment – such as seismic materials, drilling equipment, vehicles, vessels, and aircraft imported for exploration activities – are free of all taxes, tariffs, and fees. Also, right holders may transfer the materials they import for petroleum activities to other right holders and their contractors.

In 1998 the government adopted the **Automatic Pricing Mechanism (APM)**, which operated between July 1998 and the end of 2004. The APM capped the prices of almost all oil products in Turkey, on the basis of international petroleum prices and the exchange rate. In principle, refining companies and importers could set prices freely, provided these prices did not exceed the ceilings. However, there were still license requirements for importing and capacity requirements for storage, and these requirements presented large barriers for market entry. In practice, distribution companies and retailers were not allowed to set their prices freely but, instead, prices were set by the government. TÜPRAŞ benefited significantly from the APM and became a profitable enterprise, whereas before APM it had often incurred losses because the government kept the prices of petroleum products low.

In early 2005 the government decided to remove the price caps, which led to an increase in pretax prices. Since then, fuel prices have been set by the market. Turkish gasoline and diesel prices are now among the highest in the OECD, owing to the relatively high excise taxes that are reflected at the level of retail prices.

The **Petroleum Market Law** was passed in 2003 to achieve the institutionalization of the market economy and to comply with EU legislation. The law took the regulatory authority of the petroleum market from the Ministry of Energy and Natural Resources (MENR) and placed it under the control of the Energy Market Regulatory Authority (EMRA), an independent agency established in 2001 as the regulator of the electricity and natural gas markets. Under the Petroleum Market Law, the government's control of the petroleum market, through such means license requirements and importation limits, was significantly reduced. The privatization of state-owned enterprises was also accelerated under the law and was completed by 2005.



### 3.7.1.1 Tax

As with many other emerging countries facing challenges related to high domestic debt and budget deficits, Turkey uses **motor fuel taxes** to raise revenue to bridge the financial gap. So, despite the fact that in theory motor fuel tax policy may be imposed for many alternative objectives, including environmentally related ones (for example, a fuel tax may internalize external costs such as noise, road safety, air pollution, and traffic congestion), the main reason for relatively high fuel taxes in Turkey has mostly been purely fiscal – that is, revenues were deemed necessary for fiscal consolidation, also because fuel taxes evasion is much more difficult to be subject to evasion compared with the overall Turkey's income tax system.

Value-added tax (VAT) was introduced in Turkey in 1985. It is similar to the European Union's VAT system, requiring payments to the tax authorities at each transaction point in the sales chain. To simplify the indirect tax system and harmonize it with the EU system, a **special consumption tax (SCT)** was put into effect on 1 August 2002, abolishing different indirect taxes and funds (including a petroleum consumption tax, a liquid fuel price stabilization fund, a motor vehicle purchasing tax, an environment fund, a supplementary motor vehicle purchasing tax, supplementary VAT, and so on). The SCT is structured as a single tax levied equally on both domestic production and imports of products such as alcoholic beverages, cigarettes, motor vehicles, and petroleum products. When the SCT came into force, the high VAT rates were lowered to a maximum of 18%. At present, Turkey levies an 18% VAT on all energy products. In addition to this, an SCT is levied on motor vehicle fuels. The SCT is a fixed sum per liter or kilogram, for each type of fuel, adjusted by government from time to time for inflation. The Council of Ministers may increase the taxes on motor fuels by 50% and may reduce them to zero.

**Energy-related taxes** in Turkey are levied mainly on the transport sector. Although not explicitly imposed for an environment-related objective, gasoline and diesel tax rates are differentiated according to the composition of the fuel – octane rating for gasoline and sulphur content for diesel. As in many countries, the per-liter tax rate on gasoline is higher than that on diesel, and biodiesel has a further tax advantage relative to diesel. The current level of the gasoline excise is the highest among OECD countries. Lower tax rates are levied on LPG and natural gas. As a consequence, there has been a significant increase in LPG consumption since the beginning of 2000s. Domestic aviation is currently exempted from energy taxation. A tax rate is set on marine transport fuels, but several exemptions apply.

Besides fuel taxation, a highly differentiated **motor vehicle tax and a special consumption tax** on other transport vehicles are applied. In the heating and process use category, energy taxation is, in principle, not differentiated among user sectors. LPG and natural gas excise rates are set at a lower level than with respect to road use. Other gases and coal are exempted from taxation. The LPG excise rate is lower than that for gasoline and diesel.

An **excise tax** is levied on the use of natural gas in electricity production, while the use of coal, diesel and fuel oil<sup>102</sup> for that purpose is not taxed. Although most energy-related tax revenue comes from transport fuels, the transport sector represents a smaller proportion of energy use – about 15% – than in most other OECD countries. Diesel, taxed at lower rate than gasoline, represents more than 50% of total energy consumption in the sector. Gasoline, subject to the highest tax rate among OECD countries, accounts for only 16%, overtaken by LPG and natural gas, which receive a more favorable tax treatment.

Aviation, marine and rails are taxed on average at a much lower level, due to the exemption for aviation fuel and to the lower rate for the shipping industry. Within the heating and process category, natural gas share accounts for about 30% of energy use in this category and is taxed. Coal usage has a similar share in energy content, but it is untaxed. The emission map, however, shows that coal represents more than 40% of the category's CO<sub>2</sub> emissions and above 20% of total CO<sub>2</sub> emissions from energy. Lignite, which is among Turkey's most important energy resources, is still widely used by households for heating. Diesel and other oil products are taxed

at a higher taxation, and represent around 20% of energy use for heating and process purposes. Renewables and waste account for about 14% of both energy use and emissions from heating and process use.

Natural gas (which accounts for about 46% of the energy used to generate electricity and about 36% of the carbon emissions from this use) is taxed, while coal (which accounts for about 38% of energy use and 55% of emissions) is not taxed.

Although pre-tax fuel prices and the VAT on them constitute two important components of the relatively high fuel prices in Turkey, the governments are not directly held responsible for them, and any concern related to the increases in pre-tax prices is usually addressed on the grounds that they originate from developments in international oil markets that cannot be controlled by the government. The politically problematic part of the end-use fuel prices is the special consumption tax (SCT), and also the fact that there seems to be an asymmetry in how gasoline prices in Turkey respond to changes in crude oil prices. As confirmed in a recent study using a structural vector auto-regression methodology, when crude oil prices increase, this is reflected in higher tariffs; but when crude oil prices decrease, there is no response. However, recent changes in the exchange rate (i.e., the U.S. dollar appreciating versus the Turkish lira) do not allow the reduction in crude oil prices to be fully reflected in domestic market prices.

On many occasions, even Turkish finance ministers have admitted in public that fuel end-use prices in Turkey are high, mainly due to high taxes; but they also underline the fact that the taxes are critical to meeting the revenue requirement of the central government budget. Therefore, it is not expected that the government will reduce any of the fuel taxes in the short term – and perhaps not in the long term, either.

The huge margin between pre- and post-tax motor fuel prices is the main motivation for smugglers. At present, oil smuggling is a chronic problem on Turkey's borders with Iraq and Iran.

### 3.7.1.2 Poverty Alleviation Measures

Erdoglu (2014)'s analysis shows that the income elasticities of all three transport fuels (gasoline, diesel, and LPG) are positive, meaning that people tend to consume more fuel as their income increases. Long-run elasticities are always higher than short-run elasticities, implying that consumers are more responsive to price and income changes in the long run. The price elasticity of gasoline is negative in both the short and long run. Surprisingly, however, price elasticities for diesel and LPG are positive in both the short and long run. This underlines the fact that demand for diesel and LPG increases even if their prices rise. This is explained by the fact that gasoline-fueled car owners easily convert their car into LPG-fueled one, and therefore an increase in gasoline prices translates into a decline in gasoline consumption. This interpretation is supported by the finding of a positive diesel-price elasticity for gasoline demand, meaning that as the price of diesel increases so does the demand for gasoline.

Overall transport fuel demand in Turkey is quite inelastic and unresponsive to price increases caused by an increase in either pre-tax prices or taxes. Therefore, fuel market in Turkey is open to opportunistic behavior either by firms (through excessive profits) or by the government (through excessive taxes). Although firms' opportunistic behavior may be prevented by efficient regulation, the government's opportunistic policies are much more difficult to prevent and may be limited only by the pressure imposed on the government by civil society institutions.

Several targeted measures were taken to mitigate the impacts of reforms as follows:

- *Tax exemption for LPG consumption.* Between 1999 and 2001, the government supported the use of LPG by households for cooking purposes by foregoing both value-added and the special consumption tax. These tax exemptions resulted in the price of LPG being below that of both gasoline and diesel. As regular motor engines cannot use LPG, the government expected the fuel's use in cars to remain limited. However, an underground



industry soon developed to make gasoline engines compatible with LPG. With a payback period of less than two years, the operation proved sufficiently simple and cheap for drivers to convert their vehicles to LPG use. This provision resulted in significant increases in LPG consumption. Alerted by the resulting loss of tax revenue, the government began to phase out this tax exemption at the end of 2000.

- *Tax exemption for public transportation.* According to the New Turkish Corporate Tax Law passed in 2006, public transport companies owned and managed by municipalities, villages, or special provincial administrations are exempted from both value-added and excise taxes.
- *Rebate for diesel used in agriculture.* A rebate program was introduced by the Ministry of Agriculture in 2007 to help farmers grow specific crops. The program defines three types of crops, each of which corresponds to a different aid level. The amounts of aid are calculated according to the area of the land used in growing specified crops, and paid according to a schedule defined by the Cabinet. There are no restrictions on how grant money is spent. The measure is to be phased out.



## Turkey's Energy Transition - Milestones and Challenges



## Appendix 1: The Implementation of the BOT, BOO, and TOOR Models in 1984–2001

### Achievements and Problems in Implementing the BOT Model

In December 1984, Law No. 3096 was enacted to enable private sector participation in the power industry. This law in effect ended TEK's monopoly on generation by introducing private generation investment models such as **build-operate-transfer (BOT)**, **transfer of operational rights (TOOR)**, and **autoproduction**. Due to insufficient progress prior to 1994, Law No. 3996 (the BOT Law, which also addressed other sectors beside the energy sector) was enacted in 1994. The projects to be carried out under the Law No. 3096 were also deemed eligible for state guarantees and private law contracts.

As a result of BOT model implementation 24 power plants with a total installed power of 2450 MW were commissioned (18 hydro, 2 wind and 4 natural gas CCGT) in 17 years (1984-2001).<sup>103</sup> Given the needs, the continuous government efforts, and the ambitious expectations, this outcome cannot be considered a success. There are several reasons for this unsuccessful implementation.

#### Unclear and Continuously Changing Legal Framework

At the beginning the BOT concept was new and there was considerable opposition to this model. Law 3096 had established a legal framework but lacked the necessary conditions to attract foreign investment. There were initially no state guarantees for payments by state utilities and no international arbitration possibilities for dispute settlement. Government attempts before 1990 to implement the BOT model under private law contract were cancelled by the Council of State (the *Danıştay*), the nation's highest administrative court.

In order to open the door again for contracts based on private law and to provide state guarantees for payments made by public authorities, Law No. 3996 (BOT Law, which also addressed other sectors beside the energy sector) enacted in 1994. The projects to be carried under the Law No. 3096 were also deemed eligible for the state guarantees and private law contracts.

Law 3996 enabled private law contracts and international arbitration for dispute settlement without *Danıştay* review or approval. However, in 1995, the Constitutional Court ruled that, according to Turkish Constitution, the only way in which the private sector can participate in a public service is through concessions, and private law cannot be used. Although the government contemplated private participation in the electricity industry, the Turkish constitution defined the provision of electricity as public service that could be supplied only by state-owned enterprises. Thus, private participation in the industry could be authorized only through concession arrangements with the state, with the state itself retaining the ownership of investments at the end of the concession term.

As a result, except for some BOT generation projects that had been enacted before cancellation, any projects started after the passage of Law 3096 had to be carried out using concession contracts. It was only after 1999 that private law contracts and international arbitration were made possible by changing the Constitution. Furthermore, a new Law (No 4501) allowed the conversion of previously made concession contracts to private law contracts.<sup>104</sup> The main reason for this change was to attract private, especially foreign investors to the power sector; since administrative law contracts, administrative authorities' involvement, and lack of international arbitration were deemed risky by private investors.

In summary, there was continuous debate over whether the BOT model should be implemented under (a) a concession framework requiring administrative contracts, *Danıştay*<sup>105</sup> supervision and approval, and dispute settlement through the *Danıştay*; or (b) under private law contracts that do not require *Danıştay* approval and permit international arbitration for dispute settlement. Several decrees and laws were issued on those matters, most of which were annulled by either the *Danıştay* or the Constitutional Court. This argument was not settled until 1999, causing loss of time and motivation.

In 1999, the Turkish constitution was amended, allowing electricity investments to be subject to private law, thus paving the way for international arbitration. The Danıştay's role in disputes was limited by this amendment, and the approval process for investments was expedited. A new law for infrastructure projects (Law no. 4501) was enacted in 2000 to provide the aforementioned constitutional modifications.

The problems in implementation had showed that, without a clear and transparent legal and administrative framework, supported by a consensus on the main legal framework and principles, no model can be successful.

### Implementation Problems

Although virtually no interest was expressed by private local and foreign investors until 1993–94, after Law 3996 was enacted there was great interest – especially after contracts were signed for three natural gas plants at very favorable prices and practically no risk to the investors.<sup>106</sup>

Even after cancellation, the prospect of favorable prices, state guarantees, and low risk (due to take-or-pay provisions and continuous government efforts to implement private law) were the main reasons for this investor appetite. This situation later created project cost inflation and stranded costs on one hand, while increasing the contingent liabilities of the State on the other.

As a result, the number of applications to the Ministry of Energy and Natural Resources (MENR) increased substantially. In early 1999, in addition to projects amounting to 2,400 MW already in operation or under construction, there were **hundreds of project applications**, amounting to over **30,000 MW of capacity**, at various stages of processing (prefeasibility submission, evaluation, waiting for government approval etc.). Furthermore there were already signed contracts for five power plants (6,100 MW) to be implemented under BOO model.

The BOT model provided for off-take and payment guarantees. All of the contracts that had already been signed (or initialed, waiting for approval) were front-loaded. That is, the tariffs were higher in the first 10 years (i.e., the first half of the contract duration).<sup>107</sup> Therefore, the implementation of the model had to take into account future liabilities. The contracted energy per year should have been determined according to the future demand and supply (taking into account the existing generation, BOT, autoproducer, ongoing public generation investments, and BOO plants). The model should also have been implemented according to an optimized generation plan, and the number of plants, power ratings and generations, commissioning times, fuel source, and locations of those plants should have been determined beforehand. After this planning, MENR could announce the roadmap and implementation schedule. A competitive tendering mechanism could have been applied according to a determined sequencing. Under the BOT Model, the main expectation was to transfer the risk and also to decrease operational costs, to increase the quality of services, and to adapt new technologies in the design and implementation of projects. Competitive tendering and prequalification would have resulted in more-effective implementation if there had been a clear and transparent framework.

However, most of those principles were not followed. Except for some unsuccessful hydro and wind plant tenders, there was no requirement for prequalification and competitive tendering. The method was to take offers from three interested companies, and the negotiations were based on feasibility studies done by investors. The project developers were determining the technology, fuel, installed power, location, and timing of the BOT plants and submitting their feasibility reports to MENR. The projects developed were based on fixed prices and purchase guarantees, while the risks were still carried by the government and the benefits of efficiency were not passed on to consumers.

During evaluation of the feasibility reports, MENR was sending all applications to TEAŞ for getting its technical comments. As a system operator and buyer, TEAŞ was evaluating the applications and sending its views to MENR. As the number of projects increased, TEAŞ started to object.



There were three main reasons for this resistance:

- No planning, which may create over- or under-capacity in time;
- Locations of the plants, which were selected by project owners without taking into account regional supply/demand balance and transmission system conditions; and
- The amount of the future payments (due to take-or-pay commitments).

According to regulation, the State Planning Organization's (SPO) approval was necessary in order to sign BOT contracts. After the number of applications increased, SPO also started to object and did not provide approvals. SPO wanted a planned approach that sequenced the implementation according to future supply/demand balance.

Since the payment guarantees were backed by state guarantees, Treasury also was reluctant due to its increasing contingent liabilities.

Another important reason for the opposition of TEAŞ, SPO, and Treasury, especially after 1998, was the emerging idea of establishing a competitive market instead of take-or-pay guarantees. The liberal market model, and the concrete steps toward it, had also affected the TOOR model implementation. This issue will be elaborated further in subsequent sections.

Hence, the government adopted a new implementation program determined collectively by SPO, MENR, Treasury, and TEAŞ. After prolonged discussions in 1999 and 2000, it was decided that, in addition to those already under construction, only 29 BOT projects (the ones that had contracts with MENR and/or were deemed useful) could continue, and the rest of the BOT project portfolio should be cancelled. Based on this decision, MENR cancelled more than 120 projects at different stages of implementation that did not have a signed contract in early 2001. However:

- Due to insufficient generation investment (not enough BOT realization and, due to over-reliance on this model, not enough state investment), reserve capacity decreased sharply and created problems during 1998–2001. If there had been no economic crises in 2001, partial rationing would already have started to be widely applied throughout the country.
- The 1997–98 supply/demand projections indicated an alarming situation for the future and led to the use of quickly realizable generation technologies (i.e., natural gas CCGTs) through the BOO Model, resulting in over-dependency on natural gas.
- Similarly, temporary, high-cost generation solutions, such as fuel-oil fired mobile power plants, had to be used after 2000.
- The remaining existing contracts (for the power plants not yet built at that time) necessitated regulatory arrangements and effort to convert them to IPPs; after lengthy negotiations, most of those project owners gave up their contractual rights in return for preserving their grid connections and water-use rights, and they were licensed as IPP plants.
- There were several legal challenges, damage claims, and lengthy local court and local and international arbitration cases for those projects that were not implemented.

The take-or-pay guarantees provided in this period (for the BOT plants in operation) necessitated transitional measures after the competitive market was established.

## Achievements and Problems in Implementing the BOO Model

Due to insufficient realization of BOT plants by 1997, and instead of trying to review and compare hundreds of unsolicited proposals, the government decided to focus on priority projects of its own choice – and to select investors for these projects through competitive bidding in order to secure more reasonable prices and conditions. Accordingly, it introduced the **BOO model** with Law 4283 in 1997.

Under the BOO model, companies are allowed to build, own, and operate power plants and sell their generation to the public utility (TEAŞ) through a long-term power purchase agreement (PPA). However, unlike the BOT model, the plants are owned by the private companies. Also, the implementation procedure was different: there was no “concession” or “assignment” agreement with MENR. The only agreement was the PPA between TEAŞ and the company. Unlike BOT, this model required a competitive tendering procedure for selecting the companies that would build the power plants determined in the long-term optimal generation plan. According to the Law, the tenders were to be carried by TEAŞ instead of MENR, and PPAs would be negotiated and signed by TEAŞ.

Initially 10 plants were chosen, and as a first step five of them were tendered (later, the rest were cancelled). As a result of the tendering process, contracts for four natural gas CCGT plants and one imported hard coal power plant were signed in 1998 and 1999. The total installed power of these plants was 6,100 MW and all of them were commissioned in 2002–04.

When compared with the BOT model, the BOO model was successfully implemented, and 6,000 MW was added to the generation system relatively quickly. The reasons for this fast and successful implementation were as follows:

- An international competitive tender was carried out and more than 30 local and international companies participated.
- The legal framework was solid and transparent, the PPA was subject to private law, and international arbitration was possible for dispute settlement.
- The plants were to be owned by the companies (no transfer to the state, as with the BOT model).
- The prices were reasonable due to competition and conditions: the capacity and O&M tariffs were less than half of the BOT capacity and O&M tariffs. This created widespread acceptance by public authorities.
- The plants and their locations were determined by TEAŞ according to the optimum generation expansion plan.
- The power purchase obligation duration was less than that of BOTs (the total PPA term is 20 years, including construction time).

However, the implementation of the BOO model also had some negative implications. To avoid legal problems, the Law did not allow the use of domestic sources such as lignite and hydro (the use of natural resources would necessitate concession contracts); thus only natural gas and imported coal could be used. Even if it had not been so, there was an urgent need for additional capacity in the upcoming years and only natural gas plants could be commissioned in such a short time. Hence in addition to the existing plants, an additional 4,800 MW in BOO gas plants caused an overdependence on imported natural gas in electricity generation. Furthermore, as with the BOT plants, the electricity supply from BOO plants (due to the take-or-pay obligations) crowded out competition in the electricity market.



## Achievements and Problems in Implementing the TOOR Model for Generation Privatization

TOOR Model was used to privatize state-owned power plants in 1984–2001. One hydro plant was transferred in 1996 and one thermal plant was tendered in 1994. In 1997, the tender of 16 thermal power plant was started. The total installed power of these plants was 9,576 MW. Following an evaluation, contracts were negotiated for eight plants and concession contracts were signed for six plants in 1999. After constitutional amendments and legal changes allowed concession contracts to convert to private law contracts subject to international arbitration, new implementation contracts were signed with four companies; the other two preferred to continue with concession contracts. However, Treasury was reluctant to provide state guarantees due to contingent liabilities arising from BO, BOT, and TOOR contracts. The generation TOOR process could only be finalized in 2002.

Following lawsuits by NGOs and labor unions, in 2001 and 2002 the Danıştay cancelled the Ministerial Council Decisions that had authorized MENR for contract negotiations and, except for one, all contracts were cancelled. Some of these contracts were private law contracts (enacted after 1999) and, after international arbitration proceedings, Turkish government had to pay compensation.

Hence, the result of TOOR implementation was highly unsatisfactory. In the end except for one HEPP plant (30 MW, transferred in 1996) and one lignite plant (Çayırhan, a 620 MW concession contract, transferred in 2000 and 2001),<sup>108</sup> none of the other contracts could be implemented.

Although the Danıştay decision was the main reason, there were other reasons for this unsuccessful implementation:

- Due to the prolonged tendering and negotiation process, the legal framework changes (discussed in the previous section), and the conversion of already-signed concession contacts into private law contracts, a great deal of time and effort was consumed. As in the BOT case, after 1998–99 the motivation of state authorities (Treasury, SPO, and TEAŞ) was lost due to the desire to establish a new electricity market. Studies indicated that the guaranteed sales of existing BOO, BOT, and TOOR plants<sup>109</sup> would initially constitute an overwhelming share of the generated electricity in Turkey, leaving practically no place for competition in the market.
- The already existing opposition to privatization was enhanced, especially after providing the possibility of private law contracting and international arbitration to companies that had been selected according to tender documents that did not provide for such possibilities.
- The accusations of corruption regarding the BOT and TOOR process, which caused substantial turmoil (in 2001 several bureaucrats were accused and some were subjected to lengthy lawsuits) and political problems. All these factors influenced the decision-making process and judiciary decisions.

All of these factors influenced the unsuccessful attempts to privatize generation through the TOOR model of Laws 3096 and 3996. The experience shows that it was a mistake to begin privatization without a solid legal framework and without evaluating the future implications for market structure.



### Achievements and Problems in Implementing the Distribution TOOR Model

In 1995, 29 distribution regions were defined. Four of these regions were operated by concessionary companies at that time (the Aktas and Kayseri regions were already operated by private companies; the Cukurova and Kepez Regions were included in the concession contracts of CEAS and KEPEZ companies). It was decided to transfer the operating rights of the other 25 regions according to the TOOR model defined in Law No. 3096. Tenders were carried out in 1996 and winning bidders for 20 companies were determined (for five regions the bids were found to be inappropriate). Three of these 20 successful bidders did not fulfill the bid requirements. Ministerial Council Decisions were obtained for the remaining 17 regions for the "assignment" of the companies, and MENR was authorized to carry out contract negotiations. For some of the regions, contract negotiations on concession contracts were completed and submitted to the Danıştay for approval since they were deemed "administrative" contracts. Upon approval by the Danıştay, the concession contracts were signed in 1997–99. At the same time, some organizations (NGOs and the labor unions) applied to the Danıştay and brought suits against the Ministerial Council decisions asking for cancellation of the authorization.

While the cases against concession contracts were continuing, in 1999 the Constitution was changed and the signing of implementation contracts (private law) instead of concession contracts became possible. Upon this change, new legislation was prepared and some of companies preferred to renew their concession contracts and apply for signing of implementation contracts. MENR obtained an authorization from the Council of Ministers and started the negotiations. Six implementation contracts were signed in addition to five concession contracts. However, new lawsuits were opened against those contracts also.

The cases against the Ministerial Council decisions and contracts took a long time. After three years, except for two regions, the Council cancelled Ministerial Council decisions and the contracts could not be implemented. The main reasons declared by the Council for cancelling the contracts were that (a) the tendering conditions did not take public interest into consideration and (b) investment programs for the regions were not required to be submitted by the bidders. The corruption claims against MENR and defects in the tendering process were also arguments for cancellation decisions.

As a result, except for two regions, the privatization process was not successful. After the Electricity Market Law of 2001, the contracts for the two regions that were not cancelled were renegotiated and revised according to the new legislation, and the regions were transferred.

The dispute resolution method for the implementation contracts was international arbitration. Four companies applied to the International Chamber of Commerce (ICC) for arbitration with their compensation claims. Although one claim was rejected, Turkey paid roughly \$150 million to the other three companies.



## Appendix 2: The Development of Hydro and Wind Capacity in Turkey

### Hydro

Turkey's annual hydroelectric generation potential is reported as 140,000 GWh (considering the historical average utilization factor, this potential can be utilized with 40,000 MW installed capacity).<sup>110</sup>

In 2001 total hydro installed power was 11,673 MW, including 870 MW under BOT schemes and 1,120 MW via plants built by concessionary companies (such as CEAS and Kepez).

Although the EML allowed private companies to build HEPPs, there was no regulation defining (a\_ the rights and obligations of the parties regarding the use of water and (b) procedures for licensing HEPPs. One of the important steps in the development of renewable energy in Turkey was the issuance of the "**Regulation about the Rules and Procedures for Acquiring Water Use Rights for Electricity Generation**" in 2003.<sup>111</sup>

This regulation did not only define the procedures, but also allowed private companies to invest in the projects that had been developed by DSI and EIEI. EIEI since 1935, and DSI since 1953, had assessed on river basins to determine hydroelectric capacity, preparing feasibility reports and plans for the candidate HEPP projects on several river basins. However, DSI was only interested in building big dams and the private sector could only build and operate HEPPs under the BOT model before 2001. Hence this regulation was an important step for hydro development (especially small-size) by the private sector.

It should be mentioned that one of the reasons for issuing such a regulation was to define a methodology for the use of a \$200 million **World Bank loan** aimed at developing renewable energy in Turkey (the First Renewable Energy Loan). To use this loan for small hydro projects, it was necessary to determine potential projects that were eligible, and thus to define a procedure for selecting the projects. Therefore, it can be said that WB loan was an important factor in initiating the studies for this regulation. The Loan has been used successfully through intermediary banks (the Turkish Development Bank TKB, and the Turkish Industry Development Bank, TSKB) and 1 wind, 4 geothermal and 16 small hydro projects with a total installed power of 585 MW were built in 2004–09.

Following the "**Regulation about the Rules and Procedures for Acquiring Water Use Rights for Electricity Generation**" in 2003, the DSI and EIEI project portfolio was announced. The total number of those projects was 183, and in time – with the inclusion of some half-completed DSI projects and projects that could be realized under previous intergovernmental agreements – this number increased to roughly 400. As a second step, it was permitted to develop projects that were not on the DSI-EIEI list, but had rather been developed by the private sector. In 2004 the number of such projects was 678; in time it reached 1,215. However, due to problems mentioned later in this appendix, DSI has not accepted new project applications from the private sector since October 2007. As of November 2013, DSI had approved 1,618 projects with an installed capacity of 25,000 MW.

As of January 2015, the total capacity of the 521 HEPPs in operation was 23,643 MW. Of these plants, 444 (7,036 MW) are run-of-river-type (RoR) and the remainder are reservoir-type. The capacity of private HEPPs is 10,646 MW. It should be noted that, although all HEPPs are considered renewable energy facilities, only RoR types and reservoir types with a lake area smaller than 15 km<sup>2</sup> are eligible for the support mechanism.

Nearly 80% of the new HEPP capacity has been realized by private companies in the last 10 years. Most of the new plant investments started after the REL. According to EMRA project progress reports, in addition to the existing plant capacity, 356 licensed private HEPP projects with a total capacity of 10,000 MW are under construction.<sup>112</sup> If these are realized, nearly 85% of Turkey's total hydroelectric capacity will be utilized.

The progress in the hydroelectric plant investments has been substantial (roughly 8,000 MW private plants in 10 years). Even though the feed-in tariff is considered insufficient (and there have been unsuccessful attempts by the private sector to increase it), the private sector has either realized or is trying to realize roughly 20,000 MW in hydro capacity, including those under construction. Even though the big reservoir-type HEPPs are ineligible for support mechanism, they too are being built by private investors.

In addition to the reasons discussed in the previous section, there are other hydro-specific reasons for this investor appetite for the realization of HEPPs:

- The major cost item of HEPPs is the civil works and construction. In Turkey there are many experienced construction companies and most of the HEPPs are owned and built by them.
- Medium- and large-sized reservoir-type plants have to ability to store water during low price periods and generate and sell during peak consumption periods when the marginal prices in the market are determined by natural gas peaking plants. Since the operating cost of HEPPs is negligible, they are having a good mark-up on top of their marginal costs.

However this fast-track implementation has also its problems, as will be discussed in the following sections.

- Connection to the Grid

As mentioned previously, since the market was opened to private investment, roughly 1,500 projects have been developed. The installed power of the new projects ranges from a few MW to a few hundred MW, and they are distributed all over the country.

This has created a bottleneck for grid connection. Previous TEİAŞ grid development plans were prepared for known, generally big reservoir-type HEPP development. TEİAŞ was not ready to connect hundreds of new plants (the issue applies also for wind plant projects). Ideally, the distribution and transmission plans should have been prepared for HEPP development in each river basin and so-called river-basin substations, which are designed to connect several plants in the same area, should have been envisaged.

Lacking of such a planned approach initially caused delays in project implementation. However, in time, new substations and transmission and distribution (T&D) lines were incorporated into the investment program and gradually built. Since TEİAŞ' technical and financing resources are limited, the EML has been amended to enable the building of connection lines and substations by private firms on behalf of TEİAŞ. If the connection point is approved by TEİAŞ and if new transmission facilities (substation, line) are not in TEİAŞ' investment plan, or if the proposed timing of the new investment is not suitable for the investor, TEİAŞ can ask the market participants to finance and build the connection lines and the related equipment on behalf of TEİAŞ, or to finance their establishment. After construction is completed and power plant is commissioned, the cost of investment will be repaid to the power plant license holder within 10 years. This provision has accelerated the connection investment pace.

However, there are still problems for the construction of river-basin substations. Since all the projects in the same river basin are not built in the same timeframe, the first company has to build the substation. For small (a few MW) HEPPs, the cost of substation becomes a burden to the project developer. Although it is paid for later by TEİAŞ, the financing of transmission facilities is a problem for small projects if they are realized prior to the participation of other projects in the same basin.

The new licensing regime brought by the new EML, in which new licenses shall be provided according to TEİAŞ' available capacities, might be a solution to this problem. However, as mentioned earlier, most of the projects have already been licensed, and these projects will continue to face the same problem.

- Selection Process of the Project Developer

According to the regulation, if more than one firm applies to build the projects being developed by DSI and EIEI, an auction is held. Also, projects developed by the companies are announced on the DSI website and, if there are other applicants to the project site, they are included in the auction. In each auction, bidders propose a contribution fee (TL/kWh) that will be paid to DSI after commissioning the HEPP. The company proposing the highest contribution fee wins the right to build the plant. Although the applicants have to submit a feasibility report to DSI, those reports are not detailed and DSI rejects only those reports containing substantial errors or showing violations of basin water usage rules. After selecting the successful bidder, DSI asks for a more-detailed feasibility report, and the companies are responsible for the accuracy of the studies and data for their project site and hydrology. As of 2014, the number of projects subject to auction was 698 (for others, no auction was necessary because there was only a single application).

This selection methodology has created the following problems:

- Since there is no detailed technical and economic evaluation of the projects, the success of the project is left only to the developer. In the “rush to the hydro project” period (2004–10), hundreds of new projects were developed by incompetent companies or persons and without sufficient studies of the project site and the hydrology; these projects experienced problems in the construction phase and in the operation period. For some projects it became apparent that the project was infeasible in that it generated much less energy than anticipated and the construction cost estimate was not realistic. Furthermore, DSI changed the regulation and obliged the companies to leave at least 10% of the last ten years’ average water inflow in the river basin to protect wildlife. Although this was a useful and necessary provision, it was announced after many projects were already under construction.
- In some auctions, in order to increase their chances of winning, the applicants submitted very high bids for the contribution fee (as high as 2 or 3 US cents/kWh). Given that the support tariff level is 7.3 cents, for inefficient projects the high contribution fees drastically lowered the internal rate of return (IRR) and these projects will probably not be continued. By the end of 2013, only 36 of 698 projects that been subject to auctioning had been realized.
- A separate EIA study is done for each project. However, for projects on the same river basin, or even in neighboring basins, the studies should have been prepared and evaluated collectively in order to assess the aggregate risk to environmental sustainability. Cumulative environmental effects constitute a growing risk because a growing number of HEPPs are being built. Integrated Basin Management is necessary to inform the long-term investment and river basin management plans; this would also take into consideration the formulation of appropriate regulatory arrangements to mitigate the potential cumulative impact of HEPPs. One of the reasons for the courts’ cancellation of EIA reports was this factor. Although a National Basin Strategy has now been approved by the High Planning Council, it should have been implemented from the beginning.
- Especially during the first few years of implementation, some developers did not act carefully and harmed the environment during the construction of channels, tunnels, and roads. During the construction and operation phases of the HEPPs, some of the projects caused adverse environmental impacts that were not mitigated successfully; this provoked a public reaction and there have been many attempts by the public to stop these projects. EIA reports have been challenged in the courts and some EIA reports have been cancelled. These impacts include damage to the habitat due to clearing vegetation for the HEPP itself as well as its associated structures; this generates the risk of erosion into the riverbed from these slopes, disrupting the continuity of the ecological flow in the



bypass reaches (between the intake structure and the tail water). In some river basins, the number of projects was so high that the projects were positioned one after the other, leaving practically no free space for natural life. This was also the reason for the public reaction and EIA cancellations.

- Part of the public opposition to the projects stems from the lack of adequate public consultation prior to the licensing and the decision-making stages of the projects. Depending on project size and the environmental category, some consultation may be required during the EIA preparation; however, meaningful and accessible consultation with the surrounding communities before, during, and after the project construction is often lacking. As a result, the courts remain the main venue to which people resort in order for their grievances to be addressed.
- In addition to cumulative environmental impacts, public animosity toward the projects also results from issues surrounding expropriation procedures. Standard expropriation laws and implementation in Turkey require advance written notice to land owners specifying when the state will expropriate their lands. An exception to this standard legal framework, called “Expedited (or emergency) Expropriation,” is legally warranted when a project needs to be completed speedily in times of urgent national need. In such cases, advance notice is not required to be given to land owners and, while compensation is deposited to land owners’ accounts, expropriation and construction can start with on-the-day-of notice to the landowner. Due to national priority, the Expedited Expropriation exception is used in almost all renewable energy investments. This method is far from optimal in managing public reactions and social risks, and the application of the exception itself has been taken to court in addition to disputes about the expropriations themselves.
- From the project development phase through to commissioning, many approvals, permits, and licenses are required by ministries, EMRA, transmission/distribution companies, municipalities and other local authorities. Project developers complain of weak coordination among public institutions, overlong procedures, and low implementation standards.

For the technical, environmental, and social reasons stated above, the licenses of 415 projects that had been licensed before the new EML were cancelled at the project owners' request (328 of these were developed by private sector).<sup>113</sup> Still, some of the remaining projects face technical, financial, social, legal, and/or environmental problems. According to EMRA Progress Reports, out of 396 projects which were licensed, only 65 have a progress ratio greater than 20%. After the new EML, these projects will have pre-license. If they can manage to solve their problems in due time they will be licensed. In all likelihood, some of those projects will not be able to get licenses and they will be cancelled.<sup>114</sup> In fact, in June 2014 EMRA began to evaluate all the projects and some projects have already been cancelled. The evaluation process continues.

It can be said that most of these problems resulted from the lack of a sound implementation roadmap, DSI project approval without sufficient evaluation, and carelessly prepared and approved EIA reports. Bad examples have created a general public reaction against all hydroelectric projects that has undermined current efforts to develop good projects.

- Other Challenges

### *Inspection of Construction*

The quality of construction of structures such as water channels, tunnels, and especially dams is vitally important, since any event during the construction and operation phases may have catastrophic consequences. Therefore this type of construction should be carefully inspected by project owners and public authorities. Although it is DSI's duty to inspect projects built by private firms, DSI's ability to monitor hundreds of projects at the same time is limited. After several attempts, the DSI law was amended in 2014 to authorized DSI to transfer control and inspection



duty to third parties authorized by DSI. Hence, it can be said that, although DSI tried to inspect the projects, due to limited capacity these inspections were not at the desired quality for the facilities built in 2004–14.

#### *Suboptimum Use of River Basin Potential*

To ensure the optimum use of water resources (for irrigation, for electricity generation etc.), it is necessary to handle all basins together with their branches, to make a river basin development plan. The optimum capacity of each possible project, the sequence of timing of the realization, etc. could have been determined through this type of planning. The HEPP construction permissions should have been provided after preparation of such a plan. This would also help in determining environmental impacts and could be a logical step for a basin-based EIA. Unfortunately, except for some basins which were studied by DSI and EIEI, most projects were treated individually and were allowed without considering an overall river basin plan. In addition to insufficient evaluation of environmental impacts, this approach prevented the optimum use of hydroelectric potential.

#### *Challenges Related to the Operation of HEPPs in the Same Basin*

Lack of optimum basin planning will also cause operational problems and conflicts among the project owners. On the same basin, there are run-of-river (RoR) /diversion-type plants and plants with a certain reservoir capacity. RoR-type plants have to be operated according to reservoir-type plants' operation. From time to time there is not enough water; for example, if the owner of reservoir-type plant at the source decides to keep the water and use it during peak times to increase revenue, the RoR-type can have only the minimum flow, and will operate at a reduced capacity. By contrast, if the plant at the source operates fully, then some water have to be released without electricity generation in the RoR-type plant. This is already causing, and will continue to cause, conflicts among project owners, and will certainly cause suboptimal use of the total capacity.

The solution is basin operational planning by DSI. However, since the plants have already been built or are under construction, some projects may be adversely affected and may not get the revenues envisaged in their feasibility studies. According to the “Water-use Agreement” between DSI and project companies, DSI has the authority to re-adjust operational plans at any time it deems necessary. This may create a risk for the investors. However, they do not have the right to challenge the DSI decision because they accepted this possibility by signing the agreement.

**Hence the development of Turkey's hydroelectric potential by the private sector has not been smooth and without problems. The existing and future challenges and problems will cause suboptimal use of total usable potential or at least delay full utilization. Still, the achievement is substantial and can be considered a major success.**

#### **Wind**

Turkey has a considerable wind potential waiting to be utilized. REPA study showed that high-efficiency wind energy potential in Turkey is nearly 19,000 MW and the technically feasible installed capacity potential of regions with a wind speed between 7.5 and 8 m/sec is 29,259 MW. That is, Turkey has 48,000 MW of potential capacity for mid-to-high-efficiency wind energy generation at an annual average wind speed of 7.5 m/sec and higher. High-potential fields exist in the Aegean and Marmara regions as well the coastal part of its Eastern Mediterranean regions.

Turkey's first wind power plant (WPP) was commissioned in 1998 and had an installed capacity of 8.7 MW. In 2001 the total WPP capacity was only 18.9 MW, all of it built under the BOT model. The WPP projects licensed by the Energy Market Regulatory Authority (EMRA) between 3 September 2002 (when the market was opened) and 4 June 2004 (when license applications for WPPs were suspended) were mainly the old BOT projects developed before. Some of those projects' owners gave up their existing contracts and correspondingly became license holders,

as mentioned above. However, after the legal framework was set by the EML, the high level of unexploited potential attracted the interest of domestic and foreign investors. In addition to the "old" BOT projects, there were several license applications to EMRA for new wind projects. There were no wind project sites predetermined by the public authorities, and no published information about the regional or substation-based transmission system connection capacity. Therefore, companies assessed the project sites according to their evaluations and connection points. However, those applications could not be concluded by TEİAŞ with respect to connection and use of system.

Moreover, TEİAŞ criticized the process for accepting all WPP license applications and asked for a limitation on it. The main reasons for this criticism were the limited connection capacity as well as the possible problems that may arise due to intermittent wind conditions and their possible effect on system operation. Furthermore, the regulation at that time was insufficient for choosing between different applicants for the same project site. Accordingly, EMRA's board decided on 4 June 2004 to suspend all license applications for WPPs – that is, to stop the review, evaluation, and granting process for six months – until TEİAŞ issued the yearly maximum WPP capacity to be connected to the grid.

However, TEİAŞ was subsequently unable to issue the projection for WPP connections. This forced EMRA to continuously postpone the suspension decision, and the suspension period lasted more than three years. This situation created public pressure on EMRA and, although the required study was not issued by TEİAŞ, EMRA decided to re-open the applications on 1 November 2007.

An extraordinary day was experienced on 1 November 2007, when EMRA received 751 applications corresponding to nearly 78,000 MW of capacity. There were more than one application for the same zones, and the total capacity of the projects was far beyond the capacity for feasible development. Most of the applications were made for the same or overlapping project sites. However, as expected before 1 November, EMRA was unable to conclude the applications without the opinion of TEİAŞ on connection and the use of system. So, another prolonged period began due to the lack of necessary tools for the evaluation and selection of the applications.

As a result, the EML was amended on 2008 to introduce an auctioning process for the qualification of applicants that have the right to connect to the system in case (a) more than one firm applies for the same plant site or (b) total requested capacity is more than the substation capacity. Meanwhile, new regulations were issued regarding the pre-elimination of projects by EIE<sup>116</sup> and the auctioning process by TEİAŞ.<sup>117</sup> TEİAŞ issued its official view about the total capacity to be connected to the grid. Accordingly, EMRA informed license applicants of TEİAŞ' view and requested the downward revision of installed capacities. Applicants that did not reduce their original installed capacity figures within 10 days' time were refused by EMRA with no additional notice.

The remaining applications were reviewed and technically evaluated by EIE, and the applied capacity of nearly 78,000 MW was finally reduced to 31,268 MW. 1,378 MW of this capacity consisted of single applications and the owners were granted licenses; while the remaining capacity, having more than one applicant, was subjected to auctions held by TEİAŞ.

The auctioning process, executed by TEİAŞ according to maximum contribution fee, began in 2010 for 13 different groups of applicants and concluded in July 2011. A total of 149 projects were qualified, with a total installed capacity of about 5,500 MW. The weighted average of contribution fees per kWh was 1.91 kuruş<sup>118</sup> and the highest fees were 6.52, 5.60, and 5.25 kuruş. (Those highest fees were offered for Antakya, Can-Canakkale, and Izmir substations, respectively.) The winners applied to EMRA and their projects were licensed. As a result, the evaluation and licensing of the 2007 applications lasted more than three years and a considerable time has elapsed for the installation of WPPs.



The marketing of wind and hydro projects has also created continuous delays. This is mainly due to project trading in the Turkish market. Because the Licensing Regulation (LR) prohibited the transfer of licenses – which created a margin of safety but frustrated the project developers – the developers began selling companies that had one or more licenses. To prevent this, the EML was amended and a letter-of-guarantee mechanism was introduced; but even this mechanism did not stop the developers. The main negative effect of this secondary project market was the false signaling to the Regulator, the Transmission Company, and the Ministry. In addition, market confidence deteriorated while the cost of projects increased.

As of December 2014, EMRA is not accepting new license applications. New applications will be permitted a specific date which will be announced by EMRA. According to Article 23 of the new EML, the regional generation connection capacity will be issued by TEİAŞ and the distribution companies in every year for the following 5- and 10-year time periods; no other connection opinion will be given. Therefore, the wind generation investors will first take into account the available capacity issued by the system operators. TEİAŞ is working to determine the regional connection capacities for the new projects. The intention is to determine the new capacity to be utilized each year, starting from 2014. The unused capacities allocated with previous auctions will be determined and included in the new capacity list.

If more than one applicant applies for the same connection capacity or connection region, TEİAŞ will organize an auction to determine the qualified applicant(s) to be connected to the connection point. During the auction, the bidders who offer the highest price per MW (contribution fee) will become eligible to connect to the grid until the available capacity is reached. The offered amount will be paid in the first three years of operation.<sup>119</sup>

As of January 2015 the installed capacity of the 99 wind plants in operation was 3,630 MW. WPP development gained pace after 2006. Although the feed-in tariff level for wind plants is lower than in many countries, there has been a substantial growth in wind plant capacity in the last six years. It can be said that there is substantial investor interest in wind project development. However, as with the development of hydroelectric capacity, the development of the country's wind potential by the private sector has not been without its problems. Although there are similarities with hydro – such as grid connection problems, lengthy bureaucratic processes, and careless feasibility studies – there are also problems specific to wind investments.

As of January 2015, in addition to existing WPPs, there exist 182 licensed projects with a total installed power of 6,013 MW.<sup>120</sup> Although licensed mostly before 2011, only 27 of the plants (837 MW) are more than 30% completed.

Although the 2009 Strategy Paper assumes 20,000 MW of wind plant capacity in 2023, unless specific measures are taken it will be very difficult to install roughly 16,500 MW in 9 years to achieve this target. The 10,000 MW target set in MENR's 2010–14 Strategic Paper<sup>121</sup> could not be realized. However, the 20,000 MW target may be achieved with a few years' delay.

It is interesting to note that, although the auctioning process ended in 2011, nearly 50% of the eligible projects have either not yet been licensed or, even if they are licensed, the project companies have not yet signed connection agreements with TEİAŞ. The main reason for this slow pace appears to be the high and unrealistic bid prices during the auction. Considering the feed-in tariff level or the market prices, it is very difficult to finance those projects for which the auction prices are as high as 3–4 cents/ kWh. One can expect that a high bid for the contribution fee indicates an operator's or project's efficiency; that is, the bid prices normally should be based on the bidder's feasibility studies. Because more-efficient projects can have higher revenues, those project owners will bid higher prices. In the previous tenders, bid prices for some projects were as high as 4–5 cents/kWh. Not only the support price of 7.3 cents, but even the market price of 9–10 cents will not be sufficient to make that project feasible. (If the bidders act consciously – some did not make the necessary studies before bidding – then the bidding price will indicate the merits of the project. But unfortunately, past experience showed that it is not always so).

The new EML introduces a new challenge for project developers based on a provisional license concept. In the provisional license period, license holders are not allowed to sell the companies. It was thought that this new concept would be useful for stopping the project trade, or at least for ensuring that only those projects that have fulfilled their provisional license obligations can be transferred to other parties.

According to Articles 5 and 6 of the new EML, the granting process of a license is divided into two phases. The first phase is the provisional licensing stage, which covers the acquisition of necessary permissions, approvals, and property rights by investors before the construction period. In the second phase, EMRA will grant licenses for the construction and operation period to investors that have fulfilled the requirements set forth during the provisional licensing phase.

According to the new EML, TEİAŞ will announce available capacity in April and EMRA will accept license applications in October of each year.

Considering the low progress ratios and the new requirements and time limits introduced by the new EML, it is expected that the licenses of a great number of projects will be cancelled due to non-fulfillment of the requirements on time. The projects with high contribution fees will probably not be realized, and those capacities will be re-issued to the market.

The projects are financed mostly by export credit agencies and international financial institutions such as the World Bank and the EBRD (working through local banks), and through some contributions via voluntary carbon trading mechanisms. Still, financing remains an important bottleneck.

The chaotic process of the past has provided valuable lessons for the administration as well as investors. The companies are now exercising much greater care in analyzing and selecting projects. Previously they requested the removal of the measurement requirement and forced the regulator to open up the license applications, without considering grid integration problems and lenders' financing requirements. Now, by contrast, they are requesting that development be organized and gradual. Progress from now on will be slower but will enable the realization of feasible projects by "real investors." The views of the developers<sup>122</sup> about the challenges for speeding up the development of wind business in Turkey are as follows:

- Hard currency risk
- Non-escalation of the feed-in tariff
- Contribution to grid investments
- Improper project planning
- Incorrect turbine selection
- Misleading financial analyses
- Financial and administrative weakness of the Transmission Company
- Long reimbursement time for grid investments realized by the licensee
- High contribution fee
- Lack of implementation standards in WPP commissioning procedures
- Weak coordination among public institutions and lengthy permission procedures
- Few local banks able to extend the loans from international finance institutions (IFIs)

In addition, a major problem remains the integration of wind power plants into the power system. The transmission system operator, TEİAŞ, must improve its ability to integrate increasing volumes of wind and other intermittent renewable sources into the Turkish power system. At the moment the share of WPPs in total installed power is around 5%. As this share increases, the negative

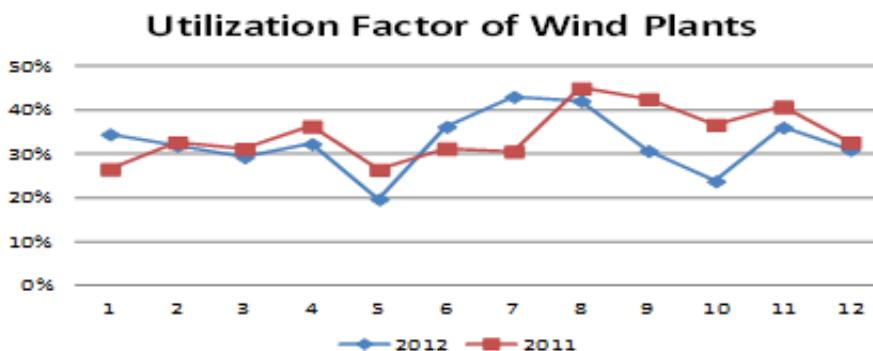


effects on system operation may be a problem. This requires more transmission investments and control/dispatch tools (such as SCADA – supervisory control and data acquisition) to ensure reliable system operation. The establishment of the Wind Power Forecast Center (RITM) by MENR-YEGM was an important step in this respect. The Center uses meteorological information and generation data gathered online from WPP sites and publishes wind generation forecasts and current generation data. The data are used by TEİAŞ' National Control Center as well as by generators. Although not all plants are yet connected to the center, it will allow system operators to estimate hourly wind generation for the next day and overcome problems of intermittency. Together with the implementation of the TEİAŞ project, which aims to enhance the forecast ability and control capacity of the National Dispatch Center against variations in wind generation, this will allow the system to be operated more efficiently.

- Utilization Factor of the WPPs in Turkey

The average utilization factor of the existing WPPs in Turkey is around 35% and varies between 20% and 40%, as shown in Figure 79. The calculation is based on monthly installed power and monthly generation of the wind plants. Naturally, there are efficient sites and plants as well as plants with lower efficiency.

**Figure 79. Wind Power Plant Utilization in 2011 and 2012**



Source: TEİAŞ Load Dispatch Reports.

- Environmental Issues

There are also some environmental challenges related to Turkey's ambitious wind power development plans. Wind project investments are generally concentrated at locations with high wind potential, and these locations are often critical for local and migrating birds. The impact of WPPs on bird species is twofold: (a) collision risk (birds can fly into turbines directly) and (b) loss of habitat (bird habitats are degraded by wind development). Moreover, not only the wind power turbines, but also the associated infrastructure affects the local ecology. Construction of temporary and permanent access roads requires clearing dense vegetation and cutting trees. Mitigation measures must start during the site selection process, and the critical issue is avoiding ecologically sensitive habitats and bird migration routes when deciding on the location of a WPPs.

- Lessons Learned

There are lessons to be learned from the Turkish experience, and the recommendations based on this experience are as follows:

- The private sector and the government authorities should be well informed about the challenges and peculiarities of wind power projects and a consensus is necessary among all parties.
- It is obvious that the realization of WPPs without a supporting mechanism is almost impossible; so, a sustainable, robust support scheme should be produced at the beginning.

- The support scheme should be implemented in an environment where the administrative infrastructure is in place. A development road map will be useful, and all the rules and regulations should be prepared before opening up the license applications.
- It will be useful if the related public organization performs measurements and provides the results to the market for constructing WPPs on suitable sites.
- The grid company should conduct the studies necessary to determine the connection's required grid capacities.
- The specifications of these sites, together with the available connection capacities, should be announced.
- In case of receiving more than one application, an auction can be held to select the successful applicant. However, the tender should be conducted among equals. Also, the result should not be the allocation of the limited connection capacity to an inefficient or unfeasible project, just because the project bid proposes the highest contribution fee. In this light, it would be useful to implement a pre-selection method based on technical merits and financial capability.
- To integrate wind power into the system without causing system reliability problems, system operator should be equipped with wind forecasting tools and control mechanisms.
- Projects should be developed according to international technical and financial requirements.

## How the Support Mechanism (YEKDEM) Works

Renewable energy (RE) generators that prefer not to sell their generation in the market can participate in the pool during the first 10 years of operation. To participate in the next year's implementation, they must apply to EMRA before 31 October. The list of suppliers is published on EMRA's website. Their generation is accepted as "must-run" generation and dispatched independent from their price. As long as they can generate energy, they deliver their energy to the power system (to the transmission or distribution grid, depending on the connection point). There are no contracts or constraints except for technical limitations. In a way they "pour" their energy into the power pool. They should inform the system operator one day before about their hourly generation for the next day; however, this requirement is only for system planning purposes and is indicative. This information is not used to settle daily or hourly imbalances of each RE generator; total imbalance in the pool is settled through another mechanism.

At the end of each month, the generated electricity from each RE supplier is determined. The total cost of the RE generation is calculated by market operator as follows:

$$\text{PCOST} = \text{total cost of support mechanism (pool cost)} = P_1 * F_1 + P_2 * F_2 + \dots + P_i * F_i$$

Where:

- $P_i$ = generated electricity by supplier i,
- $F_i$ =Price per unit of energy according to source (wind, hydro, geothermal..., etc.).

### Cost Sharing

According to REL and related regulation, the cost of the pool is shared among the supplier license holders and generation companies that sell electricity to consumers directly. For each settlement period, the total cost is shared according to the following formula:

$$\text{POA}_i = \text{SS}_i \times \text{PCOST}$$

Where:

- $\text{POA}_i$  = payment obligation of supplier i (TL)
- $\text{SS}_i$  =Share of Supplier i in total supplied electricity (%)
- $\text{PCOST}$  = total pool cost (TL)
- $\text{SS}_i$  is determined at each settlement period as a ratio of sales of supplier to total electricity supply to the consumers

As described above, the support mechanism is a payment obligation to suppliers (except those RE generators which do not prefer to participate the pool). In other words, the cost of the renewable energy in the YEKDEM is shared proportionally by all suppliers.



## Turkey's Energy Transition - Milestones and Challenges

**Notes (Endnotes)**

- 1 Liquefied natural gas (LNG) is natural gas that has been converted to liquid form for ease of storage or transport.
- 2 Cogeneration is the simultaneous production of electricity and heat, both of which are used.
- 3 In “take-or-pay” agreements, the buyer must either take delivery of goods or pay a specified amount.
- 4 Following an investigation of alleged irregularities, the State Security Court in April 2001 indicted 15 people including a former energy minister and a former director general of TEAŞ. They were accused of “taking bribes, committing irregularities and forming a gang with the intention of committing crimes.” The case became known as the White Energy Operation. Although not indicted, the sitting energy minister resigned. It must be emphasized that only three people were ultimately sentenced.
- 5 Turkish-language versions of both 2004 and 2009 strategy papers are available at [www.enerji.gov.tr](http://www.enerji.gov.tr).
- 6 With vesting contracts, EÜAŞ and TETAŞ commit to sell a specified amount of electricity to distribution companies at a regulated price.
- 7 Captive consumers are consumers who have no legal right or opportunity to select their suppliers.
- 8 The assigned supplier is like any other supplier except that it also has captive customers and must act as supplier of last resort.
- 9 See section 2.1.4.1 regarding the safety mechanism for renewable energy. It provided for the purchase of renewable energy at \$55/MWh should the renewable generators not be able to achieve a higher price in the market.
- 10 Compared to the publicly reported support arrangements – approved by the European Commission in 2014 in a landmark state-aid ruling for the European Union – in the United Kingdom for the proposed nuclear project by a Chinese-French consortium, Turkey’s support arrangements for the Akkuyu plant are much less extensive and also less expensive per unit of electricity for the guaranteed portion. The proposed plant in the UK would reportedly be supported by a mechanism which would guarantee a price of British Pound 92.5/MWh (\$136/MWh at the exchange rate of 1.47), inflation adjusted, for the full output at least for the first 35 years of the envisioned 60-year life of the plant.
- 11 <http://www.oecd.org/corporate/ca/corporategovernanceofstate-ownedenterprises/oecdguidelinesoncorporategovernanceofstate-ownedenterprises.htm>.
- 12 Source: TurkStat (the Turkish Statistical Institute).
- 13 One of the reservoir-type hydro plants was commissioned in 2004.
- 14 The plant has two units. One was already in operation and was transferred in 2000; the other was built and, after trial operation period, transferred in 2001.
- 15 Cogeneration is the simultaneous production of electricity and heat, both of which are used.
- 16 The reconciliation process required that expenditures and revenues be determined at the end of each year. If the profit was less than the predetermined level, TEAŞ covered the deficit; if the profit exceeded the predetermined level, the company paid the excess to TEAŞ.
- 17 Studies for the separation of transmission and generation were started long ago. In the TEAŞ Loan Agreement with World Bank, dated 15 May 1998, preparation of legal framework for the establishment of a national transmission company was envisaged. Also in the context of “Economic Stability and Measures for Lowering inflation” program, this issue was one of the subjects. Hence, before the EML, the Turkish government issued a decree for restructuring on 5 February 2001, 15 days prior to the EML.

- 18 our of the remaining project owners preferred to apply local and international arbitration. Of these, two failed whereas two received some compensation. The rest of the contracts were cancelled by mutual agreement.
- 19 SPO was converted to the Ministry of Development in 2011.
- 20 The percentage of the difference between available generation capacity and peak demand, to the peak demand.
- 21 The implementation of APM for natural gas (BOTAS) will be discussed in Natural Gas Section.
- 22 Depending on connection voltage level, there are different industrial tariffs, the industrial tariff shown in the figure is for medium-voltage single term tariff.
- 23 A Supply Security Report was prepared and an expert panel contributed to the MENR studies in 2006–07.
- 24 [www.enerji.gov.tr](http://www.enerji.gov.tr).
- 25 Main ancillary services are; primary and secondary frequency control, reactive power control, black start capability. Secondary and Tertiary frequency control is realized in BPM.
- 26 As of March 2015, 97 private companies became shareholder and EPIAŞ officially established.
- 27 The assigned supplier is like any other supplier except that it also has captive customers and must act as supplier of last resort.
- 28 Some examples for unrealistically high bidding are: Istanbul: \$2.990 billion, Izmir: \$1.915 billion. In the renewed tender, bidding prices for the same regions were \$1.06 billion and \$1.231 billion, respectively.
- 29 After 2012, the transitional contracts expired. According to the new EML, the DistCos purchase energy from TETAŞ to cover their losses, and TETAŞ supplies energy to assigned retail companies for their needs as last-resort suppliers.
- 30 One of the private DistCo was not paying TETAŞ. This was not because of low collection rates, but because the company was transferring the money to other companies under the holding company. Despite EMRA's warnings, the problem could not be resolved and ultimately EMRA intervened, appointed a new executive board, and sold the company to a new owner in February 2015.
- 31 Source: EMRA
- 32 In electricity supply, technical losses occur naturally and consist mainly of power dissipation in electricity system components such as transmission and distribution lines, transformers, and measurement systems. Non-technical losses derive mainly from electricity theft, non-payment by customers, and accounting errors.
- 33 The transfer fee is not included in the revenue cap. In other words, there is no return-of-capital item in the tariffs.
- 34 The approved investment for 2011–15 is nearly TL 9 billion (about \$3.3 billion as of April 2015).
- 35 The capacity factor of a power plant is the ratio of its actual output to its potential output.
- 36 The theoretical market opening ratio is the ratio of the total annual consumption of consumers who are deemed eligible to the total annual consumption of all consumers. Effectively, it is an indicator of the liberalization level.
- 37 Until the new EML (2013), to become an eligible consumer, it was possible to aggregate the consumption of facilities in the same commercial or industrial companies – for example, all shops of the same commercial company in several places, or multiple workshops/factories of the same industrial company, or GSM operators which have thousands of consumption points.



- 38 Includes generation facilities in operation, under construction and licensed but not yet started construction.
- 39 Due to decommissioned plants in the same period, the real increase in the total installed power is 41,100 MW.
- 40 The three asynchronous connection modes are isolated island, isolated generation, and DC back-to-back.
- 41 The Union of Coordination of Transmission of Electricity (UCTE) changed its name to the European Network of Transmission System Operators for Electricity (ENTSO-E) on 1 July 2009.
- 42 Regional Group Continental Europe (RG CE under the System Operation Committee) Plenary and the Regional Group Continental South East (RG CSE under the System Development Committee).
- 43 For Turkey, 154 kV.
- 44 In “island mode,” a power plant unit or total plant is isolated from the power system of one country and directly connected to power system of the other country.
- 45 MENR, Energy Balance 2013.
- 46 Amended in 2007 and 2009.
- 47 This additional support is calculated according to the components used in each of the plant and maximum cumulative support amount is shown in the table.  
The domestic product incentives are deemed “arguable” in EU progress reports. The EU’s Turkey 2011 Progress Report ([http://ec.europa.eu/enlargement/pdf/key\\_documents/2011/package/tr\\_rapport\\_2011\\_en.pdf](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 yet to be confirmed. The 2012 progress report (“Ability to Take Obligation of Membership,” in Part 4, Chapter 15: Energy) also referred to domestic product incentives ([http://ec.europa.eu/enlargement/pdf/key\\_documents/2012/package/tr\\_rapport\\_2012\\_en.pdf](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 law on renewable energy are questionable according to WTO or Custom Union trade rules.
- 48 This provision is often criticized in environmental circles because, according to a new draft of the law, the olive groves – which are strongly protected in separate legislation – will be opened for energy generation. People have begun petitions in protest against this.
- 49 Source: MENR. Earlier this potential was declared as 125,000 GWh. However, following recent studies by state authorities and the private sector, it has been increased. Because of the increased cost of electricity generation, potential projects that had earlier been declared unfeasible are now becoming feasible. If all private applications are taken into account, the potential increases to 165,000 GWh. However, considering technical, environmental, and social factors, it is safe to use 140,000 GWh.
- 50 EMRA, 2014 Activity Report.
- 51 Wind Energy Potential Map of Turkey (REPA), prepared by EIEI in 2007.
- 52 EMRA, January 2015 Progress Report
- 53 The MTA was established in 1935 with the aim of conducting scientific and technological research on mineral exploration and geology.
- 54 Source: MTA.
- 55 Although in the 2009 Strategy Paper the capacity is declared as 600 MW, it has been increased by new exploration.
- 56 MENR’s General Directorate of Renewable Energy (YEGM).
- 57 World Energy Council and Turkish National Committee, Solar Energy Report, 2009.

- 58 MENR 2012 Energy Balance Table.
- 59 This limitation indicates a slow and careful approach. After the lessons learned from uncontrolled and chaotic developments in the wind, a gradual progress is preferred.
- 60 MENR 2015–2019 Strategic Plan.
- 61 TEİAŞ, Installed Power Document, December 2014.
- 62 EMRA, April 2014 Progress Report.
- 63 LV = effective voltage less than 1,000 volts; HV= effective voltage higher than 1,000 volts.
- 64 "Regulation on the Generation Activities without Licensing," issued on 21 July 2011, amended in 2013.
- 65 The utilization factor is the ratio of a plant's actual generation during a certain timeframe to its generation if it operates during all the hours of that timeframe.
- 66 The VVER – from the Russian Vodo-Vodyanoi Energetichesky Reaktor, meaning water-water power reactor, or a water-cooled and water-moderated reactor – was originally developed in the Soviet Union. VVER power stations are used by Armenia, Bulgaria, Czech Republic, Finland, Hungary, India, Iran, Slovakia, Ukraine, and the Russian Federation. The proposed plant is the third generation of its 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%). Pursuant to the Agreement, foreign investors may own a stake of no more than 49% of the company's share capital at any time.
- 68 Designed by AREVA (France) and Mitsubishi (Japan), the ATMEA-1 is a Generation III+ type pressurized water reactor with a capacity of 1,100 MWe.
- 69 MENR Blue Book, 2013.
- 70 According to OME's Mediterranean Energy Perspectives: Turkey report of 2014, from 2014 to 2030 Turkey's generation capacity is expected to increase from 68 GW to 125 GW in the Conservative Scenario and to slightly less than 110 GW in the Proactive Scenario.
- 71 EMRA reports on the progress of licensed generation projects twice each year.
- 72 The Price Equalization Mechanism is explained in Section 3.2.2.7. It was planned to end this implementation in 2015; however, it has been extended to 2020 with the new EML.
- 73 Turkstat (Turkish Statistics Institute), Income and Living Conditions Survey, 2006–2013.
- 74 World Bank, Balancing Act: Cutting Energy Subsidies While Protecting Affordability. Europe and Central Asia report. Washington, DC: World Bank, 2013.
- 75 A statistical value of a data set that represents 20% of a given population. The first quartile represents the lowest fifth of the data (1–20%); the second quartile represents the second fifth (21–40%); and so on.
- 76 Calculated from the data in the SAYIŞTAY BOTAŞ 2013 Report.
- 77 Source: [www.enerji.gov.tr](http://www.enerji.gov.tr)- Report "Enerji ve Tabii Kaynaklar Görünümü- Nisan 2015 No 8)
- 78 2009 Strategy Paper.
- 79 Although the NGML allows for the licensing of more than one transmission grid inside Turkey, BOTAŞ still stands as the only company holding the pipe lineTransmission License.
- 80 Regasification means converting liquefied natural gas (LNG) back to natural gas at atmospheric temperature.



- 81 Normally regasification capacity is 17 mcm, and at peak times it can be increased to 22.5 mcm; however, according to BOTAS this is not a sustainable sendout rate.
- 82 The state-owned Turkish Petroleum Corporation.
- 83 Also a very small part of Adapazarı could use natural gas since 1993, city distribution of Adapazarı is completed in 2003.
- 84 The economic crisis in 2000–01, and the stand-by agreements with IMF, have also accelerated progress.
- 85 Note that “transit” is not among the defined market activities. The regulatory framework relating to gas transit is under Law (no 4586) on the Transit of Petroleum through Pipelines.
- 86 Temporary Article 2 of the NGML.
- 87 The privatization of Istanbul Gas is on the agenda and is expected to take place in 2015.
- 88 EMRA 2013 Natural Gas Market Report.
- 89 Ibid.
- 90 EMRA- January 2015 NG Market Monthly Report,
- 91 EMRA 2013 Natural Gas Market Report
- 92 The NGML has a provision that BOTAS should not enter into any new gas import contracts (except for LNG). It further expects BOTAS to transfer existing contracts (or contract volumes) to other legal persons that have import licenses until the total amount of BOTAS’ import contracts or its sales is reduced to 20% of national consumption. BOTAS was required to do this by running tenders for the transfer of contracts.
- 93 Gulmira Rzayeva, “Natural Gas in the Turkish 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 that BOTAS declare balancing prices each month, according to private market participants this declaration is generally delayed and determined in a non-transparent way.
- 96 SCADA refers to “supervisory control and data acquisition,” a system that operates over communication channels to control remote equipment.
- 97 According to Automatic Pricing Mechanism (APM), Energy SOEs are required to attain the financial targets set in the General Investment and Financing Program through new tariffs to be determined reflecting their costs
- 98 Competition Authority, NG Sector Report 2012
- 99 SAYISTAY- 2013 BOTAS Report
- 100 Gulmira Rzayeva, “Natural Gas in the Turkish Domestic Energy Market: Policies and Challenges,” Oxford Institute for Energy Studies, 2014.
- 101 The *acquis communautaire*, or Community *acquis*, is the accumulated body of European Union (EU) law and obligations from 1958 to the present day.
- 102 Fuel oil and diesel, temporarily till 2019.
- 103 One of the reservoir-type hydro plants was commissioned in 2004.
- 104 This provision caused a lot of problems following an international arbitration process related to cancelled TOOR projects. This is discussed in later sections.
- 105 The Danıştay is the Council of State, the nation’s highest administrative court.

- 106 Although the provisions for private law in Law 3996 were cancelled one year after, these contracts were signed prior to cancellation. They were criticized after 2001 due to their high cost, unfavorable conditions, and questionable legal validity.
- 107 Although, especially after competitive BOO tender in 1997, in which the PPA tariffs were substantially lower than BOT contracts, the price proposals for new BOT applications were lower than those already signed between 1994–97, still BOT tariffs were higher due to lack of competition for selection and ownership difference.
- 108 The plant has two units. One was already in operation and was transferred in 2000; the other was built and, after trial operation period, transferred in 2001.
- 109 These plants have to be considered as “must run” plants, whatever their position in the economic merit order.
- 110 Source: MENR. Earlier this potential was declared to be 125,000 GWh. However, following recent studies by state authorities and the private sector, it was increased. Because of the increased cost of electricity generation, potential projects that had earlier been deemed infeasible are now becoming feasible. If all private applications are taken into account, the potential increases to 165,000 GWh. However, considering the technical, environmental, and social conditions, it is safe to use 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 Article 5 and 6 of the new EML, the granting process of a license is divided into two phases. The first phase is the provisional licensing stage, which covers the acquirement of necessary permissions, approvals, and property rights by investors before the construction period. In the second phase, the license will be granted by EMRA’s board for the construction and operation period to investors fulfilling the requirements of the provisional licensing phase.
- 115 *Wind Energy Potential Map of Turkey* (REPA) prepared by EIEI in 2007.
- 116 Regulation on Technical Evaluation of Wind Energy License Applications.
- 117 Wind Energy Auction Regulation.
- 118 Approximately 1 US cent.
- 119 Previously the contribution fee was in TL/ kWh, changed by the new EML to TL/MW.
- 120 EMRA, January 2015 Progress Report.
- 121 MENR 2010–2014 Strategic Plan, Target 2.2: “The wind plant installed capacity, which was 802.8 MW as of 2009, will be increased up to 10,000 MW by 2015.”
- 122 Report of the Turkish Wind Energy Association (TWEA) dated November 2012.