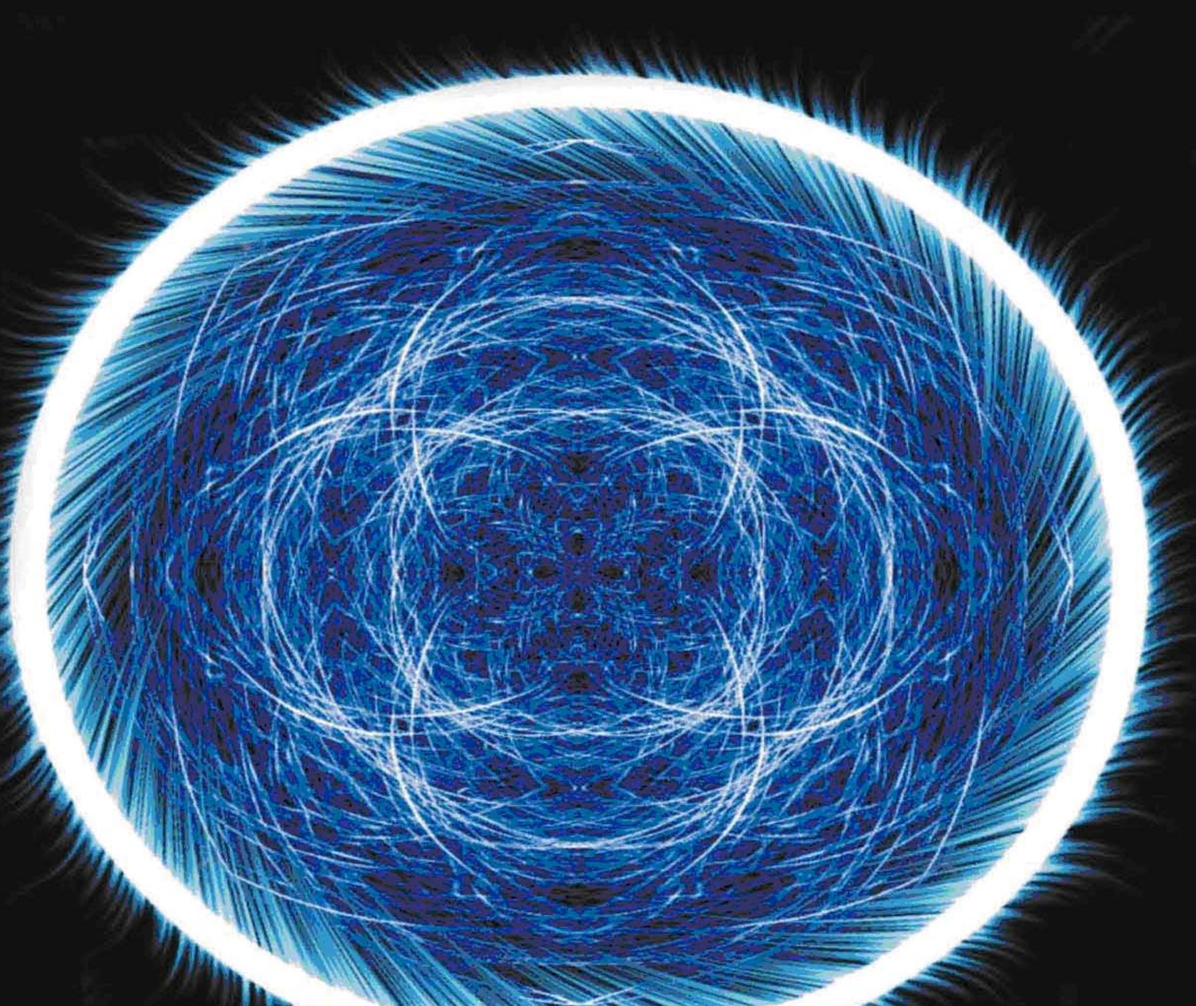
RESTRUCTURING, COMPETITION, AND REGULATION IN THE TURKISH ELECTRICITY INDUSTRY



Investment Climate and the Role of Competition Policy in Turkey

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Executive Summary

Turkey has undertaken reforming its electricity industry in the last two decades. The reform process started in the mid-1980s with the opening of much of the generation segment of the industry to private sector participation. However, the first steps were without solid legal footing. Rather than resulting from a long-term restructuring plan, liberalization of the electricity industry stemmed from high demand growth, and a corresponding urgency for investment needs. Lacking a clear legal framework, the process has been subject to interruptions and reversals. The overall outcome of the past decade's reform efforts can be summarized as comprising a moderate level of private capital inflow into the generation segment. Under conditions of regulatory uncertainty and a less than favorable investment climate, new generation investment has endured high-risk premiums, which have resulted in elevated energy costs.

Further reform efforts have been initiated in the past few years as a result of Turkey's aspiration to become a member of the European Union (E.U.). Starting with the Electricity Market Law of (March) 2001 and the subsequent Natural Gas Market Law of (May) 2001, Turkey has established a well-intentioned legal framework for restructuring the Turkish energy sector to meet the requirements of E.U. legislation and E.U. standards (collectively known as the Acquis Communautaire). This reform program, if implemented vigorously, is expected to bring about efficiency improvements and lower energy prices, and therefore bring increased competitiveness to various sectors of the Turkish economy as well. In fact, the aforementioned laws contain more liberal aspects than the E.U. Acquis Communautaire stipulates in the E.U. Electricity and Natural Gas Directives of 1996 and 1998, respectively. Despite a good start by the market reform program however, there has been little progress to date in regards to initiating competition in the generation segment; establishing cost-based pricing; and expanding the base of customers who are eligible to choose their own energy supplier.

For instance, a much needed road map laying out the specifics of the industry reform was announced with considerable delay three years *after* the enactment of the Electricity Market Law of 2001. While the Strategy Paper of 2004 draws a time line for restructuring that includes privatization and details regarding opening Turkey's electricity market to competition, some of its features are debatable in terms of sequencing and scope. Particularly, in combination with the existing excess capacity in generation, freezing the currently high limits at which customers become eligible to choose their provider (such limits are in effect until 2009), and instituting transition contracts (in effect through 2010 and beyond) for the output of state-owned and contracted generators currently leaves little room for new entry into the market by private investors. Also, giving priority to the privatization of distribution rather than generation assets can delay and limit many of the benefits expected to be gained from liberalization in the industry.

Although most of the secondary legislation has been issued by EMRA to include the establishment of pricing mechanisms for various services supplied by the state-owned entities, as of 2005 accurate cost-of-service calculations and complete account unbundling allowing for cost-reflective pricing have not yet been accomplished. The Treasury's continuing income requests also prevents these entities from being able to implement such pricing mechanisms. As a result, competition in the generation market has not progressed significantly, primarily due to a lack of sufficient consumer choice and transparent, cost-reflective pricing of the state-owned industry elements.

In this sense, losing the momentum of the initial reform program will signal a lack of commitment on the part of the government, and could severely lessen the expected benefits of market reform. Thus, the government should reaffirm its commitment to structural reform in the industry and announce its intended future role in the industry with clarity; this is particularly true as regards the generation segment, as uncertainty affects decision making regarding much needed private investment. First and foremost, policy decisions that can be seen as contradictory with respect to originally announced decisions for market liberalization — for example, the Electricity Market Law of 2001— should be avoided.

This study assesses the current structure of the Turkish electricity industry, and its standing in terms of the evolving competitive restructuring and regulatory environment. The study also offers several recommendations for achieving a workable competitive structure in the industry that can be achieved through the ongoing restructuring process.

Policy recommendations made in the study can be highlighted as follows:

Cost Calculation Issues, Pricing, and Regulatory Governance

- The success of competitive restructuring will depend largely upon establishing a market mechanism in the *generation* segment where demand and supply conditions are indicated to market participants via price signals. Merit-based dispatch requires the use of accurate generation cost data. Specifically, in a power exchange setting where spot electricity trade takes place, generators will have an incentive to bid their own marginal costs. Thus, possessing accurate cost data is indispensable for the efficient operation of a given market. Private generators can be expected to calculate such figures, as it will be in their own self-interest. In the case of publicly owned generators, however, cost determination must be obtained through regulatory or state mandate. To date, no such marginal cost studies have been undertaken regarding the state-owned generation side of the Turkish electricity industry.
- In an unbundled electricity market, the major focus of the regulatory framework is the pricing of monopoly services — namely the transmission and distribution of electricity, because the generation (energy) component of the service is subject to market-based pricing via competition. For the most part, leaving pricing of generation outside the new regulatory framework is a crucial cornerstone of any competitive restructuring. In this new environment, potential efficiency gains that will be achieved in generation are linked more to market design than to ownership structure.
- Given the market-based character of the reform strategy for Turkey's electricity industry, the resolution of cost calculation issues should be considered a *priority*. This point is crucial, not only for the industry and its efficient work *per se*, but also for the

efficiency and international competitiveness of the Turkish economy as a whole. It is now apparent that state-owned assets will be a significant part of the market mechanism for some time to come; thus, potential distortions to pricing in the market must be prevented by accurately pricing the services supplied by state-owned assets — the monopoly elements in particular. The accurate pricing of electricity services will also help the privatization process of such assets, as cost studies will help asses the assets' fair market value and will help potential investors make informed bids. Specifically;

- Proper cost-of-service studies for state-owned generation, transmission, and distribution assets should be undertaken to indicate service-specific marginal cost figures for each segment of the industry. Specifically, the calculation of the true costs of state-owned hydroelectric plants must include fixed capital costs, so that accurate pricing of electricity generation can be realized.
- EMRA should require all service providers (public and private alike) to submit marginal cost calculations for their activities along with any request for tariff approval. A common misconception among newly liberalized markets and their regulators is that incentive regulations such as price caps (as set by the RPI-X method, for example) are easy ways to avoid cumbersome cost-of-service studies. To the contrary, proper implementation of price caps requires that cast-off rates for the initial period be based on a carefully designed cost-of-service calculation; otherwise, the starting point for the price cap may not be accurate.
- Cross subsidies should be eliminated between rate classes (with a possible exception of low-income residential customers) and between regions. To secure this, tariffs should be designed and approved on the basis of reliable cost-of-service studies. Thus, rates can be unbundled *accurately*
  - to allow all customers to see separate charges for distribution, transmission, generation, and other services in their end-user bills;
  - to allow different customers classes to receive fair pricing based on their classes' delivery cost; and
  - to allow customers living in different geographic locations to receive fair pricing based on their region's delivery cost.
- In particular, in concert with accurate and balanced pricing, the policy of substantial degree of cross-subsidization of residential consumers at the expense of industrial consumers must be reconsidered, and corrected. This adjustment will also have a significant influence on the input costs — and hence the competitiveness — of the remaining industries.
- The Electricity Market Law of 2001 mandates "cost reflective pricing," which requires elimination of cross subsidies. However, the Strategy Paper of 2004 stipulates the implementation of *national tariff* for the ensuing five years. This apparent conflict should be reconciled in favor of the Electricity Market Law.
- By the same mandate, any portions of tariffs unrelated to the cost of the provision of electricity service — such as the Treasury's annual income requirements which are based on "macroeconomic indicators" — or subsidies to other public services must be eliminated.

    - As part of adhering to the “cost reflective pricing” principle, future implementation of a *locational* transmission pricing scheme that takes into account congestions of load areas should be contemplated, and the necessary studies must be initiated. In a competitive market, transmission pricing plays a crucial role in providing incentives to those who invest in generation as well as in transmission. Locational transmission pricing and associated incentive mechanisms influence the *value* and *location* of future generation investments; in other words, they send signals to investors of generators to locate their plants where needed to relieve congestion. Congested regions with high locational transmission prices will therefore be more attractive to potential investors of generation and transmission.
- Basically, the success of the restructuring program will depend on the ability of Turkey’s institutional environment to restrain arbitrary administrative action with regard to regulation of the industry. First and foremost, a strong and credible judiciary is a *necessary* condition to employ the regulatory system as a means of securing private participation in the industry. Therefore, the judiciary’s strength and institutional capacity provide an important basis for regulatory design, and choosing an appropriate regulatory governance option in line with Turkey’s other formal and informal institutions becomes feasible. Otherwise, commitments can be secured only via international or state guarantees, as establishing a credible regulatory system proves infeasible.
- Parliamentary systems, which unify executive and legislative powers, are generally vulnerable to discretionary behavior by the government, as discussed in the study. In this case, making credible regulatory commitments has a better chance if a governance option in which the regulatory process is defined through contract law rather through administrative law is chosen. Under such a system, an independent and impartial judiciary can best enforce operating licenses of the utility companies that specify pricing methods and access regulations within the existing regulatory system. For this system to be implemented in Turkey, price setting and access rules adopted by the secondary regulations may have to be embedded in the licenses of utilities. Operating licenses may then allow the implementation of a regulatory governance option that uses formal regulatory contracts to restrain government discretion in Turkey.
- The main focus of public regulation is to protect the interests of the final consumer. In this sense, regulation of Turkey’s electricity industry should not be thought of as an end, but rather as a means of promoting, creating, and maintaining competitive conditions within the marketplace.
- The adjustment process set forth by the E.U. Acquis Communautaire can certainly serve as a strong impetus in improving the existing institutional environment in Turkey. In fact, a change in the institutional paradigm in Turkey has long been an aspiration of the public at large, various bodies of government, and the private sector. Hence, the course of E.U. accession is a valuable opportunity for any stake holder involved in economic life in Turkey.

Market Design and Market Power Issues

- The selection of an appropriate model for wholesale market design must take into account the characteristics of the local market, the physical industry structure, demand conditions, and institutional environment. The influence of the British model (NETA) on the design of Turkey's wholesale electricity market is apparent. When choosing from available models, understanding the underlying reasons for any given model's selection for its respective market is important. Any design options with a good record for instituting competition must be taken into consideration.
- Establishment of even a small-scale spot electricity market should be considered, in combination with the residual balancing market already in progress. The operation of spot markets contributes to the development of a competitive structure by signaling the current and future market prices of energy; bringing transparency and liquidity to the market; and facilitating market participants' knowledge of the competitive environment.
- Demand forecasts prepared on a regional basis will be more useful than systemwide forecasts. This is because future transmission and generation investments will necessarily be guided by regional parameters in addressing issues such as the congestion and mitigation of market power. Preparing demand forecasts on a regional basis will also allow the accuracy of demand forecasts to be improved, while potential debates regarding the overestimation of demand by systemwide forecasts can be avoided.
- In markets with restructuring experience, demand–supply imbalances, insufficient reserve capacity, bottleneck areas, and associated transmission constraints have constituted major barriers for competition and were root causes of market power. In Turkey's new era, it is crucial that TEİAŞ undertakes well thought, capacity planning that is based on regional requirements — requirements that are also simultaneously directed at mitigating transmission constraints. Such careful planning would contribute to the ultimate goal: achieving the merit-based dispatch of generation resources in the country.
- To effectively run system operations, wholesale markets, and network planning, the administrative and financial independence of TEİAŞ must be secured.
- Establishing competition in the generation market is the key to establishing competition in the industry. Therefore, customers must have a choice of their energy (generation) supplier. This can be assured only by allowing *all* customers the right to shop for their energy needs. (Currently, only 28 percent of the total load is eligible to shop for their needs.) *Without delay*, eligibility limits should be progressively lowered from the current 7.7 GWh/year level, until full eligibility is established.
- Retail shopping for power by residential and small commercial customers has not progressed well in most markets that have a relatively high level of income. This is in part due to market design flaws and the low profit margins available to marketers who penetrate these market segments; but it is also in large part due to a low price elasticity of demand within the residential class. Furthermore, the benefit these consumers can expect from shopping for electricity does not come close to offsetting the high time cost given the relatively small share of a typical residential bill that electricity costs have in the median household income. In Turkey, however, the

situation may differ significantly from that of high-income OECD countries. This is because Turkish residential customers face one of the highest end-user electricity prices of any OECD countries, while possessing the lowest median income of any country within the OECD group. Consequently, a real potential exists for the establishment of retail competition in the small-customer segment of the Turkish electricity market, as these customers also stand to benefit greatly from competition. The lack of the necessary retail marketing infrastructure (namely, human capital—that is, knowledge and experience — and institutional capacity) does not constitute an obstacle for this segment, because local distribution companies can aggregate small customers' load in their service territories. In fact, research indicates that, even with a developed retail marketing infrastructure, profit margins will not allow retail marketers to succeed in the small-customers segment; it can further be argued that this situation will remain for the foreseeable future. Distribution companies are the only entities that can minimize acquisition costs for small customers, thanks to their scale economies and their accumulated experience in retail services. These advantages make local distribution companies *natural aggregators*. Therefore, distribution companies should be allowed (and even required) to aggregate their small customers' loads in their service territories, in order to establish competitive power procurement. A major boost for competition in the generation market would thus be provided.

- Demand response mechanisms serve as an important element, not only in reducing peak capacity needs but also for maintaining system reliability and mitigating market power in times of capacity shortages or transmission congestions. Thus, in addition to time-of-use metering (which is already being implemented in Turkey), various demand response programs, as discussed in this study, should be considered.
- Although Law No. 4628 establishes some safeguards for generator concentration by instituting universally accepted ownership thresholds, in today's competitively restructured electricity markets, where trade is centralized and vertical monopolies no longer exist, detecting market power in the generation segment requires more sophisticated approaches than the establishment of simple thresholds. For instance, the potential for market power can be assessed by considering transmission constraints in *load-pockets* to determine what supply sources can reach buyers to compete with the generator in question. In the United States, FERC has recently initiated a test — Pivotal Supplier Analysis (or PSA) — that establishes a threshold based on whether a generator is *pivotal* to the relevant market (that is, whether a generator's uncommitted capacity exceeds the difference between the market's total uncommitted capacity and the wholesale load). Effectively, the PSA identifies whether a generator is a *must-run supplier* needed, at least in part, to meet peak load in a specific market. In this situation, the threshold is sensitive to a generator's potential to successfully withhold supplies in the market in order to raise prices. In addition, a "market share" test is applied for Summer, Fall, Winter, and Spring that determines whether a generator's uncommitted capacity in a geographic market is less than 20 percent. By contrast, under the *plain threshold method*, as established by the Turkish Electricity Market Law, a generator passes the test for market power as long as its market share is less than 20 percent — even if its capacity is pivotal. For this reason, the market share test of the Turkish system must be complemented by a

pivotal supplier analysis. Furthermore, the current method treats the entire Turkish market as one even though various conditions, particularly transmission constraints, can create various load pockets and sub markets. These factors should be taken into consideration in defining relevant geographic markets for market power analysis. In advance of expected market imperfections, the regulatory framework in Turkey must adapt and further develop such market monitoring rules, in accordance with the peculiarities of Turkey's infrastructure. Because the current legal and regulatory framework aims to develop a competitive market structure — one in which energy will be commercially traded among market participants and regions — these issues need to be considered *before* privatization takes place, to prevent the serious consequences of market manipulation.

- Given the urgent need for substantial new investment in the generation segment for the near future, current market conditions — such as the continuing integration of EÜAŞ and TETAŞ, transition contracts between distribution companies and TETAŞ as envisaged by the Strategy Paper of 2004, and the current eligibility limits for retail choice — must be improved to attract private investment. In conjunction with opening the market to competition, the use of binding, long-term, state guaranteed power contracts must be reconsidered in favor of market-based purchase arrangements.
- Autoproduction must be allotted appropriate incentives aligned with overall system efficiency and market efficiency considerations.
- The importance of the UCTE project for interconnection to European markets must be acknowledged; this project will present a source for new supplies and will provide a check on the potential market power in the domestic electricity market by constituting an alternative source of energy, provided that adequate interconnection capacity is built.
- To ensure a smooth transition to a competitive market Turkey's current excess capacity must be taken advantage of during the interim period.

Stranded Costs and Power Purchase Contracts

- By definition, stranded costs are a dynamic concept; changing market prices may change the initially estimated extent of them. Given the future declining trend of contract prices, the probability that BOT and BOO contracts will not create significant stranded costs — if they create any costs at all — is high. For these contracts, most of the front-loaded capital cost recovery periods have ended (or are about to end); meanwhile, the thermal generation cost figures of state-owned assets are comparable to the current prices of these contracts. Note also that most state-owned generation assets have already largely depreciated; thus, using their seemingly competitive low prices as a reference point is not an appropriate way to assess future market prices in the generation segment. Consequently, the concept of stranded costs *cannot* be used as an argument against the transition to a competitive market.
- Nevertheless, all possibilities for the mitigation of stranded costs must be considered, including eliminating state subsidies, which would keep power prices artificially low (and hence, increase stranded costs). If stranded costs do arise, depending on the development of power prices in the future, appropriate methods for an accurate

measurement of stranded costs and their actual recovery must be chosen, as discussed in this study. Regardless of what method is chosen, the key to minimizing the program's political risk as well as to minimizing the creation of distortions in the market as a result of cost recovery is to provide both transparency and accountability in the process of deciding which methods to use. As part of the new regulatory framework — which must have a strong *participatory* character — a consensus must be achieved among the state, regulators, industry and ratepayers regarding the issue of cost recovery.

- Furthermore, the relatively low-priced power to be supplied by these contracts in upcoming years should be expected to contribute to the development of competition, as these contracts will provide a substantial amount of electricity generation to the market.

<u>Privatization and the Strategy Paper</u>

- To some extent, the Strategy Paper of 2004 contains policy statements that may be interpreted as contradictory with regard to the declared intention of the Electricity Market Law. Specifically, the Strategy Paper stipulates that:
    - a tariff equalization mechanism (namely, the national tariff) will be employed in the first five years, which is in conflict with the "cost reflective pricing" principle of the Electricity Market Law;
    - distribution companies will have five-year transition contracts with TETAŞ and portfolio generation companies for 85 percent of their noneligible customers until *at least* January 2010, which would stall competition from developing in the generation segment of the electricity market; and finally,
    - the market will be open for competition by 2011, which represents an unnecessarily prolonged time table for establishing competition, and which would lead to doubts concerning the commitment of the government to genuine market reform.
- Implementation of tariff equalization will continue the practice of cross subsidization and the existence of price distortions among the respective regions of Turkey. On the other hand, regional "cost reflective pricing" would rationalize end-user electricity prices and would greatly reduce the incentive for theft (particularly in low income areas), as discussed in this study. The data pertaining to absolute amounts (MWh) of theft/loss in Turkey reveal this to be a general rather than a regional problem.
- The current sequencing of privatization in the industry — which gives priority to distribution assets — is counterproductive and represents a less than optimal way of prioritization. Most efficiency gains from privatization are expected to be achieved by the privatization of potentially competitive segments of the industry, rather than by the privatization of natural monopoly segments. The "privatization of distribution first" approach that aims to establish accurate metering/billing and settlement functions may make sense in markets with no prior experience with the commercialization of electricity service, such as the transition economies in Eastern Europe and in the Caucuses. However, Turkey already has a long-standing commercial system in place, and the loss/theft problem discussed in the study is unlikely to be addressed by a change of ownership in this segment alone. Better

collection and settlement practices are possible under performance-based methods and an effective regulatory framework, regardless of ownership structure, provided that prudent institutional capacity and a management structure equipped with incentives is established. Privatization of generation assets should thus be undertaken *first*, to expedite the transition to a competitive market structure.

- The privatization approach should not be aimed solely at maximizing privatization income, as contemplated in the 2004 Strategy Paper; rather, it should first and foremost target the creation of a competitive market. For this reason, generation portfolios for privatization should primarily be designed by taking into account the *post-privatization* market power potential of generators or holding companies, rather than considerations of financial viability. Aggregate market share of generators or holding companies can be an insufficient and misleading indicator when assessing market power. Among the factors that greatly influence the likelihood of the exercise of market power are: the post-privatization locations of generators; their potential ability to supply load pockets; and, consequently, their potential ability to become pivotal suppliers in regions with transmission constraints.
- Because the eligibility threshold will be kept at its current level until 2009 *and* transition contracts will be honored until 2010 (and beyond), newly privatized generation companies will have a hard time being competitive in the market until at least 2010. In other words, the benefits of competition cannot be realized until the beginning of 2010, despite the expected start of the privatization of generation assets more than three years earlier. Obviously, such a market prospect will not be attractive to potential investors.
- The current strategy's prioritization system seems to be heavily influenced by the issue of stranded costs. By making strong assumptions regarding stranded costs, proper sequencing of market reform may become fundamentally distorted, and the expected early benefits from liberalization may be minimized, if not eliminated. From the perspective of maximizing net benefits from liberalization, proceeding with the right sequence of market reform is safer than focusing on the cost recovery.
- International experience indicates that the sequencing of liberalization is more important than the sequencing of privatization. For liberalization to yield most of its expected return, a credible legal and regulatory environment — working together with a functioning market structure — must be established *prior to* changing the ownership structure of industry assets (that is, before privatization). Only after laying such groundwork will privatization be less risky in terms of market power and supply security; more attractive for the investor and more rewarding for the government in terms of revenue generation; and, most importantly, more beneficial for consumers of electricity. In the case of the privatization of the Turkish electricity industry, while considerable progress has been made on legal and regulatory fronts, the program is going forward before the necessary market parameters are in place.

Investment and Business Environment

- Given its geographic location and existing and potential market size, Turkey is capable of attracting a substantial amount of private sector investment to its electricity industry, provided that a credible and effective legal and regulatory environment is established in the upcoming period. The establishment of such an environment would also help mitigate the negative effects of recent past episodes concerning BOT, BOO, and TOOR investment schemes, which occurred during the 1980s and 1990s.

- Legal initiatives are generally in line with pro-reform efforts; however, genuine implementation of all legal initiatives should follow.
- Institutional capacity building is progressing well with regard to EMRA and the TCA. To coordinate the monitoring of anti-competitive behavior and the enforcement of the competition law within the industry, full cooperation among these agencies must be achieved.

1 INTRODUCTION

Turkey has undertaken reforming its electricity industry in the last two decades. The reform process started in the mid-1980s with the opening of much of the generation segment of the industry to private sector participation. However, the first steps were without solid legal footing. Rather than resulting from a long-term restructuring plan, liberalization of the electricity industry stemmed from high demand growth, and a corresponding urgency for investment needs. Lacking a clear legal framework, the process has been subject to interruptions and reversals. The overall outcome of the past decade's reform efforts can be summarized as comprising a moderate level of private capital inflow into the generation segment. Under conditions of regulatory uncertainty and a less than favorable investment climate, new generation investment has endured high-risk premiums, which have resulted in elevated energy costs.

Further reform efforts have been initiated in the past few years as a result of Turkey's aspiration to become a member of the European Union (E.U.). Starting with the Electricity Market Law of (March) 2001 and the subsequent Natural Gas Market Law of (May) 2001, Turkey has established a well-intentioned legal framework for restructuring the Turkish energy sector to meet the requirements of E.U. legislation and E.U. standards (collectively known as the Acquis Communautaire). This reform program, if implemented vigorously, is expected to bring about efficiency improvements and lower energy prices, and therefore bring increased competitiveness to various sectors of the Turkish economy as well. In fact, the aforementioned laws contain more liberal aspects than the E.U. Acquis Communautaire stipulates in the E.U. Electricity and Natural Gas Directives of 1996 and 1998, respectively. Despite a good start by the market reform program however, there has been little progress to date in regards to initiating competition in the generation segment; establishing cost-based pricing; and expanding the base of customers who are eligible to choose their own energy supplier. In fact, the Strategy Paper of 2004 (the most recently announced policy document) seems to push the time line for restructuring further into the future, while maintaining the status quo and causing confusion among stake holders in the industry. In this sense, losing the momentum of the initial reform program will signal a lack of commitment on the part of the government, and could severely lessen the expected benefits of market reform.

This study assesses the current structure of the Turkish electricity industry, and its standing in terms of the evolving competitive restructuring and regulatory environment. The study also offers several recommendations for achieving a workable competitive structure in the industry that can be achieved through the ongoing restructuring process. Importantly, the Turkish electricity industry will require a substantial amount of investment in the next decade; given the continuing fiscal constraints of the state, attracting private capital into the industry becomes a virtual necessity. Establishing a good investment environment requires credible policymaking and a legal and regulatory framework working in conjunction with open and competitive markets and transparent pricing mechanisms. In this context, this study establishes the extent to which existing market structures, anti-competitive business conduct, and policy interventions pose obstacles to investment and competitiveness within the Turkish electricity industry. Being a major production input providing industry for the rest of the economy, the competitive structure of Turkey's electricity industry carries utmost importance for the macroeconomic performance of the country, as well.

The study is organized as follows. Section 2 describes the current physical structure of the industry and the existing pricing and tariff-making practices, thereby providing background information for a thorough assessment of competition-related issues, emphasized in Section 3. (See Annex for material related to this discussion.) Section 3 itself discusses the main issues and challenges that lie ahead for competition — both in general terms and in relation to the help of international experience elsewhere — and then develops policy recommendations for Turkey. Topics highlighted include cost accounting, pricing and tariff-making, the regulatory/institutional framework, market design for wholesale and retail trade (as well as demand-side management), the potential for companies to exercise market power and the monitoring of anti-competitive behavior within the industry, stranded costs in the context of power purchase contracts of the recent past, and the envisaged privatization program. Section 4 evaluates the investment and business environment and reports the results of informal interviews carried out with some of the major private stakeholders involved in electricity generation investment in Turkey. This section further touches upon the antitrust cases handled by the Competition Authority (CA) and likely jurisdictional issues that may arise between the Energy Market Regulatory Authority (EMRA) and the CA regarding the electricity industry. Finally, Section 5 concludes the study by reemphasizing the study's policy recommendations for establishing a market structure that promotes competition, provides a reliable supply of electricity, and is attractive to private investors.

2 ANALYSIS OF THE CURRENT STRUCTURE OF THE TURKISH ELECTRICITY INDUSTRY

2.1 A Background Note Regarding the Evolution and Mechanics of the Electricity Industry

Historically, the electricity industry has been known as a network industry defined by concepts of economies of scale and scope; minimum efficient scale (MES); sunk costs; and duplication of investment. Recently, however, these characteristics have begun to decline in importance.

The industry is traditionally organized into three major segments: generation, transmission, and distribution/retail activities. Since its inception, the industry has been vertically integrated, with all operations organized under a single ownership. In the past, the main economic rationalization for this structure was the prevailing economies of scale and scope that made the delivery of the end product (energy) more efficient. The presence of both large fixed costs and large sunk costs,[1] a high MES level inherent to earlier generation technologies, and cost disadvantages resulting from the unnecessary duplication of distribution and transmission facilities, offered the economic argument that a single firm (that is, a natural monopoly) could service any given territory at a lower cost than could two or more firms.

Moreover, as was (and is) the case in many countries, the industry was (and is) not only vertically integrated, but was (and is) operated and owned by the state (ostensibly for "political/strategic" reasons). One official justification for state ownership was (and is) the industry's "public service" character; as a result, service can be supplied only by state-owned enterprises. Nevertheless, the role played by the political patronage of constituents — especially in the developing world — and the fiscal concerns of the state (as they relate to using the electricity industry as a source of indirect tax revenue) can also be considered reasons underlying for the past and current ownership structure.

Importantly, electricity cannot be stored; it must be supplied instantaneously, and on demand. Demand varies over time — by hour, day of the week, and season. Each customer class (residential, commercial and industrial) has unique demand characteristics and distinct service requirements.[2] In an unliberalized market, most customers are "captive" — that is, they do not have a choice of supplier.

The wave of liberalization that swept many countries in the late 1970s; improvements in the technologies that are employed in the generation of electricity and the corresponding decreases in the level of MES, and parallel developments in the field of economics of

[1] *Fixed costs* are those that do not vary with energy output and that are positive when the output is zero. *Sunk costs* are those that are incurred only once — namely, during the original investment in plant and equipment — and cannot be recovered (or *salvaged*) if activity is ended.
[2] These customer classes have differing *load factors* (the ratio of the average load to the peak load), and different capacity requirements.

network industries have made reform efforts more justifiable and more viable. Countries throughout the world have now initiated restructuring programs, mainly by targeting the breakup (or *unbundling*) of the electricity industry's vertically integrated structure.

In an unbundled setting, each of the three segments of the industry is operated under separate ownership, with no organic ties between the owners. The basic approach of unbundling (and hence, restructuring) is to keep the segments that still exhibit natural monopoly characteristics — namely, the transmission and distribution networks — under effective public regulation, while letting electricity generators compete to supply cheaper power for consumers. The rule is to provide equal, non-discriminatory third-party access (TPA) to transmission and distribution lines, so that third-party service providers (wholesalers, retailers, or other load-serving entities[3]) are able to transport electricity to end-users, who then are able to choose their own providers. The basic premise of restructuring is to create efficiency gains, especially in the generation segment; provide a portfolio of increased service choices to consumers; and, eventually, lower customer bills.[4]

Room also exists for further unbundling in the industry — namely, by separating retail and wholesale functions from that of physical distribution. Ultimately, *retail unbundling* includes separating functions such as metering and billing — both of which are vital for maintaining trade in a functioning, competitive electricity market. While possibilities of extracting further efficiencies by such advanced unbundling are being discussed in certain jurisdictions throughout the world, some early implementations have already begun.[5]

Another area in the power industry achieving advancements is *distributed generation* (DG). Distributed generation is defined as the decentralized, small-scale power generation located near the consumer's site (*load*) that is connected to the distribution network for sale of surplus energy to the system. Distributed generation resources are also utilized to improve transmission and distribution network operations by providing capacity for peak use; back-up power; and reliability and power quality. Distributed generation technologies include cogeneration,[6] diesel micro-turbines, wind power, natural

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[3] Load-serving entities are retail suppliers or distributors that purchase wholesale electricity for resale to end-users.

[4] For instance, in the United States (where electricity markets are relatively advanced) one-third to one-half of a typical consumer's electricity bill reflects local distribution costs. (The exact amount depends on the particular customer class.) In addition, transmission costs account for less than one-tenth of the total bill.

[5] Competitive retail unbundling includes unbundling functions such as third-party metering (installation) and meter reading (data collection); billing; and collection services. Currently in the United States, California, New York, and Pennsylvania are implementing innovations such as *competitive metering* for relatively large customers, and are considering a phase-in approach to include all customers in the near future. Concurrently, implementation of various methods of *advanced metering* (that is, meters that have either distinct time intervals or real-time data capabilities) is underway, to enhance reliability and reduce system-wide costs by way of demand response. (See Section 3.2.2.2 for further discussion.)

[6] *Cogeneration* (the combined generation of heat and power) refers to a generation technology where the DG resource (for example, gas-fired power plants) generates the electricity and the resulting heat (steam) is available for industrial use. More energy is produced by cogeneration than would be produced by a boiler

gas, and fuel cells. Constant improvement in the efficiency of DG resources, coupled with the reliability concerns of industrial and commercial consumers, are beginning to make DG a viable option to grid energy.[7]

As mentioned earlier, electricity demand is time-sensitive and must be met instantaneously. A *load duration curve* plots load in descending order of magnitude against duration and shows the period of time the total system load is at or above any particular level. Load duration curves can be constructed for specified periods of time, such as daily, monthly or yearly. For an annual load duration curve, the load is measured for each of the 8,760 hours in a year and is sorted starting with the highest (peak) load and finishing with the minimum (called the *baseload*). See Figure 6 in Section 2.2.2. Even though the peak load corresponds to a very small portion of the total duration, the system needs to hold sufficient generating capacity at all times to meet peak demand. This necessity creates a cost to the system, due to the necessity of maintaining a capacity that is in fact used for only a very limited time over the course of any given year.

Fluctuating demand — that is, a demand that fluctuates irrelevant of price — also shapes the initial decision regarding the type and number of generators a supplier will need to supply power adequately. While baseload generators run the majority of the time (shutting down only for scheduled maintenance), generators with short start-up capabilities — such as gas-fired generators— serve as "peakers." To help reduce total generating cost, an optimizing approach is therefore required to choose the best production mix when designing and building a power system.[8]

Pricing schemes may be employed to help shave the peak portion of the load duration curve by managing demand (that is, by shifting its time and amount within the day or week)[9]; however, such strategies have limited effect on the level of *reserve margins,*[10] which must be kept by the *interconnected system*[11] regardless of attenuated load duration.

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or turbine designed to produce solely electricity. For industrial sites that demand continual heat, cogeneration provides up to a 40 percent savings of primary energy use.

[7] As will be discussed later in the study, DG resources, also known as *autoproduction* in Turkey, have become a significant source of supply, owing to reliability problems of the Turkish grid system.

[8] *System planning* in the electric power industry instruct planners what types of plants they should install in their systems, and at what point in time they should be installed, subject to certain constraints (to minimize the cost of meeting a given growth in load). In general, baseload generators are characterized by high fixed costs and low (operating) marginal costs, whereas the situation is reversed for "peakers," due to their high fuel expenses. Depending on system characteristics, hydroelectric, coal and nuclear plants are usually used as baseload generators, whereas thermal plants (such as oil and gas-fired plants) are run as peakers. (Hydroelectric plants can also be used as peakers due to their short start-up times.) Between periods of peak and baseload demands, midload demands can be met by any technology (for example, coal or gas-fired plants).

[9] A *time-of-use* pricing scheme is one in which on-peak users of energy are charged higher prices than off-peak periods, thus hopefully reducing peak demand and the requirement for holding extra (or *reserve*) capacity. Real-time pricing can serve the same purpose with more effectiveness and precision. (See Section 3.2.2.2 for more on demand response programs.)

[10] A *reserve margin* is the difference between a system's dependable resource capability and its forecasted peak load, expressed as a percentage of the forecasted peak load. It is set by grid managers somewhere between 15 and 20 percent, depending on system requirements. Maintenance of a reserve margin is an indicator of system reliability. A higher reserve margin increases system adequacy (and hence, increases

Electrical energy cannot be stored; for this reason, the amount of generation must at all times be equal to the amount of consumption. Even though an interconnected system may experience an imbalance between supply and demand, the system can to some extent be kept in balance in the short-run by changes in the voltage and frequency. For instance, if a generator in the system fails, demand can temporarily exceed supply; however, the overall load can still be served without interruption by a decrease in both voltage and frequency. Higher levels of transmission voltages can be below target levels during this period but the lower level of distribution voltage can to a certain extent be kept stable by adjustments made through the transformers at the substations. Any imbalance of power flows in a system can be observed by miniscule frequency variations from their target levels.[12] In such situations, the transmission (or system) operator would require *regulation services* to balance load fluctuations and maintain system reliability and power quality. These services (also called *ancillary services*) can generally be provided through "regulated market mechanisms." See Section 3.2.1.1 for more on this subject.

In cases where transmission congestions may prevent cheaper power from reaching its destination transmission network capacity can be another possible source of strain on the system. Some advanced markets are in the process of implementing various pricing schemes to alleviate this problem.[13]

Although obtaining efficiency gains through restructuring of the electricity industry is ostensibly a great idea, pitfalls still exist, which carry potentially disastrous consequences for the overall economy.[14] Thus, policymakers will be well advised to pay attention to details of their restructuring plans that require tailoring to local particularities. A prototype prescription drawn for one particular country or market is likely to create disturbances during a transitional period in another country, thereby reducing public and political support for an otherwise successful reform.

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long-run system reliability); however it also incurs a higher cost. *Operating reserves*, on the other hand, refer to the unused but available generation resources that are in excess of demand and that are scheduled to be available on short notice to maintain short-run system reliability. These reserves include *spinning reserves*: reserves that are connected to and synchronized with a grid but that produce electricity at a less than full capacity, and which are nearly instantly available in case of a contingency. *Non-spinning reserves* are those generating units that are not connected to the system, and that require between 10 minutes and an hour to start-up before being able to supply the needed energy.

[11] In an interconnected system of an electrical network the frequency is synchronized at a standard level over AC (alternating current) lines. Interconnections can be connected to each other or to other control areas with DC (direct current) lines for an exchange of power. The frequency level is 50 hertz (Hz) in Europe and 60 Hz in North America.

[12] See Chapters 1.2 and 1.4 of Stoft (2002).

[13] One such recently developed congestion management scheme is called locational marginal pricing (LMP). Locational marginal pricing is based on real-time pricing and considers the cost of supplying the next MW of load at a specific location in the least-cost manner under any given transmission constraints. In calculating LMP, generation marginal cost, transmission congestion cost, and cost of losses are taken into account. (See Section 3.1.4 for more on transmission pricing.)

[14] The California electricity crisis of 2001 is a good example, whereby serious power shortages and blackouts enabled by a faulty restructuring plan brought one of the largest economies in the world to a standstill.

This brief synopsis on the evolution of the electricity industry has been aimed at highlighting some of the unique characteristics of the industry that can be expected to prove helpful in ensuing, competition-related discussions. The study next focuses on the Turkish electricity industry in particular terms, and makes assessments with regard to the industry's existing structure and its potential for competitive restructuring in the near future.

2.2 Supply Side

2.2.1 An Overview of the Turkish Electricity Industry and Past Investment Policies

Until the 1980s, the Turkish electricity industry was almost entirely under public ownership, either through various state agencies or through municipalities.[15] Private companies[16] operating under concession agreements and autoproducers owned less than nine percent of the total installed capacity in 1970. The industry underwent reorganization in 1970 by the establishment of the Turkish Electricity Authority (TEK). The TEK was instituted as a vertically integrated company, controlling the country's electricity industry excluding municipally-owned transmission and distribution facilities and three regional concession companies.[17] The municipal facilities later came under TEK's control in 1982 by Law No. 2705. This law represented the first legal arrangement abolishing the state's monopoly in building generation facilities, and allowed private producers to sell their output to TEK. Thus, Law No. 2705 can also be considered the first "Build–Operate" type of private sector participation scheme in the industry.[18] A more ambitious legal framework was introduced in 1984 by Law No. 3096, discussed later in the study.

2.2.1.1 Legal Developments Between 1984–1994

In the early 1980s, Turkey began to realign its economy towards more liberalized markets; in this regard, some of the initial attempts to restructure the Turkish electricity industry were also undertaken.[19] However, a major contributing factor to the decision to restructure Turkey's electricity industry was the pressure on the supply side to increase the installed capacity of electricity generation, in order to meet a fast-growing energy demand stemming from high GDP growth rates. (The Turkish economy grew at an

[15] The state agencies were: Etibank, a state-owned mining company; State Hydraulics Works (DSİ), which was responsible for building and operating hydroelectric and irrigation dams; and İller Bankası, a state-owned investment bank operating in public infrastructure sectors.
[16] Including Kayseri Elektrik, Çukurova Elektrik (ÇEAŞ), and Kepez Elektrik.
[17] Kayseri Elektrik's assets were transferred to TEK in 1982 as a result of the expiration of its concession agreement. In 1988, Kayseri Elektrik was authorized to operate in its territory for seventy years. Later, in 1989, the company was also given operation rights to TEK's assets in the same territory, for the same length of time. (Kulali, 1997. See this study for a comprehensive analysis of the Turkish electricity industry up to 1997.)
[18] Ibid. Through this law, permission was granted for only one project: a 13 MW hydro-generation plant; however, this project was never completed. (Ibid.)
[19] The following discussion on background developments in part draws on OECD (2002a).

average rate of four percent and five percent annually in the 1980s and 1990s, respectively.) However, budget constraints almost prohibited the state from undertaking concomitant capital-intensive investments.

While the government contemplated private participation (and ultimately, privatization) in the electricity industry the Turkish constitution interpreted the provision of electricity as an inherently 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. Rather than establishing a solid legal basis for private ownership in the industry, the government initially decided to structure the relationship using models of Build–Operate–Transfer (BOT) and Transfer of Operating Rights (TOOR) which included long-term purchase contracts for services provided by the private sector with the state remaining the sole buyer of those services. Naturally, this did not contribute to the development of competition in those areas, and rather led to the initiation of some high cost projects in which most of the commercial risk was assumed by the state in the form of Treasury-backed purchase guarantees.

In this regard, Law No. 3096 was enacted in 1984 to encourage private sector participation in the industry.[20] This law in effect ended TEK's monopoly in the generation, transmission, distribution, and trade of electricity in Turkey. The BOT model involved new investments in electricity generation by the private sector, and the law mandated that a private energy company's physical assets be returned to the state at the end of the contract period, with no financial liabilities incurred by the state. A typical BOT contract in electricity generation spanned 15–20 years, generally a shorter term than the full economic life of the company's investments.[21] Law No. 3096 also initiated TOORs, which covered the operation of the existing generation and distribution assets by the private sector. Law No. 3096 also provided another venue for private participation in generation by allowing "autoproduction" — the cogeneration of heat and power for the companies' own use to be combined with the sale of any surplus electricity to the network.[22]

2.2.1.2 Legal Developments after 1994

Another step towards restructuring the electricity industry was realized when the initial unbundling of TEK was carried out in 1994, establishing two companies: TEAŞ (the Turkish Electricity Generation and Transmission Company) and TEDAŞ (the Turkish Electricity Distribution Company), both of which are state-owned. Further (functional)

[20] Law No. 3096 is entitled "Granting Authorization to Institutions other than the Turkish Electricity Authority (TEK) for Generation, Transmission, Distribution and Trade of Electricity," published in the Official Gazette No. 18610 (December 19, 1984).

[21] The majority of investments under BOT (and later BOO — Build-Operate-Own) were made in combined-cycle-gas-fired (CCGF) plants that have relatively short construction periods. While the contract terms for CCGF projects under BOTs are uniformly twenty years, all CCGF projects under BOOs are signed for sixteen years. However, a typical CCGF generator has an average economic life of thirty years, depending on the actual maintenance of a specific unit.

[22] In 2003, production of autoproducers amounted to 16.5 percent of total electricity output in Turkey.

unbundling of TEAŞ was carried out in 2001 by establishing three additional state-owned entities: TEİAŞ (the Turkish Electricity Transmission Company), EÜAŞ (the Turkish Electricity Generation Company), and TETAŞ (the Turkish Electricity Trading and Contracting Company), all currently in operation.

In 1994, by enacting Law No. 3996, the government tried to make private participation in infrastructure industries and public services more rewarding by providing tax exemptions, and by making Treasury guarantees available in the form of "take or pay" clauses[23] for quantities and prices in BOT power purchase contracts.[24] Importantly, this law also stipulated that BOT contracts be subjected to the precepts and statutes of private law rather than to those of public law; contrary to the previously signed concession contracts that were subjected to public law.[25]

However, the Constitutional Court decision of 1995[26] annulled Article 5 of Law No. 3996 and ruled that BOT contracts pertained to the provision of public services, which could be arranged only as concession agreements under the current law. At the time, concession agreements came under the scope of Turkish public law, which recognized Danıştay's (the Administrative High Court) jurisdiction over such arrangements and rejected international arbitration in cases of dispute.

Notwithstanding the Constitutional Court's decision, in 1997 Law No. 4283 was enacted to initiate a different scheme of private participation projects, covering only new fossil fuel thermal power plants investments designed with a more enhanced incentive structure, known as Build-Operate-Own (BOO).[27] The main characteristic that distinguishes BOOs from earlier BOTs and TOORs is that the ownership of generation assets remains with the original investor at the end of the contract term, rather than being reverted back to the state. Also, TETAŞ awards BOOs through closed bid auctions, or by negotiations; BOOs also carry Treasury guarantees. Finally, BOOs are not granted as concession contracts; rather they are authorized as a result of "operating permissions." Despite the better incentive design of the BOO model, most of the commercial risk of these projects is still assumed by the state (via purchase guarantees from TETAŞ). Nevertheless, the BOO model has become the prevailing form of new private sector participation in the electricity generation segment in Turkey.

[23] A "take or pay" clause requires the buyer to pay for a contracted quantity of electricity at a specified price (generally determined by a specific formula), whether or not that quantity actually is used. The quantity of electricity is usually stated as a percentage of the total annual amount contracted for, over the duration of the contract.
[24] Law No. 3996 is entitled "Certain Investments and Services to be Provided Under the Build-Operate-Transfer Model," published in the Official Gazette No. 21959 (June 13, 1994). See Section 3.5 for a list of BOT, BOO, and TOOR projects. The BOT investment scheme under Law No. 3096 attracted only small-scale generation projects.
[25] See Article 5 of the law.
[26] This decision was published in the Official Gazette No. 22586 (March 20, 1996).
[27] Law No. 4283 is entitled "Law Arranging the Construction and Operation of Power Generating Facilities and the Sale of Energy Under Build-Operate Model," published in the Official Gazette No. 23054 (July 19, 1997).

In 1999, the Turkish constitution was amended, allowing electricity investments to be subject to private law, thus paving the way for international arbitration. 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.[28] Currently, all BOO contracts are subject to private law and international arbitration. Law No. 4501 can be applied retrospectively to previously signed BOT contracts, provided that BOT investors opt for the conversion. The 1999 constitutional amendment — and subsequently, Law No. 4501— were major steps in clearing the legal way for private participation and privatization in the industry.

The latest legal reform related to the industry was enacted in 2001. The Electricity Market Law (Law No. 4628) establishes a framework for the competitive restructuring of the Turkish electricity market.[29] The new framework foresees a step-by-step approach and is set in accordance with the E.U. Acquis Communautaire.[30] The current implementation established by this liberal framework supercedes earlier laws (Nos. 3096, 3996, 4283 and 4501) and rules out new BOT, BOO, and TOOR schemes. However, the law specifies that legal obligations stipulated in earlier contracts be observed.[31]

To sum up; BOT, TOOR, and BOO contracts are characterized as private participation, yet the state remains a dominant player in the market by being the only buyer of power generated by either state-owned generators or private participants in the industry. Moreover, all projects in such schemes include earlier-than-usual capital cost recovery time lines, which have front-loaded depreciation schedules, resulting in higher energy prices for the initial period of investment. Prior to the establishment of the BOO scheme, no framework existed for offering contracts via competitive bidding, and most projects were granted on the basis of executive discretion via unsolicited bids. Consequently, the system of private participation currently underway in the Turkish electricity industry at best represents a mechanism for competition *for the market* — provided that contracts are granted to lowest cost bids — rather than for competition *in the market*.[32]

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[28] Law No. 4501 is entitled "Law Concerning the Principles to be Followed When Disputes Arising from Concession Agreements Regarding Public Services are Submitted to Arbitration," published in the Official Gazette No. 23941 (January 22, 2000).

[29] Law No. 4628 is entitled "Electricity Market Law," published in the Official Gazette No. 24335 (March 3, 2001). See http://www.epdk.org.tr/english/Regulations/electric/law/electricity.html for the text of the law. Following Law No. 4628, the Natural Gas Market Law (Law No. 4646) was enacted in May 2001. This law foresees the restructuring of the natural gas market that has important interlinkages to the electricity industry.

[30] Delays and challenges with regard to implementation of the new framework are discussed in Section 3.6.

[31] Provisional Article 8 of Law No. 4628 mandates that Treasury guarantees granted within the framework of Law No. 3996 (prior to Law No. 4628) be valid only if those projects become operational before the end of 2002.

[32] When competition in the market proves infeasible or impractical, competition for the market may be a desirable option provided that the right to be the monopoly provider of the service could be auctioned off through an efficient auction. An auction is efficient if a) the most efficient firm wins the auction, and b) the winning firm gives up most of its monopoly profits. See Jamison, *et al.* (2004), p.16.

2.2.2 Physical Infrastructure

2.2.2.1 Generation

2.2.2.1.1 An Overview

Following the breakup of TEK in 1994 into TEAŞ (generation and transmission) and TEDAŞ (distribution), and the subsequent breakup of TEAŞ in 2001 into EÜAŞ (generation), TEİAŞ (transmission) and TETAŞ (trading and contracting), state-owned generation is currently being carried out by EÜAŞ. In 2003, EÜAŞ owned approximately 61 percent of Turkey's total installed electricity generation capacity and generated more than 46 percent of Turkey's total energy. That same year, private sector generation under BOT, BOO, and TOOR contracts; independent power producers; and mobile plants accounted for approximately 26 percent of Turkey's installed capacity and 37 percent of Turkey's overall energy production. Autoproduction by industrial companies provided nearly all of the remaining 13 percent of Turkey's installed capacity and 16.5 percent of Turkey's energy.[33] (See Table 1 for a historical development of Turkey's installed capacity.)

Table 1: Annual Development of Turkey's Installed Capacity, 1970–2003 (MW)

Years	EÜAŞ	Concess.	BOT	BOO	IPP	EÜAŞ Affl.	Priv. Ad.	Autop.	Municipal	Mobile	TOOR	Total	Thermal	Hydro	Wind	Total	Change (%)
1970	1,439.0	193.8	0.0	0.0	0.0	0.0	0.0	359.4	242.7	0.0	0.0	2,234.9	1,509.5	725.4	0.0	2,234.9	13.6
1971	1,764.3	263.8	0.0	0.0	0.0	0.0	0.0	402.1	147.7	0.0	0.0	2,577.9	1,706.3	871.6	0.0	2,577.9	15.3
1972	1,878.1	269.8	0.0	0.0	0.0	0.0	0.0	421.4	142.0	0.0	0.0	2,711.3	1,818.7	892.6	0.0	2,711.3	5.2
1973	2,350.4	269.8	0.0	0.0	0.0	0.0	0.0	426.5	145.8	0.0	0.0	3,192.5	2,207.1	985.4	0.0	3,192.5	17.7
1974	2,833.6	325.8	0.0	0.0	0.0	0.0	0.0	427.2	145.5	0.0	0.0	3,732.1	2,282.9	1,449.2	0.0	3,732.1	16.9
1975	3,229.2	325.8	0.0	0.0	0.0	0.0	0.0	487.0	144.1	0.0	0.0	4,186.1	2,407.0	1,779.6	0.0	4,186.6	12.2
1976	3,384.9	325.8	0.0	0.0	0.0	0.0	0.0	508.4	145.1	0.0	0.0	4,364.2	2,491.6	1,872.6	0.0	4,364.2	4.2
1977	3,684.9	325.8	0.0	0.0	0.0	0.0	0.0	571.4	145.1	0.0	0.0	4,727.2	2,854.6	1,872.6	0.0	4,727.2	8.3
1978	3,800.8	325.8	0.0	0.0	0.0	0.0	0.0	597.0	145.1	0.0	0.0	4,868.7	2,987.9	1,880.8	0.0	4,868.7	3.0
1979	4,050.8	325.8	0.0	0.0	0.0	0.0	0.0	597.0	145.1	0.0	0.0	5,118.7	2,987.9	2,130.8	0.0	5,118.7	5.1
1980	4,050.8	325.8	0.0	0.0	0.0	0.0	0.0	597.0	145.1	0.0	0.0	5,118.7	2,987.9	2,130.8	0.0	5,118.7	0.0
1981	4,442.2	325.8	0.0	0.0	0.0	0.0	0.0	625.4	144.2	0.0	0.0	5,537.6	3,181.3	2,356.3	0.0	5,537.6	8.2
1982	5,543.2	325.8	0.0	0.0	0.0	0.0	0.0	625.4	144.2	0.0	0.0	6,638.6	3,556.3	3,082.3	0.0	6,638.6	19.9
1983	5,936.1	324.4	0.0	0.0	0.0	0.0	0.0	637.4	37.2	0.0	0.0	6,935.1	3,695.8	3,239.3	0.0	6,935.1	4.5
1984	7,061.5	324.4	0.0	0.0	0.0	0.0	0.0	1,073.2	0.0	0.0	0.0	8,459.1	4,584.3	3,874.8	0.0	8,459.1	22.0
1985	7,792.0	324.4	0.0	0.0	0.0	0.0	0.0	1,002.7	0.0	0.0	0.0	9,119.1	5,244.3	3,874.8	0.0	9,119.1	7.8
1986	8,807.0	328.4	0.0	0.0	0.0	0.0	0.0	977.3	0.0	0.0	0.0	10,112.7	6,235.2	3,877.5	0.0	10,112.7	10.9
1987	11,011.1	378.4	0.0	0.0	0.0	0.0	0.0	1,103.1	0.0	0.0	0.0	12,492.6	7,489.3	5,003.3	0.0	12,492.6	23.5
1988	12,981.5	378.4	0.0	0.0	0.0	0.0	0.0	1,158.2	0.0	0.0	0.0	14,518.1	8,299.8	6,218.3	0.0	14,518.1	16.2
1989	14,287.5	378.4	16.0	0.0	0.0	0.0	0.0	1,174.2	0.0	0.0	0.0	15,856.1	9,208.4	6,597.3	0.0	15,805.7	8.9
1990	14,726.8	378.4	16.0	0.0	0.0	0.0	0.0	1,193.9	0.0	0.0	0.0	16,315.1	9,550.8	6,764.3	0.0	16,315.1	3.2
1991	15,314.6	661.9	25.6	0.0	0.0	0.0	0.0	1,204.5	0.0	0.0	0.0	17,206.6	10,092.8	7,113.8	0.0	17,206.6	5.5
1992	16,797.3	669.1	25.6	0.0	0.0	0.0	0.0	1,221.6	0.0	0.0	0.0	18,713.6	10,334.9	8,378.7	0.0	18,713.6	8.8
1993	18,277.1	692.7	35.2	0.0	0.0	0.0	0.0	1,330.1	0.0	0.0	0.0	20,335.1	10,653.4	9,681.7	0.0	20,335.1	8.7
1994	18,646.4	716.3	35.2	0.0	0.0	0.0	0.0	1,459.4	0.0	0.0	0.0	20,857.3	10,992.7	9,864.6	0.0	20,857.3	2.6
1995	15,571.7	716.3	35.2	0.0	0.0	3,284.0	0.0	1,344.6	0.0	0.0	0.0	20,951.8	11,089.0	9,862.8	0.0	20,951.8	0.5
1996	15,618.6	716.3	198.7	0.0	0.0	3,284.0	0.0	1,429.3	0.0	0.0	0.0	21,246.9	11,312.1	9,934.8	0.0	21,246.9	1.4
1997	15,783.0	716.3	328.7	0.0	0.0	3,284.0	0.0	1,777.4	0.0	0.0	0.0	21,889.4	11,786.8	10,102.6	0.0	21,889.4	3.0
1998	16,276.0	716.3	768.3	0.0	0.0	3,284.0	0.0	2,306.9	0.0	0.0	0.0	23,351.5	13,036.3	10,306.5	8.7	23,351.5	6.7
1999	17,832.8	610.3	1,655.1	0.0	0.0	3,284.0	0.0	2,655.4	0.0	79.2	0.0	26,116.8	15,570.9	10,537.2	8.7	26,116.8	11.8
2000	17,967.9	610.3	1,985.3	0.0	0.0	3,284.0	0.0	2,995.9	0.0	90.6	330.1	27,264.1	16,070.0	11,175.2	18.9	27,264.1	4.4
2001	17,779.3	610.3	2,337.8	0.0	0.0	3,284.0	0.0	3,373.9	0.0	297.0	650.1	28,332.4	16,640.6	11,672.9	18.9	28,332.4	3.9
2002	17,774.3	1,120.3	2,349.0	2310.0	0.0	3,284.0	0.0	3,735.6	0.0	622.5	650.1	31,845.8	19,586.0	12,240.9	18.9	31,845.8	12.4
2003	17,959.3	0.0	2,349.0	5303.8	153.6	2,154.0	1,680.0	4,541.8	0.0	795.5	650.1	35,587.0	22,989.4	12,578.7	18.9	35,587.0	11.7

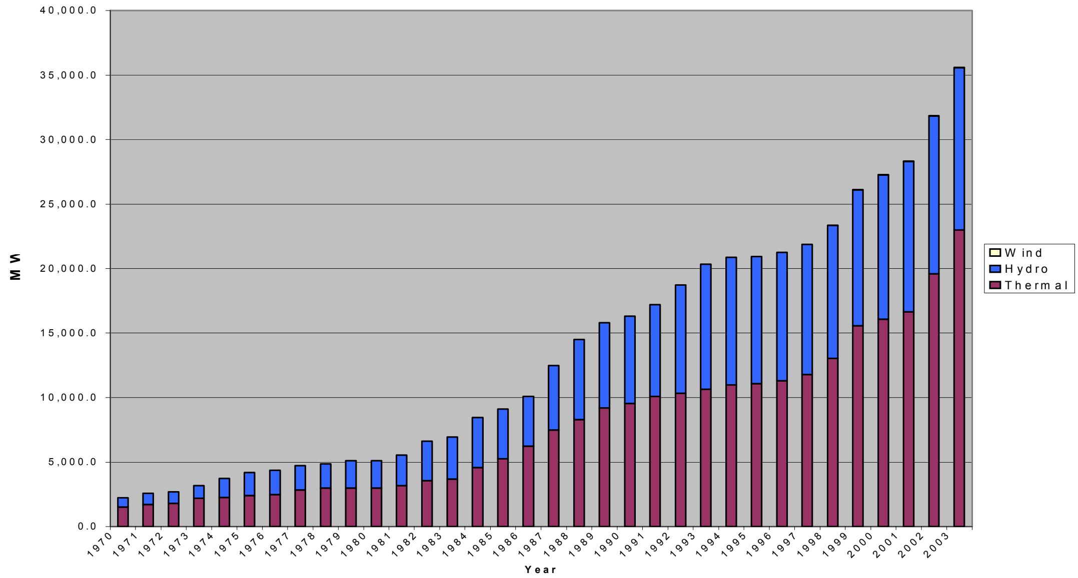
Concession Companies are ÇEAŞ and Kepez Elektik; IPP: Independent Power Producers;
Note 1: Municipallly owned plants were transferred to (then) TEK in 1983 and their numbers were included in EÜAŞ numbers afterwards.
Note 2: ÇEAŞ and Kepez Elektrik plants were transferred to EÜAŞ on June 12, 2003, and their numbers are included in 2003 EÜAŞ figures.

Source: TEİAŞ, Electricity Generation-Transmission Statistics of Turkey, 2003.

[33] Additionally, in 2003 two privately owned companies, ÇEAŞ and Kepez Elektrik, were operating under generation, transmission, and distribution concession agreements in southern Turkey when their concession agreements were cancelled by the Ministry of Energy and Natural Resources. Both companies were then taken over by the state on the basis of their failure to comply with the interconnection clauses of the newly enacted Electricity Market Law. In 2003, their combined shares of total installed capacity and energy were 3.5 percent and 3.4 percent, respectively. Installed capacity and generation numbers related to these companies are included in the previously mentioned 2003 EÜAŞ statistics.

When compared to the 1970s, the fuel composition of Turkey's installed generation capacity has remained more or less unchanged during the last three decades, although the share of hydroelectric generation capacity (with minor fluctuations) has increased steadily until the late 1990s, after which it showed a continuous decline, in conjunction with the increase of gas-fired generation. Turkey started generating electricity from wind in 1998, reaching approximately 19 MW of capacity in 2003, or a share of less than 1 percent (See Figure 1).

Figure 1: Installed Capacity Development by Fuel Type, 1970–2003



Source: TEİAŞ, Electricity Generation-Transmission Statistics of Turkey, 2003.
Note: The figure above is derived from data given by TEİAŞ (2003a).

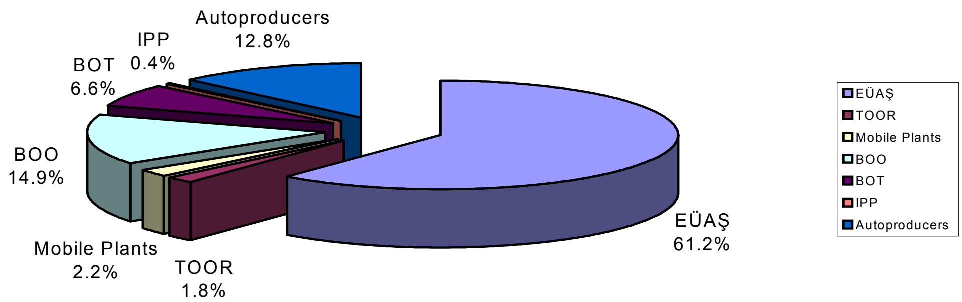
Currently, private sector participation in electricity generation primarily takes the form of BOT and BOO contracts, or the purchase through TOOR contracts to power plants owned by EÜAŞ; autoproducers, mobile generators and independent power producers comprise the remaining form of private sector participation in the industry.[34] In 2003, BOT and BOO investment schemes accounted for 2,349 MW and 5,303.8 MW of contracted capacities, respectively; together, they constituted 21.5 percent of Turkey's total installed capacity. In that same year, under the TOOR scheme, a total of 650.1 MW of capacity was operated by the private sector, equivalent to 2.9 percent of EÜAŞ's own installed capacity. In all three cases, the generated energy was sold to a single buyer, TETAŞ (See Figure 2).

In 2003, EÜAŞ plants accounted for 46.3 percent of the total 140.5 TWh of energy produced in Turkey, reflecting the fact that more than half (53.7 percent) of the total

[34] See Section 2.2.2.1.2 for more on autoproduction. Mobile generators are privately owned; their output is purchased by EÜAŞ, and they are usually contracted for a 5-year term. Currently, 16 agreements with mobile generators are in effect, with varying expiration dates. The latest agreement is scheduled to end by 2008.

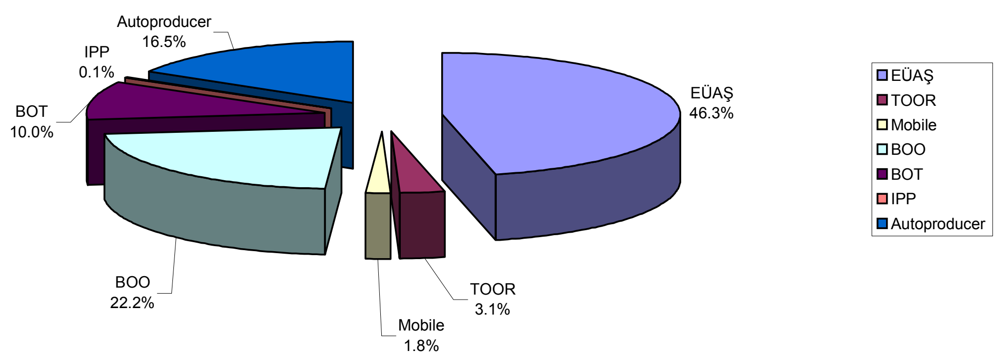
energy produced in Turkey originated from private sector plants. BOTs and BOOs alone generated 32.2 percent of Turkey's total energy in 2003 (See Figure 3).

Figure 2: Installed Capacity Based on Ownership, 2003



Total installed capacity: 13,793.7 MW privately-owned; 21,793.3 MW state-owned. Total= 35,587 MW.
Source: TEİAŞ, Electricity Generation-Transmission Statistics of Turkey, 2003.
Note: The figure above is derived from data given by TEİAŞ (2003a).

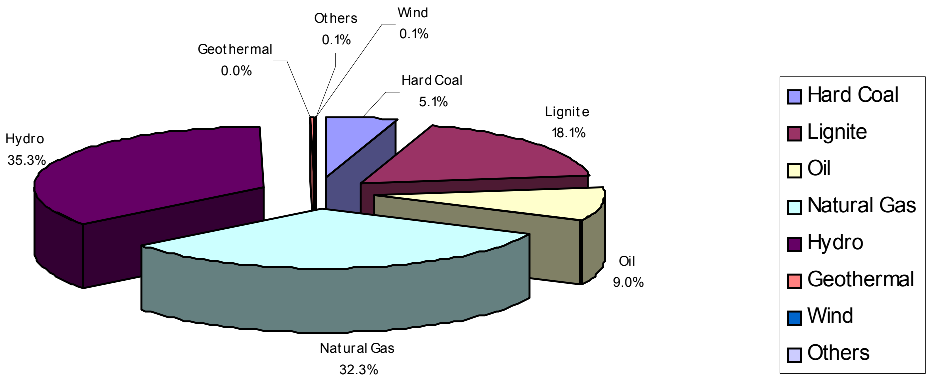
Figure 3: Output Based on Ownership, 2003



Total output: 75,462.5 GWh by privately-owned operators; 65,117.9 GWh by state-owned operators. Total= 140,580.4 GWh.
Source: TEİAŞ, Electricity Generation-Transmission Statistics of Turkey, 2003.
Note: The figure above is derived from data given by TEİAŞ (2003a).

As 2003 figures illustrated, hydroelectric power plants accounted for 35.3 percent of Turkey's generation capacity in that year, while thermal sources accounted for 64.5 percent of generation capacity, and gas-fired power plants accounted for 32.3 percent.[35] While hydraulic dams contributed 25.1 percent of the total energy generated, thermal plants contributed 74.8 percent. Finally, gas-fired plants provided 45.2 percent of the total electricity generated in Turkey in 2003 (See Figures 4 and 5.)

Figure 4: Installed Capacity by Fuel Type, 2003

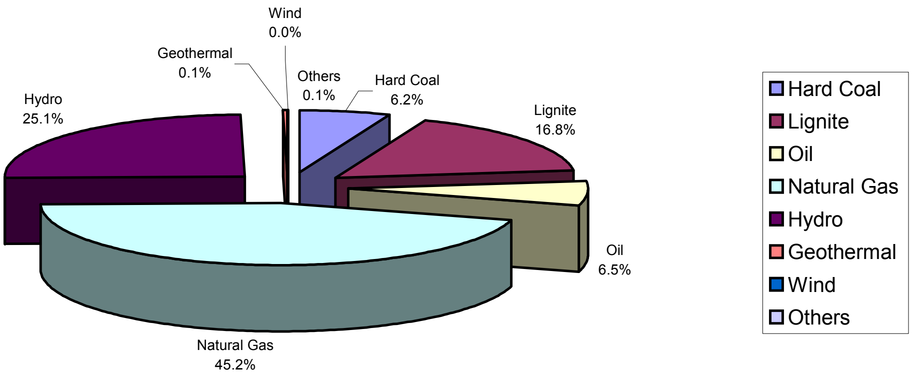


Source: TEİAŞ, Electricity Generation-Transmission Statistics of Turkey, 2003.
Note: The figure above is derived from data given by TEİAŞ (2003a).

Fuel Types
Oil: Fuel Oil + Diesel + LPG + Naphtha. Others: Renewables + Waste + Miscellaneous
(Hard Coal includes imports)

[35] CCGF generation capacity accounted for 60.7 percent and 79.2 percent of BOTs and BOOs, respectively.

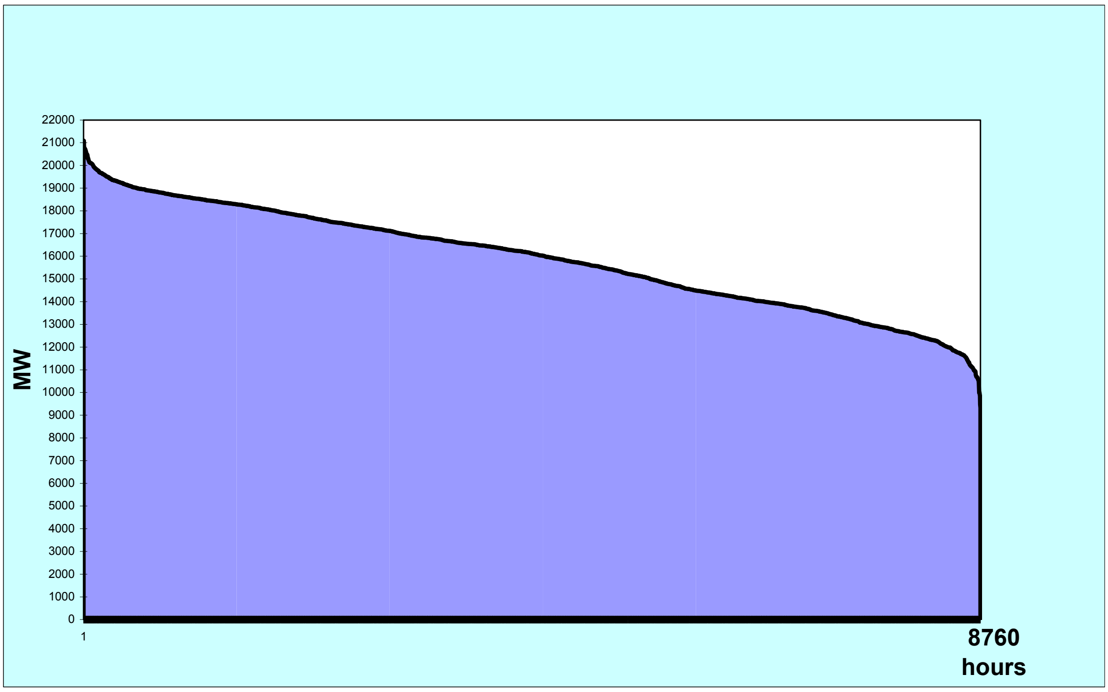
Figure 5: Output by Fuel Type, 2003



Source: TEİAŞ, Electricity Generation-Transmission Statistics of Turkey, 2003.
Note: The figure above is derived from data given by TEİAŞ (2003a).

Figure 6 illustrates the load duration curve of the Turkish power system in 2003. The system peak load was 21,728.9 MW on December 19, 2003.

Figure 6: Load Duration Curve of Turkey, 2003

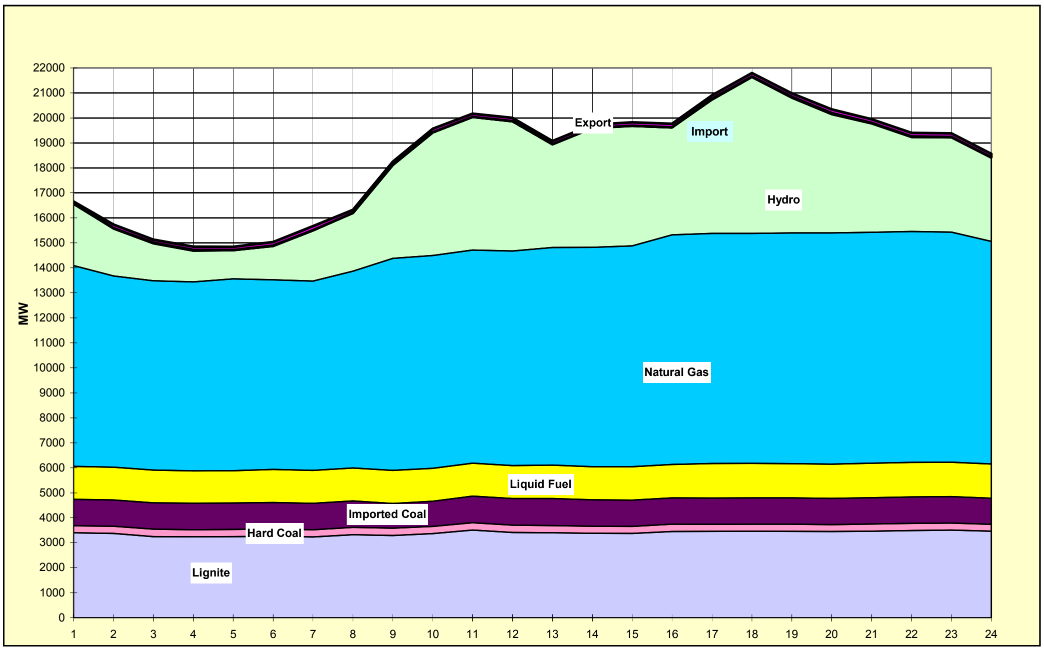


Coincident Peak : 21,728.9 MW	Date : Dec.19, 2003	Time : 17.10	Summer Coincident Peak: 20,200.4 MW	Date: Aug. 29, 2003	Time:11.30
Minimum Hourly Load : 9,270 MW	Date : Nov.26, 2003	Time : 05.00	Summer Minimum Hourly Load: 11,821 MW	Date: July 14, 2003	Time:05.00

Source: TEİAŞ, Annual Operational Activity Report, 2003.

In Turkey, baseload power generation is mostly supplied by coal-fired generation (using lignite and hard coal) while gas-fired generation is generally used to meet midload energy requirements. Hydraulic resources are often used as peaking generation units, and are employed for a total of approximately 3,000–3,500 hours a year.[36] (See Figure 7 for the daily load curve which illustrates the type of generation used to meet the peak load.)

Figure 7: Type of Generation to Meet Peak Load, 2003



Date: December 19, 2003 **Hourly Peak:** 21,539 MW **Hour:** 18:00
Consumption: 435,465 MWh **Coincident Peak:** 21,728.9 MW **Hour:** 17:10

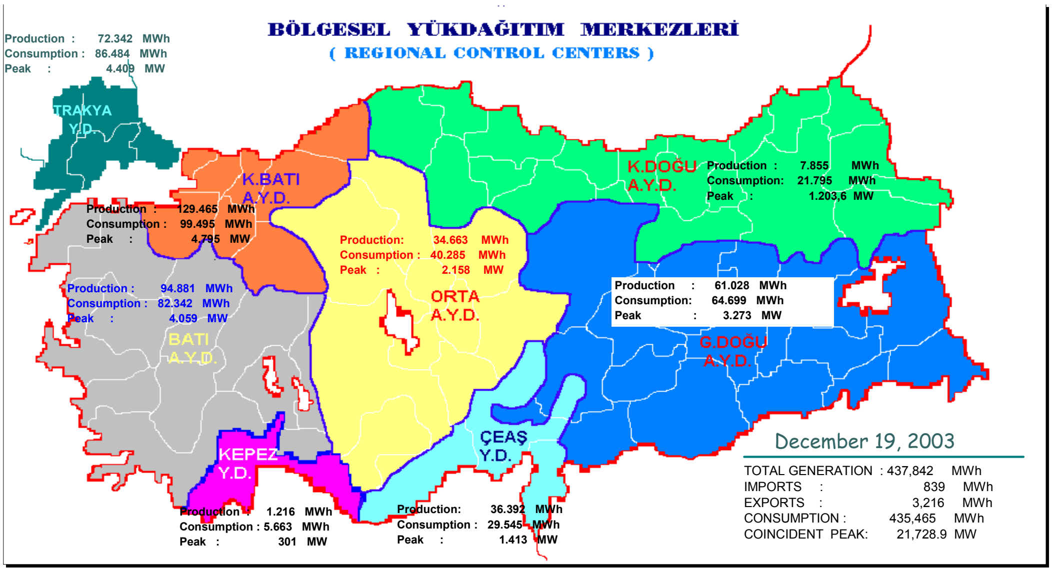
Liquid Fuel = Fuel-oil + Diesel + LPG + Naphta + Geothermal + Others

Source: TEİAŞ, Annual Operational Activity Report, 2003.

Locational characteristics relating to electricity generation and load are of the utmost importance in competitive electricity markets, revealing important regional requirements and — depending on existing transmission capacity — the potential for congestion (particularly during peak times). Figure 8 shows the regional distribution of Turkey's electricity generation and the load during coincident peak load.

[36] Reservoirs receive water at an increasing rate from April onwards, and hydroelectric resources are more extensively used for peak shaving from April to November.

Figure 8: Generation and Load During Coincident Peak by Region, 2003



Source: TEİAŞ, Annual Operational Activity Report, 2003.

2.2.2.1.2 Autoproduction

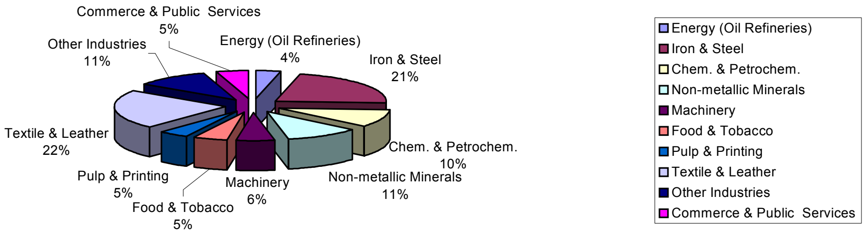
In 1984, following the enactment of Law No. 3096, autoproduction in Turkey picked up at a fast pace, increasing its installed capacity from approximately 1,073 MW in 1984 to 4,542 MW in 2003, and accounting for nearly 13 percent of Turkey's total installed capacity. The same year, 179 autoproducers generated 23,126 MWh of energy — more than 16 percent of Turkey's total output. Nearly 98 percent of the autoproducers' output was due to thermal generation, followed by hydroelectric generation (2 percent) and wind power (0.02 percent). Most autoproduction plants are cogeneration facilities that operate in the industrial sector. The Electricity Market Law (Law No. 4628) defines "autoproducers" as those entities that essentially generate electricity for their own (and their shareholders') use. Under the law, autoproducers can sell up to 20 percent of the electricity they generate during any given calendar year; this allotment can be increased to 30 percent by the regulatory agency EMRA.[37] Autoproducers that sell electricity in excess of the allotment determined by EMRA are required to obtain production licensing. In October 2002, EMRA determined that the amount of electricity that autoproducers can sell is 25 percent of the prior year's production.[38]

The major underlying reason for the fast spread of autoproduction is no doubt reliability and cost concerns of the industrial sector. Increased thermal efficiency in cogeneration

[37] See Article 2 of Section 2 of Law No. 4628, and the secondary regulation published in the Official Gazette No. 25520 (July 7, 2004).
[38] See EMRA decision No. 61, published in the Official Gazette No. 24914 (October 22, 2002).

technologies and the possibility of selling surplus energy to the national grid continues to make these investments more attractive.[39]

Figure 9: Sector Origins of Autoproduction, 2002



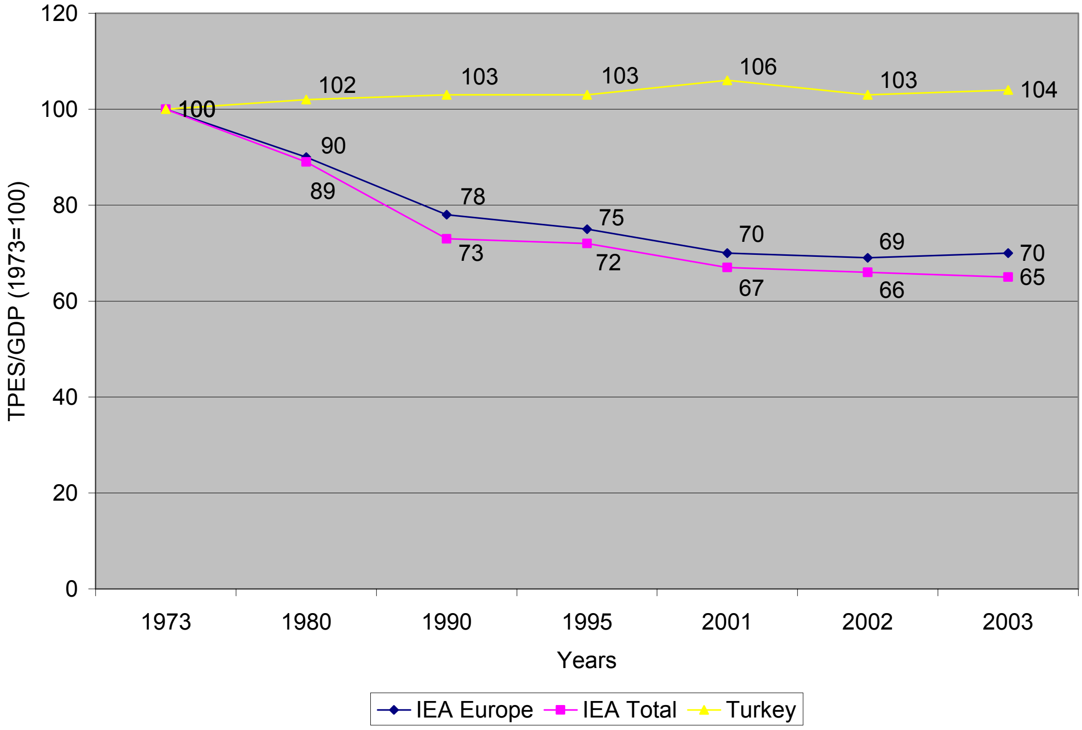
Source: IEA, Electricity Information, 2004.
Note: The figure above is derived from data given by the IEA (2004).

2.2.2.1.3 Energy Intensity and Electricity Intensity Figures

Even though *energy intensity* figures for Turkey have been relatively steady throughout the last two decades, the figures are still in line with those of developing countries and are considerably higher than those of Turkey's industrialized counterparts.[40] While the average energy intensity for IEA–Europe member countries has been *decreasing* at an annual average rate of 1.4 between 1973–1990 and 0.9 between 1990–2003, the rate of *increase* for Turkey was 0.2 and 0.1 for the same periods, respectively.[41] On the other hand, Turkey's per capita energy use in 2003 was 1.14 tonnes of oil equivalent (toe), which was considerably lower than the IEA–Europe average of 3.54 toe. Figure 10 compares the development of Turkey's energy intensity figures with that of IEA countries.

[39] Generous tax incentives directed to autoproduction investments and autoproduction generation also contributed to the fast growth in this segment.
[40] *Energy intensity* signifies the relationship between energy consumption and gross domestic product (GDP), and is expressed as the ratio between the Total Primary Energy Supply (TPES) and the GDP (that is, it is a measure of energy input per unit of GDP). It serves as an indicator for trends in energy consumption and overall energy efficiency. Although TPES and GDP correlated with one another, the degree of correlation varies among countries, based on their level of development. While energy intensity figures of industrialized countries show a stable but weakening trend, developing countries' figures show higher levels of energy intensity. This phenomenon is partly explained by the replacement of new, more energy efficient capital stock and appliances, which takes place more often in the industrialized world than in the developing world, resulting in a weaker link between energy consumption and GDP growth in the industrialized world. However, to some extent energy intensity also varies inversely with end-user prices, thus leading to higher ratios in countries where energy prices are low. This partly explains why energy intensity figures are higher in the United States and Canada, where prices are lower when compared to Japan and Western Europe. See IEA (2004) and EIA (2004).
[41] See IEA (2004) for the information in this section.

Figure 10: Development of Energy Intensity of Turkey and Other IEA Countries, 1973–2003

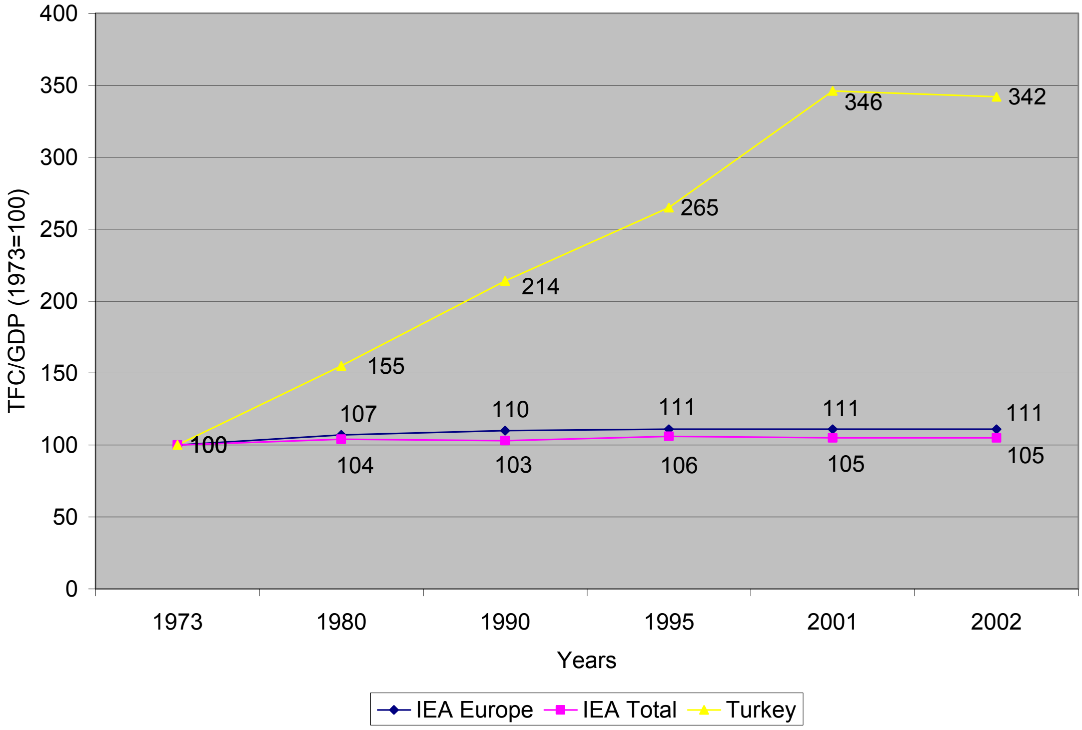


Source: IEA, Electricity Information, 2004.
Note: The figure above is derived from data given by the IEA (2004).

Electricity intensity figures for Turkey have also been increasing at much higher rates than for those of IEA countries.[42] As industrialized IEA member countries become more energy efficient they also, on average, become more electricity intensive, to varying degrees.[43]

[42] *Electricity intensity* is a measure similar to that of energy intensity; however, it measures only the total final consumption of electricity input, per unit of GDP.
[43] However, electricity intensity has been declining in the North American region.

Figure 11: Development of Electricity Intensity of Turkey and Other IEA Countries, 1973–2002



Source: IEA, Electricity Information, 2004.
Note: The figure above is derived from data given by the IEA (2004).

2.2.2.1.4 The Shape of the Supply Curve

Little information has been publicly available regarding the production cost of electricity service in Turkey; such information would help construct an aggregate supply curve of Turkey's electricity industry. Marginal cost studies at plant level would be very helpful in achieving an industry wide supply curve, the slope of which would enable the assessment of future market prices that likely would prevail as a result of competitive electricity markets. The shape of such a curve is an important indicator in determining the potential market-clearing prices in competitive markets, which correspond to various levels of quantities of energy in either the bilateral market or spot exchanges. (See Section 3.1 for a discussion of cost accounting and pricing issues).

2.2.2.1.5 The Adequacy of Supply and Future Generation Investment Projects

As set forth in the Electricity Market Law of 2001, TEİAŞ is charged with planning the country's electricity supply system, by utilizing demand forecasts developed by the Ministry of Energy and Natural Resources (MENR) as its primary input.[44] In the last supply plan, prepared in 2004,[45] TEİAŞ considered two demand scenarios — high demand and low demand — developed by the ministry. The high demand growth scenario assumes that macroeconomic targets stipulated in the Five-Year Development Plan[46] are in fact achieved, and that demand grows at an average annual rate of 7.9 percent. The low demand growth scenario assumes that subsectors follow paths of development different from those set forth in the development plan and, as a result, that demand grows on average 6.4 percent, annually.[47] Accordingly, TEİAŞ's supply plan develops a solution for each of the respective demand scenarios. The following section summarizes the main findings of the supply plan with regard to generation investment requirements based on the *high demand growth scenario*.

Solution Based on High Demand Growth

Table 2: Additional Capacity Investment Requirements in Generation (MW)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EXISTING	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588
UNDER CONSTR.	1807	2450	3520	3854	3854	3854	3854	3854	3854	3854	3854	3854	3854	3854	3854	3854
RECEIVED LICENSE	1948	2722	3163	3163	3517	3531	3531	3531	3531	3531	3531	3531	3531	3531	3531	3531
PLAN SOLUTION	0	0	125	250	1075	3843	7689	12012	16450	21213	26299	29922	34281	39784	45539	51375

Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.

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[44] The ministry uses MAED (Model for Analysis of Energy Demand) specifications for countrywide demand forecasts.

[45] TEİAŞ most recently developed two generation capacity projections, one in October 2003 titled "Electrical Energy 10 Year Generation Capacity Projection (2003–2012)" and the other in November 2004, with a longer planning horizon, titled "Electrical Energy Generation Planning Study of Turkey (2005–2020)," that serve as a system-planning output. TEİAŞ uses an optimization model WASP (Wien Automatic System Planning) package for its projections. In its November 2004 projection, TEİAŞ states that because existing power plants, plants under construction, and the projects that received license from EMRA for the years 2005 and 2006 are able to meet energy demands and attain reserve ratios exceeding 50 percent, these years are excluded from the planning calculations. Thus, the effective planning period is taken to be 2007–2020. See www.teias.gov.tr for the plan's assumptions and conclusions.

[46] Five-Year Development Plans are comprehensive macroeconomic planning documents prepared by the State Planning Organization (SPO) on a regular basis.

[47] The supply plan prepared by TEİAŞ uses data pertaining to the results of the ministry's demand forecast and the load duration curves to obtain the systemwide peak demand series for the planning period. However, TEİAŞ states that it did not use the ministry's demand forecast results for 2005, and instead utilized numbers put forward by the production program for that year.

Table 3: Installed Capacity Development, 2005–2020 (MW)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EXISTING	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588	37588
EXISTING + UNDER CONSTR.	39395	40038	41108	41442	41442	41442	41442	41442	41442	41442	41442	41442	41442	41442	41442	41442
EXISTING + UNDER CONSTR. + RECEIVED LICENSE	41343	42760	44271	44605	44959	44973	44973	44973	44973	44973	44973	44973	44973	44973	44973	44973
EXISTING + UNDER CONSTR. + RECEIVED LICENSE + PLAN SOLUTION	41343	42760	44396	44855	46034	48816	52662	56985	61423	66186	71272	74895	79254	84757	90512	96348
PEAK DEMAND	***25000***	***28270***	***30560***	***33075***	***35815***	***38785***	***41965***	***45410***	***49030***	***52905***	***57050***	***60845***	***65245***	***69835***	***74585***	***79350***

Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.

Table 4: Meeting Peak Demand with Installed Capacity, 2005–2020 (MW)*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EXISTING	12588	9318	7028	4513	1773	-1197	-4377	-7822	-11442	-15317	-19462	-23257	-27657	-32247	-36997	-41762
EXISTING + UNDER CONSTR.	14395	11768	10548	8367	5627	2657	-523	-3968	-7588	-11463	-15608	-19403	-23803	-28393	-33143	-37908
EXISTING + UNDER CONSTR. + RECEIVED LICENSE	16343	14488	13710	11529	9143	6187	3007	-438	-4058	-7933	-12078	-15873	-20273	-24863	-29613	-34378

* Excluding Plan Solutions

Note: Numbers in Table 4 are obtained by subtracting peak demand numbers in Table 3 from each corresponding row in the same table.

Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.

Data displayed in Table 2 indicate that 58,760 MW of additional generating capacity — (of which 7,385 MW is either under construction or has received a generating license, and 51,375 MW is set forth by the plan solution — is needed to meet expected peak load capacity requirements from 2005 through 2020. Table 3 shows that by 2020, Turkey's installed generation capacity will reach 96,348 MW, representing approximately a 2.5 fold increase from Turkey's current capacity.[48]

Table 4 is particularly interesting, showing that with only existing capacity; plants under construction; and projects that have received a generating license, by 2012 Turkey will face a situation where installed capacity is below peak capacity requirement, with no

[48] Reserve ratio, on average, is 21–25 percent, except for 2005–2008. A high (50 percent) reserve ratio in 2005–2006 influences years 2007–2008, as well. (See Figure 32 in Annex).

reserves available. Years where installed capacity falls below demand are indicated with a minus sign.

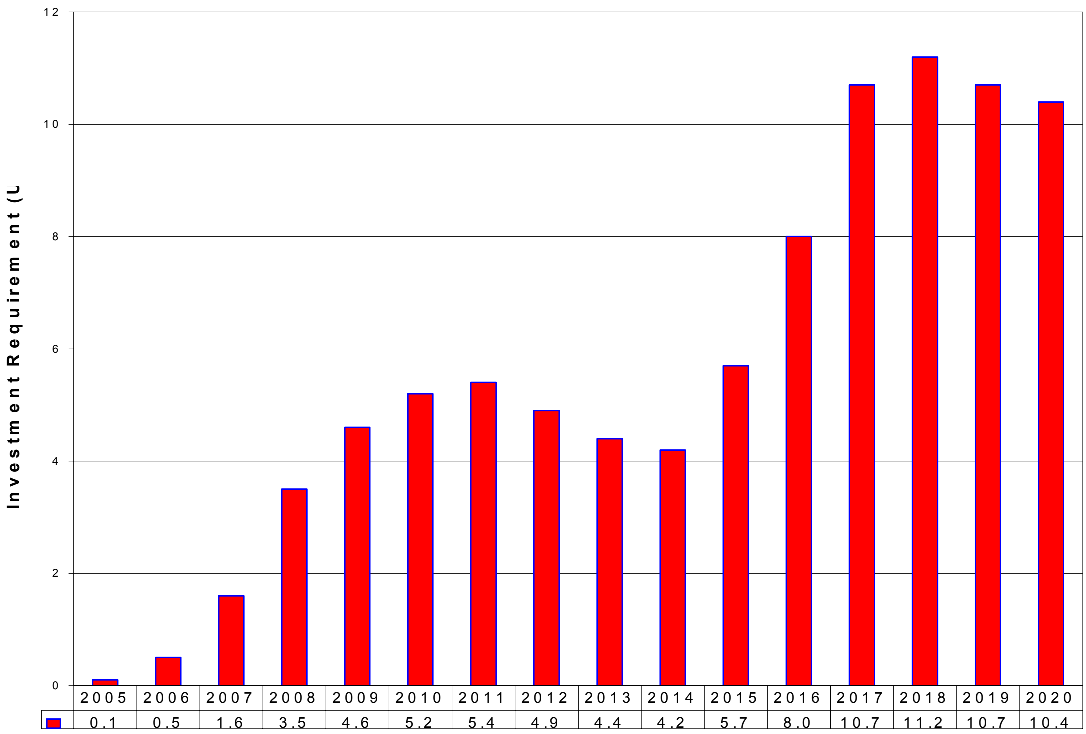
The supply plan also has solutions for shortages that may develop when hydroelectric resources are constrained by insufficient rainfall. In general, the level of output by hydroelectric resources is considered *average* under normal rainfall conditions and as *reliable* under drought conditions. Accordingly, with only existing capacity, plants under construction, and projects that have received licenses energy output just meets energy demand in 2010, with no reserves available, under an average level of hydroelectric output. When a reliable level of hydroelectric output is assumed, the same situation occurs a year earlier, in 2009.[49]

New capacity additions point to a decrease in the shares of fuel oil and natural gas generation in comparison to the fuel mix in 2003 (see Figure 4), and suggest an increase in imported (hard) coal, wind power, and new nuclear generation. (Annex highlights projections of the supply plan with regard to the fuel mix on the basis of the high demand scenario.)

The supply plan projects that a total of U.S. $91.3 billion will be needed to achieve 51,375 MW of *additional* investment in electricity generation during 2005–2020. This figure excludes investment expenditures for projects under construction and for those that have already received licenses; however, it includes expenditures for projects that will be completed after 2020.[50] Figure 12 shows generation investment requirements for the period covered by the supply plan.

[49] See Section IV of the supply plan.
[50] It is stated in the plan that the figures do not include financing (interest) costs of these projects.

Figure 12: Generation Investment, 2005–2020 (U.S. $ Billion)



Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.

Investment requirements (as indicated in Figure 12) are divided into three periods by the plan:

- During 2005–2010, a total of U.S. $15.5 billion is required, or an annual average of U.S. $2.6 billion;

- During 2011–2015, a total of U.S. $24.7 billion is required, or an annual average of U.S. $4.9 billion;
- During 2016–2020, a total of U.S. $51.1 billion is required, or an annual average of U.S. $10.2 billion.

Given the total investment requirement of U.S. $91.3 billion throughout the plan period of 2005–2020, to satisfy its future energy needs Turkey on average needs U.S. $5.7 billion annually for the generation segment alone.

International Energy Agency (2005b) notes that since 2001, state-owned electricity generators have not been allowed to make investments in new power plants; while private sector projects have started, investors are concerned with the difficulty of competing with fully depreciated state-owned generators. The same study also reports that some measures are being taken to address the future supply gap expected by 2009; these measures include rehabilitation and replacement investments for power plants to increase thermal efficiency and reduce emissions. In this regard, a three-year, U.S. $400 million rehabilitation project aims to increase the annual generation of rehabilitated plants by 15 TWh. An additional savings of 6 TWh is also planned, through the reduction of combined transmission and distribution losses from current levels of approximately 20 percent to 14 percent. These measures are expected to forestall the supply gap to 2009–2010.[51]

2.2.2.2 Transmission

2.2.2.2.1 The Current State of Transmission Infrastructure

The Turkish Electricity Transmission Company (TEİAŞ) is the state-owned entity responsible for the planning, construction, and operation of the high-voltage transmission network (66 kV and above) and of the load dispatch in Turkey. Currently, TEİAŞ operates one national and nine regional dispatch centers.[52] Table 5 and Figure 13 detail the existing high-voltage transmission infrastructure and Turkey's interconnected system of transmission lines, respectively.

Table 5: Annual Development of Length of Transmission Lines (km)

	Years	**400 kV**	**220 kV**	**154 kV**	**66 kV**	*Total (km)*
	1980	2985.1	15.7	15965.0	2332.0	21297.8
	1981	3032.6	15.7	16713.4	2313.0	22074.7
	1982	3809.5	15.7	17179.9	2174.0	23179.1
	1983	4185.8	15.7	17946.5	2196.0	24344.0
	1984	4602.1	15.7	18629.4	2181.3	25428.5
	1985	5117.0	15.7	19885.6	2057.8	27076.1
TEK	**1986**	5892.2	15.7	20842.3	1881.5	28631.7
	1987	6730.8	84.6	21367.5	1792.5	29975.4
	1988	7326.6	84.6	22225.0	1583.1	31219.4
	1989	7863.2	84.6	23422.4	1526.4	32896.6
	1990	8334.3	84.6	24039.7	1408.2	33866.8
	1991	9074.0	84.6	25094.0	1209.1	35461.7
	1992	9657.3	84.6	25454.1	1030.5	36226.5
	1993	10611.1	84.6	25813.6	986.5	37495.8
	1994	10892.4	84.6	26301.8	986.3	38265.1
	1995	11319.3	84.6	26311.5	986.3	38701.7
	1996	11321.7	84.6	26341.8	986.3	38734.4
TEAŞ	**1997**	11436.3	84.6	26670.0	986.3	39177.2
	1998	11728.2	84.6	27321.3	560.9	39695.0
	1999	12802.9	84.6	28043.3	560.9	41491.7
	2000	12957.3	84.6	28450.3	560.9	42053.1
	2001	13166.6	84.6	28559.0	549.3	42359.6
TEİAŞ	**2002**	13625.5	84.6	28999.9	549.3	43259.4
	2003	13958.1	84.6	31430.7	718.9	46192.2

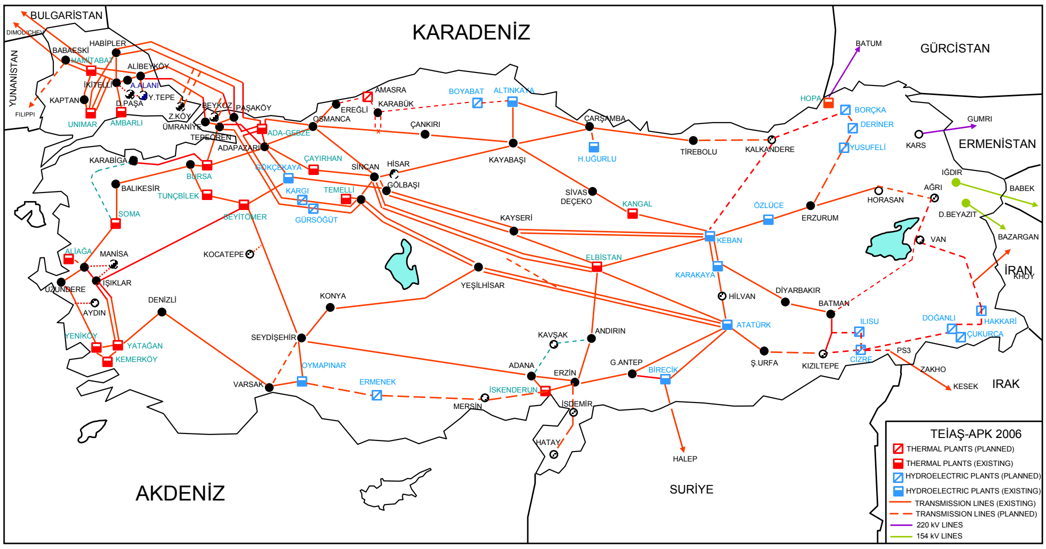
Note: The decrease in 66 kV transmission lines is as a result of operating these lines at a capacity of 33 kV.

Source: TEİAŞ, Electricity Generation-Transmission Statistics of Turkey, 2003.

[51] IEA (2005b), p. 135.

[52] Eastern dispatch region is not shown separately either in Figure 8 or Figures 28 and 29 in Annex and is included in northern and southeastern dispatch regions.

Figure 13: Transmission Line Network of Turkey



Source: TEİAŞ

Most of Turkey's installed hydroelectric generation capacity is located in the eastern region of the country, whereas most of the load originates from the west. Particularly during summer months, hydroelectric resources are used for meeting peak energy needs of the remaining regions, making Turkey's transmission grid prone to technical losses (see Figure 29 in Annex for generation and load balance during summer peak by region in 2003). Nevertheless, technical transmission losses currently amount to approximately 3 percent, a figure comparable to other IEA member countries. Table 6 shows annual technical losses.

Table 6: Transmission Losses, 2000–2003

	2000	2001	2002	2003
Total Input to Network (kWh)	106,719,331,392	104,629,539,758	105,473,456,122	112,824,307,111
Transmission Losses (kWh)	3,181,777,801	3,374,354,451	3,440,681,720	3,330,652,442
Ouput from Network (kWh)	103,537,553,591	101,255,185,307	102,032,774,402	109,493,654,669
Technical Loss	**3.0%**	**3.2%**	**3.3%**	**3.0%**

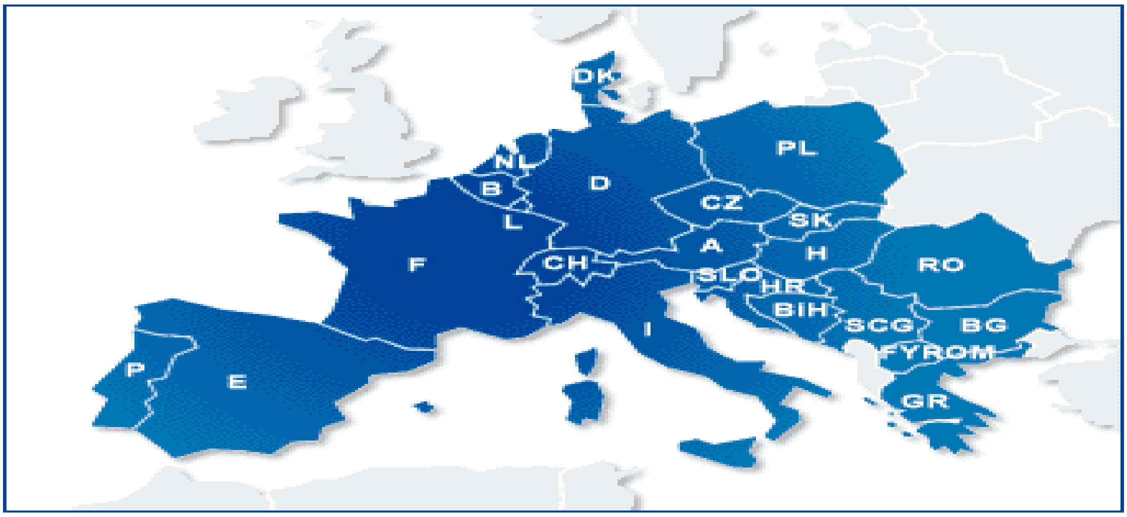
Source: TEİAŞ, Electricity Generation-Transmission Statistics of Turkey, 2003.

2.2.2.2.2 Interconnections and the UCTE (European Interconnection) Project

Currently, eight high-voltage, direct-current transmission lines in Turkey are interconnected with seven neighboring countries; a project is also underway to build a synchronous interconnection with the Union for the Co-ordination of Transmission of Electricity (UCTE) via Bulgaria and Greece. The interconnections and their capacities are as follows:[53] Azerbaijan (Nahcievan), 154 kV; Armenia, 220 kV (not active); Bulgaria, two 400 kV; Georgia, 220 kV; Iran, 154 kV and 400 kV; Iraq, 400 kV (operated at 154 kV); Syria, 400 kV; Greece, 400 kV (under construction).

The UCTE is an association of European transmission system operators, responsible for the synchronous (50 Hz frequency) operation of interconnected transmission system operators in most of continental Europe.[54] Currently, the UCTE serves around 450 million people in 23 countries throughout its control area, with total consumption amounting to approximately 2,300 TWh per year. The UCTE serves as a market base for the Internal Electricity Market (IEM) in the E.U. geographical area.

Figure 14: Area in Continental Europe Served by UCTE



Source: http://www.ucte.org

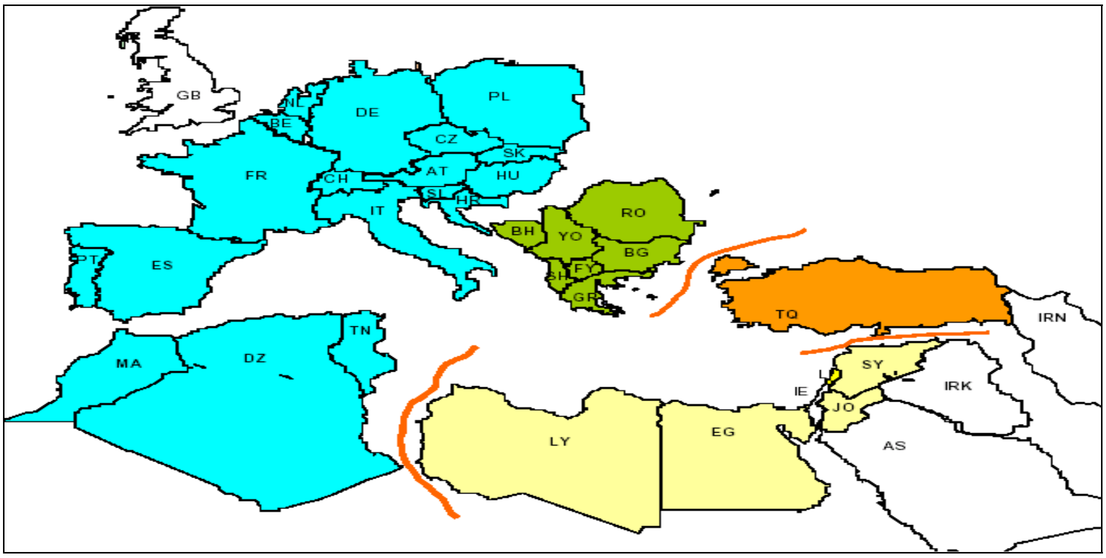
Two UCTE enlargement projects are underway. The first is the interconnection of the two largest power systems worldwide: The UCTE power system and the combined power system of the Commonwealth of Independent States and the power system of the Baltic states (UPS/IPS).[55] The second project is the interconnection of the UCTE power system to Turkey and the eastern Mediterranean region.

The part of the project that connects Turkey to the UCTE system includes a 400 kV connection between Turkey and Greece (currently under construction); in addition, two 400 kV connections already exist between Turkey and Bulgaria.[56] The Turkish power

[53] IEA (2005b).
[54] This section is based on information provided at http://www.ucte.org, and by TEİAŞ.
[55] The UPS/IPS power system includes Lithuania, Latvia, Estonia, Belarus, Ukraine, Moldova, Russia, Georgia, Azerbaijan, Kazakhstan, Turkmenistan, Uzbekistan, Khirgisia, Tajikistan, and Mongolia.
[56] In conjunction with this project, TEİAŞ currently is upgrading its system including generators and control systems in Turkey to allow for synchronous operation with the UCTE system.

system is expected to be in synchronous operation with the UCTE system in 2006, through either of its connections with Bulgaria and Greece.

Figure 15: UCTE Enlargement Project



Source: http://www.ucte.org

Regarding the eastern Mediterranean component of the second UCTE interconnection project, the UCTE intends to provide the synchronous interconnection of North African countries. Morocco, Algeria, and Tunisia — also known as Maghreb countries — are already synchronously interconnected with the UCTE system, via the Gibraltar submarine cable. Mashreg countries including Libya, Egypt, Jordan, Lebanon, and Syria constitute one interconnected power system; interface studies between these two blocks are about to be finalized. Furthermore, the UCTE is considering a permanent interconnection between two blocks provided that stability of the Mashreg system can be secured.

Completion of these projects will allow the UCTE frequency to reach both sides of the Turkish–Syrian border. The UCTE plans to investigate the stability of the interconnection binding three continents, and may consider closing the Mediterranean ring.

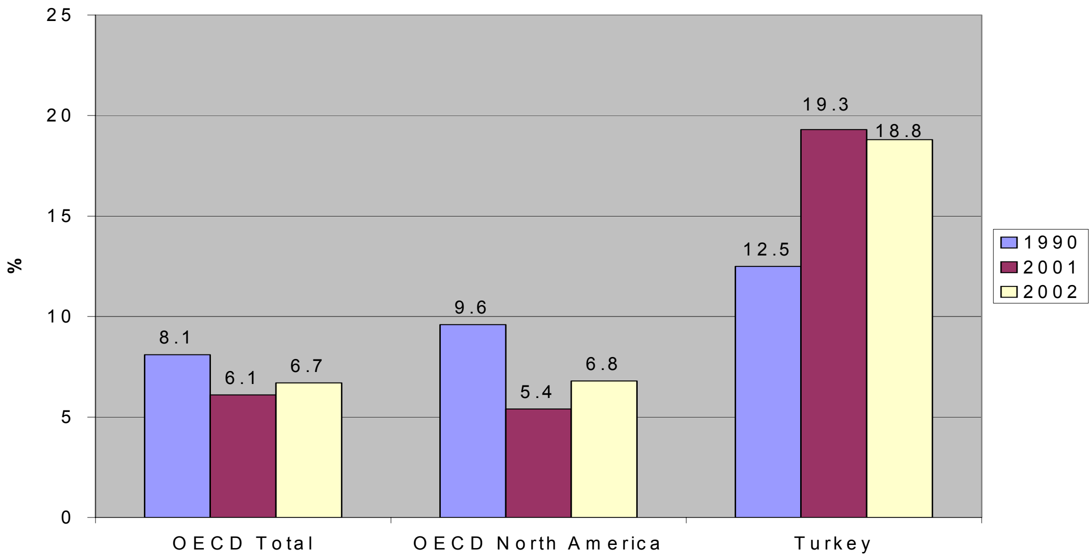
These projects' importance for Turkish electricity markets is significant. Not only will the projects enhance the efficient operation of Turkey's national electricity network and improve the security of supply, but they also create opportunities for Turkey to trade electricity with the rest of the UCTE network, contributing to the development of competitive restructuring. Interconnection will mean the opening of Turkey's domestic electricity market to international trade, thereby providing a check on the potential market power of domestic generators by constituting an alternative source of energy.

2.2.2.3 Distribution

Three types of entities are currently serving the distribution segment of the Turkish electricity industry: sixty-four TEDAŞ distribution authorities and seven regional, TEDAŞ-affiliated distribution authorities; two regional concessionaires (ÇEAŞ and Kepez Elektrik),[57] and a private franchise (Kayseri Elektrik Inc.-Kayseri province). TEDAŞ and its affiliates distribute electricity at voltage levels of 36 kV and below; in 2003 they served more than 95 percent of the customers in Turkey, with a 73 percent share of Turkey's total electricity distribution. That same year, TEDAŞ and its affiliates purchased electricity from TETAŞ (96.4 percent), autoproducers (0.8 percent) and ÇEAŞ, Kepez Elektrik, and Kayseri Elektrik (2.7 percent).

One of the major challenges lying ahead for the restructuring of the Turkish electricity industry is the combined problem of excessive losses in distribution: technical losses, and losses due to theft, poor billing, and uncollected bills. All these losses give rise to financial weakness within TEDAŞ, which in turn affects the balance sheets of TETAŞ and EÜAŞ. Distribution losses have been a chronic problem in Turkey's electricity industry, especially in the last two decades. TEDAŞ's technical and nontechnical losses amounted to 21.4 percent of total throughput in 2001, 20.9 percent in 2002, and 19.9 percent in 2003. Total losses declined to 18.6 percent of total throughput in 2004. (See Figure 16 for an international comparison of losses).[58]

Figure 16: Combined Transmission and Distribution Loss Ratios in OECD, 1990 and 2001–2002



Source: IEA, Electricity Information, 2004.

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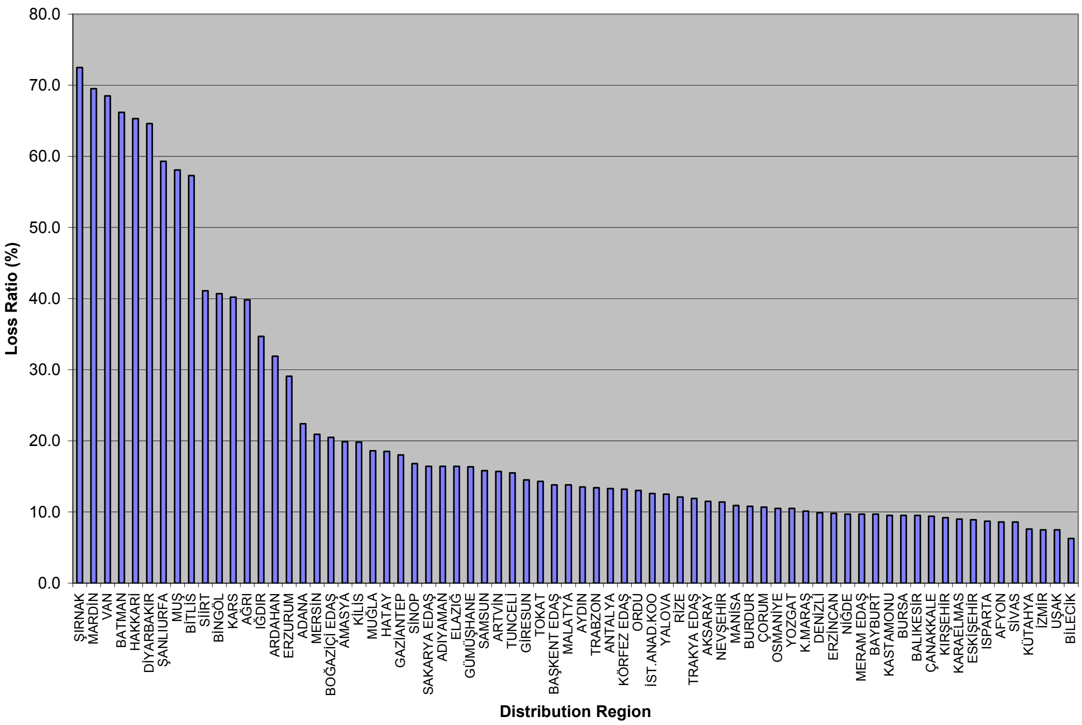
[57] ÇEAŞ and Kepez Elektrik were vertically integrated power companies operating under previously granted concessions. Their agreements were cancelled in 2003, and assets were taken over by the state.

[58] The IEA reports combined loss ratios of transmission and distribution. However, considering transmission losses around 3 percent on average, distribution loss ratios can be inferred as residual. Note that ratios given for Turkey reflect countrywide loss ratios, of which TEDAŞ losses are a part. 2002 is the latest year for which data is available for international comparison.

Note: The figure above is derived from data given by the IEA (2004).

Electricity systems are subject to technical losses in distribution (similar to losses suffered during transmission), which on average amount to 3–4 percent of total throughput in the OECD area. However, the major part of distribution losses in Turkey is due to theft (the unauthorized use of electricity either by hooking into distribution lines or by altering electricity meters). Loss ratios vary by region. (See Figure 17.)

Figure 17: TEDAŞ Distribution Loss Ratios by Region (percent), 2003

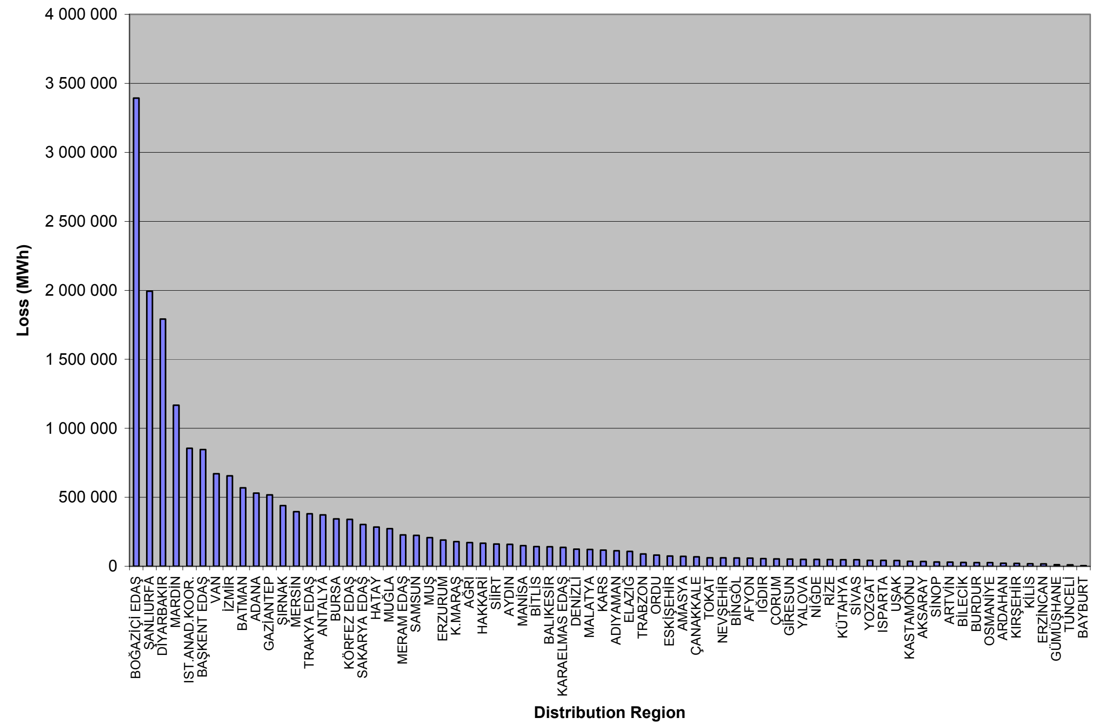


Source: TEDAŞ, Electricity Distribution and Consumption Statistics of Turkey, 2003.
Note: The figure above is derived from data given by TEDAŞ (2003).

Although loss ratios are relatively high in the underdeveloped eastern and southeastern parts of Turkey, industrialized regions such as Istanbul, Ankara, and Izmir are among the regions that have the highest absolute losses in terms of MWh.[59] (See Figure 18.)

[59] This point is relevant in the discussion of national tariff policy implementation contemplated by the Strategy Paper (see Section 3.6.1.6).

Figure 18: TEDAŞ Distribution Loss Amounts by Region (MWh), 2003



Source: TEDAŞ, Electricity Distribution and Consumption Statistics of Turkey, 2003.
Note: The figure above is derived from data given by TEDAŞ (2003).

In Turkey's case, estimation of the technical losses in the distribution segment proves difficult, given the existence of significant nontechnical losses and theft. TEDAŞ assumes a 6-8 percent technical loss ratio in their calculations, significantly higher than TEDAŞ's western counterparts. Under this assumption, technical losses in 2003 alone totaled approximately 6,143 to 8,190.6 GWh based on purchased electricity amount by TEDAŞ.[60] Because most losses are related to the lack of technical infrastructure, investments are needed to reduce losses. TEDAŞ and its affiliates invested U.S. $320 million and U.S. $280 million in 2003 and 2004, respectively for rehabilitation, upgrades, and expansion of the existing network.[61]

Finally, the electricity pricing framework played an important role in the financial troubles of TEDAŞ. For example, until 2004 some uses (such as consumption by houses of worship and street lighting for municipalities) were unbilled (see Section 2.4.1.4 for pricing categories). In 2003, TEDAŞ's unbilled delivery of electricity equaled approximately 2,478.1 GWh, or 3 percent of the company's net total sales.

For the purpose of tariff setting and privatization, the 2001 Electricity Market Law (Law No. 4628) and the subsequent Strategy Paper of 2004 issued by the government — a

[60] See TEDAŞ (2003) for purchased electricity amounts.
[61] Investment figures are from IEA (2005b), p. 139.

"policy document," discussed in Section 3.6 — envisages 21 distribution regions. Furthermore, the Strategy Paper considers the distribution segment as a first step in the government's privatization plan for the industry.

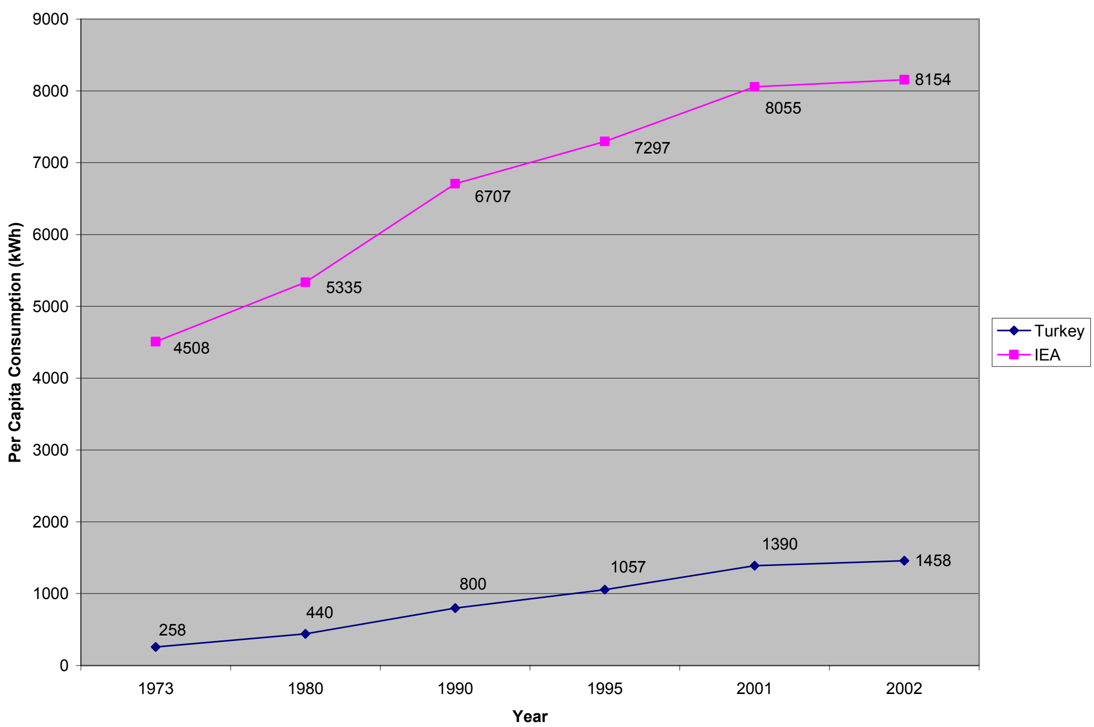
2.3 Demand Side

2.3.1 Consumption

Electricity consumption grew at a relatively high rate in the past several decades, due to high rates of economic growth. Average annual growth rates of consumption were 12.1 percent and 8.2 percent during the periods 1960–1973 and 1973–2002, respectively.[62] The economic crisis of 2001 resulted in a 1.2 percent decline in demand; however, consumption rates recovered thereafter, growing 6.1 percent in 2002 and 8.6 percent in 2003.

Total electricity consumption in Turkey was 20.3 TWh in 1980. This figure increased to 46.8 TWh in 1990 and 111.7 TWh in 2003. On the other hand, consumption per capita was 440 kWh in 1980 and increased to 800 kWh in 1990 and to 1,458 kWh in 2002. The IEA average per capita consumption was 8,154 kWh in 2002. (See Figure 19.)

Figure 19: Per Capita Electricity Consumption of Turkey versus IEA Average



Source: IEA, Electricity Information, 2004.

[62] Consumption = Electrical energy supplied – transmission and distribution losses. Data that follow are from IEA (2004) and TEİAŞ statistics.

Note: The figure above is derived from data given by the IEA (2004).

Over the past decades, the composition of consumption among the industrial and nonindustrial[63] sectors has changed in favor of the latter; particularly, the residential sector has increased its share of energy consumption. In 1973, shares of industrial and residential electricity consumption were 61 percent and 13 percent, respectively. In 2002, these ratios were 47.4 percent and 22.8 percent, respectively, reflecting a rise in standard of living. Corresponding ratios for IEA member countries in 2002 were 35.9 percent for the industrial sector and 30.3 percent for the residential sector.

2.3.2 Customer Eligibility

The new restructuring framework brought about by Law No. 4628 defines *eligible customers* as those who exceed consumption thresholds determined by the regulator, or who have a direct connection to the transmission system (eligible customers can therefore choose their own *energy* supplier). This new framework set a consumption threshold of 7.8 GWh for eligibility, and authorized EMRA to determine eligibility limits at the beginning of each year.[64] However, the March 2004 Strategy Paper stipulated that the eligibility limit set forth therein will remain in place through 2009, after which time all consumers will gradually be granted eligibility by 2011. (See Section 3.6 for further discussion.)[65]

According to June 2005 figures,[66] the number of currently eligible customers is 681. This number increases to 844 through aggregation of customers, and eligible customers now have a 28 percent share of Turkey's total electricity load.

2.3.3 Demand-Side Management

Law No. 4628 did not have a policy provision addressing demand-side management —an important shortcoming for restructuring legislation, considering the significant roles played by various demand-side measures in the establishment and maintenance of a competitive electricity market. (See Section 3.2.2.2 for the issue of demand-side management). However, TEDAŞ currently implements "time-of-use" pricing for almost all customer classes, which requires special digital metering. (See Table 10 in Section 2.4.1.4). As of December 2001, all new buildings are required to install digital meters; however, installing meters with time-of- use capability are optional. TEDAŞ does not keep records on the number of such meters in use; thus, assessing the demand response potential or load impact enabled by such metering is difficult. Until it was eliminated in April 2003, an increasing two block pricing scheme was in use for residential customers; in general, such a scheme aims to discourage high levels of energy consumption by

[63] Nonindustrial sectors include residential, commercial and public services, agriculture, transport, energy, and others (see IEA, 2004).
[64] Section 2 Article 5. b) of Law No. 4628.
[65] Initially, Law No. 4628 established the threshold for eligibility to be 9 GWh that was subsequently lowered to 7.8 GWh in January 2004 by EMRA. Most recently, EMRA lowered this threshold to 7.7 GWh in January 2005.
[66] Source: TEİAŞ.

charging customers more per kilowatt hours (up to 50 percent in this case) after the customer uses up to a given allotment (or *block*) of kilowatt hours. However, this scheme had a very low first-block allotment of 150 kWh per month, which effectively placed most households' consumption in the second block. Currently, however, no other demand response schemes are available.

2.4 Pricing, Tariff, and Cost Structure in the Turkish Electricity Industry

2.4.1 Current Pricing Practices

The current outlook for the Turkish electricity industry indicates a lack of focus on cost minimization; financial problems with respect to all segments of the industry; significant cross- subsidization among various consumer groups; and inclusion of cost elements unrelated to the provision of electricity service. These latter costs serve as an indirect form of taxation (for macroeconomic purposes), and consequently create suboptimal pricing schemes that create disincentives within the industry itself and thus result in distortions in other parts of the economy. Although both legal and functional unbundling of Turkey's electricity industry was realized in 2001, the industry is still organized in the form of a holding company that remains under state ownership. Furthermore, proper account unbundling has not yet been accomplished to the extent where it can allow the separation of costs for each industry segment — generation, transmission, and distribution — in customer billing. Thus, all pricing segments are still lumped together, revealing total cost only.

2.4.1.1 Generation

Cost figures from the state-owned generation company EÜAŞ — which generated nearly 45 percent of Turkey's total electricity output in 2004 — indicate an average actual cost of U.S. ¢8.84/kWh and an average full capacity cost of U.S. ¢4.74/kWh for its thermal plants. The EÜAŞ's overall average cost during 2004 was U.S. ¢3.06/kWh (See Table 7).

Table 7: EÜAŞ Average Generation Cost, 2004

Fuel Type	Production Cost (1)		Commercial Cost (2)	
	cent/kWh (actual*)	cent/kWh (capacity**)	cent/kWh (actual*)	cent/kWh (capacity**)
Fuel-Oil	8.37	6.85	9.35	7.00
Natural Gas	6.14	4.99	7.23	5.36
Coal	7.71	3.09	9.82	3.16
Thermal	7.16	4.66	8.84	4.74
Hydro	0.42	0.44	0.68	0.68
Average	2.39	3.01	3.06	3.06

Notes: (1) Production cost reflects generation-related costs, including operation and maintenance expenses.
(2) Commercial cost reflects the invoiced price, and includes all expenses (for example, administrative costs).
* Based on the number of hours generators actually run.
** When generators run on full capacity.

Source: EÜAŞ[67]

Note, however, that one must approach the EÜAŞ cost figures with caution because:

1) Only the operating costs of hydroelectric power plants are included in these calculations[68]; and
2) In any given year, all calculated actual cost figures vary by the number of hours the various plants were in operation that year, as *average* cost figures are obtained by dividing total annual cost by net generation — so, the less number of hours a plant runs the higher the resulting average cost.

Available cost data can therefore best be used only to *approximate* the average cost of electricity generation by EÜAŞ thermal plants.

In 2004, BOO, BOT, and TOOR contracts provided 36 percent of Turkey's total electricity output (mostly from gas-fired power generation). In the same year, the average price for the obligated purchase of energy was U.S. ¢5.97/kWh.[69]

2.4.1.2 Transmission

TEİAŞ recently adopted an "investment cost-based" transmission pricing method.[70] In this new approach, three types of charges are defined:[71] 1) a *connection charge* to recover the cost of network reinforcements required to provide service, 2) a *transmission use-of-system charge* to recover sunk costs of the existing transmission assets, as well as the operating and maintenance costs, and 3) a *transmission system operating charge* to recover loss- and congestion-related costs. The operating charge is uniform for all transmission customers. However, differentiated transmission use-of-system charges are calculated on the basis of 22 geographical zones. This zonal pricing scheme primarily aims to send long-term signals to influence the locations of new generators and new loads in order to minimize further investments in transmission and avoid congestion. The basic principle of the model is to include different investment cost requirements of various

[67] The data was provided by EÜAŞ specifically for this study to illustrate the costs of its plants in operation.
[68] The following long-time practice has been followed in the Turkish power industry regarding hydroelectric plants: State Hydraulics Works (DSİ) builds dams (most of which have irrigation functions as well) and transfers the ownership and operation of the resulting hydroelectric power plants to EÜAŞ (or, in the past, to EÜAŞ's predecessors, TEK and TEAŞ) by a written protocol which lacks any revenue requirement for recovery of construction costs, or other costs. Thus, EÜAŞ calculates only operation and maintenance costs of such plants, and includes them in their final, average cost calculations. Thermal plants, however, are subject to better cost-accounting procedures, which must account for capital costs, and employ conventional depreciation schedules.
[69] See Section 3.5 for more on these contracts.
[70] See "The Method for Determining Transmission System Use-of-System and Operating Tariffs," TEİAŞ, 2005, and "The Method for Calculating Connection Tariffs," TEİAŞ, 2004 (www.teias.gov.tr). This model was originally developed by the British National Grid Company.
[71] The following description draws on Bakirtzis, *et al*. (2001). See also this study for an application of this model.

connection points in determining the charges for the use of the transmission network (both for generation and for load).[72]

Table 8 displays TEİAŞ's most recent zonal transmission use-of-system tariffs and transmission system operating tariffs. Note that zone 23 is defined for interconnections (that is, for imports and exports).

Table 8: TEİAŞ Transmission Tariffs, 2005

	REGIONAL TRANSMISSION TARIFFS			
	Production* (Injection)		Consumption* (Withdrawal)	
Region	Transmission use-of-system Tariff	Transmission System Operating Tariff	Transmission use-of-system Tariff	Transmission System Operating Tariff
	YTL/MW–Year	YTL/MW–Year	YTL/MW–Year	YTL/MW–Year
1	16,664.70	253.69	5,885.75	253.69
2	10,574.67	253.69	13,465.22	253.69
3	7,440.87	253.69	15,340.48	253.69
4	1,605.33	253.69	20,079.36	253.69
5	11,538.90	253.69	8,827.40	253.69
6	19,603.06	253.69	1,865.29	253.69
7	76.44	253.69	26,730.69	253.69
8	1,899.69	253.69	17,726.62	253.69
9	5,300.70	253.69	15,402.55	253.69
10	76.44	253.69	18,555.31	253.69
11	5,026.67	253.69	12,642.94	253.69
12	6,958.01	253.69	19,538.03	253.69
13	10,751.91	253.69	14,263.47	253.69
14	76.44	253.69	39,070.65	253.69
15	76.44	253.69	27,613.38	253.69
16	10,699.88	253.69	14,461.70	253.69
17	9,551.52	253.69	13,677.77	253.69
18	76.44	253.69	27,009.85	253.69
19	76.44	253.69	17,094.53	253.69
20	76.44	253.69	23,225.82	253.69
21	6,549.67	253.69	16,271.24	253.69
22	6,731.07	253.69	10,705.48	253.69
23(**)	11,611.03	253.69	5,805.51	253.69

* Tariffs include a 1 percent surcharge to fund EMRA.
** Tariffs in production column are for imports.
Tariffs in consumption column are for exports.
Source: EMRA decision No. 470 (April 1, 2005).

[72] Ideally, the cost parameters of this modeling are calculated on a more detailed fashion via nodal costs. Aggregation of nodes constitutes zones.

2.4.1.3 Distribution

For the distribution segment of the industry, EMRA approves "distribution use-of-system tariffs" for 11 different customer groups; these customer groups are similar to ones in end-user tariffs (See Section 2.4.1.4). The distribution tariff structure includes a flat charge for each customer group, not differentiating between demand (capacity) and volumetric usage charges.[73] Table 9 reflects TEDAŞ distribution tariffs in effect as of January 2005.

Table 9: TEDAŞ Distribution Tariffs, 2005

Customer Category	Distribution use-of-system Tariff (TL/kWh)
Induction and arc furnaces	13,630
Industrial	14,820
Water suppliers	15,300
Waste treatment facilities	14,820
Commercial buildings, government offices, construction sites	18,750
Air-conditioned depots for agriculture	15,300
Residential	17,750
Nonprofit institutions, sports facilities, culture fishery	17,750
Veterans	15,100
Agricultural irrigation	15,300
Houses of worship, street lighting	15,300

Source: EMRA decision No. 272 (December 31, 2003).

2.4.1.4 Rate Classification, End-User Tariffs, and Taxes

Rate classification for end-users in Turkey makes an initial, broad distinction: whether or not any given customer is located in a "priority development province" (PDP).[74,75] Discounts of up to 6–7 percent are given to some customer classes located in PDPs. Furthermore, demand (capacity) and usage charges are separately indicated *only* for large industrial customers who use demand meters.[76] Finally, time-of-use pricing schemes are employed, with rate differences varying significantly across time periods, provided that customers use appropriate metering.[77]

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[73] This differentiation *is* made in end-user tariffs.

[74] According to the most recent (2005) rate classification being implemented by TEDAŞ.

[75] Priority development provinces are those provinces with per capita income of less than U.S. $1,500 in 2001, and which have a negative socioeconomic development index value, as determined by the State Planning Organization in 2003. Currently, 50 provinces come under this designation, which serves as the basis for TEDAŞ rate classification. (Note that there are a total of 81 provinces in Turkey.)

[76] Higher volumetric charges in single-term tariff categories indicate that capacity related costs are recovered through usage charges. However, optimal rate design principles require that a fixed "customer charge" be instituted for customers without demand meters to recover capacity related costs as well as other customer related costs such as metering and billing expenses.

[77] The time periods are as follows: 17:00–22:00, Peak Tariff; 22:00–06.00, Night Tariff; and 06:00–17:00, Day Tariff.

Currently, “retail sales tariffs”, “distribution use-of-system tariffs” and “transmission tariffs” are first determined, then added together, to form end-user tariffs. All tariffs are subject to EMRA approval before they become effective. Table 10 shows the most recent rate categories in effect in Turkey (as of 2005).

Table 10: TEDAŞ Rate Categories and End-User Tariffs in Turkey, 2005

Rate Class		Active Energy (TL/kWh)	Time-of-use Tariffs (TL/kWh) 17/22	22/06	06/17	Demand Charge (TL/kW)	Excess (TL/kW)	Reactive Energy (TL/kVARh)
A) TWO-TERM TARIFF								
Industrial	PDP	96,140	147,260	56,380	91,340	5,843,450	8,765,175	48,070
	Other	102,650	163,310	56,380	97,520	6,250,050	9,375,075	51,325
Induction and arc furnaces		94,290	142,650	56,380	89,590	4,507,750	6,761,625	47,145
Water suppliers	PDP	101,200	155,000	59,350	96,150	4,806,000	7,209,000	50,600
	Other	108,050	171,900	59,350	102,650	5,381,000	8,071,500	54,025
Waste treatment facilities	PDP	96,140	147,260	56,380	91,340	5,843,450	8,765,175	48,070
	Other	102,650	163,310	56,380	97,520	6,250,050	9,375,075	51,325
B) SINGLE-TERM TARIFF								
Industrial	PDP	112,240	184,040	58,240	106,640			56,120
	Other	119,800	202,740	58,240	113,810			59,900
Water suppliers	PDP	115,250	186,550	61,300	109,500			57,625
	Other	123,300	206,450	61,300	117,150			61,650
Waste treatment facilities	PDP	112,240	184,040	58,240	106,640			56,120
	Other	119,800	202,740	58,240	113,810			59,900
Commercial buildings, government offices, construction sites		151,950	277,250	61,300	144,350			75,975
Air-conditioned depots for agriculture		123,300	206,450	61,300	117,150			61,650
Residential	PDP	119,500	181,550	61,300	107,550			---
	Other	127,800	201,350	61,300	115,000			---
Nonprofit institutions, sports facilities								
Culture fishery		119,500	181,550	61,300	107,550			59,750
Veterans		81,800	120,800	61,300	69,000			---
Agricultural irrigation		115,250	186,550	61,300	109,500			57,625
Houses of worship	PDP	115,250	---	---	---			---
Street lighting	Other	123,300						---

Note: The rate categories and end-user tariffs shown here apply to TEDAŞ and TEDAŞ-affiliated distribution authorities, as of January 2005.

Source: TEDAŞ

The end-user tariffs shown in Table 10 include:

- A 2 percent surcharge levied on end-users; this surcharge subsidizes the Turkish Radio and Television Corporation (TRT), the state-owned broadcasting company.[78]
- A 1 percent surcharge to fund EMRA.

However, the end-user tariffs *do not* include:

- A municipality consumption tax, for customers located within the boundaries of an applicable municipality, equal to:
  - 1 percent for industrial customers, and
  - 5 percent for all other customers.
- An 18 percent value added tax (VAT) on all other charges.

Table 11 shows the historical development of VAT rates on electricity.

Table 11: Development of Value Added Taxes on Electricity

Value Added Tax (VAT)		
From	To	%
01.01.85	30.11.86	10
01.12.86	31.12.87	12
01.01.88	14.10.90	10
15.10.90	30.11.90	11
01.12.90	30.10.93	12
01.11.93	31.01.00	15
01.02.00	31.01.01	17
01.02.01	present	18

Source: IEA, Energy Prices and Taxes, First Quarter 2005.

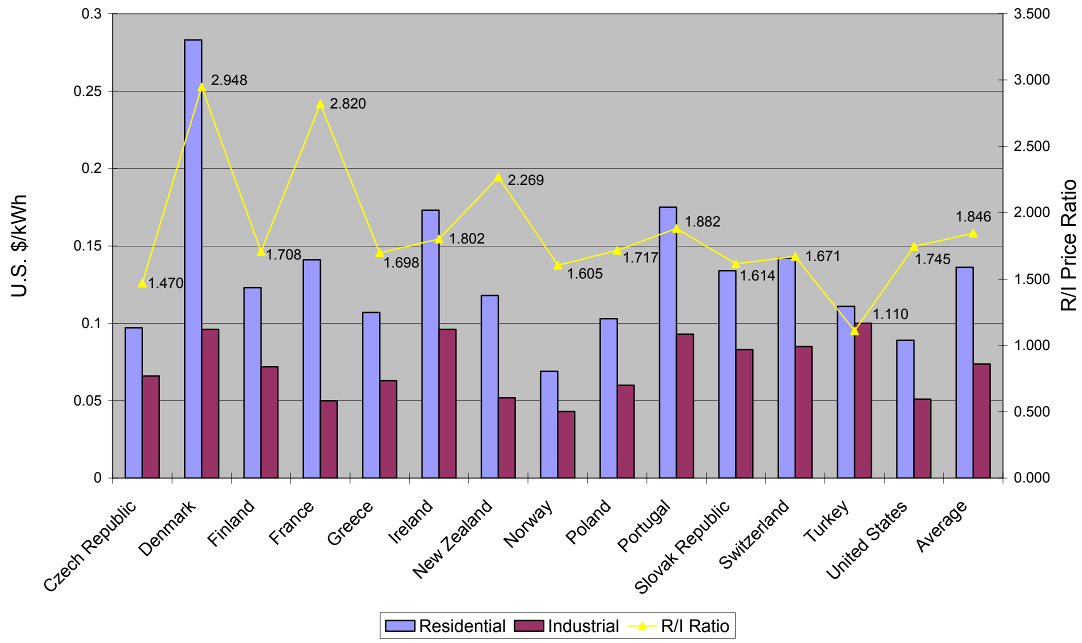
2.4.2 International Comparison

An international comparison of residential end-user electricity prices shows that in 2004, Turkey ranked slightly below the average of selected OECD countries. A comparison of industrial prices, on the other hand, indicates that Turkey has relatively high prices in the same group of countries. However, Turkey also has the lowest residential/industrial price ratio (1.11 versus an average of 1.84), which is indicative of a policy of relatively high

[78] This is a clear example of including cost elements unrelated to the provision of electricity service in electricity bills. While Article 13 of the 2001 Electricity Market Law disallows any cost items in tariffs not directly related to the market activities of a service provider (with the exception of a transmission surcharge to fund EMRA), funding for TRT continues, via end-user electricity tariffs. The surcharge was initially 3.5 percent, but was subsequently reduced to 2 percent in March 2003. Note that in the past, such surcharges were much more extensive, including a Treasury surcharge equaling 8 percent of TEDAŞ's gross sales revenues (see Kulali, 1997).

rate of cross-subsidy, which favors residential customer categories over industrial customer categories. (See Figure 20.)

Figure 20: Electricity End-User Prices in Turkey and Selected OECD Countries, 2004

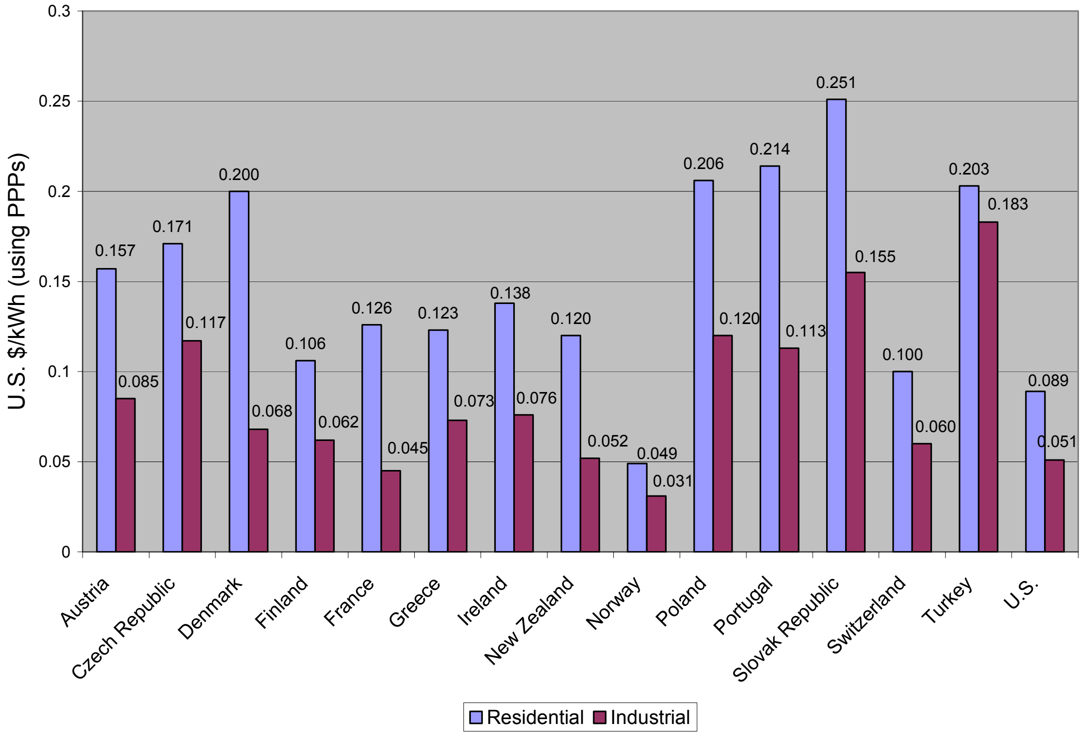


Source: IEA, Energy Prices and Taxes, First Quarter 2005.
Note: The figure above is derived from data given by the IEA (2005a).

On a purely cost basis, residential prices are expected to be higher than commercial and industrial prices, given that serving the former class of customers entails higher costs. These costs include those related to necessarily serving residential customers at a lower voltage levels than large customers; residential customers' low load factor and unpredictable load profiles; metering and billing costs.

A comparison of end-user prices by purchasing power parity (PPP) data shows that Turkey has the highest industrial prices among selected OECD countries, as shown in Figure 21.

Figure 21: Electricity End-User Prices in Turkey and Selected OECD Countries (using PPPs), 2004

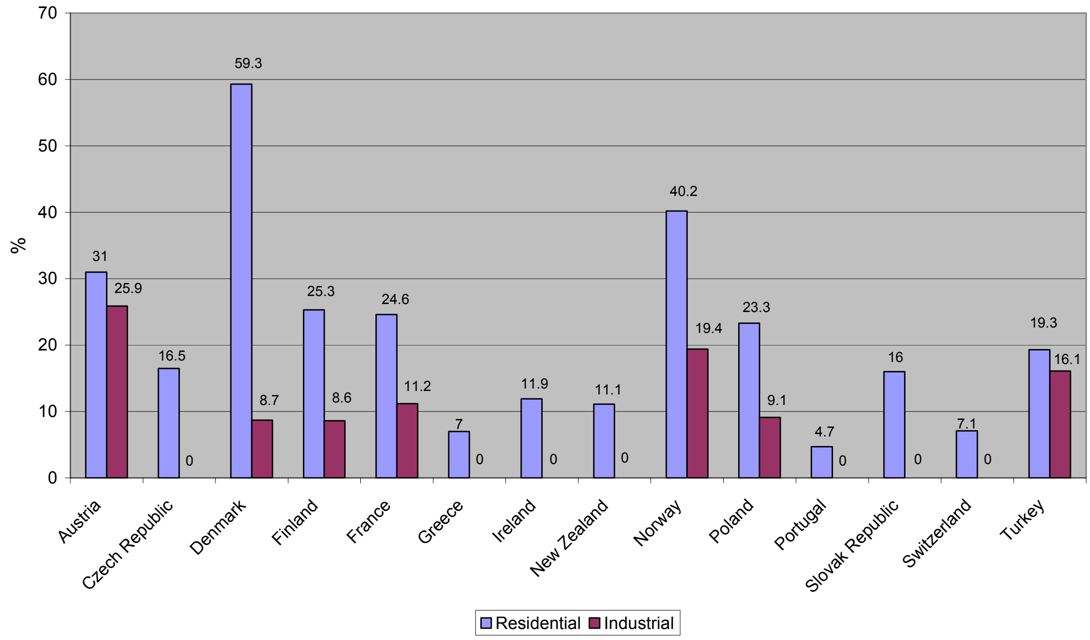


Prices exclude tax for U.S. data.

Source: IEA, Energy Prices and Taxes, First Quarter 2005.
Note: The figure above is derived from data given by the IEA (2005a).

Taxes on electricity for Turkish consumers are relatively high in comparison to many OECD countries. The level of taxes on industrial use is even more striking, and has a direct impact on input costs — and hence, on the competitiveness of the industrial sector in general. Figure 22 shows tax ratios for selected OECD countries.

Figure 22: Taxes on Electricity in Selected OECD Countries, 2004



Source: Energy Prices and Taxes, First Quarter 2005.
Note: The figure above is derived from data given by the IEA (2005a).

3 SELECTED OUTSTANDING ISSUES FOR COMPETITION IN THE TURKISH ELECTRICITY INDUSTRY

3.1 Regulatory Framework: Cost Calculation Issues, Pricing, and Tariff Setting

3.1.1 A Note on Pricing

A proper pricing policy in the electricity industry is of the utmost importance, not only for the industry itself but also for the economy as a whole, as electricity is a key input for the remaining activities of the economy. Economic distortions created by impaired electricity pricing will have significant repercussions for the overall allocation of resources. In an effective regulatory framework, cost-based pricing is the main tool used to determine the cost responsibility borne by each consumer group. Adoption of cost-based pricing schemes requires eliminating cross-subsidies among consumer groups, although minor exceptions — such as discounts for low-income residential customers — are possible. End-user rates (in case of a vertically integrated utility) or monopoly services rates (in an unbundled utility structure) can be set either by allowing investors to earn a fair rate of return on invested capital, or by adjusting rates periodically via price caps that are aligned with the rate of inflation. Nevertheless, the basis for these pricing methods must be the *actual* cost of service. Most importantly, electricity pricing in a state-owned industry should not be used as a policy tool for *indirect taxation* whereby cost items unrelated to the provision of electricity services are included in pricing schemes.

In the era of state-owned electricity industries in many countries, electricity pricing was to some extent initially seen as a public financing tool, either allowing for the provision of various public goods, or for the enhancement of budget revenue. However, in conjunction with pro-competitive regulatory frameworks, competitive electricity markets cannot allow such practices, as pricing in such settings should reflect only production-related costs (possibly including environmental externalities). Only in this way can prices serve as a market signal for present supply and future investments, which will keep the system in balance.

3.1.2 Pricing of Generation versus Monopoly Services

In an unbundled electricity market, the major focus of the regulatory framework is the pricing of monopoly services — namely the transmission and distribution of electricity, because the generation (energy) component of the service is subject to market-based pricing via competition. For the most part, leaving pricing of generation outside the new regulatory framework is a crucial cornerstone of any competitive restructuring. In this new environment, potential efficiency gains that will be achieved in generation are linked more to market design than to ownership structure.[79]

[79] With regard to British and Scandinavian experiences with state- or municipally-owned electricity industries see Newbery (1999).

For decades prior to deregulation (and unbundling) in the United States, the pricing of power produced by privately owned generation was subject to regulatory oversight through the mechanisms of *rate of return (ROR) regulation* and *fuel cost adjustment*. Thus, a vertically integrated utility earned an administratively determined rate of return only on its invested capital; the generated energy would be priced based on an adjustment mechanism for fuel cost, which would serve as a *pass through cost* for the utility company. This type of regulatory design provided little incentive for cost savings because most of the savings obtained by utilities was built into consumers' electricity rates.[80]

Economic theory suggests that one way of achieving system marginal cost (MC) pricing within a competitive wholesale spot generation market is through bid-based *auctions* for centralized power exchanges.[81] In fact, in markets with a single market-clearing price, bidders have an incentive to bid their short-run MC. (See Section 3.2.1 for further discussion of the operation of wholesale markets). In any case, power prices for large industrial/commercial consumers tend to be lower when compared to those of residential and small commercial customers, because large customers have cost advantages including predictable load profiles and high load factors.

On the other hand, in monopoly services, MC pricing is theoretically possible, albeit difficult in practice.[82] In regards to tariff making, regulators often are in a position to consider rate-making principles such as efficiency, simplicity, rate continuity, fairness, and earnings stability, while at the same time they must also consider meeting revenue requirements and following MC pricing principles. This combination of goals frequently present trade-offs, resulting in a sacrifice of the MC pricing principle to other objectives.

In a post-competitive restructuring environment, the pricing of monopoly services will still come under regulatory scope. When establishing tariffs, an effective regulatory framework that determines a pricing structure for end-users should reflect the full costs of service, by appropriately allocating the total cost incurred, according to each consumer class's cost responsibility. For example, tariffs for residential and small commercial customers should reflect the typically higher network costs required to serve them; such

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[80] Even though the U.S. electric power industry ranks high in productive efficiency compared to countries where state-owned electricity industry is dominant, rate of return is not viewed as the foremost regulatory pricing method. Most critiques of ROR regulation and proponents of deregulation in the United States have pointed to the lack of cost-saving incentives within this pricing method. A well-known study by H. Averch and L. Johnson in the early 1960s concluded that a guaranteed rate of return based on the amount of fixed capital invested results in an overbuilding of capacity; this is known as the "A-J effect" of ROR regulation. In fact, the A-J model analytically demonstrates that ROR regulation can result in a suboptimal capital/labor ratio, implying wasteful firm behavior. See Section 3.1.3 for further discussion.

[81] Stoft (2002) argues that market prices resulting from bilateral trade would be the same as those from centralized trade, as long as bilateral markets are perfectly competitive. (See Stoft, Chapters 3.1 and 5.4.)

[82] Pricing of monopoly services based on long-run MC, as indicated by economic theory, would suffice to finance future investments in the industry, to meet growth in demand. See Bonbright *et al*. (1988). See also the discussion in Section 3.2.1 on the pricing of generation in competitive wholesale spot markets where this principle differs in the short-run.

costs include the provision of electricity at a lower voltage level; metering and billing expenses; and customer service/administrative expenses.[83]

A *rate design* built upon a well-prepared "cost-of-service study" is the most vital issue regulators face in the new regulatory environment. Undertaking a cost-of-service calculation to determine key cost parameters and provide a basis for ratemaking, however, requires substantial expertise. A common misconception among newly liberalized markets and their regulators is that incentive regulations such as price caps (as set by the RPI-X method, for example) are easy ways to avoid cumbersome cost-of-service studies. To the contrary, proper implementation of price caps requires that cast-off rates for the initial period be based on a carefully designed cost-of-service calculation; otherwise, the starting point for the price cap may not be accurate.

The primary objective of rate design is to meet revenue requirements and create efficient pricing schemes. However, rates can also be designed to address social objectives, such as *affordability* for low-income residential customers. In such exceptional cases, low-income residential customers can receive services at a discount, financed (that is, cross-subsidized) by other rate payers, if policy objectives permit it. However, a consensus among consumer groups must be obtained through a collaborative process before implementation of the policy takes place.[84]

Rate design can also be structured to improve welfare gains by promoting either greater energy use or energy conservation. Multipart tariff designs that contain fixed components (for access/customer charges) and *declining* or *increasing blocks* (for usage charges) are examples of incentive pricing schemes used in the electric power industry. (In the case of declining blocks, consumers are charged lower prices at the margin as their consumption increases; the reverse is true for increasing block rate design.) In multipart pricing schemes, MC pricing for usage charges may become feasible with the help of optimally determined fixed component charges.

A typical power system has a load factor of less than 1, reflecting peaking periods in its load curve. The lower the load factor, the greater the system's need for capacity only during times of peak uses. The high cost of peak generation capacity and the energy it generates will eventually be reflected in a system's overall cost figures.[85] *Time-of-use (TOU) pricing* is another incentive pricing scheme that aims to shift demand times by considering peak time capacity constraints. Setting energy prices based on TOU in order to reflect time-varying costs of power not only corrects the distortion created by standard (or flat) pricing, but also lessens the need to install additional peak capacity. Although pricing electricity generation in competitive frameworks would then be largely left to the market (with minimum oversight required by regulatory agencies[86]) incentive pricing

[83] On the other hand, network capacity related costs for these customer classes would be lower than those for larger customers.
[84] Note that the first-best policy in this case is to provide direct subsidies to such consumer groups. However, implementing direct subsidies may lead to administrative as well as political difficulties.
[85] On average, the unit cost of peak power will be double or triple the cost of baseload or midload power.
[86] However, "hard/soft price caps," which set maximum prices for electricity generation, can be applied by regulators during abnormal market conditions, such as supply shortages, or *force majeur*.

schemes can be carried out with the help of regulators. At times of peak usage, extra capacity is needed, not only for generation but also for network services. Similarly, establishing TOU tariffs for network services helps avoid extra investment in capacity for transmission and distribution.

3.1.3 Distribution Pricing: Rate of Return versus Performance-Based Ratemaking

The pricing of distribution services is important, as up to half of a typical end-user's bill may reflect distribution charges. The pricing structure should therefore properly assign costs to the relevant user classes, depending on their respective cost responsibility, with a possible exception given to subsidies for low-income residential customers.

There are two principal rate-setting mechanisms in distribution pricing through which *base rates* are determined: rate of return (ROR) regulation and performance-based regulation (PBR). Sometimes a combination of the two methods is used. These methods serve as the basis for tariff making, upon which some variations of multipart and TOU pricing schemes are built.[87]

Regulators in the United States have used ROR regulation extensively to set rates for a wide variety of utility services, including electricity, natural gas, water, and telecommunications. Under this method (also known as *cost-based regulation*), the regulated firm is allowed to recover all "reasonable" costs it incurs plus a reasonable opportunity to earn a "fair" rate of return on capital invested. Although extensive and detailed accounting rules as well as established conventions provide guidance whether expenses incurred reasonably, it is the regulator's function to make the final determination as to what costs will actually be recovered. The fairness of the rate of return also is decided at the discretion of the regulator, by taking into account industry wide parameters and making necessary adjustments for any given utility. Consequently, pricing under the ROR method necessitates a highly administrative process and discretionary decision making. The method itself can be briefly described as follows:[88]

Whenever a regulated firm seeks a new set of tariffs or modification to its existing tariffs it files a *rate case* with public utility regulators. Typically, the firm claims that new rates are necessary in order for the firm to meet its *revenue requirement* (RR) — that is, the overall cost of providing its service, plus a return on invested capital.[89] A firm's RR can be expressed as:

[87] The following discussion on distribution pricing draws on Aybar, Guney, and Suel (2001); see Section 5.2 for a more theoretical analysis of optimal regulatory pricing.
[88] This description follows the modeling framework put forward by Averch-Johnson (1962), which attracted much attention with regard to the ROR method.
[89] The regulated firm is allowed to recover all reasonable expenses, including operation and maintenance costs; however, the firm can earn a return only on invested capital and capitalized expenses, such as labor used in building physical plants, for example.

$RR = \Sigma\ P\ Q = OC + Kf$

where

P= Price;
Q= Quantity;
OC= Allowable operating costs for noncapital inputs;
K= Capital invested; and
f= Allowable (fair) rate of return.

The method treats capital as a base input; the firm's ROR is calculated on the basis of capital invested, with *f* being the maximum allowable rate. In other words,

$\frac{\Sigma P\ Q - OC}{K}$ = earned rate of return (e) — that is, net revenues per base unit

and $e \leq f$

This method has drawn criticism, on the basis of Averch-Johnson's conclusions that it provides firms incentives to increase their profits by increasing the amount of capital they use, which in turn leads to unnecessarily high capital intensity and higher costs.[90] While theoretical research points in this direction, empirical findings are mixed. However, the ROR method fairly clearly lacks an *incentive* mechanism that would encourage regulated firms to control costs. In fact, any cost savings achieved by a given firm would be transferred to consumers by the very structure of the ROR ratemaking mechanism.

Another shortcoming of ROR regulation is the unintended time lag caused by lengthy rate cases. By the time new rates become effective, fast changing, cost conditions may necessitate that the firm seeking a rate change adjusts to a new set of cost parameters. This in turn prompts the firm to file rate cases more frequently, which in turn entails costly regulatory proceedings (which, however, are generally recoverable through rates), which in turn affects the cost of service.

Over the last decade, regulators have increasingly employed methods that involve less administratively determined pricing mechanisms. In the new competitive environment, performance- (or incentive-) based methods are gaining ground. These methods contain built-in incentive mechanisms and quasi-automatic adjustments for pricing. In this new framework, regulated firms have an incentive to improve productive efficiency, because any achieved efficiency gains (that is, cost savings) accrue to the firms.

[90] This conclusion can be reached as follows: Assuming only one noncapital input, maximization of profits Max $\pi = RR(L,K) - wL - rK$, subject to the RR constraint $[RR(L,K) - wL]/K = f$, results in $MP_K/MP_L < r/w$, where L= noncapital input, r = cost of capital, w = cost of noncapital input and MP = marginal product. Under this conclusion, the regulated firm acts as if the cost of capital is cheaper than it actually is, resulting in higher than necessary (suboptimal) K/L ratio for a given level of output, also known as the "A-J bias" of ROR regulation.

One common performance-based regulatory design is the *price cap* (PC). Under this design, price increases for monopoly services are capped at a predetermined level for a period of time (the *review period*),[91] during which the firms are allowed to keep any efficiency gains. Price caps were first used in the United Kingdom to encourage efficiency for newly privatized public utility companies.

The basic formula for setting a PC is:

PC = RPI – X

where RPI is the change in the retail price index, and X is the *expected* annual increase in the productivity level (or *efficiency*) of the firm. "X" is established upfront, and is kept constant for the review period.

Under this mechanism, firms are allowed to charge a price at or below the cap, and to keep additional cost savings achieved through any efficiency improvements for the review period. For example, if, X is initially set to 2 percent and RPI is 5 percent, this is an indication that the price increase of the service will be capped at 3 percent per year throughout the review period. However, when a firm's actual productivity rises at a higher rate (say 3 percent, instead of the 2 percent initially envisaged) the firm effectively receives a 4 percent increase in price, rather than 3 percent, and makes an additional 1 percent in profits. Hence, firms have an incentive to adopt efficiency improvements, so that they can continue to accrue surpluses until their next rate review.[92]

Meanwhile, consumers benefit from PC regulation by way of periodic reviews of the price cap. At the end of each review period, regulators assess whether a given firm made excess profits, or lost money. In a situation where the actual productivity gain was determined to be greater than the expected level (X) initially set in the PC formula, regulators can lower the cap (that is, lower the rates) to transfer some of the corresponding cost savings to consumers.[93]

When using price caps, regulators must be aware of the potential for utilities to engage in *strategic behavior*. In most cases, regulators rely on cost data from a specific reference year (called the *test year*) for the cost-of-service study; this reference point is usually chosen as the most recent (and therefore, most up-to-date) year available. This

[91] Generally, review periods span over several years.

[92] More specifically, a refined PC formula can be described as follows:

$P_{(t)} \leq P_{(t-1)} * (1 + RPI_{(t)} - X \pm Z_{(t)})$

where

$P_{(t)}$ is the company's weighted average price (cap) in year t;

$P_{(t-1)}$ is the company's weighted average price in year t–1;

$RPI_{(t)}$ is a retail price inflation index for year t;

X is a productivity offset that would remain constant throughout the review period, and;

$Z_{(t)}$ is an adjustment for exogenous costs that might occur in year t.

(See http://www.mass.gov/dte/gas/96-50/9650p1-2.pdf for an application of the PC formula above).

[93] Also, the initial setting of the X-factor level may result in additional benefits for consumers, as higher levels of the X-factor yield lower caps.

methodology can provide an incentive for wasteful behavior by firm in question, which may choose to inflate costs in that particular year, and hence achieve a higher cap to increase profits in subsequent years.[94]

Note that the PC method features a built-in regulatory lag, to provide room for utilities to improve their productive efficiency and thereby benefit from it. However, the optimality of this lag closely depends on the economic environment within which any given utility operates. In an economy characterized by high inflation, the PC mechanism would need more frequent adjustments — thus shorter and more frequent review periods — than it would in a low inflation economy.[95] When compared to ROR regulation, the PC mechanism obviously represents a more flexible, cost-effective method of regulation.[96] However, more frequent reviews may result in inefficient behavior, similar to that under ROR regulation. While less frequent reviews carry the greater potential of efficiency improvements, the possibility of a utility's strategic gaming of the regulatory rules still exists.[97] Thus, regulators must remain vigilant to minimize less-than-favorable outcomes in pricing.[98]

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[94] In general, rate reviews can be prompted by either changes in input costs or an increase in a firm's positive profits. The change in input costs is exogenous to the firm, and can easily be adjusted, by tying the cap to an *input price index*. In this way, subsequent increases in input costs will induce a review of the cap, and the firm will not change its cost-minimizing behavior. On the other hand, when the review is triggered by excess profits, the utility may strategically base its behavior on its expectations regarding regulatory action. If regulators announce in advance that they will switch from ROR regulation to PC regulation, the firm may employ more wasteful behavior prior to switching, in order to have its cap set at a higher level (thereby inducing higher profits). If the review is announced while PC regulation is being implemented and regulators are known to consider the most recent year of operation as the test year, then the utility can minimize its costs in other years, and inflate costs in the last year. (See Train, 1991, pp. 325–328). Train states that "[U]nless the firm's discount rate is very high, the present value of current and future profits will be higher if the firm wastes in the year before a review." (*Ibid*., pp. 327-328).

[95] Note that in price caps, rates are updated (adjusted) annually for inflation by the formula.

[96] However, under the PC mechanism while a utility may increase its efficiency by cutting its production costs this may at the same time result in lower service quality. For this reason, appropriate mechanisms should be established by regulators to maintain a certain level of service quality.

[97] *Ibid*., p.328.

[98] Another PBR mechanism is called *earnings sharing* (ES). In ES, utilities' revenues are capped at a given level by assuming a corresponding level of demand. Under a typical ES mechanism, a given utility's excess profits (or cost savings) are shared each year with customers, either by a rate offset or a refund. In effect, the ES mechanism acts to limit or dampen earned return variations from a benchmark rate of return, and cost savings are passed onto consumers, as in the case of the price cap method. Thus, the ES mechanism essentially represents a hybrid of ROR and price cap methods, with an emphasis on providing incentive for cost-minimizing behavior by the utility. (Schmidt, 2000. See Chapter 3 of Schmidt (2000) for more on the earnings sharing method). *Revenue cap* (RC) regulation is similar to price cap regulation such that the regulated firm's revenues rather than prices are capped under a revenue cap index (such as RPI-X). RC regulation is a more preferable method relative to a price cap regulation when costs of the utility do not vary significantly with unit of sales. Revenue caps can be used for conservation purposes as well. *Benchmarking* is another pricing mechanism where the utility's performance is compared to other (similar) utilities and penalties and awards are assessed based on the utility's relative performance. Benchmarking can also be used for service quality regulation. (See Jamison, *et al*., 2004).

3.1.4 Transmission Pricing: Embedded Cost versus Locational Pricing

One of the major outcomes of the competitive restructuring of electricity markets is an increase in the volume of wholesale trade. This is reflected by an increase in the number of transactions conducted over the interconnected transmission system. When competition is introduced in the generation market, the number of transactions is expected to increase geometrically, thus making the existence of *transmission capacity* necessary to support electricity trade and maintain reliability an essential condition for competitive restructuring. Accordingly, transmission capacity plays a vital role in developing a competitive generation market, as well as in accommodating and encouraging new and efficient capacity growth in electricity generation. In this setting, a transmission system that accommodates a functioning competitive electricity market necessitates a *pricing mechanism* that allows not only for the recovery of transmission costs but also the required incentives related to investments in generation as well as in transmission capacity expansion.

One natural consequence of an increased volume of transactions over a transmission network is the possibility for *transmission congestion*. Congestion in transmission occurs when the *flow limits* of a transmission line are not observed.[99] In such instances, the capacity of a transmission line from a given point A to a given point B becomes inadequate, and the import capability of the downstream region (toward point B) is restricted. A more expensive source of generation located within the downstream region may then have to provide the needed power.

In the short run, congestion in a competitive market can be managed in two ways: by transmission operators forcing the dispatch to observe power line limits, or through competitive *locational pricing* schemes that discourage overuse of power lines. In either case, as demand grows investment in new transmission lines becomes necessary, and a transmission pricing scheme is needed, not only to target simple cost recovery, but also to provide appropriate incentives for location of future investments both for transmission and for generation. Transmission pricing can serve as an important tool to enhance overall efficiency of a network.

Two types of transmission pricing are currently in practice.[100] The first — *embedded-cost pricing* — is based on recovering the costs of operational expenses and transmission

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[99] Transmission lines have physical flow limits that are related to capacity and that can restrict the amount of electricity that can be transported over the line. Line losses can cause power lines to heat; *thermal limits* are therefore set on the lines to prevent overheating. Electrical currents influence the line losses; thus, by keeping power lines at their rated voltage, the current can be limited by limiting the power flow (as dictated by the formula Current=Power/Voltage). The thermal limit of a transmission line can be observed by limiting the amount of power the line is allowed to carry. When thermal limits are exceeded, the line can sag, or even melt and break. Power lines also have *stability limits* that specify a maximum flow of power. Stability limits are linked to voltage — and thus to phase differences between the generator end and the load end. If these differences exceed allowed limits, a brown out (that is, a sag voltage) can occur; or, more seriously, a voltage collapse may take place at the load end. Voltage collapse can cause the entire AC interconnection to break down. (See Stoft (2002), Chapter 5.2).

[100] See Bjornsson *et al*. (2004) for this classification.

investments. This method generally follows the *average cost* pricing principle; its simplest form, known as "postage-stamp" pricing, imposes a flat charge per MWh within a particular zone. Transmission systems in most of the United States use postage-stamp pricing.

Being the least sophisticated method, postage-stamp pricing does not take into account:

- the location and the distance through which energy is transmitted;
- actual cost differentials of power delivery for different voltage levels[101]; nor
- congestion at peak times.

Variations of the embedded-cost pricing method geared toward investment cost recovery uses multipart pricing, in which prices do not vary by location or congestion, but instead differ by voltage, distance, peak and off-peak time demand (capacity) and/or energy use.[102] Multipart tariffs that institute separate charges for peak and off-peak time demand and/or energy represent an improvement over postage-stamp pricing in terms of providing incentives for optimal capacity use. Embedded-cost pricing can be implemented through either the ROR or PBR (for example, RPI-X) methods.

The second approach to transmission pricing is an *incentive based* approach that takes into account the location at which power is injected into and withdrawn from the grid. Through such *locational pricing*, users of transmission service are encouraged to make use of transmission lines in ways that minimize or relieve congestion, and potential investors are encouraged to make transmission (and generation) investments where needed.[103] Competitively determined locational prices are sometimes called locational marginal prices (LMPs) because they reflect the marginal cost of supplying an extra MW of power at a specific location given existing transmission constraints.[104] Locational marginal prices reflect true market cost signals and lead to efficient use of generation and transmission resources.

[101] The cost of building transmission lines positively correlates with voltage levels, as higher voltage transmission lines are more costly to build. Thus, charging a flat price for both high and low voltage lines causes a cross-subsidization (in favor of low voltage lines) in cost recovery. Note that technically an inverse relationship exists between voltage levels and loss ratios for transmission lines, as higher voltage transmission lines entail lower losses, thereby reducing the effective cost of transmission. This fact is not typically taken into account when regulators set transmission rates.

[102] While Germany uses a distance-based transmission pricing method, England and Wales use a method that takes into account zonal incremental costs.

[103] The locational pricing method is used in competitive markets to develop energy prices that differ by location due to lower generation costs in certain locations and limitations on transmission capacity (congestion). Conversely, absent transmission congestion, arbitrage would lead to a single price of power for two locations with differing costs of generation. Locational pricing applies charges to users of transmission lines based on the locations where power is injected or withdrawn. The injection and withdrawal points are called *nodes*. Differing *nodal* and *zonal* prices of power are calculated based on the congestion on a specific line. (See the ensuing discussion for more on zonal pricing.) Locational pricing is also called *congestion pricing*. Congestion pricing can be implemented to manage congestion in the short-run in addition to an embedded-cost pricing scheme.

[104] Each LMP has three components: energy, losses and congestion.

The most sophisticated locational transmission pricing method is called *nodal* pricing, in which the price is calculated at each node of the network.[105] In nodal pricing, when the transmission path from A to B is congested, the nodal price of power at B will be higher than the price at A.

In a competitive market, *transmission rights* can be traded separately from the power that is being supplied. The equilibrium price of transmission rights on a congested line is equal to the difference in the price of power between any two trading nodes. To secure access to transmission capacity and reduce fluctuations in nodal prices, system operators can provide transmission rights (either financial rights or physical rights) by way of auctions to users of the network. Locational pricing can be implemented through a central dispatch, by power pools and exchanges.[106] (See Section 3.2.1.1 for further discussion of power pools and exchanges.)

3.1.5 Third-Party Access and Interconnection

Even with a competitive generation market and properly priced transmission and distribution services, the wholesale electricity market cannot function effectively if transmission or distribution service providers practice discriminatory pricing or restrict access to the network. For consumers to receive the full benefits of competition within the generation market, suppliers should be able to transport electricity to end-users in an unfettered way. Securing open access or TPA to network lines at the transmission and distribution levels is a central component of competitive restructuring.

In a liberalized electricity market, TPA is used as a regulatory tool to require vertically integrated utilities to grant open access on their network and apply nondiscriminatory tariffs to power producers, traders, and customers in general. Without a TPA rule, transmission owners and their affiliates might limit access to their network facilities to sell their own power, thereby exercising market power and maintaining an unfair competitive advantage. Consequently, customer choice at the retail end — the most crucial result of a competitive market — may not be attained.

Third-party access rules can also be designed to guarantee access to information regarding the availability of network capacity, so that open access can be effectively implemented. The owners of network facilities — transmission facilities in particular — can transfer operation and control rights to an independent system operator, which then would implement the TPA rules. Such a centrally operated capacity availability

[105] For example, currently 3,000 nodal LMPs are being calculated by PJM Interconnect in the United States. A simpler form of nodal pricing is called *zonal pricing*, in which nodes are grouped into zones (areas) within which no significant congestion occurs. For instance, as a first step towards full nodal pricing, New England ISO (which runs the system operation and wholesale electricity markets for six states in the United States) has been implementing nodal congestion pricing for generators and zonal congestion pricing for load points since March 2003.

[106] See Stoft (2002), Chapter 5.4 for a discussion on how perfectly competitive *bilateral* trading would also result in the same competitive locational prices as centralized markets do.

information system can facilitate open access and prevent discrimination in regard to access.[107]

3.2 Market Design Issues

3.2.1 Wholesale Markets

3.2.1.1 An Overview of Wholesale Energy Markets and System Operation

As stated earlier, an increased volume of wholesale electricity trade is a significant indicator of the presence of a competitive market structure. Accordingly, the market design for wholesale trading is of great importance to establishing an efficient and workable market. In this regard, *power pools* and *power exchanges* are widely used platforms for wholesale transactions.

A power pool is an entity that primarily performs centralized system operations (mainly the dispatch of electricity) by scheduling supply and demand for a control area, generally considering merit (least-cost) order.[108] In other words, pools fulfill the function of a system (or transmission) operator to coordinate the physical dispatch of energy. A power exchange, on the other hand, serves as a marketplace for wholesale trade, by determining market-clearing prices and their corresponding quantities, and schedules the dispatch of power to be executed by the system operator.[109]

In some markets the functions of power pools and power exchanges are integrated into one, such as occurs in the markets of Pennsylvania-Jersey-Maryland (PJM) Interconnect,

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[107] In the United States, the Energy Policy Act of 1992 allowed greater competition in the generation segment of the electricity market by ordering transmission owners to provide TPA on their network facilities. In 1996, in response to the provisions of this act, the Federal Energy Regulatory Commission (FERC) issued its Order 888, which required all private utilities to file nondiscriminatory, open access transmission tariffs, and to set minimum standards for their service to levels similar to the standards of the service they provide to themselves. Additionally, Order 889 required the establishment of a real-time information system, to make sure all parties can gain access to information regarding the availability of transmission services. Similarly, the E.U. Electricity Directive of 1996 directed all member countries to provide independent power producers access to transmission and distribution networks, and required member states to choose between one of three types of access arrangements: negotiated TPA, whereby producers and consumers who are parties to a contract negotiate with transmission and distribution companies for access; regulated TPA, whereby access tariffs are determined by the regulator; and the single buyer model (SBM), whereby retail choice is limited and a single wholesale buyer procures energy at regulated prices for noneligible (captive) customers. See EC (1996). Because of uneven progress among member states in the areas of open access and market opening, the European Commission issued a new directive in June 2003, repealing its 1996 directive, to adopt regulated TPA with published tariffs and to eliminate SBM. By this new directive, full market opening is scheduled for all member states by 2007 (by July 2004, for all non-household customers and by July 2007, for all customers). See EC (2003). The Electricity Market Law of 2001 adapted regulated TPA arrangement for access to transmission and distribution networks in Turkey.

[108] For example, New York Power Pool operated a merit-based dispatch of electricity through generators' regulated MC data until 1999, when it switched to bid-based (market-based) dispatch under New York Independent System Operator. Similarly, New England Power Pool implemented a merit-based dispatch system prior to the establishment of New England Independent System Operator in 1997.

[109] See Bjornsson *et al*. (2004) for an analysis of this topic.

New England Independent System Operator (NE-ISO), New York ISO and Midwest ISO of North America, and England and Wales (prior to the 2001 reorganization). In these markets, a system operator is responsible for running the centralized dispatch, day-ahead and real-time energy markets, and coordinating the bilateral contracts.[110] In other markets, such as in California (before the electricity crisis of 2001) and in England and Wales (after 2001), pools (system operators) and exchanges are organized as separate entities for the activities of dispatch and trade, respectively.

In summary, ISOs and ITCs perform the following tasks:

- operational management of the transmission grid;
- coordination of bilateral contracts;
- wholesale energy market operation;
- capacity market operation;
- supply dispatching;
- the provision of ancillary services (such as reserves, regulation, balancing, and voltage support)[111]

Each of these ISO functions aims to maintain system reliability and operate markets efficiently.

Additionally, several ISOs in North America have begun to implement *multi settlement* and *congestion management systems*.[112] The multi settlement system includes two market settlements for wholesale energy markets: a) day-ahead financial markets; and b) real-time physical markets. The congestion management system, on the other hand, deals with the implementation of locational marginal pricing (explained in Section 3.1.4).

The new model determines energy clearing prices as locational marginal prices in both the day-ahead and real-time markets. The day-ahead market is a financially binding

[110] The term ISO — independent system operator — is used for defining system operators in North American electricity markets. *Independent Transmission Company* (ITC) or *Transco* are other terms used elsewhere (see subsequent discussion). The importance of "independence" for such organizations is emphasized later in this section.
[111] Ancillary services (also known as *interconnected operations services* in the United States) are those services necessary to support the transfer of electricity between purchasing and selling entities; they are generally demanded and provided by the system operator. Their provision is needed for reliability, and to maintain the quality of power supplied. Although varying and broader definitions of ancillary services exist within different jurisdictions, the North American Electric Reliability Council (NERC) — which also follows the federal regulator FERC's convention — defines six ancillary services: 1) energy imbalance service (balancing), 2) operating (spinning) reserve service, 3) operating (supplemental or non-spinning) reserve service, 4) reactive supply and voltage control, 5) regulation and frequency response service, and 6) scheduling, system control and dispatch service. (See Glossary of Terms: NERC, 1996). Stoft (2002), however, defines ancillary services by the benefit they provide to the market — not by their method of provision (as given by the NERC list). Thus, ancillary services include balancing and frequency stability, voltage stability, transmission security, economic dispatch, financial trade enforcement, and black-start capability (in case of system failures). See Chapter 3.4.
[112] See ISO-New England (2003) and http://www.iso-ne.com for more on the implementation of this system in New England.

market serving as a short-term forward market where the supply offers from sellers and demand bids from buyers are submitted. Based on the price and quantity data submitted by market participants, schedules are produced for the production and consumption of energy for the next operating day. From these schedules, the ISO constructs aggregate supply and demand curves that lead to market clearing prices at each location for every operating hour. The real-time market, on the other hand, is a spot market for energy where the differences between scheduled and delivered amounts of energy are settled at the real-time locational marginal prices. Bilateral transactions which constitute the bulk of electricity trading also take place in this setting. In addition, other products such as short-term reserves[113] and regulation are traded in the market.

Under either form of organization (ISO or ITC), those entities that operate wholesale markets must have administrative and financial independence from market stakeholders so that they can conduct their wholesale trade in an unfettered way. By nature of the product and demand, electricity markets are susceptible to price manipulation and the influence of market power; independence is therefore a central element of achieving an efficient market outcome. For this reason, ISOs are *independent* of transmission or generation owners (or of any stakeholder, for that matter) and are accountable to an administrative board free from the influence of such stakeholders.[114] In markets with centralized wholesale trade, regulatory bodies have jurisdiction, while in some jurisdictions, various market monitoring bodies provide input for their operations.

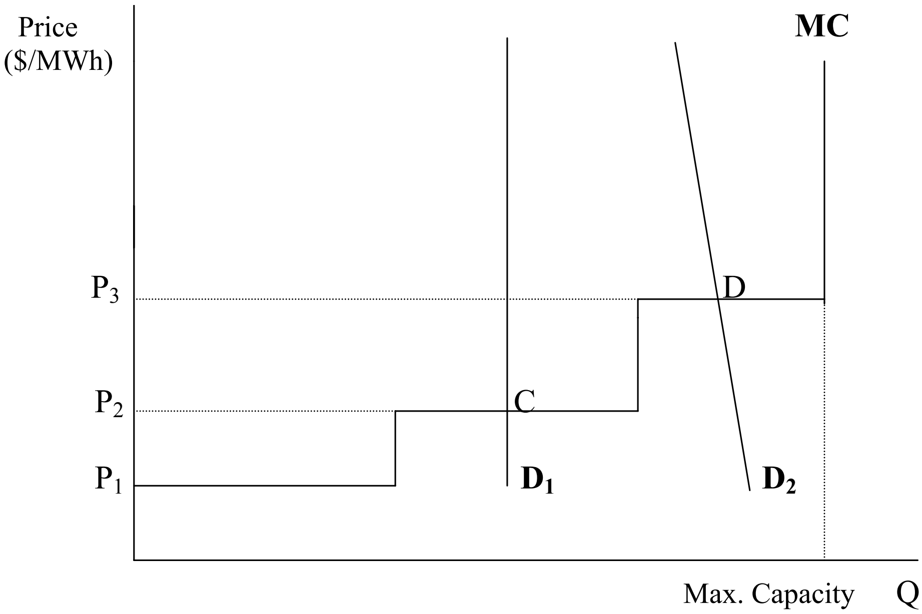
Even in most advanced centralized markets, the bulk of the electricity trade is conducted through bilateral contracts, in which buyers and sellers agree on the price, amount, and the delivery time by bilateral negotiations. In these markets, a relatively smaller portion of electricity (approximately 10–25 percent of the total system load) is traded in spot exchanges through auction- (or bid-) based pricing. Auctions are usually conducted on an hourly basis and can be run as day-ahead auctions or hour-ahead auctions. Auction-based pricing can either determine a *uniform* (single) market-clearing price or take the *pay-as-bid* form. In both cases, the market-clearing price is set at a point where demand and supply schedules intersect (see Figure 23 for a supply function with three levels of costs). In the case of a single market price, the highest bid of the inframarginal generating unit sets the market-clearing price, and all bidders below the clearing price receive that *marginal price* regardless of what they bid initially. Thus, bidders have an incentive to bid their opportunity cost (that is, their short-run *marginal operating cost*) or take the risk of being left out of the dispatch. In pay-as-bid auctions, each bidder is paid the amount bid — not the market price; thus, bidders are encouraged to bid the greater of the

[113] Independent system operators run operating reserves for short-term reliability reasons; these may take the form of 10-minute spinning reserves, 10-minute and 30-minute non-spinning reserves.

[114] Alternatively, independent transmission companies present another business model for managing transmission system operations (see ensuing discussion in Section 3.2.1.2). For example, in England and Wales, the for-profit National Grid Company (NGC) owns and controls high-voltage transmission facilities and runs the system operation and electricity trade under the regulatory supervision of Ofgem. The National Grid Company was publicly owned until 1990, when it was privatized. Under this model, the ITC must provide access to transmission lines on a non-discriminatory basis for any transmitting entity. See also Section 3.3.3.1 for a discussion of the British market design, and its comparison with the newly envisaged Turkish market.

expected market-clearing price or their opportunity cost.[115] In the long run, generators are able to recover their fixed costs (that is, their long-run MCs) via price spikes in the energy market and via payments for capacity requirements, if they exist.[116]

Figure 23: Market-Clearing Price in Electricity Markets



In both the day-ahead and real-time markets, ISO stacks up the demand bids and supply offers on an hourly basis and matches the price quantity pairs for physical dispatch. All power to be delivered through either bilateral contracts or spot market trade is scheduled through ISO, given the system constraints for deliverability (which are mostly transmission related).

Note that although spot market transactions comprise only a portion of the total volume traded in the overall market, spot prices are good indicators of short-term market prices of energy which provide market signals for longer-term bilateral contracts. Naturally, market prices influence future investment in the generation segment. Additionally, the transparency and liquidity brought by spot market transactions facilitates competition in the market.

[115] See Hogan (2001). Hogan states that even though the prices paid on average do not differ greatly, as theory and experience indicate, real costs can be higher under the pay-as-bid approach than under uniform market-clearing price. See also Kahn *et al*. (2001) which argue in favor of the uniform market-clearing price method. Stoft (2002) discusses similar points (pp. 95-96).

[116] See Chapters 2.2 and 2.8 of Stoft (2002). See also Section 3.2.1.3 of this study for a discussion of capacity markets.

3.2.1.2 ISOs versus Transcos

Currently, considerable debate centers on the use of models of nonprofit ISOs versus for-profit Independent Transmission Companies (often called Trancos) for system operation.[117] ISOs operate transmission facilities owned and maintained by various transmission entities, including vertically integrated utilities. Transcos, however, run system operations at the transmission facilities they own and maintain. Thus, Transcos adopt a business model that combines system operation with grid ownership.

In the United States, the ISO model was adopted, mainly because it was more *practical* and *cost efficient* under the terms of deregulation. In fact, because the grid in the United States was formed mostly by vertically integrated utilities that owned transmission and generation assets, by opting for the ISO model the expected long process of the divestiture of transmission assets — and the possible horizontal consolidation of those assets — as well as associated potential stranded costs were avoided. In fact, this vertical integration to a large extent still continues today in the United States. Thus, ISOs present a viable solution to secure nondiscriminatory access to the network by all market participants in a balkanized grid system. In addition, behavior of individual transmission owners that cause externalities on the grid can affect other transmission owners; these externalities include loop flow, and other network effects.[118] Independent System Operators also provide a good solution for overall system efficiency, lessening the effect of network externalities when ownership of transmission facilities is decentralized. In this case, the ISO model internalizes network externalities. Naturally, as utilities divest their generation or transmission assets — or as horizontal integration of transmission assets in adjacent areas increase — these rationales diminish in importance.

Countries that had a single transmission entity prior to restructuring — such as the United Kingdom, New Zealand, Spain, and Norway — opted for the Transco model of system operation, following the restructuring of their electricity industries. This approach is reasonable, given that state-owned transmission facilities can more easily be transformed into Transcos.

Joskow (1999) sets forth two rationales for opting for a Transco model of system operation. The first relates to the potentially significant efficiency loss resulting from the separation of ownership and maintenance decisions from the operating decisions of the transmission assets, as is the case for ISOs. The second relates to the difficulty of developing and applying good regulatory incentive schemes to the transmission owner, following such separation. The latter rationale arises because the separation divides incentive decisions affecting the direct and indirect costs of transmission between the ISO and the transmission assets owner.[119] Furthermore, while designing an incentive

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[117] The following discussion mainly follows Joskow (1999) and Oren, *et al.* (2002).

[118] *Loop flows* are unscheduled flows of electricity. Electricity has a tendency to flow on transmission lines along the path of least resistance due to its physical nature thus the physical path of electricity may be different than the contractual path intended in a contract. These unscheduled flows of electricity may move along multiple parallel paths in a network and may interfere with the system operation in a control area.

[119] *Capital*, *operating* and *maintenance costs* are direct costs incurred by the transmission owner, whereas *congestion*, *losses*, *ancillary services*, and *local market power mitigation costs*, among others, are

regulatory mechanism for for-profit Transcos is possible, it is, in practice, difficult to subject a nonprofit ISO to similar performance standards. This is mainly because a nonprofit firm's objectives may be different and more complex from those of for-profit counterparts in the same business; that is, Transcos are responsible for the economic consequences of their operating and investment decisions and have equity at risk. On the other hand, although ISOs have budget constraints as well, they have the ability to pass along all of their costs to market participants and thus, they do not face similar requirements for ensuring success in the market.

One major goal when making decisions about these models is to adopt a mechanism that encourages the transmission investments necessary to achieve system reliability and market efficiency. In markets with a restructuring history, *market mechanisms* have not been successful in attracting lumpy transmission investments that often create externalities.[120] Therefore, such incentives can be more effective if directed at transmission owners who are simultaneously operating the grid. Having said that, when a decision is to be made by the system operator regarding an operating or congestion problem — and when such a decision includes options of generation resources or transmission investment — Transcos may prefer a transmission investment option, for profitability reasons. Therefore, considering options that include strong incentive regulation *and* regulatory oversight in planning transmission system expansion is beneficial. In any case, the debate regarding the appropriateness of a model for any one particular country or any one market hinges on the unique characteristics of the market in consideration. The performance of a chosen model of system operation will ultimately be linked to the governance and incentive regulatory mechanisms that are in effect for the particular grid in which the model will be operating.

3.2.1.3 Capacity Markets

Reliability is an extremely important aspect of system operation.[121] A momentary imbalance of demand and supply may affect the entire interconnected system and cause widespread blackouts. Earlier, it was mentioned that the reserve generation capacity (or reserve margin) of an interconnected system serves as an indicator of system adequacy and reliability.[122] The level of reserve margin is important for long-term planning, whereas the amount and the type of operating reserves are important for short-term

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considered to be indirect costs of transmission resulting from the decision making of the system operator but paid by market participants. (See Joskow, 1999.)

[120] In privately owned transmission networks, investors are reluctant to make such investments, due to the long cost recovery periods required by such investments and various externalities that benefit other users of the system.

[121] The North American Electric Reliability Council (NERC) defines reliability as "the degree of performance of the elements of the bulk electric system that results in electricity being delivered to consumers within accepted standards and in the amount desired." In addressing the concept of reliability NERC considers two basic and functional aspects of the electric system: *adequacy* and *security*. Adequacy is described as the ability of the system to supply the aggregate electrical demand and energy requirements of the customers at all times; security is described as the ability of the system to withstand sudden disturbances. (See Glossary of Terms: NERC, 1996.)

[122] Transmission reliability also plays an important role in overall system reliability; however, this subject is not covered in this study.

reliability.[123] More reserve capacity can increase system adequacy and reliability; however, installing and keeping reserves increases the total cost of providing electricity service as well. Therefore, any interconnected system must address the problem of providing an optimum amount of reserves to its users.

The issue of system reliability can be approached through both the demand and the supply side; however, most demand-side measures (that is, demand-side management) may offer only limited help to the solution of the problem.[124] As long as there is demand growth, a system must address the long-term reliability problem by increasing its installed capacity. Thus, in this section the alternative supply-side solutions to the reliability problem are discussed.[125]

Presently, an ongoing debate exists in both academia and in industry circles regarding the ability of newly restructured electricity markets to provide the required incentives for attracting new investment for generation capacity that is necessary to maintain long-term system reliability. Specifically, the debate focuses on the ability of various market-driven capacity procurement mechanisms to provide adequate generation resources, particularly given the recent experience of the poor performance of some of the mechanisms in the restructured markets.

In the previous regulatory system, vertically integrated utilities were responsible for maintaining resource adequacy and reliability. This responsibility was administered by the regulator through the means of utilities' (mostly) annual *capacity obligations*. Utilities were also required to file with the regulator details of their periodical long-term capacity planning ("Integrated Resource Planning"). Following restructuring, however, enforcing capacity obligations is now mostly delegated to "market-based mechanisms"[126]

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[123] Stoft (2002) establishes a link between long-term reserves (which provide system *adequacy* by meeting annual demand peaks) and short-term reserves (which provide system *security* by maintaining the ability to withstand sudden disturbances) by noting that requirements for operating reserves play a role in raising capacity prices and stimulating investment, thereby contributing to adequacy. (See Stoft, 2002, Chapter 2.3.)

[124] This is especially true at the present time, when most consumers of electricity pay flat prices for their consumption and thereby do not have an incentive to adjust their consumption based on real-time electricity prices; in addition, they also lack the technical capability (namely, metering) to respond to real-time prices and shortages.

[125] Demand-side management is discussed in Section 3.2.2.2.

[126] Joskow and Tirole (2004) dispute such descriptions and argue that there are still a large number of *non-market mechanisms* that have been imposed on the emerging competitive wholesale and retail electricity markets in the post-deregulation era. These mechanisms include wholesale market caps, capacity obligations for load-serving entities (LSEs), operating reserve requirements, and other ancillary service requirements enforced by the system operator. However, Joskow and Tirole acknowledge that in some cases these mechanisms are argued to be justified by imperfections in the retail or wholesale markets, or by what are perceived to be special physical characteristics of electricity and electric power networks. In fact, Stoft (2002) attributes this situation to the uniqueness of power markets. Stoft defines two demand-side flaws that exist in the market:1) lack of demand responsiveness to price, due to the lack of metering and real-time billing; and 2) lack of real-time control of power flow to specific customers, so that a specific load has the ability to take power from the grid even if it exceeds its contract, a situation unlike those in any other markets. He further explains that due to complex supply and demand characteristics of power markets (that is, the nonstorability of power and — thus — the importance of real-time production characteristics,

through which various capacity procurement systems are expected to provide sufficient capacity for short- and long-term reliability. In general, such systems are centrally run, and are enforced by system operators.

In restructured electricity markets, new investment decisions in generation resources are influenced by the expected short-run profits from such investments. In "energy only" markets — that is, markets in which capacity is not traded as a separate product — the level of profits is determined by spikes in energy prices, which in the long run also help recover the fixed costs of the investment. In principle, this mechanism works by allowing energy prices in the wholesale markets to respond to generation capacity shortages and price spikes in turn allow generators to earn additional revenues; the price spikes also encourage more investment in the market. However, concerns shared by many are that either temporary price spikes of energy may not be high enough to attract sufficient investment in capacity — especially given the implementation of price caps, or scarcity rents may also originate from the exercise of market power — given the unique characteristics of power markets.

In markets where capacity is traded as a separate product, revenues resulting from capacity transactions represent another source of revenue for investors, supplementing revenues investors receive from the energy and ancillary services markets. In general, various capacity procurement mechanisms employed by system operators present a more direct approach for providing incentives for new generation investment; and, because capacity availability is more assured under this approach, lower price spikes are expected in the energy market.[127]

To ensure that enough capacity is available to meet a specific long-term reliability level in the newly liberalized markets, system operators use either a *capacity payment system* or a *capacity obligation system*. In the capacity payment system, per unit (kW) capacity prices are determined by the system operator and payments are made to generators for merely maintaining an available (or installed) capacity, whether it is dispatched for energy generation or kept unused. Thus, an extra payment is provided to owners of capacity to induce them to supply more generation capacity. In some markets, such as the U.K. pool system before the start of NETA, capacity payments mechanisms were used for ensuring generation adequacy.

On the other hand, the capacity obligation system is used for both *operating reserve* and *installed capacity* markets. In operating reserve (short-term) markets, the system operator designates certain generators as necessary resources for short-term system reliability and

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and the two demand-side flaws), power markets cannot operate on their own. Therefore, "It requires a regulatory demand for a combination of real-time energy, operating reserves, and installed capacity, and this demand must be backed by a regulatory policy. Without this reliability policy, the power system would under-invest in generation because of demand-side flaws." (p. 108.) See also Stoft, 2002, Chapter 1.1.

[127] However, drawbacks to either approach must be noted. In capacity markets, the demand determined by regulators or ISOs may not be sufficiently elastic, and thus may lead to the development of market power. On the other hand, infrequent price spikes may increase uncertainty and risk for investors, which, as a result, can lead to an increase in the cost of capital. The possibility of extremely high price spikes can also encourage the exercise of market power. (See Stoft, 2002, Chapters 2.6 and 2.8.)

requires them to provide ancillary services including voltage support, regulation, balancing, spinning and non-spinning reserves. Payments made by ISOs to generators are recovered through various charges levied on load-serving entities. System operators procure short-term services either through auction-based mechanisms or through long-term contracts. A general consensus exists among market operators that centralized markets are a good way of providing such services, owing to their efficiency implications.

In installed capacity (ICAP) markets, the system operator generally determines each load-serving entity's capacity obligation, based on their forecasted peak load, plus a reserve margin.[128] Load-serving entities can fulfill their capacity obligations either by self-supplying, or via bilateral transactions, or from the installed capacity markets run by the system operator; they are paid on the basis of the market clearing price in the ICAP market. Participation by LSEs in installed capacity markets is mostly voluntary. If an LSE does not meet its capacity obligation by any one of the ways previously described, the relevant ISO charges the LSE a penalty rate for the amount of deficient capacity. Similarly, all payments made for capacity by the relevant ISO are recovered through charges levied on LSEs. ICAP markets have been adopted by several system operators in the United States such as ISO-New England, New York ISO and PJM. However, unlike regarding the provision of the short-term services, a debate is ongoing whether a capacity payment system or a capacity obligation system is the most effective way of ensuring long-term resource adequacy.

In summation, capacity procurement systems use either price — as in the case of capacity payments, or quantity — as in the case of capacity obligations, to control the supply of capacity. The capacity payments system has been criticized in the past mainly because this design is prone to manipulation: generators may withhold capacity in order to increase payments prior to price setting and then release the same capacity, to reap the benefits of the apparent shortage. This was in fact the case in Britain before the system of NETA of 2001 in which pool system payments were made via uplift[129] to energy sales, and the uplift was determined based on the probability of shortages.[130] Physical withholding of capacity increases the probability of shortages, thereby increasing capacity payments.

The argument for the quantity control (or capacity obligation) system can be supported by the existence of a demand for capacity function which is nearly vertical and a supply function which is nearly flat.[131] In such a case, a small error in price of capacity results in a large error in quantity supplied. Thus, direct control of quantities can yield more accurate results. In that sense, ICAP obligation can be considered a more certain way of ensuring long-term system reliability compared to capacity payments approach.

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[128] Capacity obligations are set mostly on a monthly or annual basis, though daily capacity obligations exist as well.

[129] *Uplift* refers to additional charges added to the price of electricity to recover expenses incurred by the relevant ISO, including payments to generating units from operating more expensive units to meet demand (that is, *congestion costs*) or costs of some ancillary services.

[130] Newbery (2005).

[131] The following discussion mainly follows Oren (2003).

However, the calculation of necessary levels of capacity both in the capacity payment system and the capacity obligation system is based on engineering models of "loss of load probability" (LOLP) and on estimates of the "value of lost load"[132] (VOLL) which do not take into account market mechanisms. These calculations have been criticized on the basis that the VOLL is administratively set and reflects an arbitrary value whereas LOLP calculations are based on simplistic models of probabilistic failure so it has an approximate nature, which result in a mismatch between energy market prices and capacity market values. Therefore, it is argued that until energy markets are sufficiently developed to provide correct market signals for generation investments, installed capacity obligations approach is a better solution than administratively set capacity payments.

However, peak capacity is more likely to be scarce than off-peak capacity. Therefore, a more efficient pricing system with the right allocative incentives requires a differential pricing of capacity rather than a generic payment per unit of capacity. This way, load-serving entities can also pass on the cost of capacity by time of use which would lead to a more efficient pricing for end-users.[133]

Finally, locational aspects of valuing capacity must be considered as well. A given quantity of generating capacity is likely to be more valuable in a congested load area than is otherwise.[134]

3.2.2 Retail Markets

3.2.2.1 Customer Choice

Prior to liberalization in the electricity industry, the demand side was for the most part emphasized only in the context of the industry's ability to meet system load requirements. The shape of the load curve was always of importance for suppliers, as it affected system requirements as well as the short- and long-run cost of generation. For this reason, various incentive schemes — such as time-of-use or multipart pricing — were put in place to influence time and amount of consumption. Yet, neither the consumers' ability to choose a supplier nor the potential of the demand side to affect the market price of energy has been debated.

While most discussion regarding restructuring policy tends to focus on wholesale market design, retail liberalization — and the resulting customer choice — is the essential mechanism in creating a competitive generation market. As consumers gain the ability to shop for their power needs, generators are expected to respond by competing among themselves, and consequently making their best offer.

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[132] Loss of load probability is calculated based on the expected number of days in the year that the daily peak demand will exceed the available generating capacity. Value of lost load refers to the estimated average cost of a unit of unserved energy (generally per megawatt-hour) to customers due to an involuntary outage.
[133] Lijesen (2003).
[134] Because the debate regarding the capacity markets is ongoing and has yet to be settled, this study does not intend to make any recommendation on this subject.

Customer choice or the eligibility of customers to choose their own supplier in the first place can be introduced by initially limiting eligibility to only large commercial and industrial customers, who typically consume power at high-voltage levels or have annual consumption levels exceeding predetermined thresholds. Furthermore, customer aggregation of residential as well as small and medium commercial and industrial customers to encourage the competitive supply of electricity can serve the same purpose. In this fashion, customers can be empowered by creating bargaining power on the demand side. Thus, customers become direct market participants, benefiting from the resulting market-based rates.

Initially, a predetermined eligibility threshold may be preferred, due to its administrative ease; this is especially true for markets where transition is being made from state-owned monopolies to liberalized markets and consumers have no prior experience with private enterprises and a competitive marketplace. However, these limits are meant to be provisional, lasting for only the short period of time that such markets require to mature and that retailers and customers require to gain experience.

In many jurisdictions throughout the world, no such restrictions are placed on eligibility, thus, all customers (residential and industrial alike) become eligible at the beginning of restructuring plans. In many cases, the reason for opting for a phased approach is of a political and administrative nature — not a technical one. In fact, some European countries (and many individual states in the United States) that have enacted restructuring laws envisaged no phase-in periods in their respective liberalization efforts (see Table 12). However, it must be noted that by delaying full transition to liberalized markets, a phased approach — a prolonged one in particular — can have adverse effects on the restructuring process.[135] Keeping residential and small commercial customers from participating in the free market for an extended period of time may hinder the timely development of the market. In a typical electricity market, approximately one third of the total load originates from small customers. Therefore, excluding small customers from the competitive retail market will delay the generation market from reaching its competitive potential. Conversely, including this customer segment in the process can prove to be a crucial tool in developing competition within the generation market and in gaining experience in market liberalization, for consumers and retailers alike.

Table 12: Phase-in of Supply Competition in OECD Countries

No phase-in period	Jurisdictions requiring phase-in (and length of phase-in period)
Germany, New Zealand, Norway, Sweden, United States (in some states only)	Australia (3–6 years), United Kingdom (8 years)

Source: OECD (1999).

[135] This subject is relevant to Turkey's current position. The Strategy Paper of 2004 delays the process of lowering eligibility thresholds until 2009, and, simultaneously ties distribution companies' non eligible customer load (which makes up 85 percent of the total load) with the transition contracts of TETAŞ and portfolio generating companies, until at least 2010. (See Section 3.6 for further discussion.)

Large commercial and industrial customers have several added advantages when they receive the most benefit from liberalized power markets. The shape and size of their load makes it easier for power suppliers (marketers) to offer alternative pricing schemes (that is, pricing schemes that are the most suitable to both customers and suppliers). In addition, suppliers may provide large customers with various *value added services* — such as price risk management, demand management, information regarding energy use and prices, energy efficiency and billing services. In the case of very large customers, suppliers can offer pricing schemes on a customer-by-customer basis. (See the discussion concerning demand response programs, later in this section.)

On the other hand, suppliers view residential and small commercial customers as being less attractive, due to the smaller profit margins available in this customer segment. These lower profit margins result from suppliers incurring certain marketing, advertising, and customer service costs to acquire their customer load; compared to industrial customers, such costs on a customer-by-customer basis become much higher for small customers with small load sizes. Moreover, in the residential segment, a low price elasticity of demand makes individual customers less inclined to proactively opt for a competitive retail supplier. In conjunction with the last point, a typical residential electricity bill for customers in industrialized countries takes up a relatively small share of median household income; residential customers are therefore reluctant to spend time shopping for a retail supplier, because time costs for such a search hardly justify the expected benefits of a reduced bill. (See Table 13 for data on retail switching rates in the small customers segment in selected European countries).

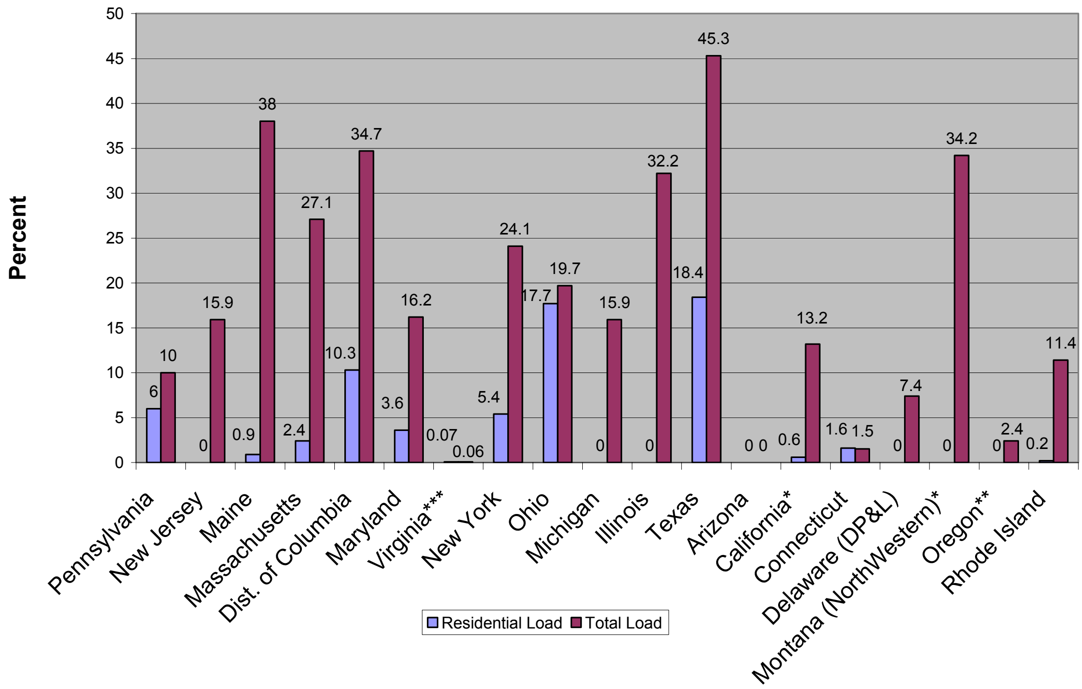
Table 13: Retail Switching in the Small Customers Segment in Selected European Countries

	Retail competition introduction	**Percent small commercial/ residential consumers switching in 2003**
Denmark	2003	5
Finland	1997	4
Norway	1991	19
Sweden	1996	10
Italy	2007	–
Spain	2003	0
Austria	2001	1
Belgium	2003	19
France	2007	–
Germany	1999	Not known
Netherlands	2004	Not known
United Kingdom	1998/1999	22
Greece	2007	–
Ireland	2005	1
Northern Ireland	2007	–

Source: Thomas (2005).

Retail market design and its performance within a competitive framework are significant factors in achieving a competitive outcome in wholesale power markets. Slower than expected progress in the U.S. wholesale markets since restructuring programs were initiated has been partially attributed to the poor performance of competition at the retail end. Partly for reasons stated earlier, the results of retail competition for small customers in the United States have been rather disappointing.[136] In particular, within the small-customer segment, retail switching for energy (that is, the migration of customers from distribution companies to unregulated retail suppliers) has remained at low levels in states that have initiated active retail choice programs within the last seven or eight years.[137] (Data in Figure 24 show the situation for states that have implemented retail choice.)

Figure 24: Residential and Total Load Switching in the United States, 2004



* California retail access was suspended, Montana suspended residential retail access.
**Oregon has retail access for large customers only.
***Virginia percentages are percent of customers, all others are percent of load.

Source: Rose (2004).

Unbundling retail services from distribution function creates cost disadvantages for retail marketers. Distribution companies with a long-running established business practice

[136] Market design problems are also attributed to this failure. See Joskow (2003).
[137] The measure of success of competitive restructuring has several dimensions. This study considers only one dimension (namely, the extent of customer switching), leaving aside price and quality-of-service effects.

benefit from scale economies in providing retail functions such as meter reading, billing, and customer services. A new retail marketer needs to establish such services — possibly for a much smaller customer base. Moreover, unlike a distribution company, the same marketer will incur marketing and advertising costs while pursuing customer enrollment. These retail supply costs (and the resulting narrower margins) have constituted a major obstacle in the development of retail switching and the market penetration of marketers.

Joskow (2003) used the Texas and England and Wales experiences to estimate that price reductions of 5 to 10 percent of the *total* electricity bill are necessary to induce significant numbers of small customers to switch to marketers for their power needs.[138] This estimation assumes that 50 percent of the total bill reflects the costs of generation (energy); consequently, price reductions of 10 percent to 20 percent on the *generation* component are necessary to trigger significant switching. When a 5 to 10 percent additional retail service cost is added, a margin of 15 to 30 percent between competitive generation and the comparable wholesale market value of power becomes necessary in order to see migration in the small-customer segment. Thus, given the switching and transactions costs outlined previously, Joskow concludes that small customers can benefit from retail competition if *local distribution companies* purchase power for their needs by putting together a portfolio of contracts.

3.2.2.2 Demand-Side Management: Demand Response and Load Management Programs

In the past, price elasticity of demand estimations in state-owned or independently regulated power markets across the globe have pointed to an inelastic demand for small customers. (See Table 14.) Given the nature of the heavily regulated electricity industry, even larger consumers have not had an incentive to alter either the amount or the timing of their consumption. Similarly, the primary aim on the supply side has been to meet load requirements, taking cost minimization as a secondary objective.

Table 14: Price Elasticity of Demand Estimations for Electricity: Residential Customers

Range of Estimates of Residential Own-Price Elasticities of Demand[139,140] (The low and high values bracket the 80 percent confidence band)					
Short-Run Elasticity			**Long-Run Elasticity**		
Low	Medium	High	Low	Medium	High
-0.12	-0.20	-0.35	-0.60	-0.90	-1.20

Source: King and Chatterjee (2003).

[138] Joskow (2003), pp. 35–36.

[139] [*Own*] *Price elasticity of demand* refers to the responsiveness of customers' demand to price changes in the same time period in which the price change occurs.

[140] Short-run estimates of elasticities take stocks of electric appliances as given and measure only their utilization rates. The long-run estimates include a measure of the growth rate of these stocks. The short-run own-price elasticity estimates are expected to be smaller in absolute value than long-run elasticity estimates.

With the start of liberalization, the operation of electricity markets has faced various challenges including generation capacity shortages, transmission congestions, increased price volatility and reduced system reliability.[141] In order to alleviate such side effects, independent system operators and load-serving entities have increasingly employed demand response and load management programs (or DRPs) to control and manage load patterns. Demand response programs are *optional* and *incentive-based* schemes designed to encourage retail customers to reduce their power consumption at certain times, or shift their usage away from peak use times. It is well-known in the electricity industry that for a system operator, managing load during times of peak use is as valuable an asset as having extra capacity or generating more electricity. Demand response programs therefore have potential not only to address reliability concerns but also to provide economic efficiency in the competitive marketplace.

In general terms, DRPs include curtailment of loads (wholesale as well as retail) either for reasons related to system reliability (load response) or wholesale market conditions (price response). A systemwide reliability issue or contingency may arise when a generation shortage or transmission constraint occurs; DRP participants agree in advance to curtail a certain minimum amount of their load when they sign up for load response programs.[142] Load reduction in these programs is called for by the ISO or load-serving entities. End-users who participate in these programs are paid for usage reductions on the basis of a predetermined price or day-ahead/real-time energy prices.[143] The incentive mechanisms for these programs in some cases include penalty payments if non compliance occurs.

Similarly, market conditions such as abnormally higher wholesale prices may activate price response programs. In this case, curtailment is provided voluntarily by end-use customers in response to offers from the ISO or load-serving entities. In DRPs derived from conditions such as these, participants are usually paid on the basis of the load they curtailed without being subject to penalties.[144] Payments in price response programs are generally tied to day-ahead/real-time energy prices.[145]

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[141] The discussion in this section generally follows Heffner (2002) and Heffner and Sullivan (2005).

[142] Load response programs define varying types of load reduction. For example, c*urtailable load* refers to the end-user load that a large commercial or industrial facility agrees to reduce with a minimum threshold amount whereas *interruptible load* refers to the end-user load in significant amounts that can be reduced or interrupted completely.

[143] Curtailable load programs generally base their incentives on direct payments. Interruptible load program participants, on the other hand, are charged special *interruptible rates* for their electricity consumption that are usually lower than regular rates.

[144] However, in some cases if a customer's bid is accepted in the day-ahead market then the customer is obligated to curtail its load or be accountable for real-time prices for non-performance.

[145] According to the findings of Heffner (2002), while the average potential curtailable load for DRPs was similar in U.S. markets, the load curtailment actually delivered was much higher and more predictable (and hence, more effective) for those programs that were implemented for system reliability reasons. However, relatively low wholesale prices in 2001 during which the study was conducted could have influenced this outcome.

The demand side's ability to affect the price of generation is at its maximum when demand can respond *instantaneously* to price fluctuations in the competitive generation market. Real-time metering is a primary tool used in this and other response mechanisms. The advanced pricing schemes allowed by real-time metering help the supply side avoid excessive buildup of installed capacity and reserves to meet peak demand. They are also an important element in limiting the potential market power of certain generators and mitigating price spikes in bottlenecked areas.

Table 15 shows the contribution of DRPs and other demand-side management measures in mitigating system emergencies in several regions of the United States during Summer 2001. Data indicate that price-responsive load and other programs reduced system peak demands by 3–6 percent and helped avoid system emergencies.[146]

Table 15: Contributions of Price-Responsive Load and other DSM Programs in the United States, Summer 2001

ISO	System Peak (MW)	Interruptible Load	Curtailable Load	Other DSM	Total DSM	DSM as percent of Peak
PJM	52,977	2,000	70	–	2,070	3.9 %
NY ISO	29,983	–	500	365	865	2.9 %
ISO NE	25,675	–	65	1,522	1,587	6.2 %

Source: Heffner (2002).

3.3 An Assessment of the Pricing, Regulatory Governance, and Market Design Issues in the Turkish Electricity Industry

3.3.1 Pricing Issues

The success of competitive restructuring will depend largely upon establishing a market mechanism in the *generation* segment where demand and supply conditions are indicated to market participants via price signals. Merit-based dispatch requires the use of accurate generation cost data. Specifically, in a power exchange setting where spot electricity trade takes place, generators will have an incentive to bid their own MC. (See Section 3.2.1 for a discussion of wholesale markets). Thus, possessing accurate cost data is indispensable for the efficient operation of a given market. Private generators can be expected to calculate such figures, as it will be in their own self-interest. In the case of publicly owned generators, however, cost determination must be obtained through regulatory or state mandate. To date, no such MC studies have been undertaken regarding the state-owned generation side of the Turkish electricity industry.[147,148]

[146] *Ibid*.
[147] Cost figures cited in section 2.4.1.1 reflect average costs for the respective technologies.
[148] Meanwhile, in preparation for transitioning to a balancing market, EÜAŞ has commissioned a comprehensive cost study at the plant level for its generators. The project is expected to be completed by the start of the balancing market.

Similarly, MC studies are lacking for the monopoly segments of the industry. In the transmission and distribution segments, where regulatory bodies are charged with administratively determining tariffs, the lack of MC studies has further importance, because correct MC data constitute the basis for cost-of-service studies of the ratemaking process.

For instance, with regard to the distribution segment, TEDAŞ has set up a tariff schedule of distribution charges for 11 different customer classes. However, lacking precise cost-of-service calculations as to serve background data and to indicate the cost responsibility of various customer classes, such pricing can serve only as a tool to meet the revenue requirements of the company. Instead, as discussed earlier, tariff design should be used as the main mechanism in the new restructured environment, to send correct price signals to the marketplace.

Currently, only the end-user tariffs include demand (capacity) and usage charges. In order to attain a truly unbundled setting — one in which ownership of the various industry segments is separated — charges must be primarily instituted for distribution tariffs.[149]

In the past, certain pricing practices — such as the unmetered consumption of electricity by street lighting and houses of worship — also played an important role in TEDAŞ's financial troubles. These practices have finally been eliminated by the new regulatory rules, which help eliminate distortions in pricing.

The secondary regulations issued by EMRA indicate that performance-based ratemaking methods — such as revenue caps and price caps or combination of the two — for monopoly (transmission and distribution) segments, retail energy sales and retail sales services (such as metering, billing and customer services) are the preferred methods of regulation for future implementation.[150] In fact, built-in incentive mechanisms and quasi-automatic adjustments for pricing contained in such methods encourage regulators to adapt these methods. However, as discussed earlier, proper implementation of performance-based methods still requires a well-prepared "cost-of-service study" to ensure that the starting point for the caps is accurately determined.

In a competitive market, transmission pricing plays a crucial role in providing incentives to those who invest in generation as well as in transmission. Transmission pricing and associated incentive mechanisms influence the value and location of future generation investments; in other words, they send signals to investors of generators to locate their plants where needed to relieve congestion. Congested regions with high locational

[149] The TEDAŞ end-user tariff schedule given in Section 2.4.1.4 indicates separate demand and usage charges only for large industrial customers who use demand meters. As discussed earlier in Section 3.1.2, optimally determined fixed component charges may allow implementing efficient usage charges for customers without demand meters.

[150] More specifically, a revenue cap for transmission, distribution and retail sales services, a price cap for retail energy sales tariffs, and cost-based tariffs for wholesale power. (See http://www.epdk.org.tr for secondary regulations regarding tariff setting methodologies.)

transmission prices will therefore be more attractive to potential investors of generation and transmission.

Locational transmission pricing affects demand side decision making as well. Varying end-use prices in various regions influence the investment decisions of large industrial and commercial customers. Importantly, when compared to labor costs, electricity costs in the Turkish manufacturing sector currently represent a relatively high share of total input costs; this is particularly true in some of Turkey's export industries. (See Table 16.)

Table 16: Share of Input Costs of Electricity in Various Industries of the Turkish Economy

Input	Iron Ore & Other Metal Min.	Textile	Paper & Paper Products	Chemical	Fertilizer	Ceramic Products	Cement	Iron-Steel	Other Metal	Casting	Hotels	Average
Electricity	5.1%	4.2%	4.3%	7.2%	4.0%	4.8%	7.3%	6.7%	5.7%	5.8%	2.7%	5.3%
Labor	17.4%	14.2%	10.4%	10.3%	10.8%	13.3%	8.4%	7.9%	8.8%	13.0%	6.5%	11.0%

Source: The Input-Output Structure of the Turkish Economy-1998, State Institute of Statistics, May 2004.

Establishing a clear policy path and signaling a commitment to issues related to transmission pricing will be a substantially positive factor in attracting private investment in the electricity industry. Law No. 4628 mandates that TEİAŞ implement cost-reflective pricing in transmission. The concept of *cost-reflective* pricing in fact implies the institution of a scheme such as locational (congestion) pricing, because average cost pricing of transmission network services inherently entails cross subsides that favor high-voltage customers and customers who live or do business in congested areas.

Therefore, adopting a pricing model with locational attributes (such as the new "investment cost-based" model for transmission pricing) is a step in the right direction. This new approach will actually signal an intent not to socialize costs on behalf of the policymakers.[151] However, for this model to lead to a meaningful implementation and contribute to competition, regional (zonal) costs must be accurately determined. In this context, EMRA is in a position to ensure that appropriate methods are followed in cost calculations. In later stages of restructuring, more precise congestion pricing (that is, locational marginal pricing) should also be considered for the purpose of accurately measuring the cost of short-run congestion and providing incentives for generation as well as transmission investments.

Finally, as a result of cost-reflective, transparent pricing principles, competitive restructuring requires the elimination of any cost elements unrelated to electricity provision. Such costs include extra charges levied or embedded in the pricing structure, in order to generate annual revenues for the state budget or various public services. This practice is so customary in Turkey that even newly established EMRA tariff decisions include a provision indicating that tariffs will be subject to change, due to changes in

[151] *Socialization of costs* allocates costs evenly, without considering the cost responsibility of customers in different locations.

macroeconomic indicators (or for other reasons).[152] In other words, the determination of current tariffs is not independent of macroeconomic indicators — a relationship that conflicts with the explicit mandate of cost-reflective pricing of Law No. 4628.[153]

In summation, the following observations can be made with regard to the pricing practices currently in place in Turkey:

- No precise cost-of-service studies have been prepared for any segment of the electricity industry; such studies would serve as a starting point for decisions regarding tariff making and incentive regulation.

- Largely owing to the lack of such cost studies, rates have not yet been unbundled to allow *all* customers to see distribution, transmission, energy, and other charges listed separately on their end-user bills.

- Although the legal unbundling of the generation, transmission, and distribution segments was accomplished in 2001, each of these segment's budgets are still subject to government control. The lack of autonomy for these entities contributes to the lack of cost-based tariff making.

- Tariffs determined by EMRA still include elements unrelated to the cost of providing electricity service.

- In calculating its costs, EÜAŞ does not take into account the fixed cost of hydroelectric plants; the company therefore underestimates the true cost of state-owned generation. This, in turn, distorts price signals sent both to users and investors in the electricity marketplace.

- In Turkey, as international comparisons indicate, intense cross-subsidization favors residential customers over industrial customers. Not only does this conflict with the ratemaking principle of "cost causation" but it also creates a comparative cost disadvantage for the Turkish industrial sector in general.

- Uniform distribution charges and end-user prices are applied to all distribution territories by TEDAŞ, despite the fact that delivery and other costs are likely to differ by geographic location.

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[152] See, for example, EMRA board decisions for distribution and end-user (retail) tariffs, No. 272 and No. 276 (both dated December 12, 2003), respectively. Another example is the surcharge of 2 percent on end-user bills, for subsidizing the state-owned broadcasting company. (See Section 2.4.1.4.)

[153] Taxes levied on residential and industrial electricity use in Turkey are also among the highest of IEA countries. The IEA (2005b) notes that energy taxes serving fiscal needs are not uncommon among IEA member countries. However, it stresses that "…while many IEA countries are, to varying degrees, also using energy taxation for certain energy policy objectives, such an approach is almost non-existent in Turkey. Tax incentives and differentiation can play a useful role in promoting energy policy and environmental goals." p. 34.

- Within *bundled* end-user tariffs, no comprehensive, well-thought welfare-enhancing rate design (for example, multi-block rate schemes) exists to reflect explicit policy and development objectives.[154]

- Given prevailing pricing schemes, Turkey's electricity industry can be characterized by extensive cross subsidies *between* geographic locations (favoring downstream localities, where most load originates, and discriminating against upstream centers, where cheaper generation sources are nearby); *between* rate classes (favoring households over industrial customers); and *within* rate classes (with respect to consumption levels), thus creating various distortions for all sectors of the economy. Again, partly due to a lack of precise cost-of-service accounting, no assessment has been undertaken to determine the extent of cross subsidies in the industry.

The effects of pricing distortions in the electricity industry are felt throughout the economy. Thus, priority must be given to undertaking cost studies — of network assets in particular. The regulatory rules must require regulated entities (whether public or private) to submit their respective MC studies each time they file a rate case. Otherwise, regardless of which method is applied in the ratemaking process, tariffs approved by regulators will reflect arbitrary cost elements.

Because the time frame for completing Turkey's privatization process is uncertain, undertaking immediate efforts toward cost calculation would take good advantage of any delay. Having accurate cost data will help not only develop pricing policies for the competitive market but also to assess the value of any assets offered for privatization. Lack of precise cost-of-service studies will create a substantial obstacle in the privatization process and in attracting potential investors.

3.3.2 Regulatory Governance and Institutional Framework

Regulatory framework and design primarily determine the outcome of a liberalization program in the utilities industries. However, both the design and subsequent implementation must conform to the specific *institutional endowment* of the country for which the design is intended. Levy and Spiller (1996) approach this issue through the lens of institutional economics — which views regulation as a contracting problem — by arguing that privatization and regulatory reform may not always lead to improved performance by public utilities "because of the way a country's political and social institutions — its executive, legislative, its judicial systems, its informal norms of public behavior — interact with regulatory process and economic condition."[155] Accordingly, an institutional environment that makes administrative expropriation and manipulation of utilities more difficult becomes an important determinant of the success of reform by influencing the confidence of investors and the performance of privatized utilities. Consequently, the credibility and effectiveness of any given regulatory framework is closely linked to that country's political and social institutions.

[154] However, TOU pricing is an improvement for demand-side management purposes and will prove more useful if more customers use appropriate metering.
[155] Levy and Spiller (1996), p. 1. The following discussion draws on this work, unless otherwise stated.

In Levy and Spiller's analysis, a key concept in determining the success of reform is the ability of a country's institutional environment to restrain arbitrary administrative action. Three complementary mechanisms must be in place to secure this condition: substantive restraints on discretionary actions by the regulator; formal and informal restraints on changing the regulatory system; and institutions to enforce such restraints.

In this framework, regulation is treated as a "design" problem having two components: *regulatory governance* — which incorporates the mechanisms a society uses to restrain the discretionary scope of regulators; and *regulatory incentives* — which comprise the rules governing pricing, subsidies, competition, entry into the marketplace, interconnection, and so forth. Regulatory incentives become fully effective only if the proper regulatory governance structure is in place. Regulatory governance and incentives are considered as choice variables for policymakers, although their choices are constrained by the specific institutional endowment of the country.

Levy and Spiller's analysis primarily focuses on two elements of institutional endowment: a country's political institutions (both executive and legislative) and its judicial institutions. Furthermore, the interaction between these elements and both regulatory governance and regulatory incentives are explored.

In the case of regulatory governance, Levy and Spiller stress that utility regulation tends to be far more credible and regulatory problems less severe in countries where political systems restrain executive and legislative discretion. However, by limiting administrative discretion in parliamentary systems, a strong and independent judiciary can restrain an executive that may have strong legislative powers. In countries with a tradition of upholding contracts and property rights, the presence of an independent judiciary opens the governance option of using administrative tribunals to resolve conflicts between the government and utilities within the existing regulatory system.[156]

The regulatory incentive structure is also affected by a country's institutional endowment, its distributive politics, and its regulatory governance. Implementation of complex regulatory designs requires a certain degree of administrative capability; thus, a lack of administrative capability can result in poor implementation of incentives.

In general, regulatory incentive structure promotes investment, allocatively efficient pricing and innovation; however, distributive politics can interfere with regulatory rules, by demanding cross-subsidization — generally from business customers to residential customers. In turn, this may hamper efforts at obtaining the full benefits of competition. Finally, in some countries the institutional environment for regulatory governance might limit options for regulatory incentives to those options that are far from the first-best; in such circumstances, the only way to curb administrative arbitrariness is to eliminate almost all administrative discretion that leaves little built-in flexibility for regulatory incentive designs. Therefore, Levy and Spiller conclude that, "…utility performance turns out to be best when countries have achieved a good fit between their institutions

[156] See the cited work for the full analysis.

and their regulatory governance and incentive designs and worst when regulatory design proceeds without attention to institutional realities."[157]

In the same study, Levy and Spiller analyze Jamaica and the United Kingdom, among other countries, in order to explore the role institutional endowment plays in shaping regulatory framework. Both countries have parliamentary systems of government and a strong judiciary. The political system and the electoral rules of each country tend to support two strong parties, and the party in power controls both the government and the parliament (that is, the legislature). As a result, in the past both countries have had policy shifts, as governments changed between parties. Courts in both countries are well regarded; however, they have no formal restraining authority on the political process, or on the discretionary behavior imposed by regulatory institutions.[158] The British system, in particular, provides no constitutional protection against discretionary regulatory behavior. Thus, when a court decision overturns regulatory interference, the government can easily get its way, by introducing new legislation or procedures.

Levy and Spiller argue that given legislative flexibility and weak judiciary oversight of regulatory decisions, neither country can base its governance structure on legislation. Thus, contract law provides an important constraint in shaping the governance structure.

In both countries, licenses that have specific price-setting provisions serve as contracts between regulated entities and their governments. Any attempt by government to deviate from the specific provisions of the license agreements is challenged in the courts. The structure of licenses that include specific price-setting procedures makes judicial outcomes predictable, which in turn contributes to the credibility of the country's judiciary. These long-term licenses also provide confidence for companies in terms of the expected profitability of their investments; and — because the licenses are enforceable through the courts — companies can be assured of substantial regulatory stability.

Therefore: "[I]n both countries the emphasis on contract rather than administrative law to provide regulatory credibility is consistent with the nature of their political institutions. A law governing regulation, no matter how precise and specific, would offer little assurance of regulatory stability, whereas the courts in both countries have a strong tradition of upholding contracts among private parties."[159]

In their work on British regulatory institutions, Spiller and Vogelsang (1996) make similar assessments regarding the interaction between the political and the judicial system and the regulatory governance. After emphasizing both the political system's lack of constitutional protection against discretionary regulatory behavior and the privatization success of the 1980s in the telecommunications, electricity, water, gas, and airport industries, they pose the following question: "Why were private investors willing to

[157] *Ibid.,* p.7.
[158] This part also draws on the work by Spiller and Vogelsang (1996), which analyzes the British system within this context.
[159] Levy and Spiller (1996), pp. 20-21.

invest large amounts in sectors that, in principle, were vulnerable to confiscatory regulation in the future?"[160]

Their explanation was as follows: 1) regulatory authorities designed a privatization strategy that was aimed at achieving a broad base of ownership (this was achieved by selling shares of utilities to the public via the stock market, rather than by privatizing the companies, by block sales to large investors);[161] 2) ensuring that certain mechanisms of regulatory governance were in place, to restrain administrative discretion (these mechanisms included the use of licenses to stipulate pricing policies and access regulations; close monitoring of competition; allowing for the involvement of several agencies if a company opposed a proposed license modification; and acknowledging the significant role played by informal "norms" [see ensuing discussion], which limit ministerial discretion); and 3) the establishment of a detailed regulatory incentives system (such as price caps) to limit regulatory discretion.

Spiller and Vogelsang assert that privatization and the regulation of the telecommunications industry in the United Kingdom was in large part successful because these reforms were well suited to the country's institutions, which include independent courts, informal norms of proper government behavior, and the existence of agencies such as the Monopolies and Mergers Commission and the Office of Fair Trading. Because no tradition for the judiciary's role in actively restraining the administration has been established, the role of other formal and informal institutions (*norms*) needs to be explored. Spiller and Vogelsang focus on three informal norms as the main mechanisms for restraining government discretion in regulatory governance: the permanent bureaucracy, white papers, and the delegation of substantive powers to regulators.

The first element points to a tradition whereby senior government bureaucrats remain virtually untouched after the party in power changes. This results in bureaucratic stability, which limits the potential for abrupt policy changes. The second element — the use of white papers — serves to announce the government's intention for policy changes and provides an opportunity for interest groups to form an opinion, and to lobby. White papers also create a means for public discussion of any impending policy changes. Lastly, if a major regulatory change — such as license modifications — is to be undertaken by the government, a favorable recommendation by the head of a regulatory agency is first required, even though ministers retain formal powers over such changes. When a minister does not want to follow the recommendation made by the regulatory agency, both sides must adhere to a well specified process.

Spiller and Vogelsang argue that these *informal* norms of government decision making are not sufficient to guarantee policy stability (as indeed is seen by the regulatory policy shifts in the United Kingdom), "[r]ather, these norms of government decision making provide a base for the design of formal regulatory institutions that reflect the realities of institutional commitment mechanisms. Since changing decision making norms simply to

[160] Spiller and Vogelsang (1996) p. 79.
[161] This point was also made by Levy and Spiller (1996).

obtain a particular policy outcome is politically costly, basing the formal regulatory institutions on these institutions infuses the regulatory system with greater stability."[162]

In summation, by analyzing the regulation of the telecommunications industry in the United Kingdom, Spiller and Vogelsang conclude that: 1) a country's institutions play an important role in serving as guarantors of a commitment to a regulatory policy that offers adequate safeguards for private investment and incentives for efficiency: 2) an independent judiciary with a strong tradition of upholding contracts and property rights provides a setting whereby regulatory agreements are enforced through a well-defined licensing mechanism: 3) the use of licenses with specific pricing rules allows the possibility of a judicial check on the enforcement of contract provisions: and 4) widely accepted informal norms limiting ministerial discretion help make the delegation of regulatory authority another source of commitment to regulatory policies.

In this sense, Spiller and Vogelsang also offer an answer to the question posed at the beginning of their study regarding the seemingly surprising success of the privatization of British utilities in the 1980s. The reason for that success may primarily be due to the nature of the institutional environment in which the regulation took place. Certain elements of that environment restrained regulatory discretion and created regulatory stability — and thus created confidence for private investors. Two of the most important of those institutional elements are put forward by Spiller and Vogelsang: the need to have the regulatory system in place before privatization begins, and the need to place limits on unilateral actions by the regulators.

Finally, Spiller and Vogelsang note that the findings of their study have important specific implications for regulation in those countries that contemplate privatizing their utility industries. "In particular, countries without a strong tradition of judicial restraint of administrative decisions may find that attempts to design a U.S.-style regulatory system will fail because of the time needed to develop the relevant jurisprudence. For some countries the British system could provide an alternative, as long as their courts have a tradition of upholding contracts."[163]

As stated previously, in Turkey, the Electricity Market Law of 2001 also established EMRA, the independent agency responsible for regulating the Turkish electricity market.[164] The law provides a considerable amount of administrative and financial autonomy to EMRA. The regulatory agency finances itself through a surcharge on transmission tariffs and various licensing fees, and its decisions cannot be overruled by the government. To date, EMRA has issued much of the secondary legislation necessary for implementation of the law.[165] Furthermore, the agency has announced its tariff-making principles, as well as specific methodologies for network, wholesale, and retail services.

[162] Spiller and Vogelsang (1996), p. 82.
[163] *Ibid*., p. 120.
[164] Following the enactment of the Natural Gas Market Law of 2001 and the Petroleum Market Law of 2003, EMRA has also been given the task of regulating the natural gas and petroleum markets in Turkey.
[165] See www.emra.org.tr for more information.

However, a question arises: namely, what is Turkey's standing on the issue of regulatory governance based on the aforementioned framework, and what conclusions can be drawn regarding the prospects of Turkey's electricity industry restructuring and the new regulatory system?

Basically, the success of the restructuring program will depend on the ability of Turkey's institutional environment to restrain arbitrary administrative action with regard to regulation of the industry. First and foremost, a strong and credible judiciary is a *necessary* condition to employ the regulatory system as a means of securing private participation in the industry. Therefore, the judiciary's strength and institutional capacity provide an important basis for regulatory design, and choosing an appropriate regulatory governance option in line with Turkey's other formal and informal institutions becomes feasible. Otherwise, commitments can be secured only via international or state guarantees, as establishing a credible regulatory system proves infeasible.

Parliamentary systems, which unify executive and legislative powers, are generally vulnerable to discretionary behavior by the government, such as is the case in Britain and Jamaica, as mentioned earlier. In this case, making credible regulatory commitments has a better chance if a governance option in which the regulatory process is defined through contract law rather through administrative law is chosen.[166] Under such a system, an independent and impartial judiciary can best enforce operating licenses of the utility companies that specify pricing methods and access regulations within the existing regulatory system. For this system to be implemented in Turkey, price setting and access rules adopted by the secondary regulations may have to be embedded in the licenses of utilities. Operating licenses may then allow the implementation of a regulatory governance option that uses formal regulatory contracts to restrain government discretion in Turkey.[167]

Furthermore, in countries where informal norms restraining arbitrary action are well developed, credibility can be maintained by a more flexible regulatory system. In other countries, legislation is needed to delineate specific, substantial rules to achieve credibility. Turkey is likely to lie within the latter category: a regulatory process with little flexibility can be put in place, along with the necessary rules to restrain arbitrary action. Obviously, however, such a system would have an incentive design that lacks the much needed flexibility a fast-evolving, innovative market environment for utilities requires.[168]

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[166] Recall that under a unified system of government, enacting regulatory commitment through legislation is difficult, because the political party in power is able to exercise its discretion simply by changing the law. On the other hand, political systems that do not lead to a unified government (such as is the case in presidential systems), may allow a regulatory governance option that uses administrative procedures and legislation to specify the process for regulatory decision making, thus providing a check on regulatory discretion.

[167] Political interferences such as cross-subsidization or income requests by the Treasury could be eliminated through formal regulatory contracts.

[168] In the meantime, the importance of developing informal norms must be emphasized. Specifically the issuance of policy papers to initiate policy discussions prior to the government's delineating its intention

Finally, an institutional endowment that requires specific, substantive rules to achieve credibility must also have strong administrative capabilities enabling it to set up a regulatory system that restrains administrative discretion. A country with weak administrative capabilities may have to run their regulatory mechanism with less efficient rules. In view of its well-established bureaucratic structure, the administrative capability of Turkey is sufficient to operate complex regulatory designs.

In effect, the technical and professional capability of the designated regulatory agency is a crucial factor in establishing credibility. Expertise on issues related to electricity markets in particular and energy markets in general is absolutely necessary in order to keep up with fast evolving developments in energy markets around the world. The practice of energy regulation has always been closely related to academic developments in the field, and a mutual exchange of ideas has always helped determine the regulatory agenda, both in practice and in theory. Therefore, any regulatory agency should be viewed as an expert institution, rather than just another layer of bureaucracy. Staffing must be made accordingly, based on qualifications. This is also important for signaling credibility to private investors.

The success of regulation also depends on the qualitative aspects of its implementation. In the course of regulation, making the process transparent in every step of decision making also greatly contributes to the credibility of the regulator. All regulatory filings, positions of the various parties, and final decisions must be made available to the public (except in the case of commercially sensitive material, the disclosure of which might put a firm in a competitively disadvantageous position). Transparency can be significantly enhanced if decision making is opened to the public via various *collaborative* processes, whereby input from all stakeholders, (consumers in particular) can be received. In essence, public regulation is meant to be a *democratic* process in which decisions are made with the full participation of various market participants in a process that is open to appeal. Such a system would also ensure efficiency in the decision making process, and would protect regulatory agencies from the undue influence of private parties, or pressures from the government.

The main focus of public regulation is to protect the interests of the final consumer. In this sense, regulation of Turkey's electricity industry should not be thought of as an end, but rather as a means of promoting, creating, and maintaining competitive conditions within the marketplace.

The adjustment process set forth by the E.U. Acquis Communautaire can certainly serve as a strong impetus in improving the existing institutional environment in Turkey. In fact, a change in the institutional paradigm in Turkey has long been an aspiration of the public at large, various bodies of government, and the private sector. Hence, the course of E.U. accession is a valuable opportunity for any stake holder involved in economic life in Turkey.

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for policy changes, and the institution of consultations between the executive branch and the regulator in cases where major policy changes are being proposed, would contribute to credibility.

3.3.3 The Turkish Wholesale Market Model Envisaged by the Restructuring Plan

3.3.3.1 Model Selection

The Turkish electricity system operates a load dispatch system, in which the main principle is to meet total demand via the use of available resources, without necessarily observing the merit order of respective generators.[169] In the newly restructured environment, TEİAŞ will be kept out of the privatization plan and will continue to function as a state-owned entity: it will be the system operator, running real-time load dispatch and balancing supply and demand, as it does at present. However, as part of the ongoing liberalization efforts, TEİAŞ is also in the process of establishing a more advanced central dispatch system. The new system will run the physical dispatch of energy, while for the first time providing a settlement market for balancing supply and demand.

The Turkish restructuring plan is based on *bilateral contracts* for wholesale trade; for the time being, it envisages only a *residual balancing market*. This latter market will operate under the name of Market Financial Reconciliation Center, and will perform financial settlements arising from the differences in bilateral contract amounts and actual electricity generation and consumption. In its present form, the plan, as indicated by Law No.4628, does not set out a framework for instituting a centralized pool or power exchange that would include a spot market.[170]

Importantly, the success of various wholesale market models being implemented across the globe depends on whether each particular model addresses the specifics of the market for which it is being applied. *Merely copying a model that is essentially designed for a different location, with a different market framework (including a different physical industry structure, different demand conditions, and different institutional environment) would carry considerable risks and lessen the expected benefits from liberalization of Turkey's electricity industry*. Accordingly, any wholesale market design must take into account characteristics of the local market and wide array of experiences gained in markets elsewhere. Furthermore, when choosing from available models the underlying reasons for any given model's selection within the market from which it is being imported must be understood. Simply installing a system without assessing its merits may cause more harm than good.

Apparently, the new Turkish model is influenced by the current British model, NETA (New Electricity Trading Arrangements), a bilateral contacting model, which was instituted in 2001 following the dissatisfaction of both the British government and the

[169] One contributing factor to this situation is the lack of accurate generation marginal cost data. Another factor is the presence of long-term power purchase obligations of the state through "take or pay" clauses of BOT and BOO contracts.

[170] However, more recently, a policy paper issued in March 2004 foresees the creation of a spot market as an objective. (See discussion of the 2004 Strategy Paper in Section 3.6).

regulatory agency with the (compulsory) power pool that had been in place since 1990.[171] Although debate in Britain regarding the failure of the power pool and its subsequent replacement with NETA is still ongoing, a consensus has more or less been reached regarding the shortcomings of the initial design of the British wholesale electricity market. Importantly, however, these shortcomings are related mostly to the poor design of the power pool and the structural position of the British power industry at the time of implementation, rather than to the pool system itself.[172] Elsewhere, pool implementations have been working rather successfully for some time (such as pool systems in several jurisdictions in North America,[173] Scandinavia,[174] Australia,[175] and New Zealand.[176]) Thus, it is important to understand why the pool system has failed in Britain — and whether any given system that replaces a failed pool system could be an appropriate one for Turkey.

As stated earlier, industry experts widely agree that one important reason for the failure of the pool system in Britain was *the poor design of the pool*.[177] The poor design incorporated several aspects. First, in the new competitive environment, the system operator (National Grid Company, or NGC) used the dispatch software of the *old* generation and transmission monopoly (Central Electricity Generating Company, or CEGB). It had earlier been argued that if successor generating companies had copies of CEGB's software, they could use it to optimize their revenue, rather than to bid their true parameters.

The second aspect of the poor design of the pool system related to *capacity payments* — that is, payments made to generators that are primarily used in the wholesale markets to encourage investment. In Britain, the mechanism was such that the payment price was declared the day before the delivery was actually scheduled. Certain plants manipulated the system, by first declaring that plant would be unavailable, then re-declaring that the plant was in fact available on the day capacity was actually needed, thereby collecting the higher payment offered by the system operator. The erratic price signals this mechanism produced were claimed to strongly discourage buyers and sellers from trusting the pool

[171] See Law No. 4628 and discussion in Section 3.6 for other aspects of the Turkish restructuring plan such as transitional contracts, phased-in approach for eligibility of retail customers and allowing for vertical integration of generation and retail supply.
[172] While the pool system in Britain operated as a compulsory (day-ahead) spot market — producing the reference price — and a balancing market, the majority of electricity trade was conducted through bilateral contracts. (Newbery, 2005). See Newbery (2005) for more on the British pool system.
[173] Including PJM Interconnection (1997), New England ISO (1997), New York ISO (1998), and the newly launched Midwest ISO (2005). California was the only example of a failure in the North American markets, for reasons that are now common knowledge. (These reasons include faulty restructuring legislation, not allowing for hedging contracts and the compulsory "pool participation rule" for market participants, which made the system prone to manipulation of market power).
[174] The Nordic Power Exchange was established in 1993 as a Norwegian market. Sweden joined the power exchange in 1996, and the pool was renamed Nord Pool ASA. Finland (1998) and Denmark (2000) were also later integrated into the system.
[175] Australian ISO, known as the National Electricity Market Management Company (NEMMCO), has been in operation since 1998.
[176] New Zealand Wholesale Electricity Market began operating in 1996.
[177] The following discussion mainly follows Newbery (2005) and Thomas (2001), and highlights certain topics of importance. For more detailed analysis, see Newbery (2005).

system to fairly process their sale and purchases. During the 1994–1995 financial year, capacity payments constituted an estimated 20 percent of total payments for electricity generation, under NETA of 2001, capacity payments were removed from the system.

A *high concentration of power suppliers* in the generation segment of the market also played an important role in claims of market manipulation and high prices. This was especially true up to 1996, when National Power and Powergen dominated the generation market. It was argued that the tight timetable set forth by parliament for privatization did not allow the establishment of a sufficient number of generating companies at the beginning of the privatization.

Lack of consumer competition — particularly in the context of *transitional contracts* — is seen as another contributing factor for the failure of Britain's power pool. The government had required the two largest generators to sign take-or-pay contracts with state-owned British Coal in the post-privatization period between 1990–1993; in the same period, regional electricity companies (RECs) were required to buy nearly all the output of these two generators. Similar requirements were implemented for nuclear power. The net result was that during the 1990–1993 period, more than 90 percent of the power requirements of the British market were provided outside the competitive marketplace. These purchase guarantees continued, to some extent, until 1998; hence, the development of a competitive generation market was effectively stalled. Meanwhile, Britain's Electricity Act set fort a phased-in approach for customer eligibility, initially allowing 5,000 customers who each had more than 1 MW of demand to choose their own supplier. This limit was lowered to 100 kW in 1994, letting another 45,000 customers choose their supplier; finally, full eligibility for the remaining 22 million customers was established in late 1998. Nonetheless, given the existence of transitional contracts, declaring full eligibility for retail customers at the outset of the Electricity Act would not have made a difference in terms of competition in the generation market.

Vertical integration of generation and retail supply was allowed, leading to a reduction in the concentration of suppliers in the generation segment; however, such a reduction came at the cost of increased entry barriers. Furthermore, because the generation segment of the integrated companies had in most cases been sized to match the demand of their respective customer base, these companies were strongly discouraged from supplying cheaper, surplus power to the market.

While competition in the British market was beginning to develop by 1998 — coinciding with a time period of important favorable market developments (such as the end of transitional contracts; a reduction in the concentration in the generation segment of the market; the entry of a significant number of new generators; and the introduction of retail competition) — the new system design, NETA, was chosen in mid-1998. In other words, just as major impediments for the development of a competitive wholesale market were being phased out, a decision was made to change the market design. In the words of Newbery (2005), "[T]he ideal of a Pool with adequate competition, capacity payments, and a better governance structure for rule changes was never tried, and might have worked as well or better than NETA, with its emphasis on bilateral contracting and opaque balancing costs."[178]

In conclusion, the previous discussion tries to draw attention to the importance of appropriate model selection, and is helpful in providing guidance for avoiding pitfalls during the restructuring process in Turkey.

3.3.3.2 Other Issues

Aside from being a good indicator of short-term market prices, a functioning spot market can serve as a proxy for a full-fledged competitive market. The practical experience gained by market participants and the accumulated human capital in such an environment shortens the time span necessary for actors in the market to become accustomed to the mechanics of a competitive setting in the industry. Transactions based only on balancing market and bilateral contracts do not utilize the full potential of the market. Therefore, a spot exchange — even at a small scale — is a highly desirable platform for the early development of a future competitive market.

In view of the single integrated transmission network structure in Turkey, a Transo (rather than an ISO) is an appropriate business model for system operation to be run by the state-owned TEİAŞ within the new restructuring framework. As mandated by Law No. 4628, TEİAŞ is responsible for transmission system expansion investments and preparation of all generation capacity projections. The law further requires *regional* distribution companies to prepare periodic demand forecasts, to assist for TEİAŞ planning.[179] In fact, demand forecasts undertaken on a regional basis will be more useful than systemwide forecasts, as future investments in transmission and generation will necessarily have to be guided by regional parameters while dealing with issues such as congestion and mitigation of market power.

In the past, demand projections that play a vital role in supply planning have been controversial. Projections made by various state institutions differed substantially and, in many occasions, caused public debates. In particular, the necessity of concession contracts (BOTs and BOOs) has been intensively questioned, based on the observation that MENR's forecasts have frequently overestimated demand.[180]

Note that disparate forecasts confuse private investors who are planning to enter the market. A unified approach to the issue of demand forecasts must be established, both for the sake of accurate supply planning and for the purpose of reliably signaling market

[178] *Ibid*. pp. 68-69.
[179] Because regional distribution companies have not yet been defined, TEİAŞ uses demand forecasts prepared by MENR. Demand forecasts and TEİAŞ plans are subject to EMRA approval.
[180] In the past, both MENR and SPO prepared demand forecasts. However, these two entities were frequently at odds with each other, due to their varying views on the need for energy investments (SPO was often critical of MENR's forecasts that overestimated demand). These debates were widely publicized in the media. See Ediger and Tatligil (2002) for a review of the primary energy demand forecasts and their performance. The same models used for overall energy demand forecast are used in estimating electricity demand forecasts.

conditions to private investors. Meanwhile, as the share of private investment increases *and* market liberalization progresses, the relative need for supply planning becomes reduced with time — if not entirely eliminated. In the same context, generation capacity projections become more challenging. However, because Turkey's economy is a developing economy in need of attracting private investment to the electricity industry, for the foreseeable future TEİAŞ's planning can serve as an important reference guide for new investment.

In markets with restructuring experience, demand–supply imbalances, insufficient reserve capacity, bottleneck areas, and associated transmission constraints have constituted major barriers for competition and were root causes of market power. In Turkey's new era, TEİAŞ — both as a system operator and as the entity responsible for system planning — will become the backbone of the Turkish electricity market. It is crucial that TEİAŞ undertakes well thought, capacity planning that is based on regional requirements — requirements that are also simultaneously directed at mitigating transmission constraints. Such careful planning would contribute to the ultimate goal: achieving the merit-based dispatch of generation resources in the country.[181]

Finally, in this new regulatory environment, TEİAŞ must fulfill its aforementioned roles under conditions free of government control or any influence by other market participants. To this end, the administrative and financial independence of TEİAŞ can be secured by making access tariffs its only source of revenue. The use of *only* access tariffs is necessary for the efficient operation of the wholesale market, and is particularly important while state-owned generation assets dominate the market. However, for TEİAŞ, as a state-owned (and possibly a nonprofit) entity, regulatory challenges for designing a performance-based incentive scheme will exist, similar to those faced by nonprofit ISOs elsewhere. TEİAŞ's state-ownership and the potential for interference by the government is an added complexity when considering regulatory design. In that sense, the independence of TEİAŞ becomes the foremost prerequisite for success.

3.3.4 A Policy Note Regarding the Turkish Retail Market

At present, time-of-use metering is the only demand management program in use in Turkey. (See Section 2.3.3). Considering the capacity shortages forecast for the near future and the systemwide efficiency implications of DRPs, TEİAŞ — as the prospective system operator for the Turkish market — needs to initiate programs in cooperation with load-serving entities. Employing proper incentive schemes such as the ones currently being used in other markets would encourage substantial participation in the Turkish marketplace. Furthermore, considering the increased use of air conditioning in Turkey, secondary summer peak demand may soon become problematic in times of tight capacity, particularly if the generation market were allowed to operate on a market-based basis. In that sense, DRPs would also help mitigate potential market power situations.

[181] As discussed earlier, another important factor in achieving merit-based dispatch is to posses accurate generation marginal cost data.

As stated earlier, retail shopping for power by residential and small commercial customers has not progressed well in most markets that have a relatively high level of income. This is in part due to market design flaws and the low profit margins available to marketers who penetrate these market segments; but it is also in large part due to a low price elasticity of demand within the residential class. Furthermore, the benefit these consumers can expect from shopping for electricity does not come close to offsetting the high time cost given the relatively small share of a typical residential bill that electricity costs have in the median household income.

In Turkey, however, the situation may differ significantly from that of high-income OECD countries. This is because Turkish residential customers face one of the highest end-user electricity prices of any OECD countries,[182] while possessing the lowest median income of any country within the OECD group.

Consequently, a real potential exists for the establishment of retail competition in the small-customer segment of the Turkish electricity market, as these customers also stand to benefit greatly from competition. The lack of the necessary retail marketing infrastructure (namely, human capital— that is, knowledge and experience — and institutional capacity) does not constitute an obstacle for this segment, because local distribution companies can aggregate small customers' load in their service territories. In fact, as Joskow (2003) points out, even with a developed retail marketing infrastructure, profit margins will not allow retail marketers to succeed in the small-customers segment; it can further be argued that this situation will remain for the foreseeable future.

Note that the most desirable competitive outcome is the attainment of the lowest possible prices for energy. Distribution companies are the only entities that can minimize acquisition costs for small customers, thanks to their scale economies and their accumulated experience in retail services. These advantages make local distribution companies *natural aggregators*.

Distribution companies can conduct competitive solicitations for a portfolio of short- to medium-term energy contracts for small customers; these portfolios would also contribute to market stability for existing generators and potential investors. However, while more frequent power procurements for very short-term durations may create volatility in the wholesale market, extended long-term contracts may delay the effect of demand-side responses to energy prices.[183] Therefore, contract durations should be chosen carefully, taking existing market conditions into consideration. As a result, wholesale suppliers would compete to provide the power necessary to satisfy market demand and customers would benefit from the resulting competition. The Energy Market Regulatory Authority can develop transparent rules for the power procurement process and oversee the execution of contracts (Presently, TEDAŞ and its affiliates can fulfill the

[182] Using PPPs. (See Figure 21).
[183] Also, extended long-term contracts are expected to have high-risk premiums factored into their prices, owing to uncertainties in future fuel prices and overall economic conditions. Furthermore, extended long-term contracts can potentially cause stranded costs for future consumers.

function of competitive power procurement). However, the steps that must first be taken to institute such a policy include:

- start liberalization (and privatization) in the generation segment rather than in the distribution segment;[184]
- let state-owned generators run their operations on the basis of their respective true costs;
- without delay, make all customers progressively eligible for retail choice;
- unbundle rates so that distribution companies serve as "wire only" companies, and do not make profits on the energy they sell; and
- abandon plans for distribution companies to have five-year, transition supply contracts with TETAŞ, to supply 85 percent of their load to non eligible customers in their region, until at least January 2010 as envisaged in the 2004 Strategy Paper.[185] (See Section 3.6).

Ample opportunity exists for policymakers and regulators to take advantage of the unique characteristics of the Turkish market. The policy initiatives outlined here can introduce competition to small (and medium) customers segment at an earlier time than suggested by the Strategy Paper — even before full restructuring of the industry (that is, privatization of Turkey's distribution assets) is completed.

3.4 Exercising Market Power and Monitoring Anti-Competitive Behavior in Electricity Markets

3.4.1 Background

By its nature, the electricity industry is susceptible to exercise of market power. In a vertically integrated structure, holding companies may restrict outside suppliers' access to their transmission or distribution networks, in order to advance their own generation sales — thereby impeding the development of a competitive market. The threat of the exercise of market power is substantial not only in state-owned industries that have a single (or dominant) provider, but also in markets that have many vertically integrated, privately owned utilities. In markets with elements of competitive trading in electricity generation, a substantial share of installed capacity, significant control over transmission infrastructure, notable barriers to entry, and the possibility of reciprocal dealing can create market-power issues.[186]

[184] See the discussion in Section 3.6.1.6.2.

[185] Currently, the state has a concern that if the load for captive customers in distribution territories are not tied via some sort of compulsory power purchase agreements (such as the five-year transition contracts with TETAŞ), the output designated in binding BOT and BOO contracts may remain unsold, and the state will incur great financial losses. This argument does not have much validity, because the various demand and supply projections cited in this study indicate that there will not be any excess capacity in the Turkish market for the foreseeable future.

[186] See FERC (2001) and FERC (2004) for these issues.

Disintegrating such a structure via ownership separation and instituting strict regulatory rules for third-party access to monopoly networks is a solution presenting certain caveats. In a post-breakup environment, the threat of exercise of market power will still exist, through the *horizontal* concentration of generation with transmission constraints. Given that some load areas will have limited import capabilities — and hence face transmission congestions — transmission operators may not be in a position to follow merit-based generation dispatch during certain hours. This situation may encourage generators that have potential market power to "game" the system, by either withholding generation resources during peak times to raise prices, or by manipulating prices in the power exchange.[187]

3.4.2 An Assessment of the Pre- and Post-Privatization Environment in the Turkish Electricity Industry

3.4.2.1 Generator Concentration

The legal unbundling of the generation, transmission, and distribution segments of Turkey's electricity industry was accomplished in 2001. However, continued ownership integration by the state still exhibits a holding company structure even today. Following enactment of Law No. 4628, the generation company EÜAŞ took over state-owned hydroelectric and thermal plants from TEAŞ, and currently operates approximately 61 percent of Turkey's total installed capacity.[188] Presently, EÜAŞ is the dominant generator entity in the industry; and until privatization of generating assets is realized, it will remain so. Furthermore, the law mandates that the newly established trading and contracting company, TETAŞ (which assumed control of all earlier energy sale and purchase agreements of TEAŞ and TEDAŞ in 2001) is the sole buyer of energy generated in the plants owned by EÜAŞ.[189] TETAŞ's control extends to previously signed BOT, BOO, and TOOR contracts as well. This makes TETAŞ the dominant wholesaler in the Turkish electricity market by a wide margin. [190,191]

Law No. 4628 contains some provisions limiting concentration within the *private* generation segment of the electricity market. It requires that a private generator company

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[187] The primary tool for exercising market power is *physical* or *economic withholding*. Physical withholding refers to the act of not offering to sell or schedule output or services when it is economically advantageous to do so, such as falsely declaring a resource has been forced out of service (or otherwise become unavailable) or deliberately withholding capacity by a transmission facility. Economic withholding refers to submitting an unjustifiably high supply offer for a resource, so that either the resource will not be dispatched or scheduled, or the bid or offer will set an unjustifiably high market-clearing price. See ISO-New England (2005) for detailed definitions and market monitoring practices.

[188] Except certain DSİ hydroelectric plants, which are operating under TOOR contracts. However, EÜAŞ will keep the ownership of these plants. (See Electricity Market Law, Part I, Section 2, Article 2a) 1).

[189] However, recently enacted Law No. 5307 allowed EÜAŞ to sell electricity to wholesale companies under bilateral contracts provided that the purchase is intended for exporting abroad. Law No. 5307 is entitled "Liquefied Petroleum Gas Market Law and Law Concerning Changes in Electricity Market Law" published in the Official Gazette No. 25754 (March 13, 2005).

[190] See the discussion in Section 5.3 of OECD (2002a).

[191] Although Law No. 4628 envisaged this arrangement on a temporary basis (until 2007), the Strategy Paper of March 2004 (discussed in Section 3.6), foresees such arrangement as remaining valid until 2010.

and its affiliates own no more than 20 percent of the total installed capacity of the previous year.[192] State-owned generation, however, is not subject to such limitation. This latter exemption may be interpreted being set forth provisionally for the purpose of recovering expected stranded costs from BOT, BOO, and TOOR contracts as this exemption otherwise represents a conflict with a future competitive structure.

Although Law No. 4628 establishes some safeguards for generator concentration by instituting universally accepted ownership thresholds, in today's markets these safeguards are by no means sufficient to detect or prevent exercise of market power. To ensure minimum safeguards for mitigating market power in the generation segment, regulatory (or antitrust) rules must contain provisions assessing whether a generator has transmission market power; whether barriers to entry exist; and, finally, whether reciprocal agreements exist among market participants.

Finally, in competitively restructured electricity markets, where trade is centralized and vertical monopolies no longer exist, detecting market power in the generation segment requires more sophisticated approaches than the establishment of simple thresholds. For instance, the potential for market power can be assessed by considering transmission constraints in *load-pockets*[193] to determine what supply sources can reach buyers to compete with the generator in question. In the United States, FERC has recently initiated a test — Pivotal Supplier Analysis (or PSA) — that establishes a threshold based on whether a generator is *pivotal* to the relevant market (that is, whether a generator's uncommitted capacity exceeds the difference between the market's total uncommitted capacity and the wholesale load).[194,195] Effectively, the PSA identifies whether a generator is a *must-run supplier*[196] needed, at least in part, to meet peak load in a specific market. In this situation, the threshold is sensitive to a generator's potential to successfully withhold supplies in the market in order to raise prices. In addition, a "market share" test is applied for Summer, Fall, Winter, and Spring that determines whether a generator's uncommitted capacity in a geographic market is less than 20 percent.

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[192] Electricity Market Law, Part I, Section 2, Article 2a) 2.

[193] A *load pocket* is a region within which competition for generation from outside the region is restricted due to transmission constraints. In such an instance, for example, only local generators may have to operate during peak hours to provide power reliably. Load pockets are potentially vulnerable to the exercise of market power depending on the prevailing conditions in their particular market. The amount of excess capacity and its degree of ownership diversification; cost conditions of local generators; and price sensitivity of demand in the region can influence the outcome. While long-run solutions to this problem include making necessary generation and transmission investments in the region, in the short run, any load pockets in question may need to be regulated during hours of congestions.

[194] Uncommitted capacity refers to the capacity available to the (short-term) wholesale market. It is calculated as total capacity less native-load obligation (that is, sales to end-use utility customers), long-term contracts and operating reserves.

[195] See FERC (2004) for this analysis.

[196] *Must-run suppliers* refer to those generating units that must be on-line or on the grid and that are designated to operate at a specific level to ensure the stability of the system. These units may become crucial to the system operation only for a short duration of time during a year, and may be more expensive to operate than other units available for dispatch. Must-run suppliers have the potential to exercise a significant degree of market power; thus, they may need some degree of regulation.

By contrast, under the *plain threshold method*, as established by the Turkish Electricity Market Law, a generator passes the test for market power as long as its market share is less than 20 percent — even if its capacity is pivotal. For this reason, the market share test of the Turkish system must be complemented by a pivotal supplier analysis. Furthermore, the current method treats the entire Turkish market as one even though various conditions, particularly transmission constraints, can create various load pockets and sub markets. These factors should be taken into consideration in defining relevant geographic markets for market power analysis. Currently, in the United States, more detailed market monitoring and market-power mitigation procedures are being implemented by various ISOs in their respective control areas. In advance of expected market imperfections, the regulatory framework in Turkey must adapt and further develop such market monitoring rules, in accordance with the peculiarities of Turkey's infrastructure.

In general, an important task for the new privatization program is to identify transmission constraints and bottleneck areas in Turkey, and assess the potential for market manipulations. Portfolio generation companies (discussed in Section 3.6) should be established, by considering the threat of possible anti-competitive practices in respective generator locations and load areas. Because the current legal and regulatory framework aims to develop a competitive market structure — one in which energy will be commercially traded among market participants and regions — these issues need to be considered *before* privatization takes place, to prevent the serious consequences of market manipulation.

3.4.2.2 Prospects for Entry in the Generation Market

In order to minimize the threat of market power and price manipulation during instances of peak time capacity shortages, transition to a competitive generation market requires an abundant supply of generating resources. Assuming that all plants currently under construction in Turkey, and all projects that have received licenses are realized, forecasts indicate that by 2012 installed capacity will be below peak capacity requirement, with no reserves available. From 2005 to 2020, investment in 58,760 MW of generating capacity is required to meet expected peak load capacity demand; of this, 7,385 MW is either under construction or has received license, and 51,375 MW is still to be added (see Section 2.2.2.1.5). Hence, for Turkey's future liberalization efforts, the importance of attracting new private investment into the generation market is evident.

However, as long as the integration of EÜAŞ and TETAŞ continues, new entry by private investors into the generation market is likely to be challenging, if not impossible. At present, nearly 85 percent of Turkey's total output is contracted via TETAŞ and, excluding autoproducers, all existing *private* generating capacity is under exclusive purchase agreements with TETAŞ. Furthermore, the Strategy Paper of 2004 stipulates that distribution companies will have five-year transition contracts with TETAŞ, supplying 85 percent of their non eligible customers until at least 2010. Therefore, new entrants in the generation market will have a hard time competing with EÜAŞ generators and the binding purchase contracts of the BOT, BOO, and TOOR schemes that are currently held by TETAŞ. (See Section 3.6 for further analysis.) Also, current excess generation capacity makes new investment unattractive for private investors (although projections indicate this to be a short-term situation).[197]

Another factor that limits market possibilities for the new supply entering the generation segment is the eligibility of customers to have retail choice. The potential market share for eligible customers is 28 percent of the total consumption during the first half of 2005. Thus, for the near future,[198] less than a third of the market is a realistic candidate for having bids solicited by generators (or wholesalers) outside control of the state sector.

Aside from new investment in generation, extra supply can come from autoproducers and imports. In 2003, Turkey's autoproducers provided 16 percent of the total electricity output. This is a significant source of supply to the eligible market; however, under current rules autoproducers can sell only 25 percent of their output to the market without acquiring an electricity production license. Law No. 4628 required state-owned power entities to purchase the excess production of autoproducers at a price equal to 85 percent of TEDAŞ's sales price to industrial customers, and allowed autoproducers to sell their power directly to consumers at prices agreed upon bilaterally. However, this favorable legal environment changed in July 2002, when purchase requirements by the state were eliminated, thus leading to lower prices being paid to autoproducers.[199]

Presently, autoproduction — both in terms of installed capacity and generated energy — plays a substantial role in the Turkish electricity market. The rate of growth of this industry segment has been remarkable in the recent past; the extent of projects waiting for permission to proceed makes its growth prospects even greater. Note that during the 1980s, a similar development in the United States greatly contributed to the development of additional installed generation capacity. Following the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978, growth in the non-utility power industry has originated primarily from cogeneration facilities and renewable energy facilities, which sell their power to local utilities under long-term contracts.[200]

However, implementation problems regarding autoproduction in Turkey exist.[201] Initially, industrial companies were given an incentive to start autoproduction — mostly in the form of cogeneration — to provide electricity and heat (steam) to their own, or their shareholders', facilities. In cogeneration, most efficiency gains are realized when facilities are integrated with established industrial facilities near the load points: both loading of transmission lines (that is, congestion) and related losses can thus be avoided and the resulting heat (steam) output can be used for industrial or residential heating/cooling purposes. When a cogeneration plant is located far from industrial

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[197] On the other hand, excess capacity is considered helpful for the transition period.
[198] The 2004 Strategy Paper envisages eligibility limits to be kept fixed at 7.8 GWh until 2009, from which point on limits will be decreased. The current eligibility threshold is at 7.7 GWh level.
[199] IEA (2005b), p. 137.
[200] See Joskow (2003). Under PURPA, those small power producers and cogenerators were called *qualifying facilities* and were allowed to sell their power to public utilities.
[201] See Yigit (2001).

facilities, only the electrical output of cogeneration can be used, because heat cannot be transported long distances, thereby lowering efficiency gains of cogeneration.

Currently, autoproducers in Turkey are no longer required to install cogeneration units or integrate their units with industrial facilities. Autoproduction based on hydroelectricity or wind resources are in a similar situation. Because autoproducers are allowed to practice "wheeling," they can supply power at one point and intake it for use at another. For cost considerations, some autoproducers in Turkey therefore locate generation units away from load centers and sell their power to the grid while withdrawing power for their own use at a point near their industrial facilities. This can cause congestion and loss in transmission lines, which partially offset the initially intended purpose of autoproduction.

Autoproducers serving as independent power producers bring the efficiency implications of such design into question. In this regard, a policy assessment must be made regarding efficiency considerations for cogeneration and similar investments. Based on such an analysis, the autoproduction segment of the industry should be supported by appropriate market design incentives. The wide availability of entrepreneurs who have already gained operational and market experience in this industry and who will function as the independent power producers is an added benefit of the appropriate design of market incentives.

Finally, imports are a potential major source of alternative new supplies. Once the UCTE interconnection to European markets is established (See Section 2.2.2.2.2) and an adequate amount of capacity is built, imports may represent a significant competitive source of supply. In fact, under current conditions with regard to ownership and contractual arrangements in the Turkish market, imports stand to play a major role in the creation of competitive conditions within the generation market.

3.5 Stranded Costs and BOT, BOO, and TOOR Contracts

3.5.1 Definition, Scope, and Experience Elsewhere

In the early 1990s, starting with the divestiture of utility assets in the United States and privatization in the United Kingdom, the issue of *stranded costs* sparked intense debate in the restructuring field, leading to a substantial amount of literature about stranded costs being written in the field of economics. Mutual feedback between the utility business and academia on the subject was common at the time — as was a heated debate among stakeholders in the industry (consumers, utilities, and regulators). Discussion is still ongoing regarding the fairness of the *stranded cost recovery* methods currently being implemented, and even the *necessity* of recovery.[202] The issue, however, for the most part

[202] Proponents of stranded cost recovery claim that in the past, regulators, shareholders of utilities, and consumers were parties to an "implicit regulatory compact" that imposed an obligation on utilities to serve all customers and to invest in anticipation of demand growth. Due to this historical compact, it is thus claimed that shareholders are owed the full recovery of these costs. (See, for example, Baumol and Sidak, 1995, for an economic justification of stranded cost recovery). Opponents of stranded cost recovery generally discount such implied regulatory compacts and argue that utilities — not the rate payers — must bear the burden of such costs.

has been "resolved" and the debate has subsided in the United States; this has resulted mostly from the enactment of legislation in states undertaking utility restructuring. In general, the outcome has been cost recovery schemes based on consumers paying the stranded costs through a surcharge in their electricity bills. In the United States, the total financial figure for stranded costs has been estimated to be as high as $100 to $300 billion.

Stranded costs are those costs related to "transition costs" that are created or *expected* to be created by transitioning from regulated to competitive utility markets. Such costs include those of "stranded assets" (mostly in the form of capital costs related to generating assets, particularly the difference between the book and the market value of these assets); decommissioning liabilities (that is, the cost of decommissioning power plants, especially nuclear plants); utility expenses, termed "regulatory assets" (which arise from deferred cost recovery practices used to keep rates low for policy reasons); and contractual obligations (which generally are long-term power or fuel purchase contracts).[203] *Wholesale stranded costs* are defined in the United States by FERC as "any legitimate, prudent and verifiable costs incurred by a public utility or a transmitting utility to provide service to a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled transmission services customer of that public utility or transmitting utility."[204] Transition costs may arise in the new competitive environment mainly because utilities, under the old regulatory system, were either allowed or required to incur such expenses to meet their obligation to serve their customers; utilities may in fact not be able to recover these costs, however, given that electricity prices are expected to be lower in the new competitive market. Once restructuring is implemented, for instance, eligible customers may leave utilities to purchase their power needs from another supplier, thus leaving utility companies stranded with long-term investments.

As in the United States, the United Kingdom enacted legislation to address the issue of stranded costs. The Electricity Act of 1989 initiated the restructuring of the industry, which also included the privatization of state-owned generation, transmission, and distribution assets. In the period of transition from a state-owned system to a market-based system, the U.K. government faced problems in two energy-related industries:[205] the state-owned coal industry (whose output had been used by the power generation industry) and the nuclear industry (whose decommissioning costs were going to be a

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[203] In the United States following the Public Utility Regulatory Policies Act (PURPA) of 1978, utilities — in addition to their utility-owned power — were required to buy power from independent power producers under long-term contracts, in anticipation of high electricity prices and demand growth. Regulators also allowed utilities to invest in large-scale power plants, including nuclear plants. In the United Kingdom during the 1990s, state-owned nuclear plants and long-term coal purchase contracts became the main source of stranded costs, owing to the policy of privatization.

[204] Similarly, *retail stranded costs* are defined by FERC as "any legitimate, prudent and verifiable costs incurred by a public utility or a transmitting utility to provide service to a retail franchise customer that subsequently becomes, in whole or in part, directly or indirectly, an unbundled transmission services customer of that public utility or transmitting utility." FERC also defines an unbundled transmission services customer as "one who purchases transmission as a product that is separate from the purchase of generation." See Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, Federal Register 18 CFR Part 35 [Docket No. RM94-7-000], 1994.

[205] See Newbery (2005) and Thomas (2001).

significant financial burden). The first problem was addressed by establishing "take-or-pay" contracts between British Coal and two large generators (PowerGen and National Power), requiring the two generators to continue purchasing coal above world prices for three years (from 1990 to 1993). Similarly, retail electricity companies (RECs) were required to buy nearly all of the output of these two generators, to be sold to their captive customers. (These contracts were later renewed, and to some extent remained effective until 1998.) Stranded costs due to the decommissioning of nuclear units were addressed by imposing a "non-fossil fuel obligation" on RECs (that is, a power purchase obligation largely directed at purchases from nuclear generators) and a fossil fuel levy on all fossil-fuel generation (revenues from which were to be transferred to the nuclear generation segment to pay its liabilities).

The discussion of who should pay stranded costs takes a different form in different jurisdictions, depending on the ownership structure of the stranded assets. In the United States — where investor-owned utilities constitute most of the electric power industry[206] — the issue of who should take financial responsibility for these costs was between *shareholders* and *ratepayers*. In the United Kingdom, however, where the industry was predominantly state-owned, the issue of who should pay lay between the *taxpayers* and *ratepayers*.[207]

Regardless of the method chosen for recovery, a framework setting out solid criteria is needed to assess the likelihood of the future existence of stranded costs and to measure the extent of stranded costs if, in fact, they do occur. Note that by definition, stranded investments can be defined only in relation to the past; one cannot definitively determine the full extent — or even the existence of — stranded costs in advance, because such calculations will be based to a great extent upon whatever future market prices are expected to prevail. Stranded costs are a dynamic concept; changing market prices may change the initially estimated extent of them.[208]

When determining the extent or existence of stranded costs, all possibilities for mitigating such costs must first be considered; these possibilities may include eliminating state subsidies in the industry and discontinuing the operation of inefficient plants. (Subsidies, for instance, keep power prices artificially low, and hence increase the extent of stranded costs.) Also, the buyout of uneconomic plants may help minimize stranded costs at the outset.

Some options for stranded cost recovery include to:

- make utilities (shareholders) absorb reductions in asset value;
- make customers pay for asset reduction through a surcharge in their bills; or

[206] While approximately seventy five percent of the electric utility generating and transmission capacity is comprised of investor-owned utilities, the remaining is made up by federally and publicly (mostly municipally) owned utilities and cooperatives.
(See http://www.eia.doe.gov/cneaf/electricity/page/prim2/toc2.html)
[207] See the discussion in EIA (1997), p. 14.
[208] Initially, stranded costs are determined on the basis of the balance sheet of the utility. However, this initial amount is subject to change, as the market value of power changes.

- provide direct government (that is, taxpayer) subsidies to asset owners, to offset projected reductions in asset valuations.

One option for reducing the financial burden of stranded costs is to change the time line and structure of cost recovery through the *securitization* of the stranded assets. Securitization refers to the monetization of the future income stream of a utility, by issuing bonds to finance anticipated stranded costs. Under this scenario, when utilities face stranded costs, the state passes legislation to back bonds to be issued for a fixed amount, equal to the whole or part of the anticipated stranded costs; in addition, all prospective transition charges to be collected from ratepayers until costs are recovered are paid in one lump sum to the utility responsible for paying for these assets. Securitization serves as a tool to lower the financing costs of utilities, particularly in the case of assets in the generation segment. As a matter of industry practice, utilities initially borrow from the financial markets for their investments through the issuance of debt and preferred or common stocks; the total cost of borrowing by these methods, however, is generally higher than that of bonds issued for securitization because the latter has the backing of the state.

Given that power purchase contracts are based on (annually varying) predetermined unit prices with take-or-pay obligations and annual streams of revenues, securitization of stranded assets might initially seem to not serve its usual purpose of saving financing costs. However, because an initial financing cost for these generation investments exists (and because contract prices surely reflect those costs), a buy-out option (that is, a lump sum payment to generators) can be negotiated by the government (or regulators) with investors of these generation projects; the funds necessary for the buy out may then be securitized. If such a buy out is in fact agreed upon, some savings (namely, the difference between the costs of the initial financing of the projects and the cost associated with securitization) can be achieved. Thus, securitization still can be a sensible option for reducing the extent of stranded costs in power purchase contracts — notably, BOT, BOO, and TOOR projects in Turkey.

3.5.2 The Turkish Case

3.5.2.1 An Assessment for the Calculation of Stranded Costs

The issue of stranded costs may arise in the context of BOT, BOO, and TOOR contracts, and may shape the process of competitive restructuring in Turkey. The method by which these costs are recovered and the time frame[209] required for this process will ultimately affect the start of a functioning competitive market.

Turkey's BOT, BOO, and TOOR contracts would lead to stranded costs if energy prices in the competitive market turn out to be lower than the prices stipulated by these contracts. Thus, the reference point in this assessment (and the related cost calculation) is the competitive prices that are *expected* to rule after the restructured markets start

[209] A delay may occur, not necessarily because stranded costs exist *per se* but because their existence is speculated, and thereby seen as an obstacle.

functioning. Because Turkish restructuring is currently in its very early stages, pinpointing the price level at which energy will be traded in the future in Turkey is difficult, given various demand growth projections and exogenous conditions (such as fuel prices). Hence, the existence and the magnitude of stranded costs related to BOT, BOO, and TOOR contracts cannot be accurately determined *a priori* — particularly in this case, where contract prices evolve on an annual basis. Moreover, in a situation where large-scale privatization is expected in the industry, the direction and the level of market prices that are likely to follow remains hard to forecast.[210]

Consequently, estimates of stranded costs related to Turkey's BOT, BOO, and TOOR contracts will be educated guesses at best, and hence, must be examined with caution. This is in part because public support is of great importance for successful restructuring programs; sensationalizing and overemphasizing certain aspects of the reform program could potentially hamper the program itself. In fact, such an approach may be perceived as implying a more severe financial burden on the society than is actually the case, and thus reduce the reform program's perceived feasibility by the public.

On the other hand, public discussion of stranded costs should be encouraged, in order to ensure a fair and efficient restructuring program. Transparency and accountability, without disclosing commercially sensitive contract terms, will prove very helpful in the process. Annual financial obligations and average price and quantity figures, at a minimum, can be made public, so that a consensus is achieved among the state, regulators, industry and ratepayers regarding the issue of cost recovery. Secrecy will negatively influence advocacy efforts for reform.

3.5.2.2 BOT, BOO, and TOOR Investment Schemes in Turkey

Based on the framework of Law No. 3096 enacted in 1994, a total of 23 BOT generation projects are currently underway in Turkey. These include four combined-cycle-gas-fired (CCGF) plants, 17 hydroelectric plants, and two wind farms. Tariffs prepared by BOT companies are subject to MENR approval before taking effect. Tariffs for gas-fired generators in BOT projects have three components:

1. **Fixed capacity expenses** are subject to a one-time increase from the date of agreement to the date of operation, and remain constant until the end of the contract duration (20 years).
2. **Variable capacity expenses** are increased on the basis of changes in the U.S. consumer price index, at the beginning of each year of operation.
3. **Fuel (natural gas) expenses** are adjusted monthly on the basis of charges paid to, BOTAŞ (Turkey's state-owned national pipeline company), the heat rates of generators, and other variables.

In gas-fired BOT projects, 100 percent of annual output levels is contracted for the exclusive sale to state-owned TETAŞ which guarantees the purchase. Additionally, for

[210] On the other hand, a well thought privatization program would greatly help determine the market value of assets, and hence the extent of stranded costs.

some CCGF projects contract clauses for *excess output* contract for any output that is beyond the aforementioned output levels; these contracts are subject to separate tariffs. The excess output tariff formulas for majority of the gas-fired projects are as follows:[211]

a. For 100 % < Excess Output < 105 % →Variable Capacity Expenses * 0.75 + Fuel Expenses

b. For 105 % < Excess Output →Variable Capacity Expenses * 0.25 + Fuel Expenses

The first BOO generation projects were undertaken following the enactment of Law No. 4283 in 1997; they include four CCGF plants and one coal-fired plant. Tariffs for generators in BOO projects have four components:

1. **Investment expenses** are fixed charges that remain the same throughout the contract period.
2. **Fixed operating expenses** represent expense items that do not vary by level of output, and are increased on the basis of the contract terms at the beginning of each operation year.
3. **Variable operating expenses** are those expenses that vary with the amount of energy generated and are subject to increases in the same manner as fixed operating expenses.
4. **Fuel (natural gas) expenses** are adjusted in the same way as in the case of BOT contracts, mentioned previously.[212]

In the BOO scheme, TETAŞ guarantees the purchase of 85 percent of the net energy generated and the companies reserve (that is, assure the availability of) 100 percent of the output for sale to TETAŞ. A full tariff is applied to 85 percent of the energy generated; any purchase above that level is priced on the basis of fuel expenses plus variable operating expenses.

At present, two generation projects are being operated under the TOOR framework initiated by Law No. 3096 (one hydroelectric project and one-coal-fired project). Tariffs for the thermal plant are based on:

1. **Fixed capacity expenses** that remain constant throughout the contract period and include payments for the transfer of operating rights, depreciated investment, fixed operating and maintenance expenses, and other expenses.
2. **Production expenses** that vary by the amount of energy generated and include variable expenses such as fuel, labor, and other intermediate inputs.

Tariffs for the hydroelectric project are determined according to cash flow statements subject to MENR revision.

[211] Tariffs for hydroelectric and wind projects are determined mostly according to annually revised cash flow statements, as part of the projects' concession/implementation agreements.
[212] Fuel charges for the coal-fired plant are adjusted on the basis of imported coal prices.

See Table 17 for BOT, BOO, and TOOR generation contracts listed on project-by-project basis:

Table 17: BOT, BOO, and TOOR Contracts

BOT CONTRACTS UNDER OPERATION

Project No.	Name	Location	Company	Fuel Type	Contr. Ins	Contr.	Date of Conces.	Date of	Contract Duration
					Capacity	Output	Agreement	Operation	and End of Contract
					(MW)	(GWh)			
1	GEBZE DİLOVASI CCGT	Gebze Dilovasi/Kocaeli	Ova Elektrik	Natural Gas	253.4	1,963	5/31/1996	1/21/1997	20 years (01/21/2017)
2	ESENYURT CCGT	Esenyurt/İstanbul	Doğa Enerji	Natural Gas	180	1,400	5/12/1995	5/22/1999	20 years (05/22/2019)
3	MARMARA EREĞLİSİ CCG	Marmara Ereğlisi/Tekirdağ	Trakya Elektrik	Natural Gas	478	3,600	2/16/1996	6/5/1999	20 Years (06/05/2019
4	MARMARA EREĞLİSİ CCG	Marmara Ereğlisi/Tekirdağ	Uni-Mar	Natural Gas	478	3,600	3/18/1996	6/12/1999	20 Years (06/12/2019)
Gas Total				**4 Natural Ga**	**1389.4**	**10,563**			
5	KISIK HET	K. Maraş	Ayen Enerji	Hydro (River)	9.6	33-35.45	8/18/1988	1/5/1994	15 Years (01/05/2009)
6	ÇAMLICA I	Kayseri	Ayen Enerji	Hydro (River)	84	429	9/9/1994	12/12/1998	15 Years (12/12/2013)
7	BİRECİK DAM and HET	Birecik/ Ş. Urfa	Birecik Baraj-HES	Hydro (Dam)	672	1,900-2,400	3/19/1993	10/4/2001	15 Years (10/04/2016)
8	Aksu-Çayköy	Çayköy/Eğridir/Isparta	Aksu Enerji	Hydro (River)	13	36	2/19/1986	12/1/1989	50 Years (11/01/2039)
9	Hasanlar HET	Hasanlar-Düzce/ Bolu	Altek Elektrik	Hydro (River)	9.4	42	6/18/1987	5/17/1991	15/20 Years (05/17/2011)
10	Berdan HET	Tarsus/I/İçel	Altek Elektrik	Hydro (River)	10	47	11/15/1993	12/271996	15 Years (12/27/2011)
11	Gönen HET	Karasuçam /Balikesir	Gönen Elektrik	Hydro (River)	10.6	47.2	2/5/1996	3/7/1998	20 Years (03/07/2018)
12	Sütçüler HET	Sütçüler/Isparta	Sütçüler Enerji	Hydro (River)	2	12.2	6/14/1991	6/18/1998	1-20 Years (06/18/2018)
13	Tohma-Medik HET	Malatya	Altek Enerji	Hydro (River)	12.5	58.9	6/10/1996	12/23/1998	20 Years (12/23/2018)
14	Ahiköy-I HET	Divriği/Sivas	Ahiköy Enerji	Hydro (River)	2.1	9.03-11.4	8/13/1990	9/2/1999	15-20 Years (09/02/2019)
15	Ahiköy-II HET	Divriği/Sivas	Ahiköy Enerji	Hydro (River)	2.5	8.44-11.3	8/13/1990	11/18/1999	15-20 Years (11/18/2019)
16	Fethiye HET	Fethiye/Muğla	Fethiye Enerji	Hydro (River)	16.5	90.0	7/30/1996	12/20/1999	15 Years (12/20/2014)
17	Suçatı HET	Suçatı/K. Maraş	Ere Elektrik	Hydro (River)	7	27.7	5/31/1996	1/18/2000	15 Years (01/18/2015)
18	Dinar II HET	Dinar/Afyon	Metak Enerji	Hydro (River)	3	16.3	7/30/1998	12/1/2000	15 Years (12/01/2015)
19	Çal HET	Çal/Denizli	Limak Enerji	Hydro (River)	2.2	11.8	3/9/1998	1/12/2001	20 Years (01/12/2021)
20	Girlevik II and Mercan HET	Çağlayan/Erzincan	İçtaş Enerji	Hydro (River)	11.6	40.6	2/11/1999	3/30/2001	20 Years (03/30/2021)
21	Gaziler HET	Iğdır	Gaziler Enerji	Hydro (River)	11.1	43.3	6/4/1992	11/7/2002	20 Years (11/07/2022)
Hydro Total				**17 Hydro**	**879.1**	**2,852-3,360**			
22	Alaçatı WT	Sadlıktepe/Çeşme/İzmir	Ares Alaçatı	Wind	7.2	19.0	7/30/1998	11/28/1998	20 Years (11/28/2018)
23	Bozcaada WT	Bozcaada/ Çanakkale	Bores-Bozcaada	Wind	10.2	29.9	6/13/2000	7/25/2000	20 (Years (07/25/2020)
Wind Total				**2 Wind**	**17.4**	**48.9**			
BOT Total				**23 BOT**	**2285.9**	**13,464-13,972**			

Notes:
CCGT: Combined-Cycle-Gas-Turbine; HET: Hydro Electric Turbine; WT: Wind Turbine

BOO CONTRACTS UNDER OPERATION

Project No.	Name	Location	Company	Fuel Type	Contr. Inst.	Annual Aver.	Date of	Date of Add.	Start of	Date of	Contract	Contracted
					Capacity	Contr. Output	Agreement	Protocol	Construction	Operation	Duration[1]	Duration of
					(MW)	(GWh)						Operation[2]
1	Gebze CCGF	Adapazarı/Sa.	Gebze E. Üretim	Natural Gas	1,540	12335-12885	10/8/1998	5/12/2000-05/28/2001	7/28/2000	10/25/2002	20 years	16 Years
2	İzmir CCGF	Aliağa/İzmir	İzmir E. Üretim	Natural Gas	1,520	12174-12662	10/8/1998	5/12/2000	9/14/2000	3/28/2003	20 years	16 Years
3	Adapazarı CCGF	Adapazarı/Sa.	Adapazarı E. Ü.	Natural Gas	770	6117-6424	10/8/1998	5/12/2000-05/28/2001	7/28/2000	10/9/2002	20 years	16 Years
4	Ankara CCGF	Temelli/Ankara	Baymina Enerji	Natural Gas	770	5,800	10/8/1998	11/14/2001	11/23/2000	2/4/2002	20 years	16 Years
Gas Total				**4 N. Gas**	**4,600**	**36426-37771**						
5	Sugözü-İsken.CT	Yumurt./Adana	İskenderun En.Ür.	Imp. H.Coal	1210	9,100	1/7/1999	5/30/2000-9/28/2000	8/29/2000	11/22/2003	20 years	16 Years
Coal Total				**1 Hard Coal**	**1210**	9,100						
BOO Total				**5 BOO**	**5,810**	**45526-46871**						

Notes:
CT: Coal Turbine
[1] effective from contract date; [2] 20 years - duration of construction

TOOR CONTRACTS UNDER OPERATION

Project No.	Name	Location	Company	Fuel Type	Installed	Annual Contr.	Date of Cons.	Effective Date	Contract Duration
					Capacity	Output	Agreement	of Transfer	and End of Contract
					(MW)	(GWh)			
1	Hazar I, II HET	Mollakendi/Elazığ	Bilgin Elektrik	Hydro (River)	29.8	60	8/8/1996	12/10/1996	26 years (2022)
Hydro Total				**1 Hydro**	**29.8**	**60**			
2	Çayirhan CT	Çayırhan/Ankara	Park Termik Elektrik	Coal (Lignite)	620	4,420	1/11/1999	(I-II)6/30/2000-	20 years (2020)
								(III-IV)10/4/2001	
Coal Total				**1 Coal**	**620**	**4,420**			
TOOR Total				**2 TOOR**	**649.8**	**4,480**			

Notes:
CT: Coal Turbine

Source: TETAŞ

Table 17 shows the BOT, BOO, and TOOR contracts by generation technology, installed capacity, contracted output, operation date, and contract duration. In terms of installed capacity and output, most of the BOT and BOO contracts are of the CCGF type. Among BOT plants, approximately 60 percent of the total contracted capacity and 75 percent of the total contracted output is from CCGF plants. Gas-fired plants have an even higher share of these measures in BOO projects, for which approximately 79 percent of the total contracted capacity and 80 percent of the total contracted output is due to CCGF plants. Another striking point about these projects can be observed when the extent of renewable generation encompassed by these projects is taken into account: While renewable generation takes the remaining 39 percent of the contracted capacity and 24 percent of the output in BOT projects (and constitutes 19 of 23 projects), the BOO investment schemes are designed only for fossil fuel thermal projects. In summation, around 74 percent of total capacity and 79 percent of total output originates from gas-fired plants in BOT and BOO schemes. Most projects became operational in the late 1990s and have contract durations of 15–20 years. The majority of these contracts include take-or- pay clauses backed by the Treasury with regard to quantities and prices.

Based on the projections made in 2004, from 2004 through 2022, the total projected guaranteed energy purchases for BOTs amounted to approximately 199,654 GWh, with a price averaging U.S. ¢6.12 per kWh.[213] On the other hand, from 2004 through 2019, the guaranteed energy purchases for BOOs equaled approximately 695,778 GWh.[214] In this case, the average price per kWh was U.S. ¢4.39.

BOT and BOO contracts in Turkey have earlier than usual capital cost recovery schemes. Contrary to a conventional scheme (which employs a flat rate of depreciation) most of the fixed-cost recovery in BOT and BOO contracts is front-loaded. Obviously, this caused elevated energy costs early on in the project cycles. Given the life span of Turkey's BOT and BOO contracts, as of 2005 most of the period of accelerated recovery of capital costs is over (or about to end) for the majority of them. Considering the current cost of generation in Turkey — and depending on the development of future market prices — the vast majority of expected stranded costs may have already been recovered.

In fact, a comparison of the average cost of these contracts with that of EÜAŞ generation assets supports this possibility (see Section 2.4.1.1 for EÜAŞ thermal generation costs). The latest available average cost figures for EÜAŞ thermal plants are very much in line with those of BOT and BOO figures previously indicated.[215] Note also that the accuracy of EÜAŞ cost accounting practices is debatable; consequently, underestimation is highly likely. Thus, it is possible that no (or no significant amount of) stranded costs will be incurred due to these contracts if privatization in generation assets takes place by 2006

[213] These figures are quoted from meetings with government officials.
[214] This includes the 85 percent of net generation that TETAŞ is obligated to buy under the BOO scheme.
[215] The reason for taking thermal plant costs for comparison is twofold: first, most of the installed capacity and output due to these contracts originates from thermal plants. Second, as stated earlier, EÜAŞ takes into account only *operating costs* in estimating generation cost figures of hydroelectric plants in Turkey.

and opening wholesale markets to competition is moved up to a date earlier than 2011, as contemplated in the 2004 Strategy Paper.[216]

Furthermore, as the initial period of cost recovery for the BOT and BOO projects is unwinding, annual obligations will decline over time. Consequently, these BOT and BOO contracts can contribute to the evolution of a competitive market by supplying relatively cheaper power in the upcoming years. Thus, the public must be correctly and honestly informed about this point.[217]

3.5.2.3 Possible Schemes for Stranded Cost Recovery in Turkey

Competitive restructuring of state-owned generation assets will play a major role in setting the market value of generating capacity and energy, which in turn determine the extent of stranded costs. Consequently, the successful execution of the reform program takes a central role in analyzing stranded costs in Turkey. In this framework, three scenarios are likely to occur:[218]

Scenario 1: Competitive restructuring does not go forward → competitive market does not develop → no stranded cost issues arise.[219]

Scenario 2: Competitive restructuring goes forward[220] → competitive market develops → prices do not go down→ no stranded cost issue arises

Scenario 3: Competitive restructuring goes forward → competitive market develops → prices go down → stranded costs issue arises

Obviously, only in the case of Scenario 3, would a need for a stranded cost recovery scheme arise, in which case the debate for cost responsibility would be between

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216 Here, it is implicitly assumed that EÜAŞ costs will set the market price (at least in the initial phase of a competitive market), because the bulk of generation assets will still be owned by EÜAŞ.

217 A considerable amount of debate in Turkey has taken place about the financial burden of these contracts. While the debate had merits both on the basis of the overall investment scheme of these contracts and their initial cost recovery period, it did not have validity in terms of constituting an obstacle for transitioning to a competitive electricity market. In fact, it may well be "politically convenient" for governments to put the blame on their predecessors with the goal of political gain by capitalizing on the overall cost argument rather than making the aforementioned points clear to the public. This approach may also create a political opportunity for governments to continue to indirectly *tax* ratepayers by means of electricity prices, while keeping up-to-date information about the annual cost development of these contracts from the public.

218 Variables other than those indicated here (especially demand growth and fuel prices) will be at play, influencing the outcome of these scenarios with respect to market prices.

219 Although, BOT, BOO, and TOOR investment schemes may have higher costs than comparable state-owned generation and bring financial burden on the state, in this case they cannot technically be considered "stranded" assets. Meanwhile, the government currently has a policy of subsidizing the cost of these contracts through state-owned, low-cost hydroelectric generation sources, to keep power prices at a predetermined level.

220 Here, it is assumed that the reform program includes privatization of state-owned generation assets — but not on a full-scale level (that is, EÜAŞ keeps some of its assets as a nondominant player in the market). See the discussion in Section 3.6.1.6.2 on privatization.

taxpayers and *ratepayers* as costs arise from state-owned assets. Three possible methods can then be considered for cost recovery:

1) the state can continue to subsidize BOT and BOO contracts via mostly low-cost, state-owned hydroelectric generation;[221]
2) the state can buy out contracts (either at book value or through negotiated securitization, a process in which savings can be obtained on the financing cost of initial generation investments), then release the power and the capacity set forth in the contracts into the market at a price that the market can bear. The resulting costs (the difference between buyout value and market value) can be recovered over time through transition surcharges on customer bills; or,
3) the state can release the power and the capacity set forth in the contracts into the market without executing the buy-out option and levy a transition surcharge on customer bills until the end of the contracts.

The first option reflects the ongoing subsidy scheme that mixes the costs of BOT and BOO contracts with the benefits of state-owned, low-cost hydroelectric generation, so that the effects of elevated contract costs can be reduced. By this method, the precise extent of stranded costs would not need to be estimated and the political risk of a transition surcharge on electricity bills would be avoided.[222]

In fact, the Turkish government is considering a new policy — devoting only as much hydroelectric capacity as is necessary to offset the stranded costs, and releasing remaining capacity to the market by establishing separate *state affiliated* generation companies.[223] One could expect this policy to initiate *some* competition in generation; however, the full benefits of such reorganization would come to fruition only by releasing the output of *all* hydroelectric resources in the marketplace and addressing stranded cost recovery issues separately. In part this is because in 2003, Turkey's hydro plants constituted approximately 35 percent of the total installed capacity and provided 25 percent of the total output; thus, reserving the bulk of the plants to offset stranded costs would greatly slow the development of a competitive generation market.

The second method of cost recovery would be particularly beneficial because:

a) the buyout of contracts would place a substantial amount of power in the marketplace, which would help develop a competitive generation market;

b) consumers would receive welfare benefits when they purchase their electricity at market prices (which would presumably be lower then the prices of long-term binding TETAŞ purchase arrangements); and

[221] See OECD (2002a) for the discussion of this option. Note that here, there is still an *opportunity cost* for ratepayers and a *value loss* associated with not releasing hydroelectric assets into a competitive market, thereby hampering market evolution.
[222] *Ibid*.
[223] *Ibid*. See also the discussion on the Strategy Paper in Section 3.6.

c) an added benefit may accrue if the buyout is financed by state-backed securitization that carries better interest rates than the contracts have originally set.[224] The difference would help reduce transition (stranded) costs to be recovered from ratepayers.

However, the financial feasibility of issuing bonds for securitizing the future power purchase contract obligations must be carefully assessed because, for instance, total obligations designated by BOT and BOO contracts in 2005 are approximately $3.2 billion, and amount to $43.1 billion through 2022.

The third option for cost recovery is similar to the second, except that it does not carry the added benefits of securitization; thus, this option obligates the state to account for the full extent of stranded costs. The power generated by these contracts could still be placed in the market to enhance competition, while transition charges could be levied on ratepayers for stranded cost recovery.

Some political risk exists if the second or third options are chosen, because any stranded costs will be assumed by the ratepayers and will appear as an *extra cost* paid for the reform program.[225] However, the institution of these costs constitute the only viable way these options can contribute to the early development of competition in the generation market; and on balance, the expected societal benefit from the earlier development of competition is likely to surpass the burden of these costs.

In any case, the transition surcharge must be "non-bypassable," levied to *all customers, equally*, on a per kilowatt-hour basis.[226] This is necessary, not only to achieve fairness, but also for ensuring competitive conditions, given that discriminative surcharges would keep new or existing generation from receiving valid, accurate price signals. At the end of each year — depending on market prices and revenue collection — charges can be reconciled on the basis of whether the total amount of revenue actually collected by transition charges exceeds or falls short of the amount needed for cost recovery.[227] In this cost recovery scheme, cost accounting needs to be *transparent* to fully indicate the details of the charges (such details include fixed and variable components and reconciliation accounts, among others). Each step of the cost recovery process would also need to be approved by EMRA.

[224] Note that financing costs are built into contract prices by investors of generation projects. Thus, this outcome can be achieved if contract owners are convinced that receiving a lump sum payment via securitization would also save them in their long-term borrowing costs for generation investment.
[225] *Ibid*.
[226] The transition surcharge must also appropriately allocate capacity charge components.
[227] If securitization is used for stranded cost recovery in the case of assets other than power purchase contracts, the amount of bonds issued remains fixed, even though the extent of stranded costs may change over time (depending on the market). This is one argument critics of securitization raise, because if stranded costs were to decline over the course of time the amount of transition charges would not change, because bonds are financed by transition charges collected from ratepayers.

3.6 Privatization

3.6.1 Privatization of the Turkish Electricity Industry and the 2004 Strategy Paper

The Privatization Law No. 4046, enacted in 1994, provided a general framework for the privatization of state-owned enterprises. This law designated the Privatization Administration as the agency responsible for implementing privatization policy, in coordination with related state ministries and agencies. The Electricity Market Law No. 4628, enacted in 2001, had further specific provisions, establishing a legal basis for the privatization of generation and distribution assets.[228]

Law No. 4628 originally established a "preparatory period" of 18 months (with a possible six-month extension) in which the regulatory framework was to be put in place. During this time, the regulatory agency was to be organized and preparation of the secondary regulations was to have begun. The law also mandated that EÜAŞ would sell its energy output to TETAŞ for a period of as long as five years following the end of the preparatory period; this effectively set March 2008 as the latest date the integrated position of these two entities could be ended. Accordingly, March 2008 effectively became the date when effective competition could start to take place in the generation segment of Turkey's electricity market.[229]

Most recently, a policy document, called the "Electricity Sector Reform and Privatization Strategy Paper" ("The Strategy Paper") was announced in March 2004, laying out a more specific action plan and policy perspective for privatization, transition contracts, eligibility for consumers to choose their electricity supplier, and competition through 2011.[230] However, the Strategy Paper contains certain policy statements that may to some extent, be interpreted as contradicting the declared intention of the 2001 Electricity Market Law.

The following part highlights the relevant policy principles of the Strategy Paper (emphasis added).

3.6.1.1 General

- The main principle will be the implementation of *cost reflective prices* in the regulated electricity sectors, whereas the national tariff practice will be operational for the first tariff implementation period through the establishment of *a tariff equalization mechanism* that will prevent price differences for noneligible consumer tariffs.

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[228] Importantly, Section 3, Article 14 of the law mandated that foreign investors are not allowed to hold a controlling ownership in any of the activities of the industry.

[229] This calculation is based on provisional Articles No. 3 and No. 6 of the law. However, the 2004 Strategy Paper (see next section) pushed the time frame further to January 2010 by setting the effective start date for the implementation of transition contracts as January 2005. Thus, the 2004 Strategy Paper has in effect, overridden the provisional articles of the law.

[230] See http://www.oib.gov.tr/program/2004_program/2004_electricity_strategy_paper.htm for the full text of the paper.

- The privatization approach *will not be* solely aimed at the maximization of privatization income.

- Because the distribution companies, holding retail licenses and operating in a liberal market, have to create confidence in investors engaged or to be engaged in generation activities, *privatization will start in the distribution subsector*.

- A competitive generation structure will be achieved through *appropriately grouping generation assets* prior to their privatization.

- *The privatization of the generation assets* will start after the Market Management System (to be established by TEİAŞ) is in effect and *after distribution privatization is substantially completed, which is expected to be by mid-2006*.[231] This will ensure that efficient trading arrangements are in place to enable privatized generators to sell their output.

3.6.1.2 Privatization of Distribution

- Distribution companies shall have supply contracts with suppliers for at least the equivalent of *85 percent of the forecasted load demand of their noneligible consumers* in their regions.

- *Only distribution companies* will be allowed to sell to noneligible consumers.

- *The eligible consumer limit will be fixed at 7.8 GW-hour until the beginning of 2009*.[232] Within the framework of the schedule to be determined, the eligible consumer limit will be decreased starting at the beginning of 2009, in line with the objective of opening the whole market to competition by 2011. During this period, due consideration will be given to security of supply.

- By 30 September 2004, the *accounting separation* of the distribution regions will be completed.

- By 30 November 2004, the *transition contracts* between TETAŞ and distribution companies, or between portfolio generation companies/groups[233] and distribution companies, will be signed.

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[231] The Strategy Paper states that "... the main target will be to privatize all distribution companies/regions until 31 December 2006." Note that, as of the end of 2005, most of the timelines set forth by the Strategy Paper experience significant delays.

[232] Not a significant change. However, the eligibility threshold was lowered to 7.7 GWh by EMRA in January 2005.

[233] Companies currently within EÜAŞ's portfolio.

3.6.1.3 Privatization of Generation

- Hydroelectric Power Plants: The energy generation parts (sections) of all hydroelectric power plants constructed, commissioned, or to be commissioned by DSİ and the inseparable immovables of these plants will be transferred to EÜAŞ by May 2004, on the basis of their actual costs, without paying any charges to DSİ.

- The generation facilities to be privatized will be identified and grouped on the basis of two main criteria: (i) prevention of creating market power; and (ii) financial viability.

- By 30 September 2004, portfolio generation groups will be identified and restructured as companies.

- By 30 November 2004, the transition contracts between EÜAŞ and TETAŞ will be signed.[234]

- By 1 July 2006, provided that the Market Management System (to be prepared by TEİAŞ) is operational, the privatization process will commence for portfolio generation companies/groups.

3.6.1.4 Market Implementation

- The liberal market structure to be implemented in Turkey is based on *bilateral contracting* between buyers and sellers, together with a balancing and settlement regime.

- The *transition contracts* will be set at regulated prices and will last for a maximum of five years, *except for TETAŞ contracts*. As they run out, such contracts will be replaced by market priced bilateral contracts, and thus ensure the smooth transition to a liberal market.

- The balancing and settlement mechanism will be in compliance *with the objective of creating a spot market* and will include price signals to attract new investments.

3.6.1.5 Transition Period Practices[235]

- Tariffs: An equalization mechanism will be established to allow the balancing of tariffs between the distribution regions. This equalization mechanism will be implemented to align the principle of achieving *cost-reflective regional tariffs* for the distribution companies, with the objective of ensuring *uniform national tariffs* for noneligible consumers. The transitional tariff equalization scheme will be operational for at least the first tariff implementation period.

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[234] EÜAŞ's hydroelectric generation.
[235] The transition period started in January 2005.

- TETAŞ Purchases from Hydroelectric and Existing Contracts: The generation of the hydroelectric power plants that are not included within the generation groups and are under the possession of EÜAŞ shall continue to be sold to TETAŞ for as long as it is deemed necessary to achieve an average TETAŞ sales price that reflects the expected market price.[236]

- TETAŞ Sales Contracts with Distribution Companies: The energy purchased by TETAŞ through *existing contracts* and EÜAŞ generation will be allocated among the distribution companies through purchase agreements to be signed between TETAŞ and the distribution companies. In case TETAŞ is unable to recover adequate revenues to cover its liabilities arising from long-term contracts, these excess liabilities will be recovered through *a surcharge* to be added on the transmission use of system charges.

- Sales Contracts between Portfolio Generation Companies/Groups and Distribution Companies: These contracts should be put in place before distribution companies are privatized in order to give the generation companies/groups a track record prior to their privatization. The contracts should continue *after privatization to assure a predictable stream of revenues during the early years*.[237]

- Legislative Activities: In order to reach the objectives indicated in this Strategy Paper, the Electricity Market Law No. 4628 and related legislation will be modified as required.

In summation, based on the action plan outlined in the Strategy Paper:

- Privatization of distribution ends by the end of 2006 and privatization of generation starts by mid-2006.
- Distribution companies will have five-year transition contracts with TETAŞ and portfolio generation companies for 85 percent of their noneligible customers until *at least* January 2010.[238]
- The eligible customer limit will be fixed until the beginning of 2009.
- The market will be open for competition by 2011.

[236] Seventeen hydropower plants with a total of 7,055 MW of capacity will remain under EÜAŞ control (see IEA, 2005b, p. 144). This low-priced hydroelectric generation will be used to offset the higher cost of power purchase contracts (BOTs and BOOs).

[237] TETAŞ sales contracts with distribution companies and sales contracts between portfolio generation companies/groups and distribution companies will be used to supply 85 percent of noneligible customer load in the distribution regions.

[238] As the transition period begins in January 2005 implementation of five-year transition contracts end in January 2010, except for TETAŞ contracts. Thus, lowering eligibility thresholds may not produce its intended result even after January 2010 (when TETAŞ contracts will still be in effect).

3.6.1.6 An Assessment of the Strategy Paper

The following assessments can be made with respect to the Strategy Paper:[239]

3.6.1.6.1 The Principle of Cost-Reflective Pricing versus the Tariff Equalization Mechanism

The Electricity Market Law of 2001 mandated *cost-reflective* tariff making as the basic principle of pricing in the industry.[240] One reflection of this policy would be to set up *regional tariffs* that are free of interregional cross subsidies. If the need to provide financial assistance arises due to socioeconomic reasons, *direct subsidies* could be provided to end-users without distorting price signals within the industry. In fact, by this method of pricing, distortions in the industry would to a great extent be eliminated.

However, the 2004 Strategy Paper required that a *national tariff* practice be operational for the first tariff implementation period (five years) by establishing a *tariff equalization mechanism* that would prevent regional differences in noneligible consumer tariffs. Obviously, this implementation would contradict the policy principle of cost-reflective pricing.

The national tariff policy originates from the view that the implementation of cost-reflective regional pricing will adversely affect the relatively low income eastern and southeastern provinces of Turkey, where in 2003 distribution loss/theft ratios reached as high as 70 percent in some provinces.

This argument can be challenged in several ways. First, although overall loss/theft ratios are particularly high in the eastern and southeastern provinces, some of the more developed western metropolitan areas experience similar high loss/theft ratios, particularly in their low income districts (neighborhoods).[241] Furthermore, in absolute amounts (MWh), the loss/theft is equally high in those developed metropolitan areas, or in some instances even higher than in the eastern and southeastern provinces (see Section 2.2.2.3).[242] In other words, the eastern and southeastern regions in Turkey are not the only regions with high loss/theft problem in Turkey. Therefore, the loss/theft ratio argument simply cannot be used to support the national tariff argument.

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[239] It is worth noting that the Strategy Paper should have immediately followed the enactment of the law in 2001, so that progress regarding the goals stipulated by the document — such as privatization and the opening up of markets for competition — could have been made during the past three to four years.

[240] Section 3, Article 13 under the heading: c) Consumer Support of the Law No. 4628.

[241] Evidence from the field suggests that this problem is not unique to residential customers; commercial/industrial customers also account for a considerable portion of the electricity theft across the country.

[242] This situation can be seen from the following ranking of the first ten distribution regions with the highest amounts of theft/loss: Boğaziçi EDAŞ (İstanbul) 3,393,046 MWh; Şanlıurfa 1,993,629 MWh; Diyarbakır 1,791,275 MWh; Mardin 1,166,388 MWh; Istanbul Anadolu Koordinatorlugu 855,271 MWh; Başkent EDAŞ (Ankara) 844,618 MWh; Van 669,659 MWh; İzmir 654,964 MWh; Batman 568,593 MWh and Adana 530,073 MWh. (See TEDAŞ, 2003).

Second, even assuming that the loss/theft problem is more significant in the eastern and southeastern provinces, upon implementing cost-reflective pricing and instituting even partial liberalization in the electricity market,[243] these areas will probably see lower end-user prices, thanks to their *proximity* to sources of cheaper hydroelectric power. Proximity to cheaper hydro power in eastern and southeastern Turkey can provide benefits in two ways: first, *energy* supply would probably be procured at a much lower cost from hydroelectric power resources.[244] Second, by establishing cost-reflective pricing for the *transmission* of electricity, customers in the eastern and southeastern provinces would necessarily pay lower transmission charges, as those charges will be based on the currently implemented pricing model which places eastern and southeastern provinces in lower tariff zones.[245] As a result, regional cross subsidies *detrimental* to the east and southeast would be largely eliminated.

Consequently, as the current national tariff system (that is, tariff equalization) is abolished and liberalization progresses, consumer bills in eastern and southeastern Turkey will decline, which in turn will greatly reduce the strong incentive for theft. In fact, the best policy to counter the theft problem in the low income areas would be to eliminate the incentive to steal, rather than to rely on law enforcement. In addition, incentive-based distribution ratemaking would greatly enhance the effectiveness of the collection practices currently employed by the regional distribution companies.

3.6.1.6.2 Sequencing of Privatization

One main building block of the Turkish reform program is the privatization of state-owned assets in the electricity industry (excluding those assets related to transmission).[246] The electricity industry restructuring policies primarily aim to obtain industry wide efficiency gains, so that such gains can be reflected to end-users via lower prices. Accordingly, liberalization programs should first target the generation segment of the industry, where prospects for competition are the most feasible. (The transmission and

[243] In a market characterized by *partial liberalization*, state ownership of generating plants is to a great extent maintained; however, generators are directed to sell power on a cost-reflective basis in the wholesale market administered by TEİAŞ. At the same time, distribution companies are allowed (or directed) to aggregate load and procure power for their captive customers via competitive (bilateral) power procurement.

[244] Note that these benefits may partly be offset by the relatively higher cost of distribution in those areas.

[245] See tariff zones in EMRA decision for transmission tariffs, No. 470 (dated April 1, 2005).

[246] Apparently, a main policy decision was made some time ago by the various Turkish governments: namely, the *privatization* of state-owned generation and distribution assets. In this study, we do not go into a comprehensive discussion about the necessity of first privatizing electricity markets before liberalizing them. Nevertheless, it is worth noting that while privatization does not constitute a necessary step in the liberalization of the electricity industry, it may nonetheless accelerate the process of moving towards a competitive setting, one in which state-owned enterprises are transformed into well-functioning corporations operating under market rules. Having said that, state-owned enterprises can still be restructured to operate as corporations in the marketplace, independent of central government control. Yet the viability of such a model and the resulting performance is intimately related to a particular country's institutional environment, as well as to the ability of such an environment to restrain arbitrary administrative action. (See Levy and Spiller, 1996, and Spiller and Vogelsang, 1996.)

distribution segments are still regarded as "natural monopolies"; it seems that they will continue to operate under regulation for the foreseeable future.)

Conceptually, *liberalization* does not necessarily require *privatization* of the publicly owned assets, as can be seen in the relatively successful electricity industry liberalization experience of the Scandinavian countries where state or municipally owned industry assets are prevalent. Moreover, *privatization* does not necessarily imply *liberalization* in an economic sense. In fact, in the United States where the majority of industry assets are privately owned targeted efficiency improvements in the electricity industry as realized through liberalization (or deregulation) started a decade ago. The goal of deregulation was to break up the vertically integrated structure and open up certain industry segments — such as generation and retail — to competition. In that sense, the ownership structure has never entered into the equation. Rather, the main focus has been the reorganization of the industry and its market system through the implementation of a new design.

Critics were concerned with the lack of efficiency mechanisms in the old regulatory regime and argued for a competitive framework in the generation and retail segments. While the new framework primarily puts forward various new models for competitive energy markets, it also makes reference to the pricing methods of monopoly segments and related regulatory mechanisms to address existing inefficiencies. In this context, performance-based regulatory methods were proposed for monopoly services. Only in this way, it was argued, could significant efficiency gains be attained.

Implicit in the current approach is the fact that inefficiencies are largely due to the inherent character of the natural monopoly segments of the industry (rather than being due to the ownership structure). Consequently, it can be argued that privatization of monopoly segments may bring only limited efficiency gains, because tariffs for these services will still be determined through an administrative process. Performance-based regulatory methods for tariff making have the potential to produce improved efficiency; however, the degree to which the current ownership structure affects efficiency is open for debate and should not be overstated. Privatization *per se* may not necessarily be a sufficient condition for improving efficiency in the monopoly segments of the electricity industry. Therefore, any policy discussion with regard to the sequence of privatization of the industry segments must consider this aspect as a starting point.

More benefits can be obtained from the early parts of the liberalization process if restructuring focuses on the generation segment — where generators compete to supply cheaper energy and retail marketers compete to procure customer load — provided that an effective market design and regulatory oversight exist. If competition is established in the generation market, distribution companies, even under public ownership, can then also competitively procure power for their customers by aggregating load, if they are allowed (or directed) to do so (see Section 3.2.2.1). Thus, consumers can receive the benefits of competition early in the restructuring program. Simultaneously, experience can be gained with regard to the workings of a competitive (retail) market before liberalization in the industry may include the privatization of the distribution assets.

Even so, the establishment of a sound institutional base in the distribution segment — one that provides effective metering, billing, collection, and settlement services for efficient wholesale operations — is undeniably critical. Yet, such a base can be established prior to privatization, through effective regulatory enforcement, while a competitive structure is still being developed in the generation and retail markets. Privatizing distribution assets does not constitute an urgent step, either in the sequence of privatization or in the liberalization process.

Apparently, metering and billing problems and high rates of nontechnical distribution losses caused by theft and under collection played a major role in making the policy decision that allowed the distribution segment to become a priority in privatization in Turkey. As stated in the 2004 Strategy Paper, the underlying reason for this prioritization was to "… create confidence in investors engaged or to be engaged in generation activities."[247] Presumably, policy makers believed that inaccurate measurement (that is, inaccurate metering) and loss/theft problems would lead to difficulties for competitive generators and wholesalers in their financial settlements with distribution companies, and that this would create hurdles for attracting investors in the generation segment.

Problems with energy losses and unmetered consumption will certainly obstruct liberalization efforts in the industry. These issues need to be resolved as early as possible; however, the solution to these problems requires an accurate diagnosis.

First, many of the difficulties in the distribution segment in Turkey are related to a physical infrastructure that renders the network vulnerable to losses and theft. Second, as stated earlier, the widespread loss/theft problem in the residential segment in Turkey has socioeconomic roots and is unlikely to improve through changes in the ownership structure alone. High electricity prices relative to median household incomes play a major role in the manifestation of this problem, as most loss/theft in the residential class occurs in low income regions of the country, or in districts of more developed metropolitan areas.[248]

Finally, the "privatization of distribution first" approach may make sense in markets with no prior experience with the commercialization of electricity service,[249] such as transition economies in Eastern Europe and in the Caucuses, where billing for electricity services was not previously a common practice. However, Turkey has a long-standing commercial system; change of ownership in the segment is unlikely to address loss/theft problems.

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[247] This was also the reason put forward by an earlier OECD study (See OECD 2002a). Meanwhile IEA (2005b) argues otherwise. The report states that "International experience also shows that it is very unusual to start the privatisation from distribution rather than generation. For the distribution investors, the risk of not having an efficient upstream wholesale market in place is usually considered larger than the risk for the generators arising from lack of downstream restructuring." pp. 154-155.

[248] Note, however, that some commercial/industrial customers are involved in theft as well. Thus, there is apparently also a "behavioral" aspect of this problem in Turkey in which widespread theft has in part created a sort of culture in which paying for electricity service is often regarded as "unnecessary."

[249] Indeed, this is standard policy advice, often given to policy makers in new markets undergoing restructuring efforts.

A new policy may aim to establish more reliable metering and billing practices via private distribution companies, however, the value to be gained by a change of ownership is debatable. In fact, given Turkey's current legal infrastructure and institutional environment, one may argue that laws and regulations can be better enforced via public ownership backed by government authority than by private ownership. Better collection practices are possible under performance-based methods and an effective regulatory framework, regardless of the ownership structure, provided that prudent institutional capacity and a management structure equipped with incentives is established. Finally, as competition develops and power prices rationalize, less incentive will exist for theft on the demand side.

3.6.1.6.3 Portfolio Companies

One of the principles of the 2004 Strategy Paper appropriately states that the privatization approach will not be aimed *solely* at the maximization of privatization income, and that generation facilities to be privatized will be identified and grouped by considering: (i) the prevention of creating market power, and (ii) financial viability. In fact, as regards competitive restructuring, privatization must be considered as a means rather than an end. Thus, creating a portfolio of generators that bundle low- and high-cost generators for the purpose of setting up attractive candidates for sale may *not* be necessary — and may even prove counterproductive with regard to future competition in the market if other factors such as locational aspects of generators are not considered. This is because the current excess capacity in Turkey is expected to last only for several more years; the latest calculations indicate that by 2012 — adding up existing capacity, plants under construction, and projects that have received licenses — installed capacity will be below peak capacity requirements *with no reserves* (see Section 2.2.2.1.5). Therefore, for the near future the likelihood of a generator not being dispatched by the system operator[250] is very low. Thus, it would be unnecessary to bundle low-cost generators with high-cost generators for potential investors, who are surely aware how markets work, and have knowledge of market conditions.

The reason that a portfolio of generators that bundle low- and high-cost generators may prove counterproductive to future competition is directly linked to the possibility of inadvertently creating market power in the generation markets. Establishing portfolio companies by solely considering operating cost figures while keeping financial viability in mind may provide future buyers with the potential to exercise regional market power within the generation segment. The aggregate market shares of generators or holding companies can be an insufficient and misleading indicator when assessing market power. As discussed in Section 3.4.2, the decision to establish portfolio generation companies should primarily be made based on the *post-privatization* locations of generators; their potential ability to supply load pockets; and (consequently) their potential to become pivotal suppliers in regions with transmission constraints. These are important elements that greatly increase the likelihood of a generator to exercise market power.

[250] Either through the spot market or the bilateral market.

In essence, portfolios for privatization should primarily be designed by taking into account the *market power potential* of generators rather than considerations regarding financial viability. Otherwise, the threat of market concentration may arise as a result of misguided privatization.

3.6.1.6.4 Transition Period and the Time Line for Restructuring

Based on the time line indicated by the 2004 Strategy Paper, privatization of generating assets will start in mid-2006; however, the limit at which customers become eligible to shop for their supplier remains fixed at 7.8 GWh until the beginning of 2009, with full eligibility planned for 2011. Furthermore, transition contracts with TETAŞ and portfolio generation companies stay in effect until *at least* January 2010. Therefore, the benefits of competition cannot be realized until the beginning of 2010, despite the expected start of the privatization of generation assets more than three years earlier.[251] Absent binding transition contracts, early benefits from the privatization of generation assets *could* still have been realized.[252] Even after privatization, however, the Strategy Paper's provision for transition contracts effectively prevents this, evidently due to concerns related to the recovery of stranded costs.[253]

Apparently, the state wants to make sure that stranded costs that are *expected* to occur due to BOTs and BOOs are recovered. In Section 3.5, it was argued that given the declining contract prices over time and EÜAŞ generation costs that are substantially underestimated, the likelihood of observing significant stranded costs arising from these contracts once competition is launched in the generation market is diminished. Thus, if transition contracts are put in place for the sole purpose of cost recovery, they will likely prove unnecessary. By making such a strong assumption regarding stranded costs, the sequencing of market reform could be fundamentally distorted and the expected early benefits from liberalization could be minimized, if not eliminated. Even if stranded costs arise, these costs can be recovered by one of the methods discussed earlier; again, the expected benefit from early competition is likely to outweigh such expected costs. From the perspective of maximizing net benefits from liberalization, proceeding with the most effective sequence for market reform is safer than focusing on cost recovery.

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[251] Another important factor for developing competition in the generation segment is linked to the establishment of a parallel restructuring in the natural gas market. However, despite the good start with the Natural Gas Market Law of 2001, significant progress has not yet been made, particularly in transferring long-term gas (import) contracts to private companies; these contracts were initially entered into by the state-owned pipeline company, BOTAŞ, which holds a monopoly for gas imports. Lack of competition in the gas market would be a significant impediment for developing competition in the electricity market, given the existing and projected generation portfolio in Turkey.

[252] As IEA (2005b) correctly notes, the main driver of possible downward pressures on electricity prices in the process of liberalization in Turkey is likely to be the country's substantial excess capacity in generation. Given rapid demand growth, however, the excess capacity may quickly evaporate. "[T]herefore, any delays in market liberalization or transitional arrangements, which unduly distort the process, have the potential to remove the period of lower electricity prices."(p. 153). This would simultaneously lessen political and public support for reforms.

[253] See the discussion in Section 3.5.

On the other hand, the Electricity Market Law authorizes EMRA to lower eligibility limits at the beginning of each year; however, the 2004 Strategy Paper fixes the threshold for eligibility at 7.8 GWh until 2009. Because the eligibility threshold will be kept at its current level until 2009 *and* transition contracts will be honored until 2010 (and beyond), newly privatized generation companies will have a hard time being competitive in the market until at least 2010. In other words, during this period, it is highly likely that either 1) due to the high eligibility threshold, an insufficient number of eligible customers will be in the market to compare prices for the energy produced by the newly privatized generators (even if contacts were not in effect), or 2) due to transition contracts, an insufficient amount of power will be released to the competitive market (irrespective of the eligibility limit). Note that eligible customer load currently constitutes 28 percent of the total load served; because 85 percent of the noneligible load is covered by transition contracts, approximately 61 percent of the total load will be tied by transition contracts.[254] This situation is likely to partially persist even after 2010, because transition contracts with TETAŞ are scheduled to remain in place after 2010. Obviously, such a market prospect would not be attractive for potential investors in the generation market.[255]

Meanwhile, lowering the eligibility level a year earlier than at the end of transition contracts in 2010 may create a one-year problem for executing transition contracts, as newly eligible customers may choose to no longer have distribution companies serve as their suppliers of energy in 2009.[256]

Additionally, the 2004 Strategy Paper states that "[T]he contracts (between portfolio generation companies/groups and distribution companies) should continue after the privatization to assure a predictable stream of revenues in the early years." Importantly, one of the main reasons to institute market reform is to replace the existing business scheme by shifting commercial risk away from the state and onto private investors. Guaranteeing a certain stream of revenues would not be in line with this market-based approach, which primarily aims to create level playing fields among all market participants.[257] In fact, for private investors, a stable and predictable regulatory framework with a clearly defined liberalization schedule would be more rewarding than guaranteed streams of revenue.

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[254] Data indicate that 72 percent of the total load is captive. Thus, 0.85 x 0.72 = 0.612 (that is, 61.2 percent of the total load will be served by transition contracts).

[255] Currently, TETAŞ controls 85 percent of the wholesale market (IEA, 2005b).

[256] How many customers might choose to do this would depend on the extent of the reduction in the eligibility level.

[257] The underlying reason for the policy of keeping the eligibility level frozen for an extended period may be the government's concern to guarantee a certain number of captive customers to new investors of distribution assets during the post-privatization period. (See the panel discussion by government officials in the April 2004 issue of *Dünya Enerji*.) If this argument is in fact the case, the stated policy would be fundamentally contrary to the principles of competitive restructuring: in the new setting, distribution companies should not be making any profits from energy they deliver — thus, they should be operating as *wire only* entities. The new investor's customer base would therefore remain unchanged, except for the limited number of customers who have direct access to transmission lines.

Finally, international experience indicates that the sequencing of liberalization is more important than the sequencing of privatization. For liberalization to yield most of its expected return, a credible legal and regulatory environment — working together with a functioning market structure — must be established *prior to* changing the ownership structure of industry assets (that is, before privatization).[258] Only after laying such groundwork will privatization be less risky in terms of market power and supply security; more attractive for the investor and more rewarding for the government in terms of revenue generation; and, most importantly, more beneficial for consumers of electricity. In the case of the privatization of the Turkish electricity industry, while considerable progress has been made on legal and regulatory fronts, the program is going forward before the necessary market parameters are in place.

[258] IEA (2005b) p.154 stresses a similar point.

4 AN OVERVIEW OF THE INVESTMENT AND BUSINESS ENVIRONMENT[259]

4.1 Informal Survey and Interviews with Stakeholders

During this study, high-ranking officials from two of the largest Turkish construction companies currently operating in the power generation business have been interviewed. These companies have undertaken long-term BOT and BOO power generation contracts with foreign and domestic partners. The accounts in Boxes 1 and 2 elucidate their perspectives on the issue of private sector participation within the power generation segment in Turkey.

Box 1: An Investor in BOT Contracts in the Generation Market ("GAMA")

Gama Industry Corp., Inc. (GAMA) operates in the Turkish electricity generation market with two power plants that have been constructed within the framework of the BOT provisions of Law No. 4180. These power plants consist of a natural gas plant, Trakya and a hydroelectric plant, Birecik. The starting commercial operation dates for these plants were 1999 and 2001, respectively. A third BOT contract of the company (at Mersin Lamas) is pending, but has been delayed due to legal controversy.

GAMA has undertaken these projects with both domestic and foreign partners. The stakeholders of Birecik are Gama, EÜAŞ, and five foreign companies, with shares of 20 percent, 30 percent and varying rates between 3.7 percent–17 percent, respectively. In Trakya, GAMA owns 10 percent of the shares, while foreign companies own 90 percent.

Birecik and Trakya have installed capacities of 672 MW and 478 MW, respectively; together, they constitute 3.2 percent of Turkey's total installed capacity.

Birecik Energy Corp., Inc. and TETAŞ signed an Electricity Sales Agreement (ESA) for the sale of electricity for a period of 15 years (the actual expected operation period of the plant). According to the agreement, TETAŞ is obligated either to buy the electricity that Birecik generates or to pay the applicable price if it does not buy the electricity (a take-or-pay guarantee). If TETAŞ fails to fulfill this requirement, the Treasury assumes the responsibility.

The electricity tariff for Birecik is determined by MENR every six months by taking into consideration loan (main capital and interest) payments, operation and maintenance costs, dividends payable to stakeholders, and taxes paid during that time period. According to ESA, the average price of the electricity sold to TETAŞ over 15 years is planned to be U.S. ¢5.2 per kWh (U.S. ¢8.3 for the first 2.5 years, U.S. ¢4.7 for the following 7.5 years, and U.S. ¢3.8 for the remaining 5 years). Because the loan

[259] Section 4 is written by Yesim Akcollu of the Turkish Competition Authority in its entirety.

repayments take place during the first 8–10 years, the electricity price is expected to be highest in the first years.

Mr. Ergil Ersu, Deputy Chairman of the Board of GAMA, has stated that GAMA is *not* willing to invest in new projects unless the generation market is genuinely competitive; he sees the following issues as obstacles for potential investors in the Turkish electricity generation market:

- lack of institutional consensus (especially among Danıştay — the Administrative High Court; Sayıştay — the Court of Accounts; and other institutional authorities);

- Etatism (the Turkish culture that is inclined to maintain government authority over all issues/sectors), and

- news in the mass media recounting the excessive amounts of corruption taking place in electricity generation companies.

Box 2: A BOO Company in the Generation Market ("ENKA")

Enka Construction and Industry Corp., Inc. (ENKA) owns three of Turkey's five existing power plants that have been constructed within the framework of the BOO provisions of Law No. 4283. Those power plants — namely Gebze, Adapazarı, and İzmir — are all combined-cycled-gas-fired power plants and have a total installed capacity of 3,854 MW, constituting almost 11 percent of Turkey's total installed capacity. In 2003, those plants generated 33 billion kWh of electricity, or 23 percent of Turkey's total production.

The power plants were tendered by TEAŞ and MENR in 1998 and their construction and operation rights were awarded to the Intergen-ENKA partnership (60 percent owned by Intergen, 40 percent owned by ENKA). Subsequently, the turnkey contract of the plants was awarded by ENKA and Intergen to the 50 percent-50 percent Bechtel-ENKA joint venture. After a four- or five-year construction period, the Gebze and Adapazarı plants started operation in March 2002; the İzmir plant started in March 2003. Eventually, ENKA acquired the shares Intergen held in the three electricity generation companies; currently, ENKA holds 100 percent of the shares in those companies.

The three companies signed 20-year Electricity Sales Agreements (ESA) with TETAŞ for the sale of the electricity they generate; they also signed Natural Gas Sales Contracts with BOTAŞ for the delivery of natural gas. Because the 20-year period includes the development and construction phases, the actual period of time for the sale of electricity and the delivery of the natural gas covered by the contracts is 15–16 years (after taking into account the commissioning of the plants). The average contracted price of the electricity to be sold to TETAŞ was stated as U.S. ¢4.2 per kWh (excluding VAT), subject to change with a change in gas prices, and subject to an increase for fixed and variable operating expenses, as indicated in the ESAs.

The ESAs between ENKA and TETAŞ consist of two types of guarantees:

- *Take-or-Pay Guarantee*: TETAŞ is obliged to buy at least 85 percent of the contracted energy. TETAŞ's payment covers all of the costs for 85 percent of the energy, while paying only fuel costs of any energy it buys in excess of the obligatory 85 percent. (Electricity prices comprise four components: investment cost, fuel cost, fixed operation cost, and variable operation cost. Among these items, fuel cost is subject to an increase in price that varies with the price of natural gas.)

- *Treasury Guarantee*: If TETAŞ fails to pay ENKA for three consecutive months, the Treasury makes the payment for the energy received by TETAŞ.

By the terms of the contract, three ENKA companies are obliged to not sell energy to companies other than TETAŞ — even if they have excess capacity. If the companies fail to fulfill the requirements of the agreements, they are then compelled to pay U.S. ¢5.5 per kWh to TETAŞ and U.S. ¢4 per kWh to BOTAŞ (for every kWh of difference than the contracted amount). According to the agreements, the sole natural gas supplier of the companies is to be BOTAŞ.

Mr. Mustafa Gecek, Deputy General Manager of ENKA, summarizes the obstacles for foreign direct investment in Turkey as follows:

- Governments do not see themselves as equal parties with investors, and thus, may not feel obliged to fulfill its obligations.

- Judiciary mechanisms proceed very slowly. Additionally, as long as energy agreements do not incorporate international arbitration, companies have difficulty winning legal controversies with the government.

- Laws do not comply with one another. For example, although the responsibility for privatizing TEDAŞ is given to the Privatization Agency, TEDAŞ holds all authority to distribute electricity; however, much of the time TEDAŞ is not forthcoming in its disclosure of information necessary for investors.

4.2 Antitrust Cases in the Turkish Electricity Industry

4.2.1 Competition Infringements

Articles 4 and 6 of Law No. 4054[260] address competition infringements. Cartel agreements and other decisions and concerted practices that impair competition are prohibited under Article 4. According to Article 6 of the act, any abuse of the dominant undertakings is also unlawful and prohibited.

Between the years 1999 and 2004, seven complaints concerning the electricity industry were brought to the attention of the Turkish Competition Authority (TCA). Among those, the complaints against ÇEAŞ and TEDAŞ are the most important ones.

4.2.1.1 The ÇEAŞ Case

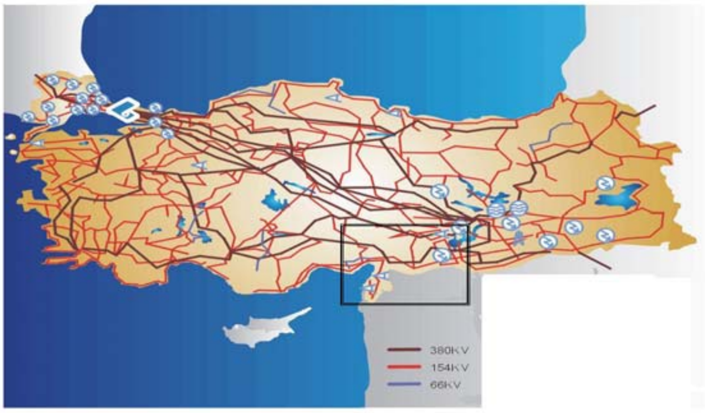
By the end of November 2003, the TCA concluded its investigation regarding the Çukurova Electricity Corporation Inc. (ÇEAŞ). See Box 3. ÇEAŞ was an electricity operator, holding the essential facility (distribution and transmission lines) in one of the distribution regions in Turkey, and had been awarded the generation, transmission, and distribution concessions in that region. The TCA decided that ÇEAŞ had abused its dominance, on the grounds that ÇEAŞ had no objective reasons for preventing access to an essential facility and had impeded present and potential competition in the electricity generation market via using its dominance in the downstream markets (that is, the transmission and distribution markets). A significant fine was imposed on ÇEAŞ by the TCA.

Box 3: The ÇEAŞ Case

The Çukurova Electricity Corporation Inc. (ÇEAŞ) was founded in 1952 and started its operations in 1953. The Council of Ministers Decision had given the company the concession to build power plants and to sell its electricity in two cities. After the enactment of Law No. 3096 (and as the result of another Council of Ministers Decision in 1988), ÇEAŞ earned the right to generate, transmit, distribute and trade electricity in one of Turkey's 29 designated distribution regions (see Figure 25). In that distribution region, ÇEAŞ operated several hydroelectric power plants, transformers, transmission lines, and distribution facilities that distributed electricity to customers consuming more than 500 kW. After public shares in ÇEAŞ had been privatized — first in 1990 and then in 1993 — the Uzan family acquired control of the firm. In 1998, ÇEAŞ signed a concession agreement with the Ministry of Energy and Natural Resources (MENR) to extend its term in the region till 2058.

[260] "The Act on the Protection of Competition" (1994). See http://www.rekabet.gov.tr/word/ekanun.doc for the text of the law.

Figure 25: The Distribution Region of ÇEAŞ



An investigation into the competitive practices employed by ÇEAŞ commenced upon complaints of two autoproducers in 2002. One of those companies alleged that ÇEAŞ had not signed the required energy transmission agreement that would have allowed the company to transmit energy to its affiliates. The second company claimed that ÇEAŞ did not obey the provisions of the existing energy transmission agreement, and thus was not permitted to transmit energy to its affiliates.

The TCA commented that the investigation into ÇEAŞ's competitive practices was a good implementation of the "essential facility doctrine." ÇEAŞ enjoyed a dominant position because it had the essential facility (namely, its transmission lines) in its designated region. The TCA ruled that ÇEAŞ had abused its dominance by refusing third-party access to the essential facility without any objective criteria. Besides using its dominance in the transmission market, ÇEAŞ hindered competition in the generation market, which the autoproducers were a part of.

The impact of the TCA's initiation of such an investigation was felt immediately. Before the end of the investigation, ÇEAŞ let the two autoproducers transmit their energy to the affiliates, either by signing the relevant transmission agreement or by renewing the existing agreement, accordingly.

Upon appeal, Danıştay (the Administrative High Court) ratified the TCA's decision. ÇEAŞ then paid an administrative fine of TL 9.5 trillion (approximately U.S. $ 7 million).

4.2.1.2 The TEDAŞ Case

Upon receiving complaints that the incumbent distribution company (TEDAŞ) and its affiliates had abused their dominance via increasing electricity prices significantly more than the 2001 inflation rate, the TCA initiated a preliminary inquiry. Thereafter, the TCA felt no need for further investigation, on the grounds that:

- between the years 1994–2000, electricity prices had increased at rates close to the inflation rates in those years; in 2001, the increase was slightly bit above the inflation rate, due to the fact that electricity prices were indexed to the increase in the exchange rate for the US dollar;
- TEDAŞ did not make huge profits (on the contrary, the company bore an operating loss in 2001);
- although according to regression analysis, TEDAŞ was ineffective in terms of managing costs, one could not conclude that the ineffectiveness caused TEDAŞ to charge excessive prices; and
- the ineffectiveness of TEDAŞ could be overcome only by structural changes that were not under the jurisdiction of the TCA.

4.2.2 Mergers[261]

In terms of type of investment, most of the growth of international production during the decade of the 1990s was via cross-border mergers and acquisitions (M&As), including acquisitions by foreign investors of privatized state-owned enterprises, rather than by greenfield investments (see Dutz *et al*., 2003).

Article 7 of Law No. 4054 addresses M&As. As per the communiqué issued in 1997, in accordance with that article, parties that exceed certain thresholds (25 percent of a segment's market share or 25 trillion TL or — 25 million YTL — of a segment's turnover) should first apply to the TCA to receive authorization. Table 18 shows the breakdown of merger cases ruled on by the TCA between 1998 and 2004. (Merger cases in the electricity industry constituted approximately 3.5 percent of all mergers — 22 out of 638 — concluded by the TCA during that time period.)

[261] The term "mergers" is used to signify both mergers and acquisitions, including privatization transactions.

Table 18: Electricity Industry Merger Cases by the Decisions Taken, 1998–2004

Type of Decision	Year							Total
	1998	1999	2000	2001	2002	2003	2004	
Beyond TCA's scope /below thresholds	—	3	1	—	—	—	2	**6**
Approval	1	—	—	—	1	—	—	**2**
Conditional Approval	2	—	1	3	1	1	6	**14**
TOTAL	**3**	**3**	**2**	**3**	**2**	**1**	**8**	**22**

As seen in Table 18, all of the applications falling under the scope of Article 7 were approved, either with or without conditions. In no case was a merger authorization rejected. Note that in 2004, the number of merger cases in the electricity industry increased significantly.

Table 19: Electricity Industry Merger Cases by the Origin of the Parties, 1998–2004

Origin of the Parties	Year							Total
	1998	1999	2000	2001	2002	2003	2004	
Foreign–Foreign	—	—	—	2	—	1	4	**7**
Foreign–Domestic	2	1		1	1	—	2	**7**
Domestic–Domestic	1	2	2	—	1	—	2	**9**
TOTAL	**3**	**3**	**2**	**3**	**2**	**1**	**8**	**22**

Table 19 shows the breakdown of merger applications according to the origin of the parties filing the application between 1998 and 2004. Note that the involvement of foreign firms in merger transactions increased significantly in 2004. A further increase in those figures can be expected in 2005, if foreign firms participate in privatization bids taking place this year. The two Foreign–Domestic cases that were concluded in 1998 were privatization transactions of the generation and distribution assets operated by the incumbent enterprises, TEDAŞ and TEAŞ.

4.2.2.1 Privatization Experience in the Turkish Electricity Industry

4.2.2.1.1 The Case of TEDAŞ (1)

In 1998, the Competition Board exercised its merger review authority over the privatization of 17 electricity distribution assets, which were owned and operated by the incumbent company, TEDAŞ, via the transfer of operating rights for 30 years.[262] The board approved the transactions, subject to conditions requiring reformation of the concession contracts between the new owners and the MENR.

The conditions the board imposed in its approval were as follows.

- The "exclusivity" term was to be removed from the concession agreements. Distribution and trading functions were to be separated and supervised by the regulatory body, when that body was established (and by the MENR until that time). For the ensuing five years, customers with a demand of over 1 MW could buy their electricity from sources outside their distribution region. The new distribution companies must provide access to their distribution lines at a "certain line utilization price."

- The new distribution companies could set prices independently, within a range, the upper and lower bounds of which would be determined by the regulatory body, when established (and by the MENR until that time). Prices were not to be fixed by TEDAŞ.

- The concession contracts must be amended to prevent discrimination.

- Further transfers of operating or production rights must be subject to the review and approval of the Competition Board. (A relevant provision was to be added to the concession agreements.)

The last two conditions were immediately realized. However, the MENR asked the Competition Board to reevaluate the first two conditions, claiming that it was impossible to realize those conditions legally and *de facto* under the legal opinions of the time. Adequately persuaded, the Competition Board amended its decision accordingly; the latter two conditions were set in place after the enactment of the Electricity Market Law No. 4628 (2001). Law No. 4628 both granted the Energy Market Regulatory Board jurisdiction over the entire industry and introduced the "eligible customer" concept for the electricity market.

Nevertheless, some companies still could not sign the contracts with the MENR. This was due to legal problems originating from Law No. 3984, which prohibited companies that have shares in radio and television companies from entering public auctions. All contracts with the MENR were annulled by the Danıştay (the Administrative High Court). See Ulusoy, 2005, p. 76.

[262] Competition Board Decision No. 87/693-138, 16.10.1998, "Conditional Approval of the Competition Board for the Transfer of Operating Rights (TOOR) of the Assets that are in TEDAŞ's Designated Distribution Regions."

4.2.2.1.2 The Case of TEDAŞ (2)

Following the Strategy Paper announced in March 2004, the process for the privatization of distribution assets was restarted. As per the Strategy Paper, distribution companies that would operate in the re-designed 21 distribution regions[263] were established under different names rather than just TEDAŞ as of March 2005. The newly established companies are to be privatized via block sale while TEDAŞ is transferring just the operating rights of the distribution assets for certain years.

According to the privatization plan, the distribution companies are to be privatized wholly regardless of legal unbundling of the distribution and the trading (retailing) functions. Besides, a new law, Law No. 5398[264] passed in July 2005 amended some provisions of the Law No. 4628 and annulled the threshold for the distribution companies to generate electricity provided that they have a generation license, and hold separate accounts for distribution and generation.

The Competition Board performed its pre-notification (pre-auction) review on the privatization of new distribution companies and assets on July 2005.[265] The Competition Board concluded that distribution companies' obligation to have accounts unbundled with its activities other than distribution (e.g., retailing and generation) is not adequate. It stated that the best solution to reinforce competitive environment would be the ownership separation, however considering the scale of economies, it might be undesirable to achieve. The other option could be the achievement of legal unbundling of distribution and retailing activities, and mitigation of the retailing activities of the distribution company over a time span.

As a minimum requirement, the Competition Board set the principle of legal unbundling of distribution activity with the activities other than distribution, which is also in compliance with the Directive 2003/54/EC (the deadline for the member states for legal unbundling is July 1, 2007). Since then neither the condition of the Competition Board has been fulfilled nor has the privatization process proceeded because the priority has been given to the new draft law that is under way and will legalize the Strategy Paper.

4.3 Interface Between EMRA and the TCA

Article 8(b) of Law No. 4628 reserves the Competition Board's right to authorize the mergers in the electricity industry that come under the scope of Article 7 (the article concerning mergers in Law No. 4054). However, no particular provision in Law No. 4628 addresses competition infringements in the market. Nevertheless, the Turkish Competition Authority (TCA) has the exclusive *de facto* responsibility regarding that

[263] A private company (Kayseri Elektrik) was already operating in the distribution market since 1926, thus TEDAŞ would hand over 20 distribution companies via privatization.
[264] Law No. 5398 is entitled "Law Amending the Privatization Applications and Some Laws," published in the Official Gazette No. 25882 (July 21, 2005).
[265] Competition Board Decision No. 05-48/695-M, July 21, 2005, "Opinion of the Competition Board on the Pre-Notification of Privatization of TEDAŞ."

issue, so therefore carries out that responsibility in all the markets in Turkey, as per Law No. 4054.

Although a provision in Law No. 4628 (Article 4) states that while issuing regulations, EMRA shall consider the opinions of legal entities operating in the marketplace and relevant institutions, Law No. 4628 does not call for explicit cooperation between the TCA and EMRA.

The TCA worked with officials from MENR during the preparation of the Electricity Market Law. After enactment of the Law, EMRA consulted the TCA during different stages of discussion regarding the enactment of the secondary legislation (which included numerous draft regulations concerning licenses, tariffs, import and export restrictions, network accounting and financial reports, and consumer services). An OECD report (2002)[266] determined that the two agencies could coordinate the consideration of common issues, even without legislative direction. However, the report stated that explicit statutory authority would eliminate any uncertainty about either agency's power, so that the Competition Board and the Competition Authority could participate, as appropriate, in the process of restructuring and developing the regulatory system for the electricity and gas industries. Another OECD report (2005)[267] mentions the urgency of establishing a statutory basis for the TCA's participation in EMRA proceedings, and suggests that the TCA pursue adoption of a formal protocol clarifying its interaction with EMRA.

Especially for subsegments of the electricity industry — where both regulatory aspects and competitive issues can occur simultaneously (such as the transmission and distribution of electricity in areas where operators have a right to operate as a monopoly under the regulatory rules) — the TCA and EMRA should be in close cooperation, each providing the necessary information for monitoring and investigating the activities of the other. A recent Competition Act case[268] against an electricity distribution firm exposed the need to delineate the respective roles of the TCA and EMRA and establish formal procedures for cooperation.

Although both the TCA and EMRA in fact believe that a statutory basis should be established for such cooperation, no progress has yet been made on this front, due to the press of other business. To delineate the respective roles of the TCA and EMRA in energy markets — and to set a timetable for the proceedings — the TCA and EMRA may consider adopting a communiqué similar to the one adapted in 1998 between the TCA and the Privatization Administration (PA).[269] Such a communiqué can help both parties

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[266] OECD (2002b), p. 86.

[267] OECD (2005), p. 44, paragraph 145.

[268] The case, described earlier in this study, was filed against ÇEAŞ, a company holding a monopoly concession for the distribution and transmission of electric power in one of Turkey's designated distribution areas. The Competition Board found that ÇEAŞ had abused its dominant position by refusing to provide autoproducers access to the network.

[269] According to that communiqué (http://www.rekabet.gov.tr/word/tebligeng11.doc), privatization transactions over certain turnover and market share thresholds are subject to the review process of the TCA, which is analogous to the merger restrictions that actually apply to a wide range of transactions and means of transferring power. The communiqué also establishes a time table for the TCA and PA to delineate their

establish a solid judicial framework for cooperation and coordination of these issues in the energy markets.

respective roles in privatization transactions. By the agreements in that communiqué, the TCA has the jurisdiction in both ex-ante and ex-post privatization proceedings. (Ex-ante review is achieved by the TCA forming its own opinion on the conditions of any given auction, in order to make those conditions compatible with the competition legislation. After the auction, the TCA reviews the first three bidders.)

5 CONCLUSIONS AND RECOMMENDATIONS

At the outset of this study it was noted that starting in the early 1980s Turkey's initiatives regarding private sector participation in energy infrastructure projects was the result of a combination of fast growing energy needs of the economy and fiscal imperatives of the state, catching up with capacity expansion requirements. The most crucial missing link in this scheme was an overall reform strategy for the electricity industry, and the necessary legal and regulatory framework. Naturally, despite the political will at the heads of government for private sector involvement in the power industry projects, the process was marked by legal disputes between parties, various legal arrangements that followed (rather than preceded) the various policy initiatives, many stalled projects, and bad publicity regarding private sector participation, which resulted in an overall negative impression of the investment climate in Turkey.

After its costly and prolonged experience, Turkey presently stands a chance to competitively restructure its own electricity industry and attract private funds for investment projects, given that most of the legal and regulatory arrangements have been accomplished and some of the early implementations have begun. In that sense, enactment of the Electricity Market Law of 2001 and the establishment of the Energy Market Regulatory Authority (EMRA) were major steps in the right direction. The 2001 law envisaged a fairly competitive framework for the electricity market and attempted to establish pricing mechanisms that reflected the actual cost of the service. In that fashion, the role of state-owned entities was planned to be reduced.

Yet, despite a good start by the market reform program, little if any progress has been made to date with regard to initiating competition in the generation segment; establishing transparent and cost-reflective pricing for the state-owned industry elements; and expanding the eligibility of customers to choose their own providers.

For instance, a much needed road map laying out the specifics of the industry reform was announced with considerable delay three years *after* the enactment of the Electricity Market Law of 2001. While the Strategy Paper of 2004 draws a time line for restructuring that includes privatization and details regarding opening Turkey's electricity market to competition, some of its features are debatable in terms of sequencing and scope. Particularly, in combination with the existing excess capacity in generation, freezing the currently high limits at which customers become eligible to choose their provider (such limits are in effect until 2009), and instituting transition contracts (in effect through 2010 and beyond) for the output of state-owned and contracted generators currently leaves little room for new entry into the market by private investors. Also, giving priority to the privatization of distribution rather than generation assets can delay and limit many of the benefits expected to be gained from liberalization in the industry.

Although most of the secondary legislation has been issued by EMRA to include the establishment of pricing mechanisms for various services supplied by the state-owned entities, as of 2005 accurate cost-of-service calculations and complete account unbundling allowing for cost-reflective pricing have not yet been accomplished. The Treasury's continuing income requests also prevents these entities from being able to implement such pricing mechanisms. As a result, competition in the generation market has not progressed significantly, primarily due to a lack of sufficient consumer choice and transparent, cost-reflective pricing of the state-owned industry elements.

The success of reform will in great part depend on following the course of reform in a persistent way and creating a credible policy environment for prospective investors and market participants. Thus, the government should reaffirm its commitment to structural reform in the industry and announce its intended future role in the industry with clarity; this is particularly true as regards the generation segment, as uncertainty affects decision making regarding much needed private investment. First and foremost, policy decisions that can be seen as contradictory with respect to originally announced decisions for market liberalization — for example, the Electricity Market Law of 2001— should be avoided.

At this point, given reform commitments made domestically as well as internationally, Turkey *cannot* afford policy reversals. Creating efficient markets in infrastructure industries would no doubt serve as building blocks for a sustainable-growth path for the entire economy and well being of Turkey. Policy makers should take advantage of the recently gained momentum in reforming the electricity industry in Turkey.

In this respect the following part highlights some policy recommendations made earlier:

<u>Cost Calculation Issues, Pricing, and Regulatory Governance</u>

- The success of competitive restructuring will depend largely upon establishing a market mechanism in the *generation* segment where demand and supply conditions are indicated to market participants via price signals. Merit-based dispatch requires the use of accurate generation cost data. Specifically, in a power exchange setting where spot electricity trade takes place, generators will have an incentive to bid their own marginal costs. Thus, possessing accurate cost data is indispensable for the efficient operation of a given market. Private generators can be expected to calculate such figures, as it will be in their own self-interest. In the case of publicly owned generators, however, cost determination must be obtained through regulatory or state mandate. To date, no such marginal cost studies have been undertaken regarding the state-owned generation side of the Turkish electricity industry.
- In an unbundled electricity market, the major focus of the regulatory framework is the pricing of monopoly services — namely the transmission and distribution of electricity, because the generation (energy) component of the service is subject to market-based pricing via competition. For the most part, leaving pricing of generation outside the new regulatory framework is a crucial cornerstone of any competitive restructuring. In this new environment, potential efficiency gains that will be achieved in generation are linked more to market design than to ownership structure.
- Given the market-based character of the reform strategy for Turkey's electricity industry, the resolution of cost calculation issues should be considered a *priority*. This

point is crucial, not only for the industry and its efficient work *per se*, but also for the efficiency and international competitiveness of the Turkish economy as a whole. It is now apparent that state-owned assets will be a significant part of the market mechanism for some time to come; thus, potential distortions to pricing in the market must be prevented by accurately pricing the services supplied by state-owned assets — the monopoly elements in particular. The accurate pricing of electricity services will also help the privatization process of such assets, as cost studies will help asses the assets' fair market value and will help potential investors make informed bids. Specifically;

- Proper cost-of-service studies for state-owned generation, transmission, and distribution assets should be undertaken to indicate service-specific marginal cost figures for each segment of the industry. Specifically, the calculation of the true costs of state-owned hydroelectric plants must include fixed capital costs, so that accurate pricing of electricity generation can be realized.
- EMRA should require all service providers (public and private alike) to submit marginal cost calculations for their activities along with any request for tariff approval. A common misconception among newly liberalized markets and their regulators is that incentive regulations such as price caps (as set by the RPI-X method, for example) are easy ways to avoid cumbersome cost-of-service studies. To the contrary, proper implementation of price caps requires that cast-off rates for the initial period be based on a carefully designed cost-of-service calculation; otherwise, the starting point for the price cap may not be accurate.
- Cross subsidies should be eliminated between rate classes (with a possible exception of low-income residential customers) and between regions. To secure this, tariffs should be designed and approved on the basis of reliable cost-of-service studies. Thus, rates can be unbundled *accurately*
    - to allow all customers to see separate charges for distribution, transmission, generation, and other services in their end-user bills;
    - to allow different customers classes to receive fair pricing based on their classes' delivery cost; and
    - to allow customers living in different geographic locations to receive fair pricing based on their region's delivery cost.
- In particular, in concert with accurate and balanced pricing, the policy of substantial degree of cross-subsidization of residential consumers at the expense of industrial consumers must be reconsidered, and corrected. This adjustment will also have a significant influence on the input costs — and hence the competitiveness — of the remaining industries.
- The Electricity Market Law of 2001 mandates "cost reflective pricing," which requires elimination of cross subsidies. However, the Strategy Paper of 2004 stipulates the implementation of *national tariff* for the ensuing five years. This apparent conflict should be reconciled in favor of the Electricity Market Law.
- By the same mandate, any portions of tariffs unrelated to the cost of the provision of electricity service — such as the Treasury's annual income requirements which are based on "macroeconomic indicators" — or subsidies to other public services must be eliminated.

    - As part of adhering to the “cost reflective pricing” principle, future implementation of a *locational* transmission pricing scheme that takes into account congestions of load areas should be contemplated, and the necessary studies must be initiated. In a competitive market, transmission pricing plays a crucial role in providing incentives to those who invest in generation as well as in transmission. Locational transmission pricing and associated incentive mechanisms influence the *value* and *location* of future generation investments; in other words, they send signals to investors of generators to locate their plants where needed to relieve congestion. Congested regions with high locational transmission prices will therefore be more attractive to potential investors of generation and transmission.
- Basically, the success of the restructuring program will depend on the ability of Turkey’s institutional environment to restrain arbitrary administrative action with regard to regulation of the industry. First and foremost, a strong and credible judiciary is a *necessary* condition to employ the regulatory system as a means of securing private participation in the industry. Therefore, the judiciary’s strength and institutional capacity provide an important basis for regulatory design, and choosing an appropriate regulatory governance option in line with Turkey’s other formal and informal institutions becomes feasible. Otherwise, commitments can be secured only via international or state guarantees, as establishing a credible regulatory system proves infeasible.
- Parliamentary systems, which unify executive and legislative powers, are generally vulnerable to discretionary behavior by the government, as discussed in the study. In this case, making credible regulatory commitments has a better chance if a governance option in which the regulatory process is defined through contract law rather through administrative law is chosen. Under such a system, an independent and impartial judiciary can best enforce operating licenses of the utility companies that specify pricing methods and access regulations within the existing regulatory system. For this system to be implemented in Turkey, price setting and access rules adopted by the secondary regulations may have to be embedded in the licenses of utilities. Operating licenses may then allow the implementation of a regulatory governance option that uses formal regulatory contracts to restrain government discretion in Turkey.
- The main focus of public regulation is to protect the interests of the final consumer. In this sense, regulation of Turkey’s electricity industry should not be thought of as an end, but rather as a means of promoting, creating, and maintaining competitive conditions within the marketplace.
- The adjustment process set forth by the E.U. Acquis Communautaire can certainly serve as a strong impetus in improving the existing institutional environment in Turkey. In fact, a change in the institutional paradigm in Turkey has long been an aspiration of the public at large, various bodies of government, and the private sector. Hence, the course of E.U. accession is a valuable opportunity for any stake holder involved in economic life in Turkey.

Market Design and Market Power Issues

- The selection of an appropriate model for wholesale market design must take into account the characteristics of the local market, the physical industry structure, demand conditions, and institutional environment. The influence of the British model (NETA) on the design of Turkey's wholesale electricity market is apparent. When choosing from available models, understanding the underlying reasons for any given model's selection for its respective market is important. Any design options with a good record for instituting competition must be taken into consideration.
- Establishment of even a small-scale spot electricity market should be considered, in combination with the residual balancing market already in progress. The operation of spot markets contributes to the development of a competitive structure by signaling the current and future market prices of energy; bringing transparency and liquidity to the market; and facilitating market participants' knowledge of the competitive environment.
- Demand forecasts prepared on a regional basis will be more useful than systemwide forecasts. This is because future transmission and generation investments will necessarily be guided by regional parameters in addressing issues such as the congestion and mitigation of market power. Preparing demand forecasts on a regional basis will also allow the accuracy of demand forecasts to be improved, while potential debates regarding the overestimation of demand by systemwide forecasts can be avoided.
- In markets with restructuring experience, demand–supply imbalances, insufficient reserve capacity, bottleneck areas, and associated transmission constraints have constituted major barriers for competition and were root causes of market power. In Turkey's new era, it is crucial that TEİAŞ undertakes well thought, capacity planning that is based on regional requirements — requirements that are also simultaneously directed at mitigating transmission constraints. Such careful planning would contribute to the ultimate goal: achieving the merit-based dispatch of generation resources in the country.
- To effectively run system operations, wholesale markets, and network planning, the administrative and financial independence of TEİAŞ must be secured.
- Establishing competition in the generation market is the key to establishing competition in the industry. Therefore, customers must have a choice of their energy (generation) supplier. This can be assured only by allowing *all* customers the right to shop for their energy needs. (Currently, only 28 percent of the total load is eligible to shop for their needs.) *Without delay*, eligibility limits should be progressively lowered from the current 7.7 GWh/year level, until full eligibility is established.
- Retail shopping for power by residential and small commercial customers has not progressed well in most markets that have a relatively high level of income. This is in part due to market design flaws and the low profit margins available to marketers who penetrate these market segments; but it is also in large part due to a low price elasticity of demand within the residential class. Furthermore, the benefit these consumers can expect from shopping for electricity does not come close to offsetting the high time cost given the relatively small share of a typical residential bill that electricity costs have in the median household income. In Turkey, however, the

situation may differ significantly from that of high-income OECD countries. This is because Turkish residential customers face one of the highest end-user electricity prices of any OECD countries, while possessing the lowest median income of any country within the OECD group. Consequently, a real potential exists for the establishment of retail competition in the small-customer segment of the Turkish electricity market, as these customers also stand to benefit greatly from competition. The lack of the necessary retail marketing infrastructure (namely, human capital— that is, knowledge and experience — and institutional capacity) does not constitute an obstacle for this segment, because local distribution companies can aggregate small customers' load in their service territories. In fact, research indicates that, even with a developed retail marketing infrastructure, profit margins will not allow retail marketers to succeed in the small-customers segment; it can further be argued that this situation will remain for the foreseeable future. Distribution companies are the only entities that can minimize acquisition costs for small customers, thanks to their scale economies and their accumulated experience in retail services. These advantages make local distribution companies *natural aggregators*. Therefore, distribution companies should be allowed (and even required) to aggregate their small customers' loads in their service territories, in order to establish competitive power procurement. A major boost for competition in the generation market would thus be provided.

- Demand response mechanisms serve as an important element, not only in reducing peak capacity needs but also for maintaining system reliability and mitigating market power in times of capacity shortages or transmission congestions. Thus, in addition to time-of-use metering (which is already being implemented in Turkey), various demand response programs, as discussed in this study, should be considered.
- Although Law No. 4628 establishes some safeguards for generator concentration by instituting universally accepted ownership thresholds, in today's competitively restructured electricity markets, where trade is centralized and vertical monopolies no longer exist, detecting market power in the generation segment requires more sophisticated approaches than the establishment of simple thresholds. For instance, the potential for market power can be assessed by considering transmission constraints in *load-pockets* to determine what supply sources can reach buyers to compete with the generator in question. In the United States, FERC has recently initiated a test — Pivotal Supplier Analysis (or PSA) — that establishes a threshold based on whether a generator is *pivotal* to the relevant market (that is, whether a generator's uncommitted capacity exceeds the difference between the market's total uncommitted capacity and the wholesale load). Effectively, the PSA identifies whether a generator is a *must-run supplier* needed, at least in part, to meet peak load in a specific market. In this situation, the threshold is sensitive to a generator's potential to successfully withhold supplies in the market in order to raise prices. In addition, a "market share" test is applied for Summer, Fall, Winter, and Spring that determines whether a generator's uncommitted capacity in a geographic market is less than 20 percent. By contrast, under the *plain threshold method*, as established by the Turkish Electricity Market Law, a generator passes the test for market power as long as its market share is less than 20 percent — even if its capacity is pivotal. For this reason, the market share test of the Turkish system must be complemented by a

pivotal supplier analysis. Furthermore, the current method treats the entire Turkish market as one even though various conditions, particularly transmission constraints, can create various load pockets and sub markets. These factors should be taken into consideration in defining relevant geographic markets for market power analysis. In advance of expected market imperfections, the regulatory framework in Turkey must adapt and further develop such market monitoring rules, in accordance with the peculiarities of Turkey's infrastructure. Because the current legal and regulatory framework aims to develop a competitive market structure — one in which energy will be commercially traded among market participants and regions — these issues need to be considered *before* privatization takes place, to prevent the serious consequences of market manipulation.

- Given the urgent need for substantial new investment in the generation segment for the near future, current market conditions — such as the continuing integration of EÜAŞ and TETAŞ, transition contracts between distribution companies and TETAŞ as envisaged by the Strategy Paper of 2004, and the current eligibility limits for retail choice — must be improved to attract private investment. In conjunction with opening the market to competition, the use of binding, long-term, state guaranteed power contracts must be reconsidered in favor of market-based purchase arrangements.
- Autoproduction must be allotted appropriate incentives aligned with overall system efficiency and market efficiency considerations.
- The importance of the UCTE project for interconnection to European markets must be acknowledged; this project will present a source for new supplies and will provide a check on the potential market power in the domestic electricity market by constituting an alternative source of energy, provided that adequate interconnection capacity is built.
- To ensure a smooth transition to a competitive market Turkey's current excess capacity must be taken advantage of during the interim period.

Stranded Costs and Power Purchase Contracts

- By definition, stranded costs are a dynamic concept; changing market prices may change the initially estimated extent of them. Given the future declining trend of contract prices, the probability that BOT and BOO contracts will not create significant stranded costs — if they create any costs at all — is high. For these contracts, most of the front-loaded capital cost recovery periods have ended (or are about to end); meanwhile, the thermal generation cost figures of state-owned assets are comparable to the current prices of these contracts. Note also that most state-owned generation assets have already largely depreciated; thus, using their seemingly competitive low prices as a reference point is not an appropriate way to assess future market prices in the generation segment. Consequently, the concept of stranded costs *cannot* be used as an argument against the transition to a competitive market.
- Nevertheless, all possibilities for the mitigation of stranded costs must be considered, including eliminating state subsidies, which would keep power prices artificially low (and hence, increase stranded costs). If stranded costs do arise, depending on the development of power prices in the future, appropriate methods for an accurate

measurement of stranded costs and their actual recovery must be chosen, as discussed in this study. Regardless of what method is chosen, the key to minimizing the program's political risk as well as to minimizing the creation of distortions in the market as a result of cost recovery is to provide both transparency and accountability in the process of deciding which methods to use. As part of the new regulatory framework — which must have a strong *participatory* character — a consensus must be achieved among the state, regulators, industry and ratepayers regarding the issue of cost recovery.

- Furthermore, the relatively low-priced power to be supplied by these contracts in upcoming years should be expected to contribute to the development of competition, as these contracts will provide a substantial amount of electricity generation to the market.

<u>Privatization and the Strategy Paper</u>

- To some extent, the Strategy Paper of 2004 contains policy statements that may be interpreted as contradictory with regard to the declared intention of the Electricity Market Law. Specifically, the Strategy Paper stipulates that:
    - a tariff equalization mechanism (namely, the national tariff) will be employed in the first five years, which is in conflict with the "cost reflective pricing" principle of the Electricity Market Law;
    - distribution companies will have five-year transition contracts with TETAŞ and portfolio generation companies for 85 percent of their noneligible customers until *at least* January 2010, which would stall competition from developing in the generation segment of the electricity market; and finally,
    - the market will be open for competition by 2011, which represents an unnecessarily prolonged time table for establishing competition, and which would lead to doubts concerning the commitment of the government to genuine market reform.
- Implementation of tariff equalization will continue the practice of cross subsidization and the existence of price distortions among the respective regions of Turkey. On the other hand, regional "cost reflective pricing" would rationalize end-user electricity prices and would greatly reduce the incentive for theft (particularly in low income areas), as discussed in this study. The data pertaining to absolute amounts (MWh) of theft/loss in Turkey reveal this to be a general rather than a regional problem.
- The current sequencing of privatization in the industry — which gives priority to distribution assets — is counterproductive and represents a less than optimal way of prioritization. Most efficiency gains from privatization are expected to be achieved by the privatization of potentially competitive segments of the industry, rather than by the privatization of natural monopoly segments. The "privatization of distribution first" approach that aims to establish accurate metering/billing and settlement functions may make sense in markets with no prior experience with the commercialization of electricity service, such as the transition economies in Eastern Europe and in the Caucuses. However, Turkey already has a long-standing commercial system in place, and the loss/theft problem discussed in the study is unlikely to be addressed by a change of ownership in this segment alone. Better

collection and settlement practices are possible under performance-based methods and an effective regulatory framework, regardless of ownership structure, provided that prudent institutional capacity and a management structure equipped with incentives is established. Privatization of generation assets should thus be undertaken *first*, to expedite the transition to a competitive market structure.

- The privatization approach should not be aimed solely at maximizing privatization income, as contemplated in the 2004 Strategy Paper; rather, it should first and foremost target the creation of a competitive market. For this reason, generation portfolios for privatization should primarily be designed by taking into account the *post-privatization* market power potential of generators or holding companies, rather than considerations of financial viability. Aggregate market share of generators or holding companies can be an insufficient and misleading indicator when assessing market power. Among the factors that greatly influence the likelihood of the exercise of market power are: the post-privatization locations of generators; their potential ability to supply load pockets; and, consequently, their potential ability to become pivotal suppliers in regions with transmission constraints.
- Because the eligibility threshold will be kept at its current level until 2009 *and* transition contracts will be honored until 2010 (and beyond), newly privatized generation companies will have a hard time being competitive in the market until at least 2010. In other words, the benefits of competition cannot be realized until the beginning of 2010, despite the expected start of the privatization of generation assets more than three years earlier. Obviously, such a market prospect will not be attractive to potential investors.
- The current strategy's prioritization system seems to be heavily influenced by the issue of stranded costs. By making strong assumptions regarding stranded costs, proper sequencing of market reform may become fundamentally distorted, and the expected early benefits from liberalization may be minimized, if not eliminated. From the perspective of maximizing net benefits from liberalization, proceeding with the right sequence of market reform is safer than focusing on the cost recovery.
- International experience indicates that the sequencing of liberalization is more important than the sequencing of privatization. For liberalization to yield most of its expected return, a credible legal and regulatory environment — working together with a functioning market structure — must be established *prior to* changing the ownership structure of industry assets (that is, before privatization). Only after laying such groundwork will privatization be less risky in terms of market power and supply security; more attractive for the investor and more rewarding for the government in terms of revenue generation; and, most importantly, more beneficial for consumers of electricity. In the case of the privatization of the Turkish electricity industry, while considerable progress has been made on legal and regulatory fronts, the program is going forward before the necessary market parameters are in place.

Investment and Business Environment

- Given its geographic location and existing and potential market size, Turkey is capable of attracting a substantial amount of private sector investment to its electricity industry, provided that a credible and effective legal and regulatory environment is established in the upcoming period. The establishment of such an environment would also help mitigate the negative effects of recent past episodes concerning BOT, BOO, and TOOR investment schemes, which occurred during the 1980s and 1990s.

- Legal initiatives are generally in line with pro-reform efforts; however, genuine implementation of all legal initiatives should follow.
- Institutional capacity building is progressing well with regard to EMRA and the TCA. To coordinate the monitoring of anti-competitive behavior and the enforcement of the competition law within the industry, full cooperation among these agencies must be achieved.

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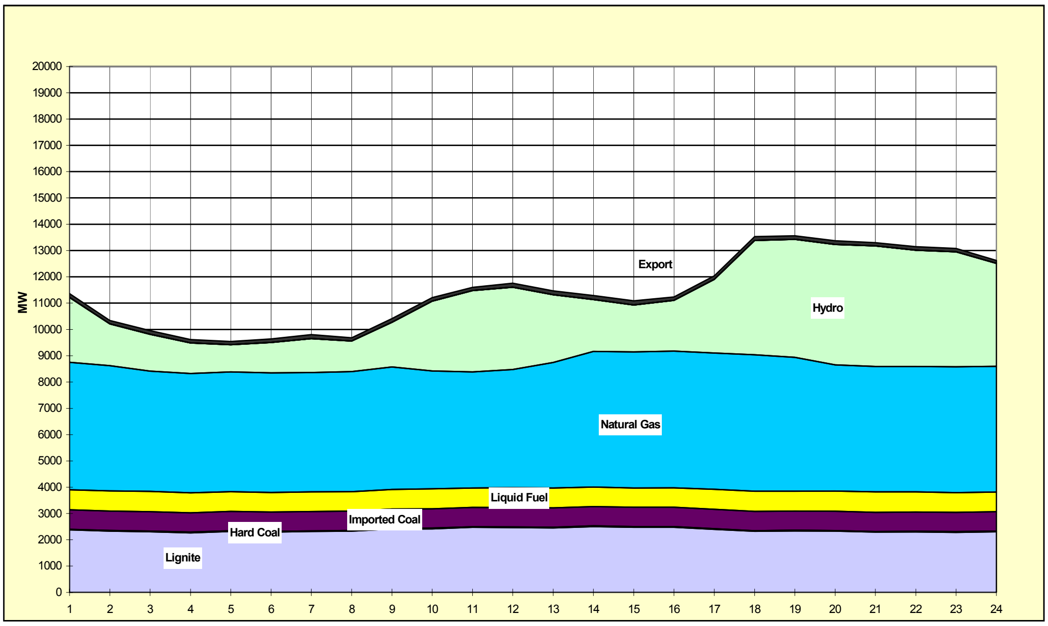
Annex

Figures 26 and 27 show the type of generation used to met the minimum and secondary summer peak loads, respectively.

Figure 26: Type of Generation to Meet Minimum Load, 2003

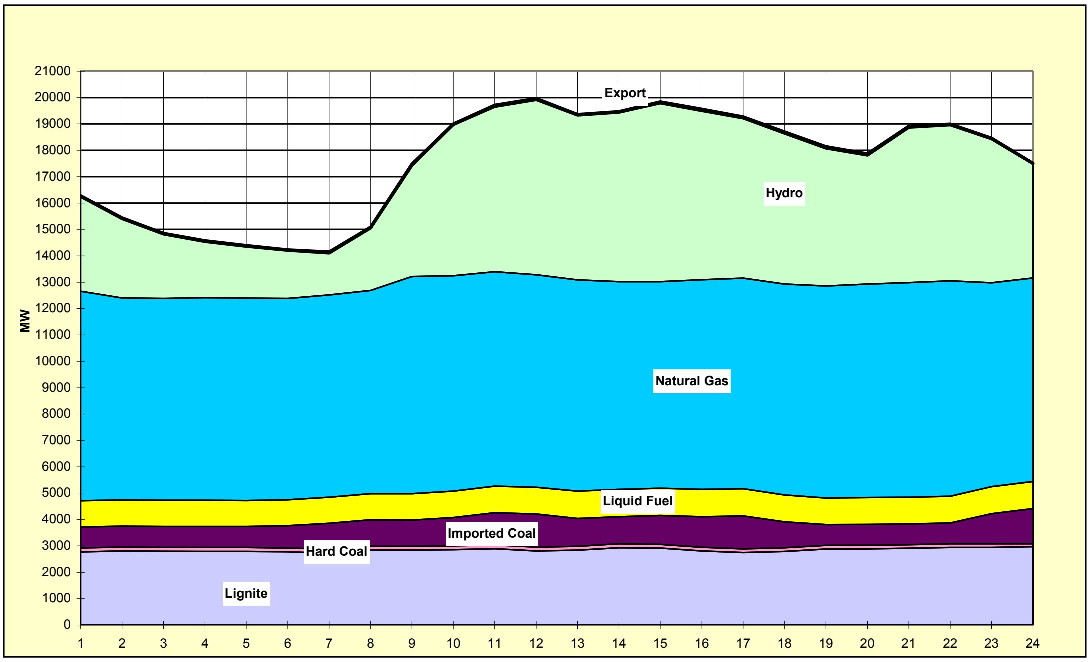


Date: November 26, 2003 Hourly Peak: 13,347 MW Hour: 19:00
Consumption: 268,151 MWh Coincident Peak: 13,380.1 MW Hour: 18:00

Liquid Fuel = Fuel-oil + Diesel + LPG + Naphta + Geothermal + Others

Source: TEİAŞ, Annual Operational Activity Report, 2003.

Figure 27: Type of Generation to Meet Peak Load During Summer, 2003



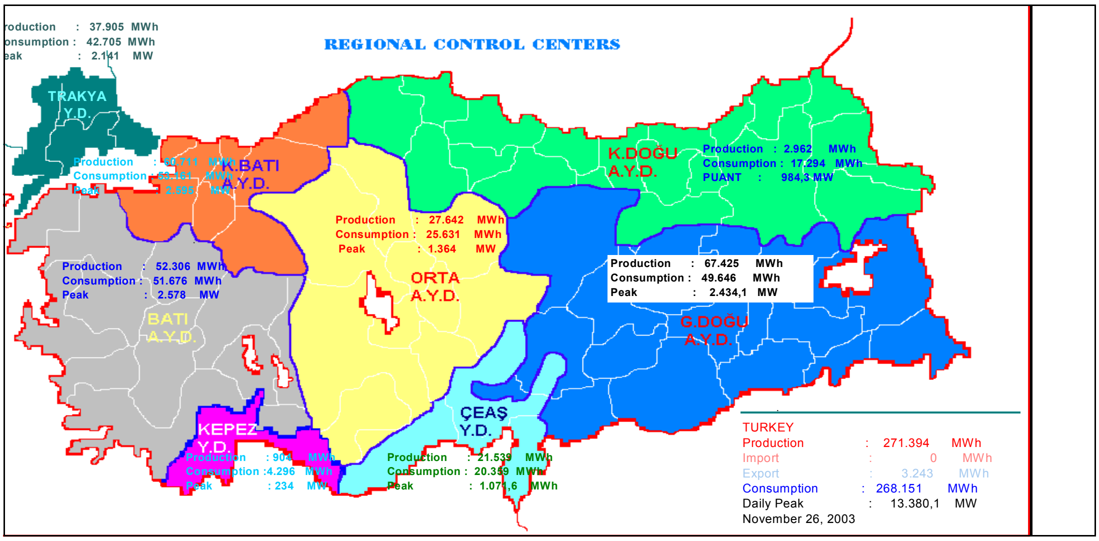
Date:	**August 7, 2003**	**Hourly Peak:**	**19,860 MW**	**Hour:**	**12.00 PM**
Consumption:	**419,561 MWh**	**Coincident Peak:**	**20,045.3 MW**	**Hour:**	**11.40 AM**

Liquid Fuel = Fuel-oil + Diesel + LPG + Naphta + Geothermal + Others

Source: TEİAŞ, Annual Operational Activity Report, 2003.

Figures 28–29 show the regional distribution of Turkey's electricity generation and the load for minimum and secondary summer peak loads, respectively.

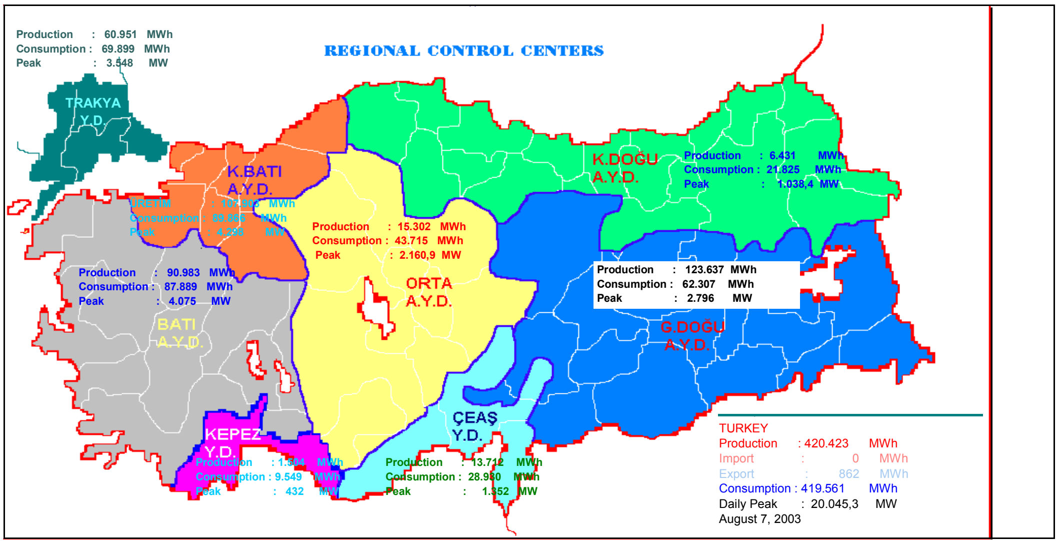
Figure 28: Generation and Load at its Minimum by Region, 2003



Source: TEİAŞ, Annual Operational Activity Report, 2003.

In recent years, demand relating to air conditioning has grown rapidly, creating a secondary peak during summer months. This is expected to result in a lower load factor, because air conditioning is used disproportionately, and only during a limited time period.

Figure 29: Generation and Load During Summer Peak by Region, 2003



Source: TEİAŞ, Annual Operational Activity Report, 2003.

Data displayed in Table 20 and Figures 30–33 summarize additional findings of TEİAŞ's supply plan with regard to generation investment requirements based on the *high demand growth scenario* discussed in Section 2.2.2.

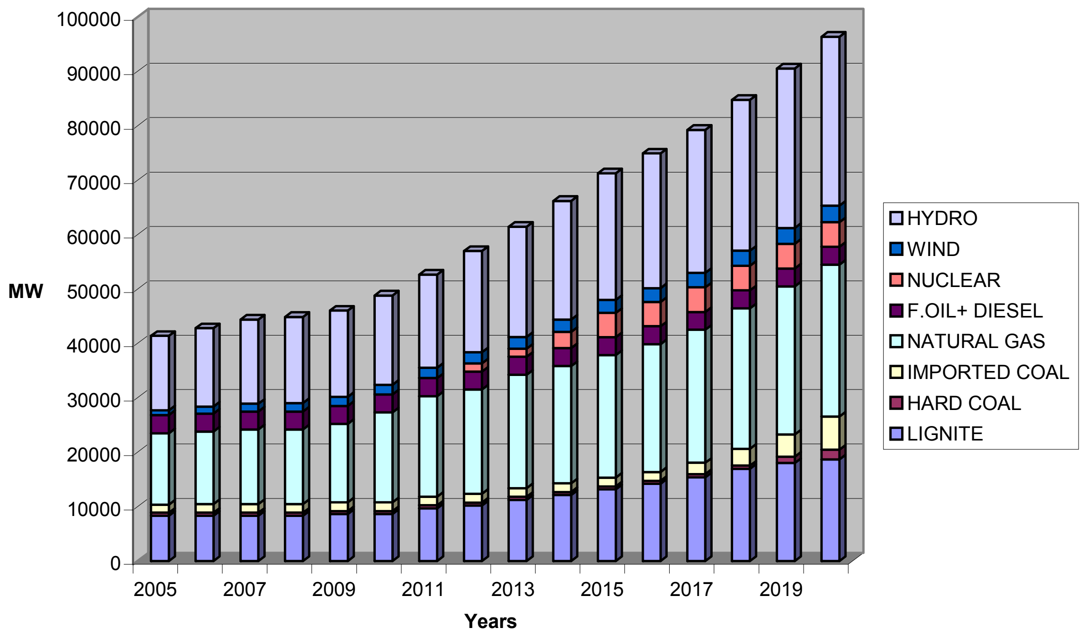
Table 20: Capacity Additions by Fuel Type, 2005–2020 (MW)

Year	LIGNITE	HARD COAL	IMPORTED COAL	NATUR. GAS	F.OIL+ DIESEL	NUCLEAR	WIND	HYDRO + GEOTHERMAL	TOTAL
2005	1082*	0	12**	922**	54**		860**	727*+98** =825	3755
2006	0	0	119**	170**	0		409**	643*+76** =719	1417
2007	0	0	0	390**		0	125	1070*+52**=1122	1637
2008	0	0	0	0		0	125	334*	459
2009	320**	0	0	700		0	125	34**	1179
2010	0	0	0	2100		0	125	14** + 542=556	2782
2005-2010	***1402***	***0***	***131***	***4282***	***54***	***0***	***1769***	***3590***	***11228***
2011	1040	0	0	1950		0	125	731	3846
2012	520	0	0	700		1500	125	1478	4323
2013	1040	0	0	1675		0	125	1598	4438
2014	880	0	0	700		1500	125	1558	4763
2015	1040	0	0	975		1500	125	1445	5085
2011-2015	***4520***	***0***	***0***	***6000***	***0***	***4500***	***625***	***6811***	***22456***
2016	1040	0	0	975		0	125	1483	3623
2017	1200	0	500	975		0	125	1559	4359
2018	1560	0	1000	1400		0	125	1419	5504
2019	1040	600	1000	1400		0	125	1590	5755
2020	680	600	2000	700		0	125	1731	5836
2016-2020	***5520***	***1200***	***4500***	***5450***	***0***	***0***	***625***	***7782***	***25077***
2005-2020	***(19.5percent) 11442***	***(2percent) 1200***	***(7.9percent) 4631***	***(26.8percent 15732***	***(0percent) 54***	***(7.7percent) 4500***	***(5.1percent) 3019***	***(30.9percent) 18182***	***(100percent) 58760***

* Under construction.
** Received license as of July 2004.

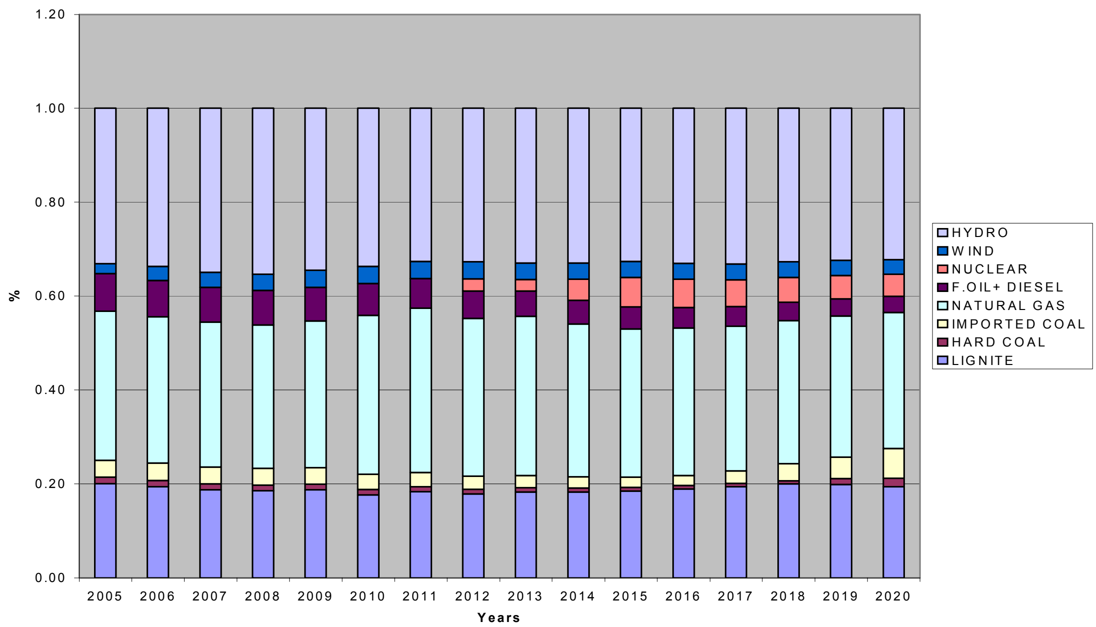
Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.

Figure 30: Installed Capacity Development by Fuel Type, 2005–2020 (MW)



Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.

Figure 31: Percentage of Installed Capacity Development by Fuel Type, 2005–2020

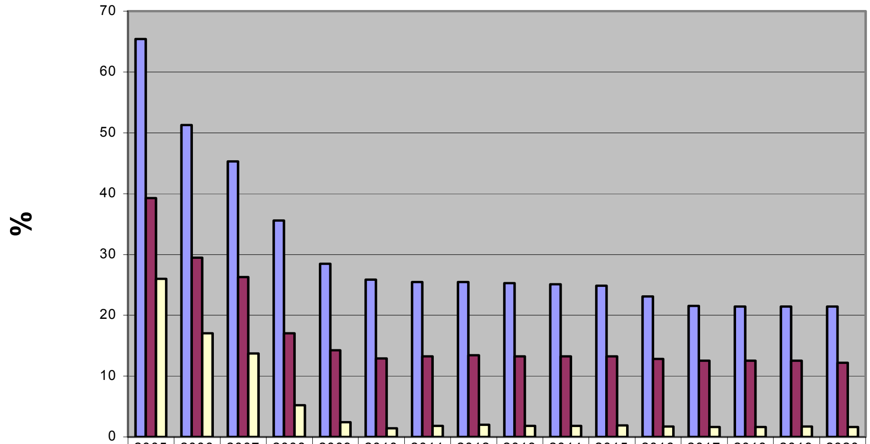


Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.

As can be seen from the Figure 32, the average *installed capacity* reserve ratio is approximately 21–25 percent over period covered by the plan (except for the years 2005–

2008, for the reason explained earlier). The average *output* reserve ratio based on average hydroelectric generation (that is, hydroelectricity produced during normal rainfall amounts) is calculated to be 12–13 percent. This ratio decreases to 1–2 percent under reliable (drought) conditions.

Figure 32: Reserve Ratios, 2005–2020

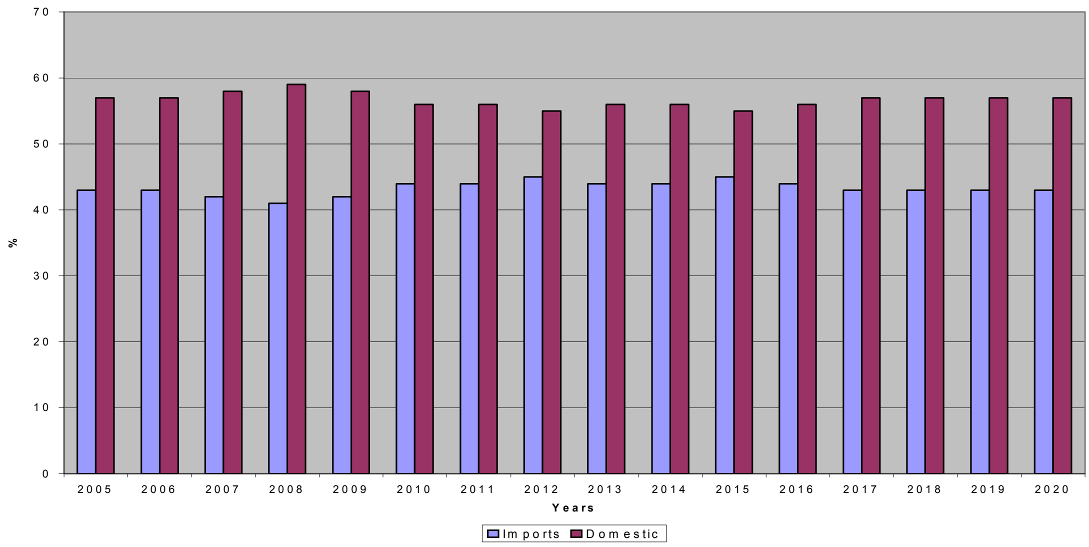


	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Installed Capacity Reserve Ratio (%)	65.4	51.3	45.3	35.6	28.5	25.9	25.5	25.5	25.3	25.1	24.9	23.1	21.5	21.4	21.4	21.4
Average Output Reserves (%)	39.3	29.5	26.3	17.0	14.2	12.9	13.2	13.4	13.2	13.2	13.2	12.8	12.5	12.5	12.5	12.2
Average Reliable Output Reserves (%)	26.0	17.0	13.7	5.2	2.4	1.4	1.8	2.0	1.8	1.8	1.9	1.7	1.6	1.6	1.7	1.6

Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.

The share of imported fuel use in relation to total fuel use for generation remains nearly the same (around 40 percent) during the period covered by the supply plan.

Figure 33: Share of Imported versus Domestic Fuel Use in Installed Capacity, 2005–2020



Source: TEİAŞ, Electrical Energy Generation Plan Study of Turkey (2005–2020), 2004.