Increasing the Share of Renewables in Turkey's Power System:
Options for Transmission Expansion and Flexibility

SHURA
Energy Transition Center

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About SHURA Energy Transition Center

SHURA Energy Transition Center, founded by the European Climate Foundation (ECF), Agora Energiewende and Istanbul Policy Center (IPC) at Sabancı University, contributes to decarbonization of the energy sector via an innovative energy transition platform. It caters the need for a sustainable and broadly recognized platform for discussions on technological, economic and policy aspects of Turkey's energy sector. SHURA supports the debate on the transition to a low-carbon energy system through energy efficiency and renewable energy by using fact-based analysis and best available data. Taking into account all relevant perspectives by a multitude of stakeholders, it contributes to an enhanced understanding of the economic potential, technical feasibility and the relevant policy tools for this transition.

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Executive Summary

The use of renewable energy resources, primarily wind and solar, is expected to grow significantly within Turkey's power system. There has been tremendous growth in the installed renewable electricity generation capacity in recent years and Turkey saw a record year in 2017. As deployment of renewable electricity generation technologies is on the eve of acceleration, there is a need to better understand how the rising share of wind and solar will affect Turkey's power system.

This evidence-based analysis is designed to highlight priority areas and inform energy planners, system operators, decision-makers and key market players on the consequences of higher shares of renewables and what they would mean for transmission investment and integration strategies in Turkey. This study – the first of its kind for Turkey – will help inform discussions about Turkey's transition to a low-carbon electricity system. Being one of the fastest growing economies and in view of the subsequent increase in Turkey's electricity demand, the analysis provides an important contribution to the energy security debate, proposing strategies on how the current transmission system can integrate higher shares of renewables.

Turkey can generate 20% of its total electricity from wind and solar by 2026 without negatively impacting transmission system and planning.

Due to affordable technology costs, the wind and solar (defined together as variable renewable energy) are expected to continue. The analysis shows that Turkey can generate 20% of its total electricity from wind and solar by 2026 without negatively impacting transmission system and planning. Doubling the installed wind and solar capacity to 40 gigawatts (GW) is feasible without any additional investment in the transmission system compared to the Base Case scenario defined in this analysis. The total investment needed to expand the transmission grid and the additional transformer stations is estimated approximately the same as earmarked by Turkey's transmission system operator (TSO) Türkiye Elektrik İletişim A.Ş.'s (TEİAŞ) Ten-Year Network Development Plan (TYNDP). The impact on redispatch and curtailment of electricity is found to be negligible. A wider distribution of solar and wind capacity across the country – based on demand, substation capacity and speed and irradiation – produces remarkable benefits for integration.

Generation from wind and solar are rapidly growing thanks to affordable technology costs and policies that utilise Turkey's excellent local resources. After a record year for adding renewables, this trend is expected to continue, as recent auctions for solar PV and wind have shown.

Added net renewables capacity (3.2 GW) was more than double that of non-renewables (1.5 GW).

In recent years, capacity additions for renewables have been marked by tremendous growth. Turkey saw a record year for renewables in 2017. Added net renewables capacity (3.2 GW) was more than double that of non-renewables (1.5 GW). At 1.79 GW, added solar photovoltaic (PV) capacity in 2017 was more than three times that of 2016, making Turkey one of the largest markets for solar PV in Europe. By the end of 2017, total installed wind capacity was nearly three times higher than its current capacity, 6.9 GW.[1] Generation from wind and solar represents 7% of Turkey's total electricity output.[2] Almost 5 GW of (pre-)licenses for wind and solar projects were awarded by auction in 2017. This growth is likely to continue for a number of reasons.

[1] *Wind Europe (2018), Wind in Power 2017. Annual combined onshore and offshore wind energy statistics.*
[2] See *http://www.emo.org.tr/genel/bizden_detay.php?kod=88369;*
Enerji IQ (2018), Turkey's Energy Market Report, No: 2018 / 93 Year: 4, 13 March 2018.

The impressive decline in the costs of solar, wind and other renewable energy technologies has inaugurated a new era in low-carbon energy. Since 2012, global net capacity additions in renewables have surpassed those of all other technologies. In 2016, 161 GW of renewable energy capacity was installed, twice as much as net additions in coal and gas.[3] Turkey has benefited from these developments, as recent auctions for large-scale PV and wind have shown. Winning bids came in at USD 3.48 cents per kilowatt-hour (kWh) for wind and USD 6.99 cents/kWh for solar PV, far below Turkey's past feed-in tariffs. A majority of wind projects that received pre-licenses in 2017 will sell power on the market without a guaranteed price, and some will even pay the state-run grid operator TEİAŞ a per-kWh fee for feed-in rights.

There is a significant resource potential to scale up wind and solar generation in Turkey. Indeed, this is the time to combine this growing business case with the availability of abundant resources spread across the country. The prime locations for wind power generation along the Aegean coast have attracted much investment. For solar power, the south of the country offers many opportunities. What's more, in many other parts of the country where land is cheap or demand is nearby there's much potential for solar and wind.

Globally, Turkey has been one of the fastest growing economies. Its gross domestic product (GDP) per capita grew by 4.8% between 2010 and 2016,[4] the second fastest rate in the OECD. During the same period, its population grew by 1.6% per year, reaching more than 78 million in 2016. Beginning in 2010, total electricity demand increased 4.3% a year. Forecasts expect this trend to continue.

Total installed capacity reached more than 83 GW in 2017, up from 78.5 GW in 2016. Half of this total is renewable energy and the other half is fossil fuels. More than 70% of all electricity generation is supplied by fossil fuels. 29.3% of all electricity generation comes from renewables, mainly hydro and wind. Solar's share is a mere 1%. Turkey wants to meet its growing energy demand whilst reducing its dependence on energy imports, which currently make up 75% of Turkey's primary energy supply. Renewable energy is a main pillar in overcoming this challenge.

Electricity generation from wind and solar is variable, that is, the output depends on the availability of wind and sunshine. This creates challenges for power system operators when it comes to meeting demand and delivering services. Global experience demonstrates that a share of 15% or more of variable renewable energy can be integrated into power systems without major changes in system planning and operation.

An energy system that is based on a higher share of renewable energy comes with multiple benefits: improved energy security, better trade balance, increased economic activity, new employment opportunities and a better environment.

An energy system that is based on a higher share of renewable energy comes with multiple benefits: improved energy security, better trade balance, increased economic activity, new employment opportunities and a better environment. Yet stakeholders and system operators often see growing shares of wind and solar as a challenge, one accompanied by additional costs and difficulties when it comes system reliability and flexibility.

Indeed, in recent years, experience in many countries around the world has shown that annual shares of solar and wind generation that reach 15% or more can be managed without major effort, provided operational aspects are taken into account and early planning occurs.

[3] *IRENA (2017): Renewables Capacity Statistics 2017.*
[4] At 2010 constant USD.

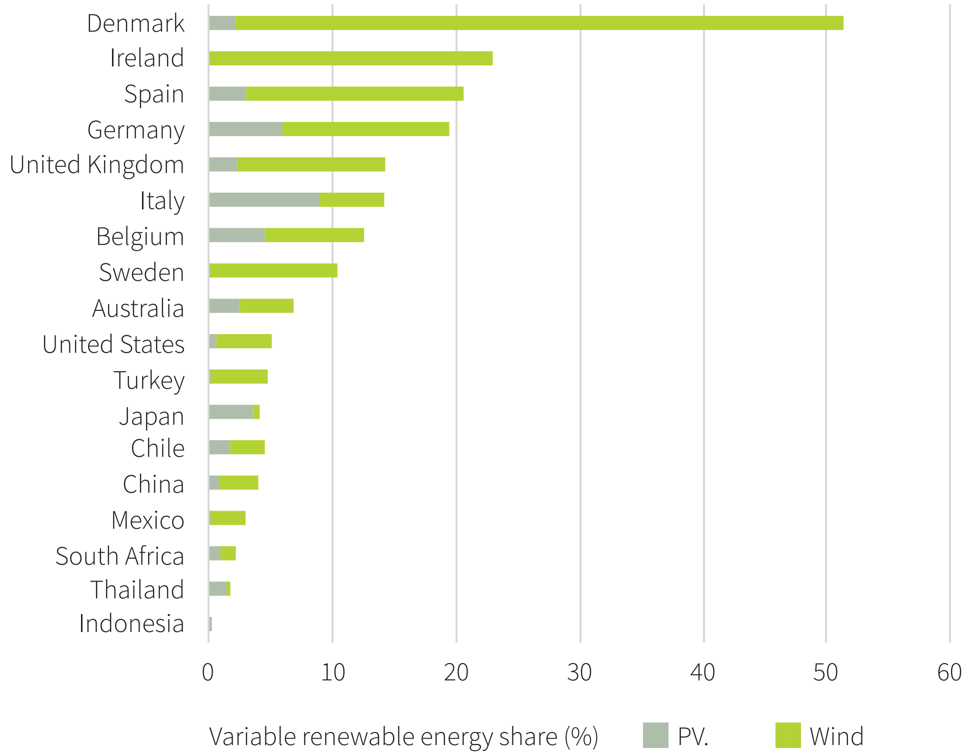


Figure 1: *Share of electricity generation from on/offshore wind and solar PV in selected countries, 2015*[5]

Global examples are showing that wind and solar shares of up to 25% can be successfully integrated without changing the power system. This can translate into more than 80% of demand at specific hours of the year. Systems in California, Germany and Spain have developed various flexibility options such as strengthening interconnector capacity with neighbouring systems, improving fossil fuel plant flexibility and allowing for limited curtailment in extreme cases. Some countries have also adapted their market design to address highly variable prices, low utilization rates of fossil plants and the associated investment challenges.

There is a need to better understand how the rising share of wind and solar energy will affect Turkey's power system. This study – a first of its kind for Turkey – will help inform discussions about Turkey's transition to a low-carbon energy system.

Country-specific assessments have become indispensable in understanding the challenges created by renewables and identifying suitable measures for efficient wind and solar deployment. But such analysis has yet to be carried out for Turkey. This is essential to prepare policymakers, system operators, regulators and consumers for managing a clean-energy transition.

The study is designed to inform stakeholders in Turkey about the consequences of a greater share of renewables and what this would mean for transmission investment and integration strategies. It builds on a robust, innovative and in-depth simulation model.[6]

[5] *IEA (2017). World Energy Balances 2017 edition. OECD/IEA, Paris.*
[6] Due to complexity and data access, the distribution system is not part of this analysis. However, long-distance power flows do not have a significant effect on the distribution system. The challenge and cost of integrating renewables into the distribution grids will largely depend on local supply-and-demand ratios, as well as on smart planning, the monitoring and control of wind and solar feed-in.

This study, which covers the 2016–2026 period, considers three main scenarios that differ in their share of total installed wind and solar generation capacity: a Base Case scenario of 20 GW (in line with the existing TEİAŞ plan, which assumes 14 GW of wind and 6 GW of solar PV), a scenario where wind and solar capacity doubles (40 GW) and another one where it triples (60 GW). Given the rapid cost decline of solar PV, an equal amount of wind and solar have been assumed for the doubling and tripling scenarios.[7] These capacity values do not necessarily reflect the most probable or desirable values. The idea is to create different scenarios in order that we may better identify challenges and system impact.

In the Base Case, the share of wind and solar reaches 12% by 2026. It increases to 21% in the Doubling and 31% in the Tripling scenarios. The total renewable energy share, including hydro, geothermal and biomass, is estimated at 35%, 44% and 53%, respectively.

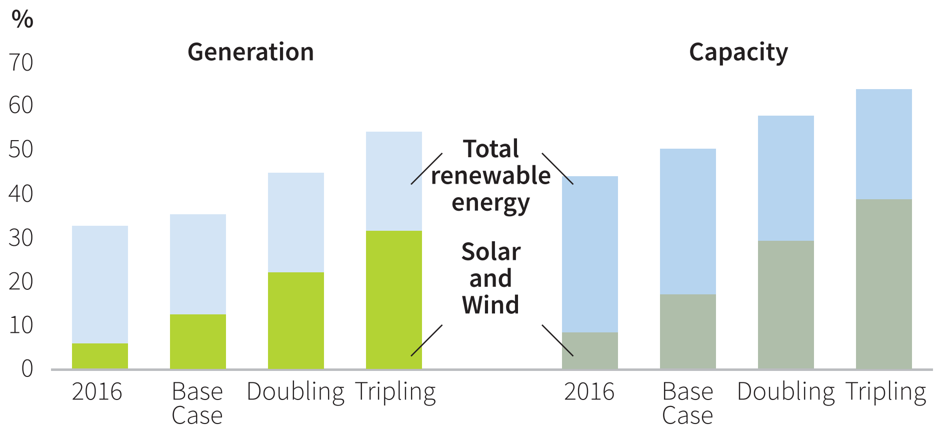
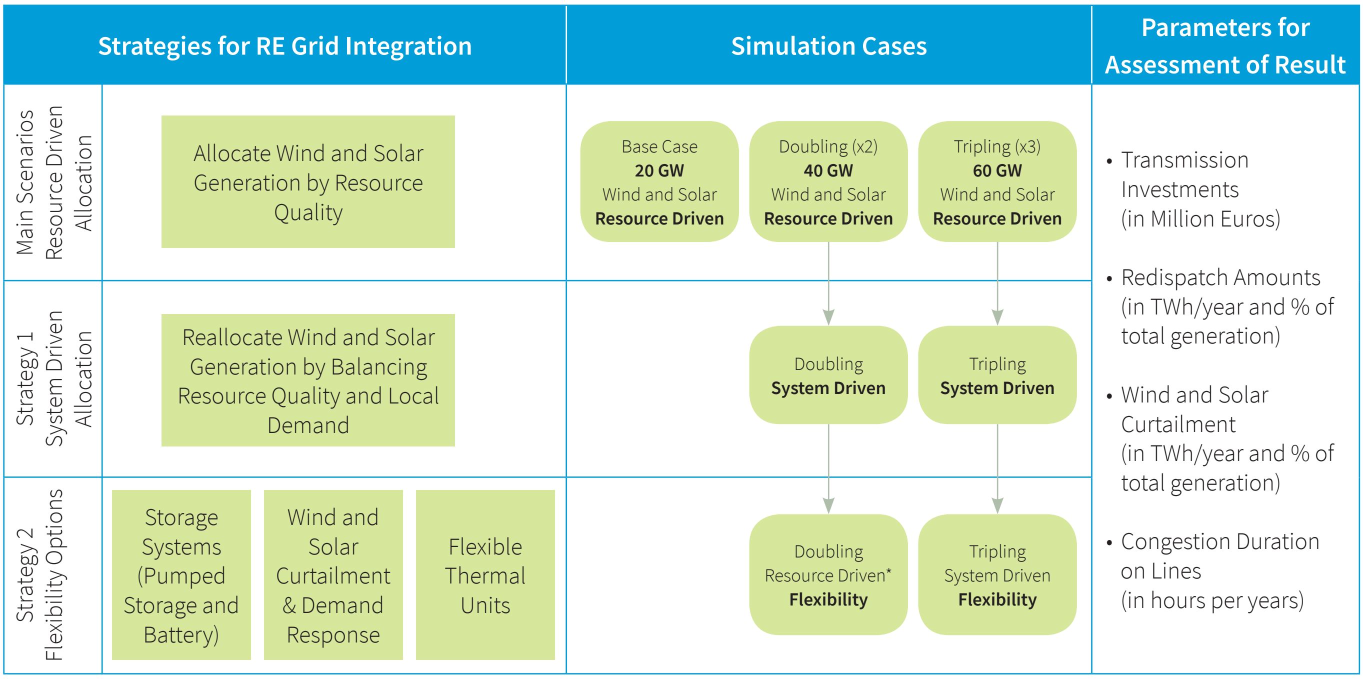


Figure 2: *Solar, wind and total renewable energy shares in the three scenarios, 2016–2026*

The effect of two grid integration strategies was assessed based on the scenarios: a *resource-driven allocation*, which locates wind and solar investment where the resource quality is best, and a *system-driven allocation*, which distributes solar and wind generation across Turkey in a balanced manner, taking into account demand centres as well as local grid capacity. The study then considers different flexibility options. All input data remain identical across the three scenarios and are based on real data and operational practices used by TEİAŞ as well as those used by current energy plans and government targets.

[7] Concentrated solar power does not feature prominently in the Turkey's context due to its high generation costs and was therefore not included in this analysis.



** Since there were only minor differences between results of system and resource driven assessment for scenario, the choice was made to assess based on resource driven allocation.*

Figure 3: *Scenario approach of this study*

Doubling the current plan of solar and wind capacity to 40 GW will not have a major impact on system planning and operation. It would be achievable without any additional costs and the impact on redispatch and curtailment would be negligible. The total investment needed to expand the transmission grid and add transformer stations is estimated at around EUR 390 million per year, roughly the same as that earmarked by TEİAŞ's TYNDP.

By 2026, Turkey's electricity generation is projected to reach 439 terawatt hours (TWh) per year, up from 272 TWh in 2016, due to an annual growth of 5%.

For the Base Case scenario, the study follows the TYNDP of TEİAŞ for the 400 kilovolt (kV) and 154 kV systems. 8,900 km of new 400 kV lines, 10,700 km of new 154 kV lines and sixty-one 400 kV/154 kV transformer stations are identified. Investment costs are estimated to amount to EUR 390 million annually for 2016–2026. This represents a continuation of the investment average of the past 5 years. Most of the new investment will be needed along the Aegean Sea in West Anatolia, between Central Anatolia and Trakya, and in Southeast Anatolia.

Doubling the installed wind and solar capacities to 40 GW is feasible without additional investment in the transmission system.

Doubling the installed wind and solar capacities to 40 GW is feasible without additional investment in the transmission system. Minor additional investment may be needed in high capacity grid connection lines for large solar parks like those planned for the Renewable Energy Designated Area (REDA) system.

In the Base Case scenario, the redispatch share of solar and wind in total electricity generation would remain at the 2016 level, around 4.8%. Redispatch increases slightly but remains within the same bandwidth of 5% when total capacity doubles.[8] The need for the curtailment of wind and solar generation is negligible.[9] By comparison, Germany in 2016 had to curtail 3.3% of its wind and solar power generation (which provided nearly 20% of overall demand) due to delays in network expansion.[10]

[8] Generation redispatch, which changes the dispatch of plants to relieve demand, provides secure and reliable system operation, but it also creates additional costs.
[9] Depending on wind conditions and solar irradiation during extreme low-load public holiday periods, curtailment may be required for a few hours, but it will nevertheless be negligible, i.e. below 0.1% of annual wind and solar generation.
[10] *Bundesnetzagentur (2017): EEG 2016 in Zahlen.*

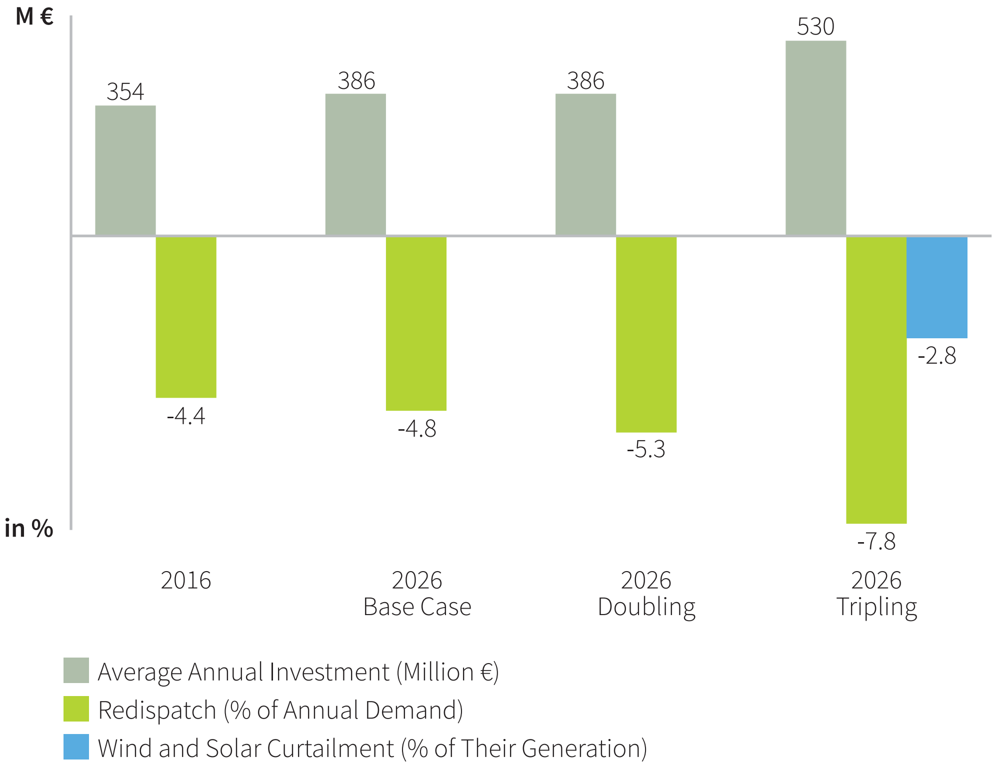


Figure 4. *Investment, redispatch and curtailment results for 2016 and for the main scenarios in 2026*

Tripling wind and solar capacity is also achievable with efficient implementation of the grid integration strategies. These include the selection of wind and solar generation sites based not only on resource quality but also on local demand, grid capacity, and increased system flexibility. A moderate increase of investment in the transmission grid to EUR 430 million annually can create a system that operates just as efficiently with limited redispatch and less than 1% of curtailment of solar and wind electricity.

Tripling installed capacity to 60 GW by 2026 would make solar and wind the largest source of electricity generation in Turkey with a total share of 31%.

Tripling installed capacity to 60 GW by 2026 would make solar and wind the largest source of electricity generation in Turkey with a total share of 31%. In this scenario, combined output from all types of renewables would represent half of Turkey's total electricity generation. A higher share of renewables would reduce the electricity provided by thermal generators. Assuming a market regime based on operational costs, plants using natural gas, lignite and imported coal would be most affected.

Without the use of grid integration strategies, achieving the Tripling scenario would require 30% more investment in transmission capacity and 20% more in transformer substations relative to the Base Case and the Doubling scenario. The annual required investment would thereby increase to EUR 530 million.[11]

The higher the share of wind and solar, the more rewarding this strategy is.

A wider distribution of solar and wind capacity across the country – based on local power demand and substation capacity as well as on wind speed and solar irradiation – produces remarkable benefits for integration (relocating approximately 50% of additional capacity). The higher the share of wind and solar, the more rewarding this strategy is. In the Tripling scenario, additional investment requirements in transmission capacity are two-thirds lower (2,750 km of extra lines as opposed to 8,300 km). Redispatch levels are lower as well – 6.6% instead of 7.8% – and the curtailment of wind and solar falls below 1% of total generation.

[11] This does not include grid connection costs, as these occur at different voltage levels and can be analysed properly only with a more detailed assessment of location and connection points at the distribution level. When comparing our scenarios, therefore, we decided to ignore the grid connections in, say, large REDA PV parks.

The strategy of balancing wind and solar geographically is economically appealing as well. Due to the widespread availability of high-yielding wind and solar locations in Turkey, the increase of levelized electricity costs for a portfolio of more distributed wind and solar generation is, at less than 5%, negligible. This creates attractive investment opportunities for wind and solar in all parts of Turkey, which will benefit these regions and positively impact transmission system expansion and operation.

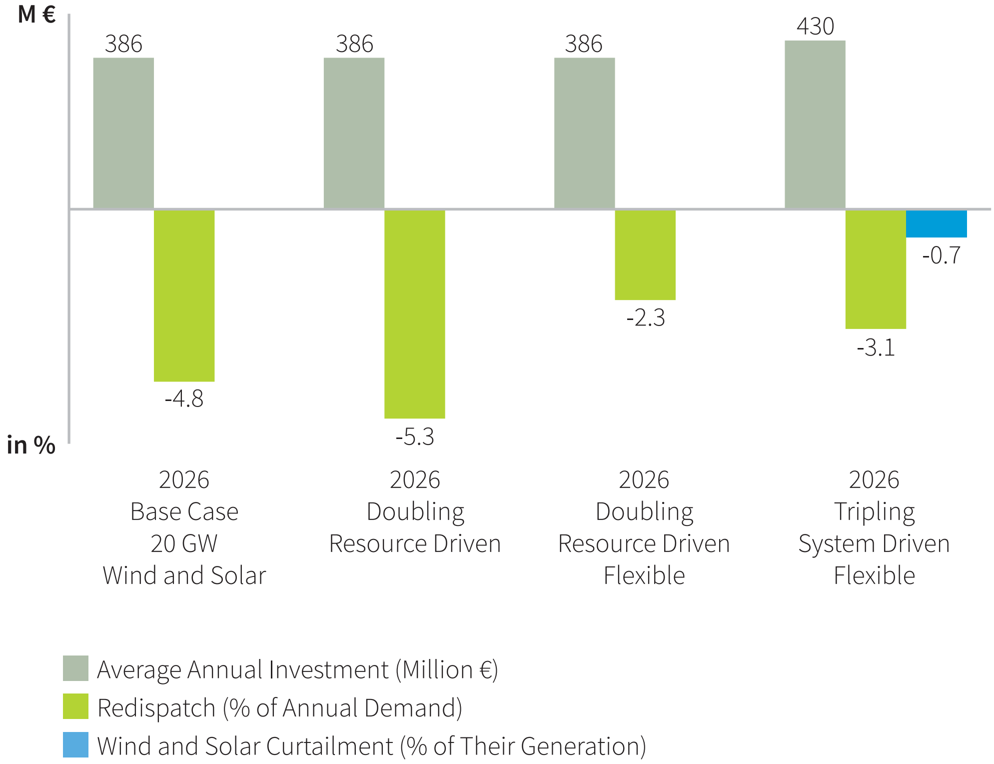


Figure 5. *Investment, redispatch and curtailment results for the main scenarios with integration strategies, 2026*

Introducing a portfolio of flexibility measures will further ease the challenge of integrating higher solar and wind shares. Flexibility can be offered by storage (2 GW pumped hydro and battery storage were modelled) and by more flexible thermal generation through modernized coal-fired plants and demand response mechanisms. In both doubling and tripling scenarios, redispatch levels would fall far below today's levels. The additional flexibility provided would have a positive albeit small effect on curtailment, with levels in the Tripling scenario well below 1% for both solar and wind.

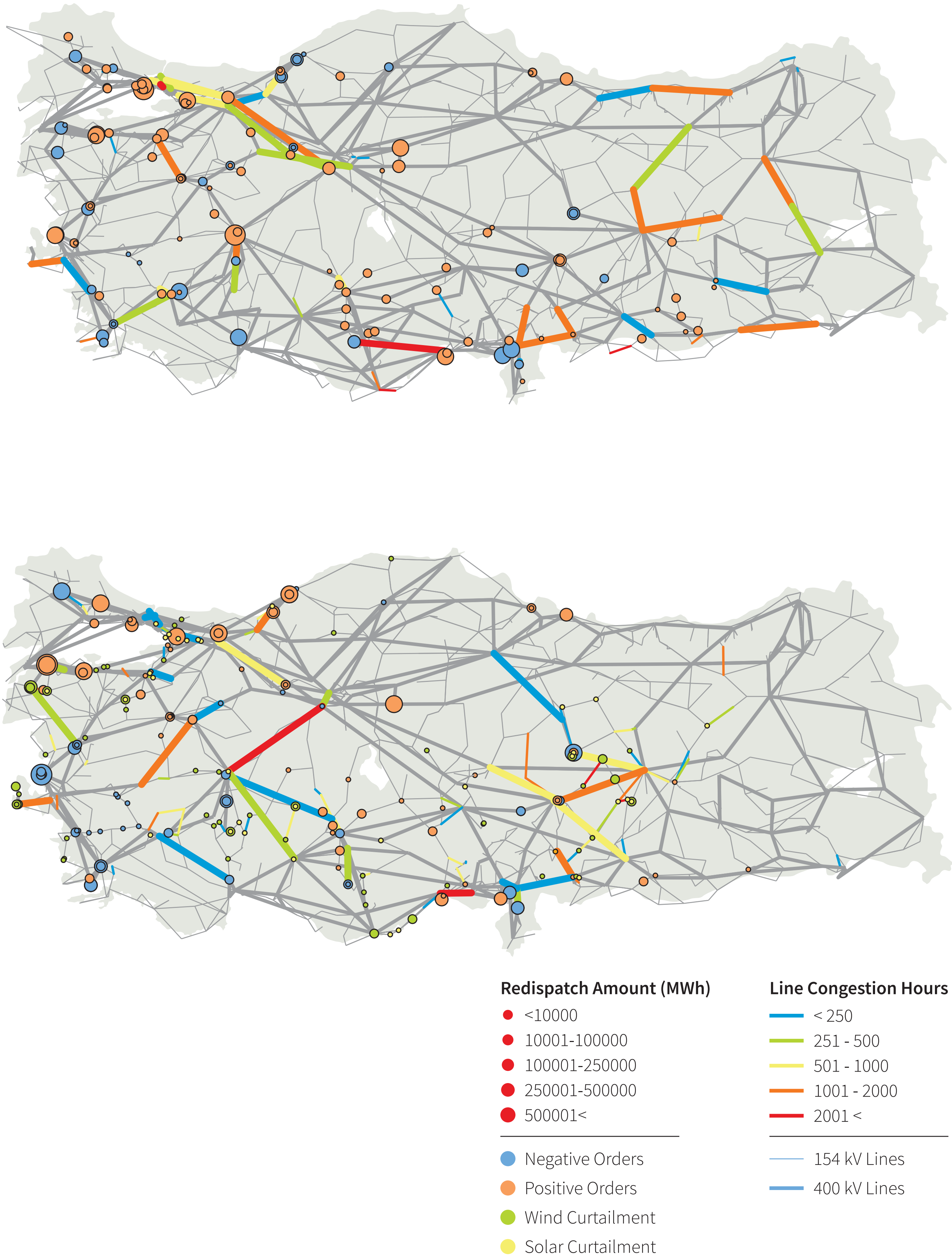


Figure 6. *Redispatch, congestion and curtailment map for the Base Case and Tripling with the system-driven and flexibility strategies, 2026*

This first-of-its-kind study highlights the priority areas for energy planners and system operators to achieve wind and solar integration in Turkey's power system. Its findings provide the starting point of a clean-energy roadmap that takes into account the perspectives of all impacted stakeholders.

This first-of-its-kind study highlights the priority areas for energy planners and system operators to achieve wind and solar integration in Turkey's power system.

This study shows that Turkey can generate 20% of its total electricity from wind and solar within less than a decade without any negative impact on transmission system and planning. Turkey, like many other countries across the globe, needs to prepare itself for a transition to a low-carbon energy system. Redefining how the electricity system is planned will be key. Data collection, transparency and management will gain momentum as demand and supply patterns change, variable resources like wind and solar spread and storage technologies are introduced. Planning is also crucial for system operators, who will have to rely on wind and solar generators' providing adequate information on power feed-in and system services.

Turkey can generate 20% of its total electricity from wind and solar within less than a decade without any negative impact on transmission system and planning.

Decoupling electricity demand from economic growth is of utmost importance because of its ability to limit power system costs. Yet as the system grows, additional generation will be required. Increasing the share of wind and solar will affect the need for flexible thermal power plants – something that system planners need to anticipate. Though many flexibility options are available, Turkey, if it is to minimize system costs, must aim at an optimal generation mix that takes into account technical capabilities, locational effects, environmental impact and associated expenses.

This study serves as a starting point for evidence-based planning to integrate wind and solar at a larger scale in Turkey's power systems.

Additional analysis will be required to undertake robust planning and to support policymakers as they set targets and introduce new regulations and incentive programs. Developing a national roadmap that prepares the power system for a higher share of renewable energy is an invaluable part of Turkey's future.

1. Introduction

Turkey has been one of the fastest-growing economies in the world since the beginning of the century. GDP growth rates between 6% (before the financial crisis in 2009) and 4.5% (since 2009) have increased electricity demand by 7% each year during the first decade of the new millennium, and by 4%–5% more recently.[12] By the end of 2017, demand and peak load neared 280 TWh and 44 GW, respectively.[13] As power demand has increased, the power sector has grown, fueled mainly by strong private investments in power generation and distribution. Generation capacity rose from 32 GW in 2002 to almost 80 GW in 2016. Turkey's power generation park is dominated by hydro and natural gas, followed by lignite and coal. By the end of 2016, Turkey had close to 6 GW of installed wind capacity, 800 megawatt (MW) of geothermal and 700 MW of PV.

According to its energy efficiency strategy, government of Turkey expects electricity demand to increase to 440 TWh by 2023. Domestic resources will play a key role in covering this growing demand and reducing trade deficits.

According to its energy efficiency strategy,[14] government of Turkey expects electricity demand to increase to 440 TWh by 2023. Domestic resources will play a key role in covering this growing demand and reducing trade deficits. Specifically, the government plans to expand capacity in lignite, nuclear, hydro, wind and solar power, while the contribution of imported resources hard coal and gas should be reduced.

The country's high levels of wind and solar irradiation, coupled with falling technology costs, have made wind and solar energy a clean and economic option.[15] Recent tenders for large-scale PV and wind installations resulted in offers well below existing feed-in tariffs, with winning bids coming in at USD 3.48 ct/kWh for wind and USD 6.9 ct/kWh for solar PV.[16] In 2017, auctions have seen PV projects being awarded contracts for USD 3–4 ct/kWh in India, South Africa and Dubai. These developments point to even greater future declines in Turkey's generation costs.

In 2015, Turkey's investment in renewable energy outpaced investment in fossil fuel generation for the first time. With further efficiency gains and cost decreases expected for wind and solar (15% and 25%, respectively[17]), this global development will continue, and investors are more determined than ever before to bring renewables capacity to Turkey's market.

Consequently, the question of how to integrate a growing share of variable renewables in the power system without diminishing supply security has become pressing.[18] Ireland, California, Denmark, Portugal, Germany and other countries have shown that it is possible to create reliable power systems with average annual variable renewable energy (VRE) shares between 20% and up to 50% provided that planning and operation of the power system are modified appropriately. As the technical fundamentals are the same for all power systems, Turkey stands to learn from their experiences.[19] On the other hand, each power system has specific conditions in terms

[12] Peak load is the maximum simultaneous total demand in the system.
[13] *TEİAŞ 2016 Sectoral Report:* https://teias.gov.tr/tr/yayinlar-raporlar/sektor-raporlari
[14] *Energy Efficiency Strategy Document 2012:* http://www.resmigazete.gov.tr/eskiler/2012/02/20120225-7.htm.
[15] *IRENA 2018, Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi*
[16] In capacity auctions for wind power connections, some investors offered to provide power below market prices. See Enerji IQ no. 90, 9 January 2018, p. 4
[17] *IEA 2017, Renewables 2017. Analysis and Forecasts to 2022, p. 5.*
[18] For the purpose of this report, we define variable renewable energy (VRE) as a renewable energy source that is non-dispatchable due to intermittent supply. We also place run-of-the-river hydro in VRE discussion. While its output may be more stable on a day-to-day basis than wind and solar, it does display significant seasonal variability in Turkey.
[19] See, for example: *DENA German Energy Agency "Integration of Renewable Energy Sources in the German Power Supply System from 2015 – 2020 with an Outlook to 2025"* https://shop.dena.de/fileadmin/denashop/media/Downloads_Dateien/

of geography, renewable resources, existing generation mix, grid infrastructure, demand patterns and market dynamics, which require their own in-depth analysis. The main reason for this study is to better understand what rising shares of renewables would mean for Turkey's particular power system.

1.1. Objectives and approach

The main objective of this study is to assess the consequences of increasing wind and solar power generation in the Turkey's power system beyond the levels planned by TEİAŞ's.

The main objective of this study is to assess the consequences of increasing wind and solar power generation in the Turkey's power system beyond the levels planned by TEİAŞ's. As a reference year, 2026 was chosen. This reflects the planning horizon of TEİAŞ's Ten Year Network Development Plan (TYNDP) 2016, which was the most recent one when the analysis was initiated. The assessment includes the effects on transmission grid investment and on transmission grid operation and what this would mean in terms of flexibility requirements. The study addresses the following questions:
- Is additional transmission grid investment necessary and, if so, where and how much?
- How does the placement of new wind and PV installations affect the power system?
- How will a greater share of renewables affect reserve requirements, redispatch of conventional power generation and renewables curtailment?
- What are the benefits of increasing flexibility in the Turkey's power system?

To these ends, the study models different scenarios for Turkey's electricity mix in 2026, which is in line with the typical planning horizon of the transmission system operator (TSO). These scenarios differ in the share and location of wind and solar PV generation across Turkey (Base Case: 20 GW, Doubling: 40 GW and Tripling: 60 GW of wind and solar combined). These scenarios were chosen without regard to probability or desirability. It was not the intention of this analysis to propose new targets; it is a "what if …" analysis based on distinct scenarios designed to assess and communicate different effects.

All other scenario parameters are the same:
- electricity demand,
- size of thermal and hydro generation park,
- transmission investment forecasts through 2026 (for the 400 kV grid) and through 2021 (for the 154 kV grid).[20]

The study scenarios are modeled by EPRA in sequential market and network simulations utilizing C++ algorithms developed by EPRA[21] and the IBM CPLEX. The methodology is currently being applied in Romania as part of the EU-funded SMARTRADE project.[22] The modeling is based on an hourly simulation of one entire year (8,760 hours) and a full representation of the complete 400 kV and 154 kV grid, as the 154 kV grid is part of the Turkey's transmission system.[23] It takes into account congestions and reserve violations and calculates redispatch and curtailment needs separately for each scenario. For ease of comparison, grid investments are kept at

esd/9106_Studie_dena-Netzstudie_II_englisch.pdf; the important work of the IEA, see: https://www.iea.org/topics/renewables/systemintegration/givar/; NREL (2010-2014), *Western Wind and Solar Integration Study; https://www.nrel.gov/grid/wwsis.html; IRENA (2015), Renewable Energy Integration in Power Grids Technology Brief.*

20 Additional investment in the 154 kV grid for the second 5-year period (2021–2026) was identified in the initial model run. See section 4.1.4.

21 The algorithm was developed entirely by EPRA and includes any type of market structure (PX market, LMP market, carbon market, capacity market, reserve market, curtailment and demand response) and/or incentive mechanism (incentives on renewables, local sources, etc.).

22 *A. Bara, S.V. Oprea, I. Simonca, O.B.Tör, "Conceptual design and architecture of an informatics solution for smart trading on wholesale energy market in Romania," Database Systems Journal, vol. VII, no. 4/2016.*

23 The study assumes all renewable energy is aggregated at 154kV substations and distribution network is excluded from the analysis.

the same level whenever feasible; additional investment is factored in for scenarios where security and reliability of the grid could otherwise not be maintained. Moreover, the study assesses strategies to facilitate the grid integration of wind and solar. It begins with an analysis of the benefits of adding wind and solar capacities from a system perspective rather than from a resource perspective.[24] Then it assesses the benefits of thermal and hydro flexibility, energy storage (batteries and pumped hydro), renewables curtailment and demand response.

The study, first of its kind in Turkey with regard to scope and detail, provides a thorough assessment of the implications of an increased share of variable renewables in the power system and its demand on the system operator and other power system stakeholders.

The study, first of its kind in Turkey with regard to scope and detail, provides a thorough assessment of the implications of an increased share of variable renewables in the power system and its demand on the system operator and other power system stakeholders. The study aims at identifying challenges and testing potential solutions for a resilient transmission grid and setting adequate incentives for improving the flexibility of the system. It is not our objective to identify a detailed transmission plan, but rather to determine order of magnitude and areas for grid extension in different future scenarios. The analysis does not look to identify a cost optimal overall system (weighing generation, storage, demand side and grid investment against each other); it does not take the perspective of a single investor interested in the business case of a particular generation (or storage) investment; and it does not consider market design or capacity mechanisms. Finally, the impact on the distribution system is not taken into account. However, it is expected that the overall results of the study would still be valid if the distribution system was included in the analysis.[25]

This report serves both the local and international audience. For Turkey, the findings are relevant for all power system stakeholders, including the system operators, energy planners, investors of both renewable and non-renewable energy technologies and technology licensors. The report outcomes are especially relevant for the transmission system operator as they show the potential challenges and where more action would be required as Turkey transforms its power system to higher shares of renewable energy sources. Given the rapidly evolving markets towards more wind and solar capacity, the outcomes are also equally important for energy planners as they indicate that early action is needed for long-term planning of this coming change. For the international audience, the study is unique since for Turkey so far no such study has been carried out. This is different compared to other countries of the OECD, G20 and ENTSO-E, of which Turkey is part of. In this sense, the findings fill an important knowledge gap. They show that the Turkish system can integrate more than 20% of its total electricity generation from wind and solar. When this is achieved, Turkey, can serve as an important international good practice case for other middle-income countries to learn from.

The study was carried out by EPRA Elektrik Enerji (EPRA),[26] and supported jointly by Agora Energiewende[27] and the Institute of Power Systems and Power Economics of RWTH Aachen.[28] The study has benefitted greatly from the valuable input of various stakeholders at workshops and bilateral discussions. Stakeholders include the transmission operator TEİAŞ, Turkey's Energy Market Regulatory Authority (EMRA), experts from Turkey's Ministry of Energy and Natural Resources (MENR) academia, and electricity companies. Their input has helped shaped the methodology, input assumptions, scenarios, and conclusions.

[24] The details of system and resource driven renewable energy capacity placement is explained in detail in Annex 3.
[25] For general considerations on the relationship between wind and solar investment, transmission grid and distribution network see the box in section 5.2.1.
[26] *EPRA: http://www.epra.com.tr/home*
[27] *AGORA Energiewende: https://www.agora-energiewende.de/en*
[28] *IAEW: http://www.iaew.rwth-aachen.de/*

1.2. Structure of the report

An overview of Turkey's power system is presented in Section 2. It includes the power generation park, demand and its planned evolution, market structure and organization, the status of the high voltage electricity grid, policy drivers and an outlook through 2026. In Section 3, the scenarios are introduced and the methodology used for performing the simulations is presented. The scenarios focus on a variation of the installed capacity of wind and solar generation stations, their locations across Turkey and their flexibility options. Input parameters and key assumptions common to all scenarios are described and explained in detail. Conclusions and key findings are described and discussed in Section 4. Section 5, focuses on ways to facilitate the integration of variable renewables. Two main elements are addressed: the impact of distributing new wind and solar plants in a more system-friendly manner and the impact of increasing flexibility in the power system as a whole. Several options that would be feasible in Turkey are tested and assessed, including the impact of increasing the flexibility of thermal and hydropower plants to that comparable with European power systems, and the introduction of small-scale battery and large-scale pumped storage. Section 6 presents conclusions on the feasibility of the efficient integration of a larger share of wind and solar in Turkey's power system, related costs and recommendations for adjustments in the regulatory framework, planning and operation.

2. Turkey's Power System

This section presents a brief overview of Turkey's power system relevant for the study. It provides key data on generation and transmission infrastructure and on the operation of the Turkey's power system. A more detailed assessment of system, operation and regulation can be found in Annex 1.

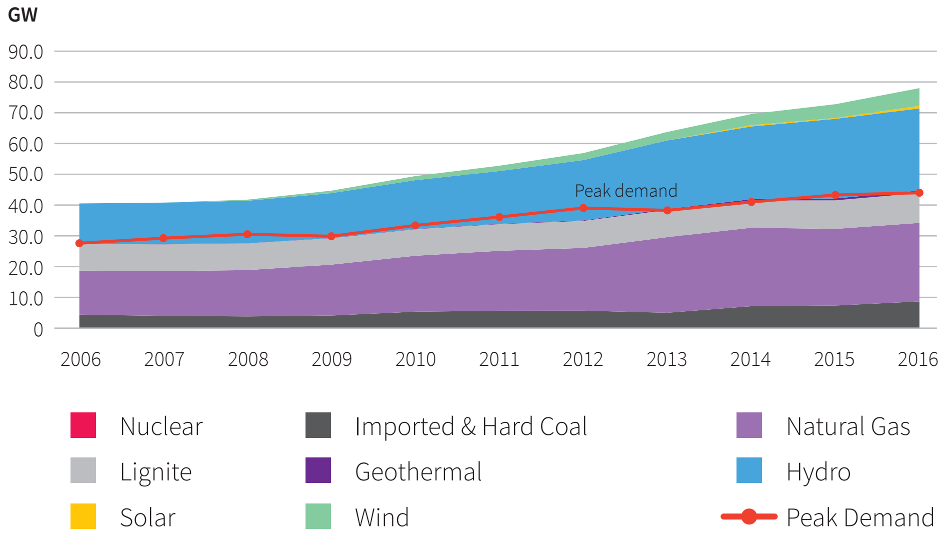
2.1. Electricity demand and power generation

Decoupling demand growth from economic growth will be a key challenge, and can help contain cost for residential and industrial consumers, increasing Turkey's competitiveness globally.

Gross electricity consumption in Turkey increased from 175 TWh in 2006 to 278 TWh in 2016. Peak load,[29] which was 27.5 GW in 2006, rose to just shy of 44 GW by the end of 2016.[10] While the exact level of growth in the coming decade is the subject of some debate, there is broad consensus that demand growth will continue. Decoupling demand growth from economic growth will be a key challenge, and can help contain cost for residential and industrial consumers, increasing Turkey's competitiveness globally. In Turkey, electricity demand peaks in the summer. As electricity is still widely used for heating in winter, the winter peak is only about 5% lower than the summer peak. Demand is more and more centralized in urban areas in the mid-western and western part of the country, and this trend is likely to continue.[30]

Generation capacity outpaced demand growth, increasing from 32 GW in 2002 to 77.8 GW at the end of 2016.[31] As most of the growth in the past decade was due to investment in large hydro and gas-fired power plants, Turkey's power generation park is dominated by hydro (26.7 GW) and natural gas (25.5 GW) plants, followed by lignite (9.3 GW) and hard coal (8.5 GW). All lignite and 1 GW of hard-coal fired power plants are fueled by local resources, while most hard-coal power plants operate on imported fuel (7.5 GW). When it comes to output, thermal generation features more prominently due to higher full load hours, especially in coal and lignite plants. The generation mix in 2016 was dominated by natural gas power plants (33%) and lignite and coal (31%). Hydro contributed 25% to overall supply.[32] The power generation sources are illustrated in Figure 7.[33]

[29] Peak load is the maximum of total simultaneous network demand in an hour.
[30] As no reliable forecast data is available on how demand may further change over geography and time, 2016 data was used for modeling.
[31] TEİAŞ 2016 Sectoral Report: https://teias.gov.tr/tr/yayinlar-raporlar/sektor-raporlari; 2017 figures show further growth. See http://www.emo.org.tr/genel/bizden_detay.php?kod=88369. We use 2016 figures here as these were the starting point of the analysis initiated in early 2017 for 2016 to 2026.
[32] https://www.teias.gov.tr/tr/elektrik-istatistikleri
[33] It should be noted that capacity factors for hydro generation vary considerably year by year as seen in Figure 74, due to diverging precipitation levels (snow and rainfall). In); this regard, 2016 can be considered an average year.



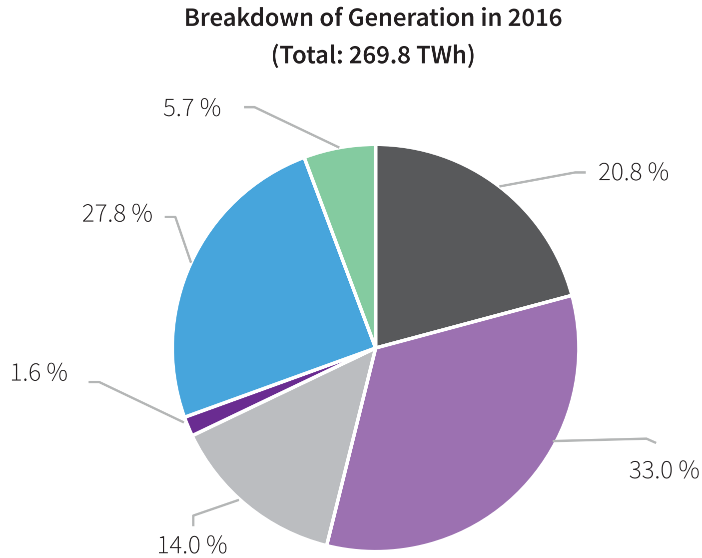


Figure 7. *Breakdown of total installed capacity (top) and electricity generation (bottom) by source (2016)*[10]

Turkey has excellent **solar, wind and hydro resources**, as can be seen in the wind atlas Rüzgâr Enerjisi Teknik Potansiyelleri Atlası (REPA), published by the MENR in 2016 (see Figure 64 in the Annex 1). While there is considerable variation of wind resources across the country, wind speeds above 7 meters per second (m/s) (at $80m_{AGL}$) can be found in almost all regions of Turkey. Particularly attractive wind conditions are present in the Aegean, Marmara, and the East Mediterranean regions.[34] These are also the areas where most wind power projects have been realized or planned.

Installed capacity of wind power increased from less than 1 GW in 2009 to almost 6 GW by the end of 2016.[35] In 2016, for the first time, annual new installations rose well above 1 GW.[36] Further, EMRA started a pre-application process for 3,000 MW of GW of installed capacity in 2015; total applications approached almost 40 GW.[37] This also indicates serious investor interest in renewable energy.

[34] *YEGM Rüzgâr Enerjisi Teknik Potansiyelleri Atlası REPA: http://www.eie.gov.tr/YEKrepa/REPA-duyuru_01.html.*
[35] *https://www.teias.gov.tr/tr/yayinlar-raporlar/sektor-raporlari*
[36] In July 2017, 808 MW of wind power plants were under construction, and another 2900 had been licensed. See *Turkish Wind Energy Association 2017, Wind Energy Statistics Report (http://www.tureb.com.tr/files/tureb_sayfa/duyurular/2017_duyurular/agustos/turkiye_ruzgar_enerjisi_istatistik_rapor_temmuz_2017.pdf)*
[37] *EMRA, electricity market pre-licenses applications, available at: http://lisans.EMRA.org.tr/epvys-web/faces/pages/lisans/elektrikUretimOnLisans/elektrikUretimOnLisansOzetSorgula.xhtml?lisansDurumu=7*

A look at a **solar** resource map of Turkey (see Figure 66 in the annex) demonstrates the attractive solar conditions across the country. Even in the North, in the Istanbul and Black sea areas, solar irradiation is consistently above 1,400 kWh/m^2/year. In the South, these values can reach 2,000 kWh/m^2/year, with particularly attractive areas in the Mediterranean and in South and Southeast Anatolia.

Despite the attractive conditions and considerable investor interest, very few PV installations had been implemented in Turkey until very recently. Total installed capacity of PV was only about 300 MW by the end of 2015; more than 650 MW were installed in 2016, followed by 1.8 GW of additional capacity in 2017.[38]

The **electricity market** is based on a power exchange (PX) market operated by Energy Exchange Istanbul (EXIST). The main function of this market is to identify the most economically efficient dispatch of available power generation. Final commitment and dispatch of power plants are determined by the national dispatch center (NDC) of Turkey's TSO TEİAŞ in day-ahead and intra-day balancing markets, ensuring N-1-secure system operation[39] and the availability of sufficient amounts of spinning reserves.[40]

2.2. Main characteristics of Turkey's electricity transmission system

The transmission grid is the backbone of the power system, connecting the country's regions and enabling long-distance power transport to the main demand centers in the West.

The transmission grid is the backbone of the power system, connecting the country's regions and enabling long-distance power transport to the main demand centers in the West. Turkey's transmission grid consists of both 400 kV and 154 kV systems[41]. Hence, both systems are analyzed in this study. The state-owned TEİAŞ is the sole owner of transmission assets in Turkey and is responsible for new investments in the transmission infrastructure as well as system operation. Since it is a monopoly, the company is regulated by EMRA using a cost-based revenue cap approach.[42]

Figure 8. *Map of high voltage transmission network, interconnections, thermal and hydropower plants (source: TEİAŞ)*

The electric power system of Turkey has been synchronized with ENTSO-E via 400 kV transmission lines in Bulgaria (two lines) and Greece (one line) since September 2010. The N-1 secure thermal capacity of the lines are above 1,500 MW, though at present transition is limited to 550/450 MW (import/export) due to inter-area oscillation

[38] *http://www.emo.org.tr/genel/bizden_detay.php?kod=88369*
[39] General system operation must be guaranteed in the event of technological failure.
[40] See *ENTSO-E Network Code on Load Frequency Control and Reserves (LFCR): https://www.entsoe.eu/major-projects/network-code-development/load-frequency-control-reserves/Pages/default.aspx*
[41] *TEİAŞ 2016: http://www.teias.gov.tr*
[42] *EMRA Lisans Yönetmeliği: http://www.EMRA.org.tr/TR/DokumanDetay/Elektrik/Mevzuat/Yonetmelikler/Lisans*

phenomena and limitations in the Bulgarian network.[43] The main advantages of the interconnection with the ENTSO-E system include frequency stability and sharing of spinning reserves among ENTSO-E countries. To the East, power exchange occurs only with Georgia, via a controllable, high-voltage direct current (HVDC) link.

2.3. Outlook through 2026

Several trends that have shaped the power sector in the past decade are expected to continue, and additional drivers are becoming apparent. Demand on Turkey's electricity market will continue to grow as industrialization and urbanization expand.

Several trends that have shaped the power sector in the past decade are expected to continue, and additional drivers are becoming apparent.

Demand on Turkey's electricity market will continue to grow as industrialization and urbanization expand. Official figures expect growth between 4 % and 5.5 %.[44]

According to the Ministry of Energy and Natural Resources, the total amount of investment required to meet the energy demand in Turkey by 2023 is estimated to be around USD 110 billion,[45] more than double the total amount invested in the last decade. The private sector will continue to play a key role in creating new power generation, modernizing the distribution system. Public attitudes will play a role as well, especially when it comes to adding large hydroelectric dams and attracting new investment in nuclear, lignite and renewable energy power stations.

The goal of diversifying the power mix while prioritizing domestic production puts a special emphasis on local resources. These include both fossils (predominantly lignite) and renewables (solar, wind, geothermal and any remaining potential from hydro). The increase of renewable energy capacity is a key element of the government strategy for the long-term adequacy of electricity supply.

The past focus on gas and hydro technologies stands to experience a major shift. The potential for additional large hydro plants is decreasing, and increasing gas imports may disrupt the trade balance, raise import dependence and create competition with non-power sectors fuels.[46] The goal of diversifying the power mix while prioritizing domestic production puts a special emphasis on local resources. These include both fossils (predominantly lignite) and renewables (solar, wind, geothermal and any remaining potential from hydro). The increase of renewable energy capacity is a key element of the government strategy for the long-term adequacy of electricity supply.[141] Further drivers are the benefits of renewables for air quality, climate change mitigation and socio-economics (e.g. new jobs).

In its "2023 vision", Turkey's government has set several targets for renewables: 34 GW of hydro, 20 GW of wind and 5 GW of solar. The falling technology costs will increasingly drive the construction of more wind and solar PV installations. Globally, more generation capacity has been added since 2015 in renewable energy technology than in fossil fuel capacity. With further efficiency gains and cost decreases expected for wind and solar (10% and 25%, according to the IEA),[47] this global trend will likely continue, as will strong interest from investors in bringing renewables capacity to the Turkey's market. REDA (Renewable Energy Designated Area) tenders have demonstrated that there is great potential to reduce the cost of solar and wind generation in Turkey. This will make these technologies more economically interesting for consumers in Turkey.

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[43] *O B Tör, C Gençoğlu, Ö Tanıdır, M E Cebeci, N Güven, "Investigation of Necessary Transmission Enforcements at the Balkan Region of ENTSO/E in the Sense of Inter-area Oscillations after Interconnection of Turkey," ELECO 2011, 7th International Conference on Electrical and Electronics Engineering, 1–4 December 2011, Bursa, Turkey, pp. 7–12.*

[44] *Energy Efficiency Strategy Document 2012: http://www.resmigazete.gov.tr/eskiler/2012/02/20120225-7.htm; ENTSO-E Mid-term Adequacy Forecast 2016 Edition: https://www.entsoe.eu/Documents/SDC%20documents /MAF/MAF_2016_FINAL_REPORT.pdf; TEİAŞ 2016 Sectoral Report: https://teias.gov.tr/tr/yayinlar-raporlar/sektor-raporlari.*

[45] *Republic of Turkey Prime Ministry Investment Support and Promotion Agency, Invest in Tukey http://www.invest.gov.tr/en-US/sectors/Pages/Energy.aspx*

[46] Turkey has limited natural gas resources and must rely on imports from neighboring countries (almost 99%). Especially in the winter, some of the natural power plants cannot operate due to natural gas shortages, making generation levels unsteady.

[47] *IEA 2017, Renewables 2017. Analysis and Forecasts to 2022, p. 5.; also see IRENA 2018, Renewable Power Generation Costs in 2017.*

Table 1. Official power sector projections / Base Case assumptions

<table>
<tr><th></th><th>2016[48]</th><th>Government Targets 2023[*]</th><th>ENTSO-E MAF (2025)[**]</th><th>Base Case 2026</th></tr>
<tr><td>Peak Demand</td><td>44 GW</td><td>N/A</td><td>N/A</td><td>69.2 GW</td></tr>
<tr><td>Consumption</td><td>278 TWh</td><td>440 TWh</td><td>458 TWh</td><td>439 TWh</td></tr>
<tr><td>Annual Demand Growth</td><td>-</td><td>7.3%</td><td>5.7%</td><td>5.1%</td></tr>
<tr><td>Imported Coal</td><td>7.5 GW</td><td rowspan="3">30.0 GW</td><td rowspan="2">8.2 GW</td><td>10.2 GW</td></tr>
<tr><td>Hard Coal</td><td>0.6 GW</td><td>0.6 GW</td></tr>
<tr><td>Lignite</td><td>9.3 GW</td><td>10.8 GW</td><td>13.3 GW</td></tr>
<tr><td>Natural Gas</td><td>25.5 GW</td><td>N/A</td><td>27.8 GW</td><td>28.1 GW</td></tr>
<tr><td>Nuclear</td><td>0.0 GW</td><td>9.3 GW</td><td>3.6 GW</td><td>6.8 GW</td></tr>
<tr><td>Wind</td><td>5.8 GW</td><td>20.0 GW</td><td>14.2 GW</td><td>14.0 GW</td></tr>
<tr><td>Hydro</td><td>26.7 GW</td><td>34.0 GW</td><td>36.8 GW</td><td>37.5 GW</td></tr>
<tr><td>Solar PV</td><td>0.6 GW</td><td>5.0 GW</td><td>6.0 GW</td><td>6.0 GW</td></tr>
<tr><td>Geothermal</td><td>0.8 GW</td><td>N/A</td><td>N/A</td><td>1.45 GW</td></tr>
<tr><td>Others</td><td>1.7 GW</td><td>5.0 GW</td><td>6.0 GW</td><td>1.7 GW</td></tr>
<tr><td>Total Installed Capacity</td><td>78.4 GW</td><td>N/A</td><td>107 GW</td><td>119.6 GW</td></tr>
</table>

N/A: Not available

**TEİAŞ Türkiye Elektrik Piyasası: https://teias.gov.tr/tr/yayinlar-raporlar/piyasa-raporlari*
***TEİAŞ 2016: http://www.teias.gov.tr*

[48] *TEİAŞ Load dispatcher information system: https://ytbs.teias.gov.tr/ytbs/frm_login.jsf*

3. Scenarios and Strategies

In this analysis, we developed three scenarios that project different levels of wind and solar uptake by the year 2026.

3.1. Levels of wind and solar deployment

As explained above, the focus of our analysis is to assess the effects of different shares of wind and solar generation on transmission grid infrastructure and operation. For this purpose, we developed three scenarios that project different levels of wind and solar uptake by the year 2026:

1. Base Case (20 GW wind and solar)
2. Doubling (40 GW wind and solar)
3. Tripling (60 GW wind and solar)

The Base Case follows the current planning assumptions by TEİAŞ for its transmission investment for the target year 2026: total installed capacities of 14 GW for wind and 6 GW for solar PV.[49]

The alternative scenarios assume an accelerated uptake of wind and solar: combined capacity of wind and solar is doubled to 40 GW and tripled to 60 GW. Given the excellent solar potential in Turkey and rapid cost decline in solar PV, we have assumed equal shares of solar PV and wind for these two scenarios.

As past attempts have shown, it is very hard to predict the future growth of renewables. The scenarios were therefore not selected to reflect probability. Instead, we chose scenarios that differ considerably among each other so as to broaden the impact spectrum without bounding the analysis to unforeseeable policy choices. In making these decisions, we consulted extensively with stakeholders.

3.2. Strategies for renewable energy grid integration: wind and solar distribution, system flexibility

Starting from these three scenarios, we have defined two main renewable energy grid integration strategies. They address the question of how to facilitate system integration, i.e. which measures would reduce the need for additional transmission investment or redispatch.

First, we assessed the effect of locational choices. What if, instead of focusing on the best sites in terms of wind speed and solar irradiation, system effects were taken into consideration, so that solar and wind investment were more evenly distributed across the country, taking into account local electricity needs and substation capacity? To this end, we modelled a *system-driven allocation* of new wind and solar plants for the Doubling and Tripling scenarios.[50]

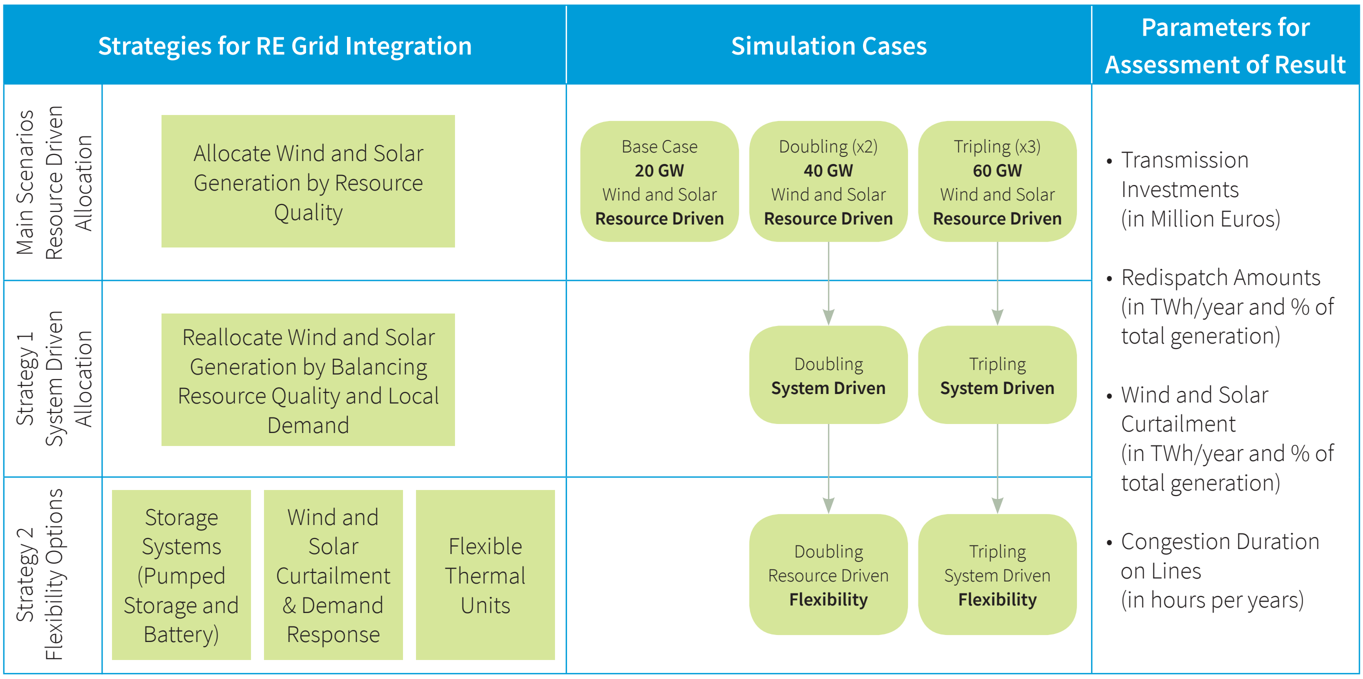
In a second step, we assessed the impact of increased system flexibility. As the share of variable renewables grows, system, flexibility becomes more relevant. The variability and uncertainty of renewable energy feed-in requires adequate spinning reserves, balancing capacity, faster ramp rates, the ability of thermal power plants to reduce operation to lower levels and rapid demand response. Several options that provide this flexibility have been identified and developed in power systems globally. In our study, we modeled the most viable options for making Turkey's system more flexible and reducing infrastructure strain:

- More flexible thermal power plants (in terms of ramping and minimum load)[51]

[49] The data was discussed at a stakeholder meeting. TEİAŞ later confirmed the numbers.
[50] See Annex 3 for details
[51] Technical details and modelling assumptions for technical restrictions of thermal plants are described in Section 3.6.2.1.

- Investment in a 1,400 MW (4x350 MW) pumped storage power plant near Gökçekaya power plant. Secondary frequency control reserve is assumed to be +/-100 MW for each unit;
- Investment in 600 MW of distributed batteries.[52] +/-300 MW from batteries is reserved for secondary frequency control. These storage services could be provided by, say, a combination of clustered electrical vehicles or various low voltage storage systems in addition to medium voltage level systems operated by the distribution system operators (DSOs) or devices directly connected to the high voltage grid;
- The ability to reduce demand by up to 5% at any given hour.

Figure 9 provides an overview of the scenarios and renewable energy grid integration strategies that were considered.



** Since there were only minor differences between results of system and resource driven assessment for scenario, the choice was made to assess based on resource driven allocation.*

Figure 9. *Scenario approach used in the study*

3.3. Market and network simulations

In this study, we identify needed transmission network investment and estimate annual redispatch levels. For this, we performed a series of market and network simulations for each scenario (Figure 10).

First, the market simulation provided optimum hourly dispatch for every single power plant in the 2026 target year (**step 1**). Next, we carried out a load flow analysis to identify congestion in the network (**step 2**). We then identified transmission line and substation investment beyond TEİAŞ planning that make economic sense for reducing redispatch levels (**step 3**); as a result of the initial network simulation (**step 4**); or due to network security (to be able to resolve all n-1 cases) and reliability constraints (supplying a sufficient amount of frequency control through spinning reserve at all times) (**step 5**). All these venues for investments are included in the grid model. New conventional power plants, which have very low utilization factors in some scenarios, do not figure in the model (**step 6**). We use the resulting grid model to perform final market and network simulations (**step 7** and **step 8**, respectively) that calculate annual transmission investment, redispatch and curtailment for each scenario.

[52] Technical details and modelling assumptions for storage are described in Section 3.6.2.2.

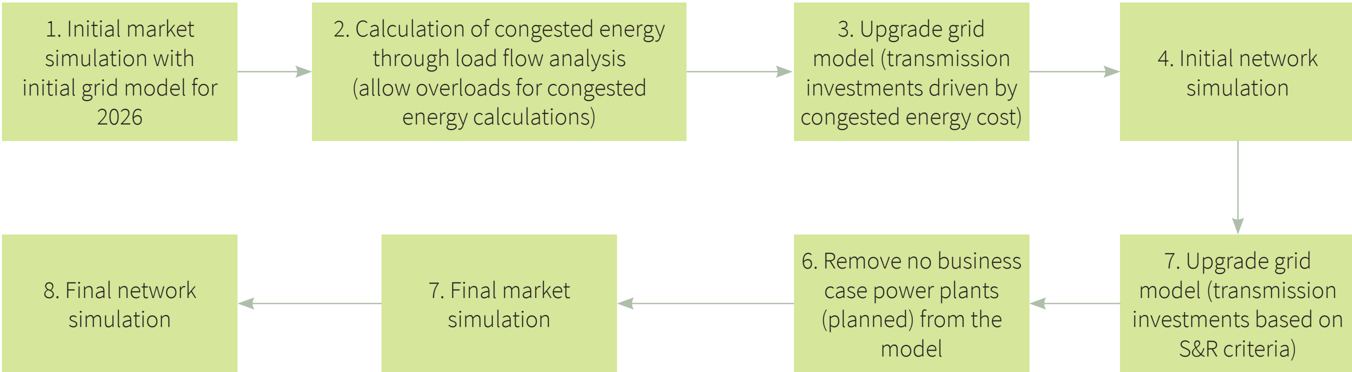


Figure 10. *Methodology flowchart*

In modelling realistic power plant dispatch, we identified a merit order for the study based on the short-run marginal cost (SRMC) of the power plants. To determine the relative SRMC[53] of the modeled Turkey's power generation park, we took into account the primary energy source, capacity, and age of each plant.[54] The details of our methodology and mathematical functions can be found in Annex 2.

3.4. Transmission grid model for 2026

TSO planning served as the baseline to ensure practical relevance for TEİAŞ and the other stakeholders. All scenarios contain the key parameters of TEİAŞ's TYNDP for 2026.[55] In that plan, which was released in 2016, TEİAŞ uses different approaches for the 400 kV and 154 kV infrastructures:

- ten-year investment plans (2016–2026) for the 400 kV system
- five-year investment plans (2016–2021) for the 154 kV system

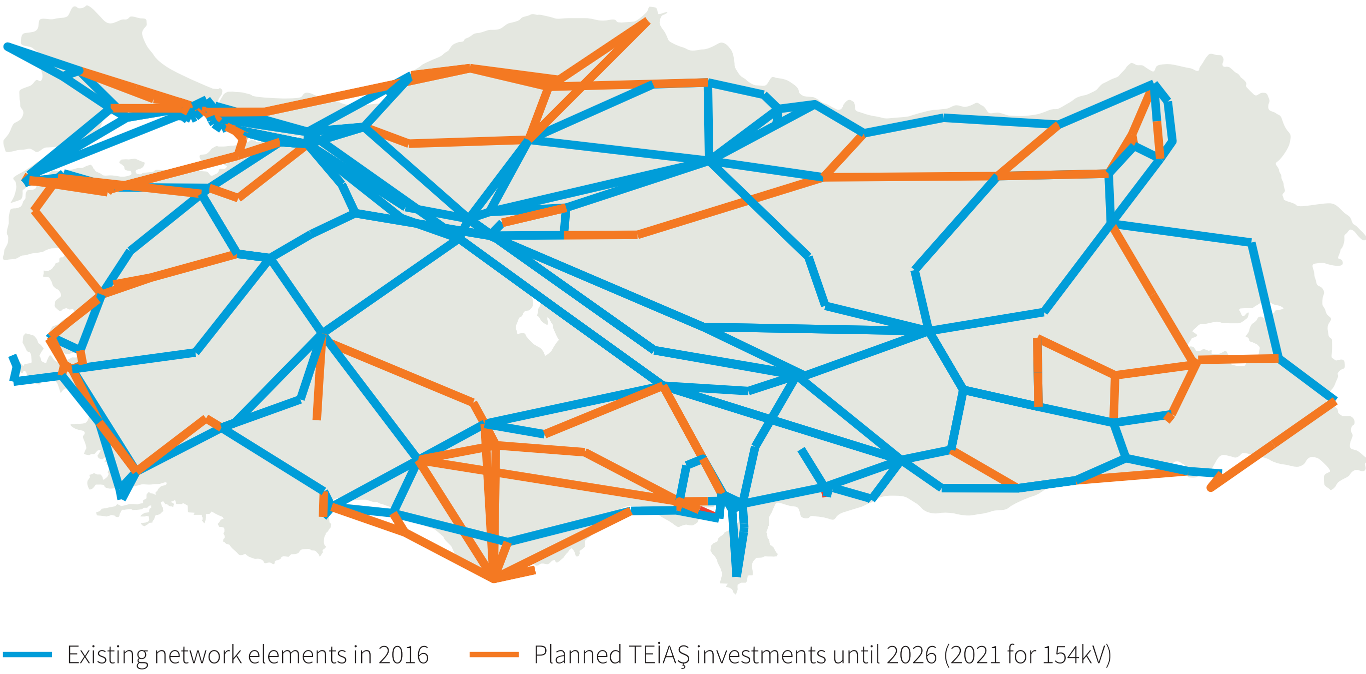
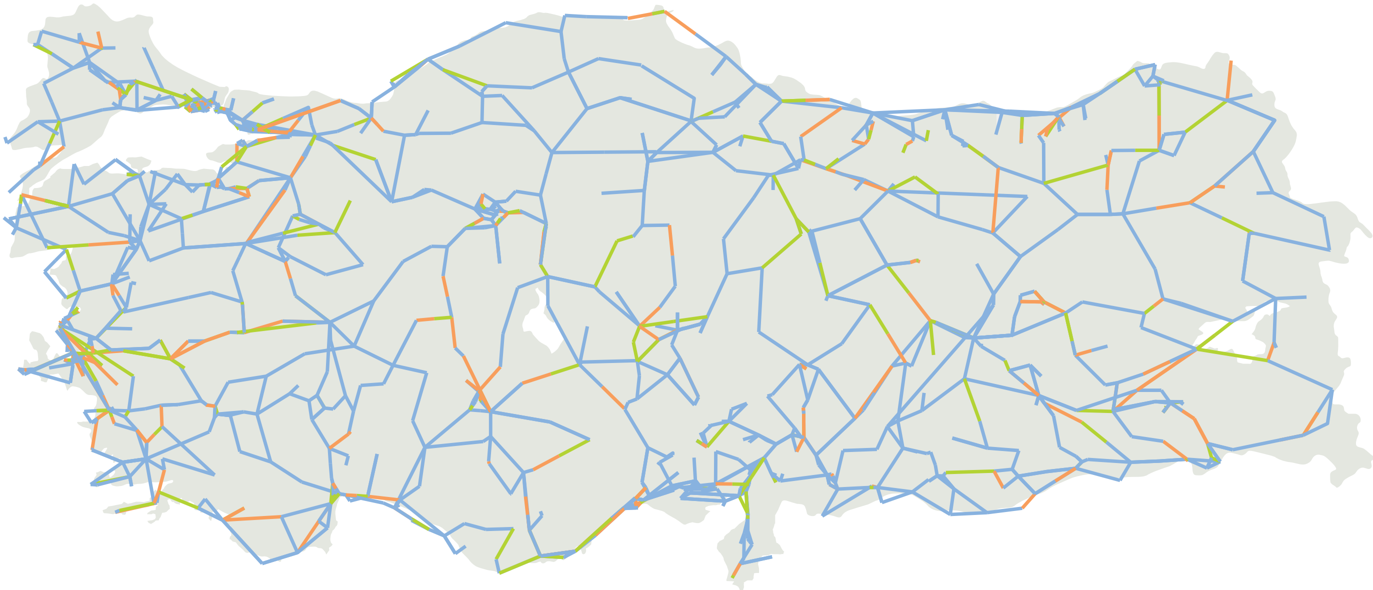


Figure 11. *400 kV network model for 2026 (TEİAŞ model includes grid investments at the 400 kV level)*

[53] *SRMC refers to the change in short-run total cost for a very small change in output. Hence, SRMC includes the variable costs of the power plants without the fixed costs.*
[54] *For this purpose, the relative cost of the power plant suffices.*
[55] *The TEİAŞ investment plan can be found here: https://www.teias.gov.tr/tr/yatirim-programlari .*



Existing network elements in 2016
Planned TEİAŞ investments until 2026 (2021 for 154kV)
Additional investments for Base Case Scenario (economically driven or security/reliability driven)

Figure 12. *154 kV network model for 2026 (TEİAŞ model, includes limited investments at the 154 kV level)*

As investment for the 154 kV part of the grid is not planned yet for the period 2021–2026, we developed a first-run reference transmission model for the purpose of this analysis. This model provides sufficient transmission infrastructure for the Base Case for n-1 secure operation and a limited amount of redispatch. We then identify potential network investment for network security and reliability in each scenario.

Simulations for the doubling and tripling scenarios are based on ten REDA zones with GW-scale solar capacity. "System-driven allocation" (strategy 1) only considers the Karapınar REDA zone as in service. Hence, the total length of the transmission network differs for regular scenarios and for this strategy, as can be seen in Table 2.[56]

Table 2. *Existing and planned network size and reference topology for different cases*

Grid	2016 grid	2026 TEİAŞ TYNDP	Resource-driven allocation	System-driven allocation
Number of Items			Reference model	Reference model
400 kV substations	166	223	233	223
154 kV substations	1,072	1,220	1,220	1,220
Line km				
400 kV branches	21,029	29,286	31,713	29,940
154 kV branches	38,682	44,502	44,502	44,502

[56] The model is based on TEİAŞ's current grid map and investment plan, the latter of which is available at www.teias.gov.tr. The model was approved at a stakeholders' meeting.

3.5. Time series generation for variable renewables and geographic distribution

This subsection presents the assumptions for the time series generation and capacity distribution of wind, solar PV and run-of- river hydropower.

3.5.1. Wind power plants

The hourly generation profile of individual wind power plants is based on a national database[57] that uses satellite data from the European Centre for Medium-Range Weather Forecasts (ECMWF).[58] Calculations were calibrated using available hourly measurements of operational plants in the vicinity. In determining suitable locations for future wind parks, we took into account limitations caused by altitude, terrain and land-use restrictions (settlements, nature preserves, etc.).[59] Figure 13 shows available resources identified by the calculation. These resources correspond to the wind project locations submitted for licensing to EMRA.[60]

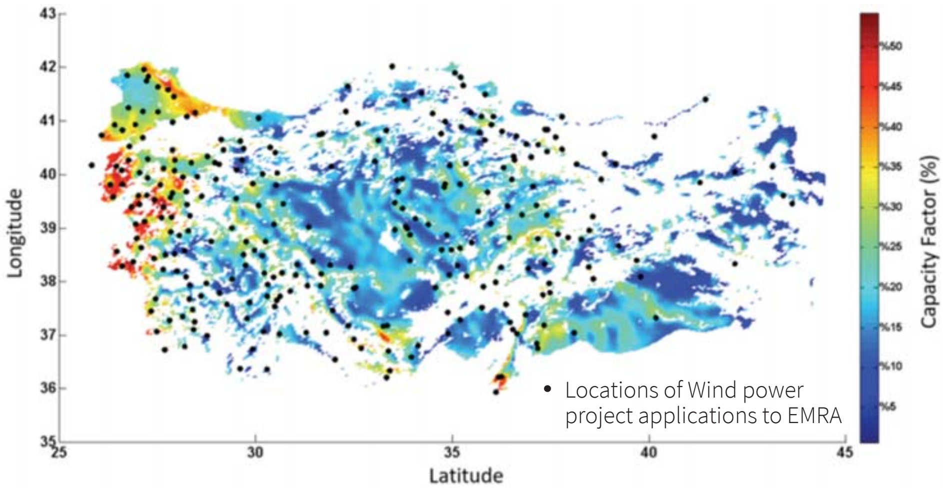


Figure 13. *Locations of the wind power plant license applications to EMRA (source of application points: EMRA)*

The selection of new wind power plants for this study is based on the resource quality of the locations. In the “resource-driven” strategy, preference is given to most attractive sites, which results in wind power plants concentrated at fewer locations; in the “system-driven strategy, wind power plant investment is distributed more to relax network congestions.[61] Finally, for modelling purposes, defined wind power plants are aggregated at the nearest transmission substation location.

3.5.2. Solar PV power plants

Like wind power, solar PV is another variable source in the network and modelled with a predefined hourly generation curve. Capacity factors are based on a substation level, utilizing the NASA MERRA[62,63] and CM-SAF’s SARAH datasets.[64,65,66]

[57] *Hale Çetinay, “Determination of Wind Power Potential and Optimal Wind Power Plant Locations in Turkey,” Master Thesis, Middle East Technical University, May 2014.*
[58] *European Centre for Medium-Range Weather Forecasts, “ECMWF,” [Online]. Available: http://www.ecmwf.int/ (Accessed 21 03 2014).*
[59] See Annex 3.
[60] *EMRA License Applications 2017; See: http://lisans.EMRA.org.tr/epvys-web/faces/pages/lisans/elektrikUretimOnLisans/elektrikUretimOnLisansOzetSorgula.xhtml*
[61] Details of the calculation are given in Annex 3
[62] *Rienecker MM, Suarez MJ, Gelaro R, Todling R, et al. (2011). “MERRA: NASA’s Modern-Era Retrospective Analysis for Research and Applications. Journal of Climate,”, 24(14): 3624-3648*
[63] *National Aeronautics and Space Administration (NASA), “https://disc.sci.gsfc.nasa.gov/datasets?page=1&keywords=MERA-2”*
[64] *Müller, R., Pfeifroth, U., Träger-Chatterjee, C., Trentmann, J., Cremer, R. (2015). Digging the METEOSAT Treasure—3 Decades of Solar Surface Radiation. Remote Sensing 7, 8067–8101*
[65] *EUMETSAT CM-SAF, “http://www.cmsaf.eu/EN/Home/home_node.html”*
[66] *Surface Solar Radiation Data Set (SARAH dataset), https://climatedataguide.ucar.edu/climate-data/surface-solar-radiation-data-set-heliosat-sarah-edition-1*

A number of exclusion criteria were used to select possible sites. Sites at altitudes higher than 2,000 m, very rugged terrain[67] and land-use restrictions (except settled areas, where roof-top applications can be used) were excluded. Solar irradiance data was converted into power output using the GSEE model[68] (Global Solar Energy Estimator). The results are given in Figure 14.

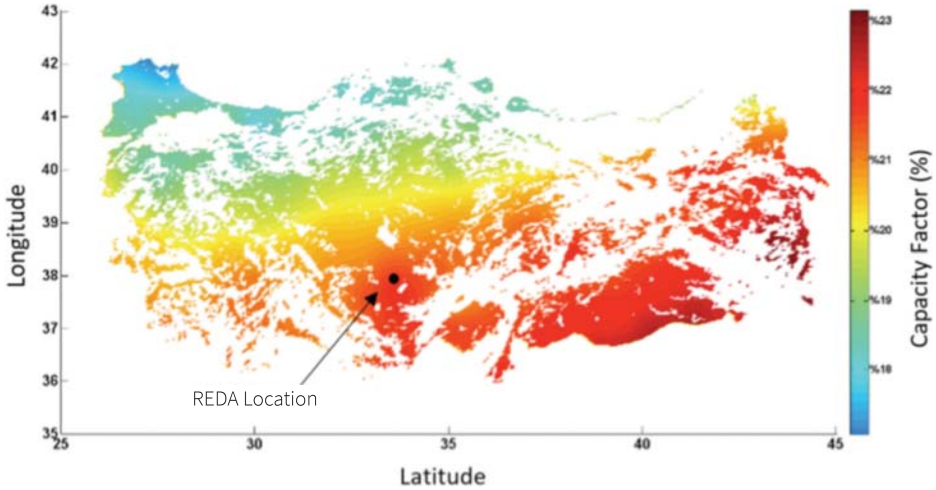


Figure 14. *Capacity factor map of solar photovoltaic power plants (restricted locations eliminated)*

Although the government currently utilizes the centralized large-scale REDA approach for increasing solar PV capacity, small installations may penetrate the low-voltage zone very rapidly.

Selection of new solar power plant locations for this study is based on resource quality and the ability of the subregion to absorb electricity. In the "resource-driven" approach, preference is given to most attractive sites, whereas the "system-driven" approach considers both the quality of solar resources and the absorption capacity of the neighboring substation. Although the government currently utilizes the centralized large-scale REDA approach for increasing solar PV capacity, small installations may penetrate the low-voltage zone very rapidly. We have defined the two approaches as follows:

- resource-driven strategy: 60% of capacity at large REDA sites in the south of the country (spread from east to west), 40% of capacity at smaller sites, located where resources are best;
- system-driven strategy: no additional REDA giga watt-scale sites; wide spread of small PV across the country, distributed based on resource quality and substation demand.

3.5.3. Run-of-river hydropower

Run-of-river hydropower plants have a very limited capability of storing water and changing operation in response to market price fluctuations. The location of new hydro generation was based on investment plans and hydro resources.[69] Because the amount of plant generation data was limited, we used past plant generation data and expert assessments to calculate plant generation. When modeling hydro output, we took into account the fact that plants that share the same hydraulic basins (see the color code in Figure 15). Locations and basin properties of hydropower plants have common feed-in properties.[70]

[67] *Riley,S.J., DeGloria,S.D., Elliot,R., "A terrain ruggedness index that quantifies topographic heterogeneity, Intermountain Journal of Sciences, Dec 1999.*
[68] *Pfenninger, Stefan and Staffell, Iain (2016). "Long-term patterns of European PV output using 30 years of validated hourly analysis and satellite data," Energy 114, pp. 1251–1265.*
[69] *DSI 2016: Dams of Turkey (http://www2.dsi.gov.tr/barajlar_albumu/files/assets/basic-html/index.html#1)*
[70] The general approach was explained in stakeholder discussions and met with general approval.

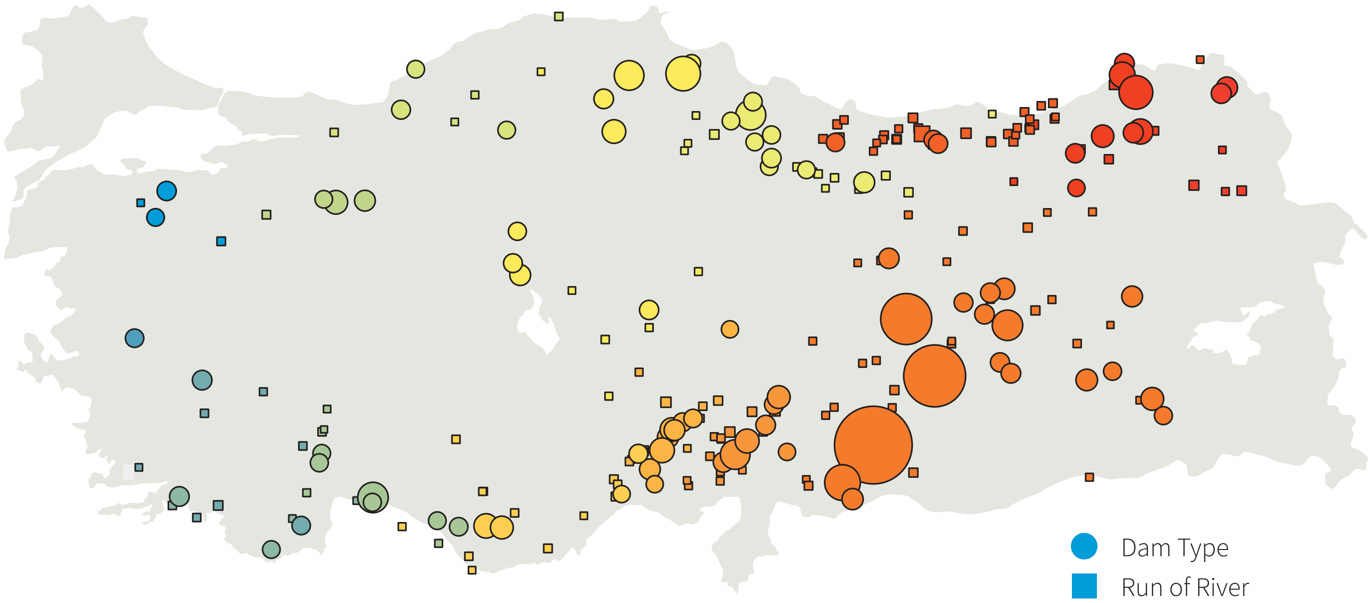


Figure 15. *Locations and basin properties of hydropower plants*

Plant operation is uncontrollable in all scenarios and is in line with the daily and seasonal variation of hydro resources, which peaks between mid-April and mid-June due to snow melt and high precipitation.[71]

3.6. Main modeling assumptions

3.6.1. Constant parameters in all scenarios

The parameters outlined in this section remain constant in all scenarios.[72]

3.6.1.1. Demand and peak load

Average annual demand and peak load increase between 2016 and 2026 and are estimated at 5.1%, based on the combination of top-down and bottom-up approaches.[73] This level falls between the demand growth target of the 2023 energy efficiency strategy and the lower growth rate assumed by TEİAŞ. Total consumption and peak demand are estimated at 439 TWh and just under 70 GW, respectively, up from almost 280 TWh and 44.5 GW in 2016. The hourly resolution of demand follows today's distribution, with the exception of the two main Islamic holiday seasons, which move throughout the calendar year, shifting by 10-11 days per year. Minimum daily load occurs during these two religious holiday periods.

Because network simulation requires time series data from substation-based hourly demand, the breakdown of total country demand by high voltage (HV) distribution substation (i.e., demand centers) took place top-down. The breakdown depends on distributions of large cities and regions and includes past data. It does not take into account major shifts in demand.

3.6.1.2. Installed power plant capacities

Assumptions about new capacities were exogenous, in line with TEİAŞ planning as given in Figure 16:

[71] See Figure 92 in the Annex 3.
[72] More details on the assumptions and methodology, see Annex 2
[73] *F. Tursun, M. E. Cebeci, O. B. Tör, A. Şahin, H. G. Taşkın, A. N. Güven, "Determination of zonal power demand S-curves with GA based on top-to-bottom and end-use approaches," IEEE PES ICSG 2016.*

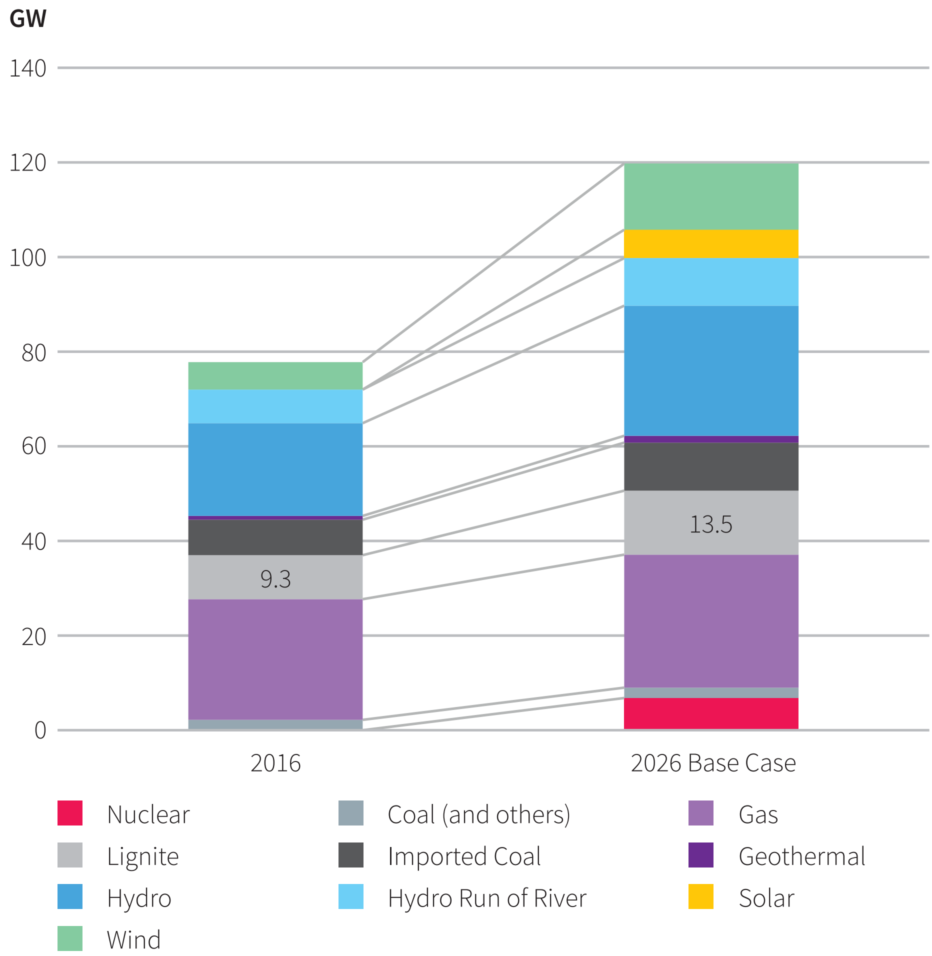


Figure 16. *Total installed generation capacity in 2016 and 2026 according to the Base Case scenario*

The distribution of generation sources is given in Figure 17. Most hydro generation is in the east; new nuclear capacity is in the central southern and northern regions; conventional generation is in the central and in the coastal western areas; gas generation is most prevalent in the northwestern region and in the greater Istanbul/Bursa area. The locations of new investments are based on resource potential (hydro, lignite, geothermal) and ongoing project developments. Other thermal generation sources ("Others") were placed in the coal group.

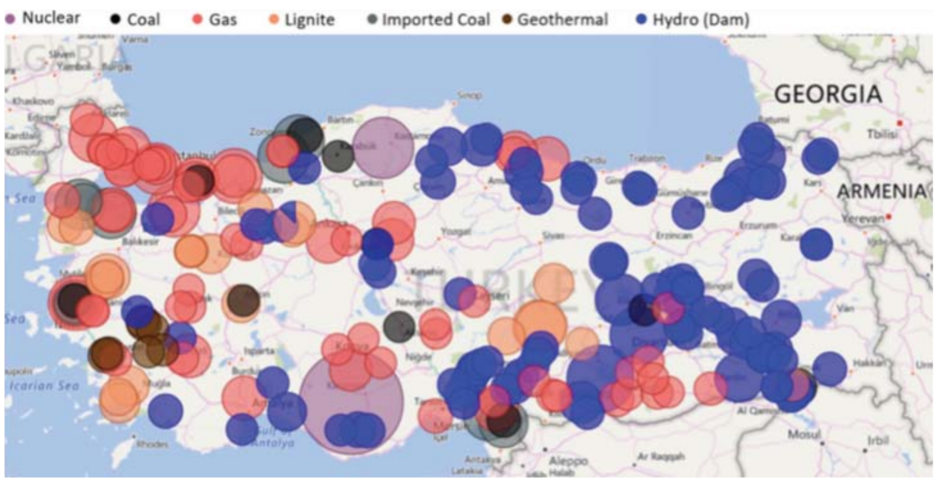


Figure 17. *Locations of the power plants in Turkey, 2026 (excluding solar photovoltaic and wind)*

3.6.1.3. Long-term constraints of hydropower plants

It is crucial that hydropower production be aligned with flood control; with residential, agricultural and industrial water supply; with navigation; and with environmental requirements, etc. These are generally referred to as the long-term energy constraints of hydropower plants.[74] The purpose of long-term scheduling of cascaded hydro energy and water resource systems is to optimize water discharge and the storage and spillage of reservoirs at every time stage. The long-term energy constraints of hydropower plants include energy constraints of dams and the interdependence of cascaded power plants such as Keban and Atatürk hydropower plants, which are located on the same river. They also reflect constraints connected with water use for agriculture and cross-border water usage agreements with Turkey's neighboring countries.[75] Further details are given in Annex 2.

3.6.1.4. Merit order, dispatch and redispatch

For market simulation analysis, cost functions for individual units are required in order to make a market clearing by minimizing the total cost of generation. A cost function for individual units, which defines the merit order, is defined and kept constant in all simulations. The details of unit costs are given in Annex A-2.3.1.2. Following the market simulation, the network simulation changes the commitment and dispatch of individual units in order to resolve network constraints or ensure required reserve capacity in the most cost-effective way. This change of commitment and dispatch is referred to as "redispatch".

3.6.1.5. Renewable energy curtailment

As Renewable energy penetration increases, so does the likelihood of difficult operational conditions. For example, in periods of high renewable energy generation, the operator may need to curtail renewable energy generation in order to keep frequency control reserve at the required level. This can occur when load is low or when load is high; it can occur when renewable energy generation is high; and it can occur to prevent congestions. We thus included renewable energy curtailment as an option to match supply and demand at every hour of the year. Curtailment is utilized as the last resort as described in Annex A-2.3.1.2.

3.6.2. Parameters that vary depending on the scenario

3.6.2.1. Technical restrictions of thermal and hydropower plants

The generating units of conventional power plants are subject to various specific technical constraints during operation. This study takes into account the following constraints: minimum power output, minimum up/down time, and unit ramp rates. In keeping with current operational practice in Turkey, we took a conservative approach when defining the operational flexibility and frequency control reserve capabilities of generating units for the three main scenarios. Our assumptions are summarized in Table 3.

[74] *B. Tong, X. Guan, Q. Zhai, F. Gao, "Long-term scheduling of cascaded hydro energy system with distributed water usage allocation constraints," IEEE Power and Energy Society General Meeting, 2011.*

[75] *DSI 2016: Dams of Turkey (http://www2.dsi.gov.tr/barajlar_albumu/files/assets/basic-html/index.html#1)*

***Table 3.** Assumptions about power plants' technical constraints*

Plant Type	P_{min} (p.u.)	P_{min}<-->P_{max} Duration (h)	Minimum Up/ Down Time (h)	Reserve Cap (%)
Coal - existing	90%	1	3	0%
Coal – new	40%	1	3	10%
Lignite - existing	90%	1	6	0%
Lignite – new[76]	50%	1	4	10%
Imported Coal	40%	1	3	10%
Nuclear	50%	1	8	0%
Gas	40%	1	1	15%
Hydro > 100 MW	60%	1	1	15%
Hydro < 100 MW	0%	1	1	0%

Making existing conventional power plants more flexible can be a major factor in integrating large shares of renewables more effectively. An increase of flexibility can be achieved not only by building new power plants but also by overhauling existing ones.

Making existing conventional power plants more flexible can be a major factor in integrating large shares of renewables more effectively. International practice shows that state-of-the-art coal- and lignite-fired power plants can ramp up significantly faster. An increase of flexibility can be achieved not only by building new power plants but also by overhauling existing ones.[77] The technical constraints of the thermal units were relaxed in a strategy analysis, as we assumed that new lignite and coal power plants would be able to ramp up and down from minimum to maximum capacity within one hour. Moreover, we set the minimum load and reserve capacity of *existing* coal and lignite plants to that of new plants using the same technology.

3.6.2.2. Storage options

Currently, there are no significant storage options present in the Turkey's power system beyond hydro dams.[78] Hence, we did not model other storage options in the three main scenarios. A variety of technologies have been developed for storing electrical power or providing short-term frequency support, from small-scale batteries to very large pump-storage plants. In our strategy analysis, we considered the integration of the Gökçekaya pump-storage project, which has been under discussion for a while now. The planned capacity is 1,400 MW (400 MW of which will serve as secondary frequency control reserve). We also factor in 600 MW of distributed MV/LV level storage swarm, which will be distributed to substations based on demand. We assume that half of these distributed storage systems provide frequency control service via aggregators.[79]

3.6.2.3. Demand response

Power system operators apply load shedding only as a last line of defense, as it may negatively affect industrial processes or private demand. In liberalized markets, however, a new concept of interaction with consumers has emerged. So-called

[76] "New" refers to power plants that are installed after the end of 2015 or that are planned to be installed by 2026.
[77] *Agora Energiewende (2017): Flexibility in thermal power plants – With a focus on existing coal-fired power plants.*
[78] See Annex 2 for details.
[79] The cycle efficiencies are assumed to be 85% and 92% for pump storage and batteries, respectively. See *US Department of Energy, Report to Congress, "Pump storage and potential hydropower from conduits", Feb 2015; NREL technical report, "Economic analysis case studies of battery energy storage with SAM", NREL/TP-6A20-64987, Nov 2015.*

prosumers supply some of the electricity themselves or can counteract power shortages or high price signals by temporarily reducing their demand. Through individuals or via aggregators, demand response can, therefore, become a player in the market. To assess the impact of such changes in the characteristics of demand, our model deploys a flexibility option, which can reduce demand at any given hour by up to 5%.[80]

In synchronous power networks, generation and demand must be balanced at all times in order to keep the frequency within close bandwidths and to guarantee proper system operation.

3.6.2.4. Spinning reserve requirements

In synchronous power networks, generation and demand must be balanced at all times in order to keep the frequency within close bandwidths and to guarantee proper system operation. Imbalances due to unplanned generator/load outages, dispatch changes or forecast errors are recovered using individual automatic controllers, centralized control systems or manual interventions by the dispatcher.[81]

In Turkey's electricity market, primary and secondary reserves are provided by conventional power plants. Hydro and gas-fired power plants, which have fast ramp-up/down capability, are mainly used as providers of secondary reserves. During the interconnection process with ENTSO-E, frequency control performance indices were defined by TEİAŞ and the ENTSO-E Project Group, and include minimum reserve amount adaptations.[82,83] These were calculated based on maximum hourly changes of net demand. Current values are set at 1,200 MW for day hours and 700 MW for night hours. This assumes that frequency control support will be provided by the ENTSO-E system during the most extreme situations.[84] As the amount of renewable energy generation increases in the 2026 scenarios, the hourly (and short-term) changes in net demand increase as well. The increase in reserves for compliance with ENTSO-E criteria was calculated using the same method and using 2026 data for the different scenarios. The calculated values are displayed in Table 4.

Table 4. *Reserve calculation results*

Scenario	Reserve Day Time (MW)	Reserve Night Time (MW)
2016	1,200	700
Base Case	1,800	1,000
Doubling	2,200	1,250
Tripling	2,700	1,600

An overview of all summary assumptions is provided in Table 5.

[80] In the simulation, fictitious generating units are introduced at each load location whose generation cannot exceed 5% of demand at any given hour.
[81] Details are explained in ENTSO-E Secretariat, *"ENTSO\E Operational Handbook, P1 – Policy 1: Load-Frequency Control and Performance [C]]", 2004, available at: https://www.entsoe.eu/publications/system-operations-reports/operation-handbook/Pages/default.aspx*
[82] *Ö.Tanıdır, M.E.Cebeci, C.Gençoğlu, O.B.Tör, "A strategy to enhance AGC performance of power systems that suffer inter-area oscillations and a case study for Turkey's power system," Elsevier International Journal of Electrical Power & Energy Systems, Volume 43, Issue 1, December 2012, p. 941–953.*
[83] *TUBITAK UZAY Power Systems Department, "Performance evaluation of the AGC System of Turkey during ENTSO/E CESA trial interconnection period,", 2011.*
[84] ENTSO-E interconnection can provide more than 1,500 MW support in the case of a mismatch in the Turkey's network. The support halts as soon as the AGC system and the manual tertiary frequency control compensate the mismatch. Further details are provided in Annex 2.

Table 5. Summary of modelling assumptions

Assumptions	Main Scenarios			Strategy 1		Strategy 2	
	Base Case Resource Driven	Doubling Resource Driven	Tripling Resource Driven	Doubling System Driven	Tripling System Driven	Doubling Resource Driven Flexibility	Tripling System Driven Flexibility
Demand and peak load	Hourly demand (based on historical data), Demand: 439 TWh / Peak: 69.3 GW fixed in all scenarios and strategies						
Installed capacity of dispatchable plants	Projected generation park by means of “Base Case” approach and TEİAŞ expectations. Initial set is fixed in all scenarios, planned investments that are utilised less than 500 hours per year in network simulation are removed from the initial set						
Long-term constraints of hydro	Energy constraints for dam type hydropower plants are defined based on seasonal historical characteristics						
Curtailment	Not applied		Applied for convergence	Not applied	Applied for convergence	Applied as a flexibility option	
Technical restrictions	Standard (as of today) Pmin, ramp rate, minimum up/down time and reserve capacity figures for all plants,excluding old coal and lignite units					Rehabilitation of the old plants	
Storage options	Not applied					1.4 GW pupm storage at Gökçekaya 600 MW distributed battery storage	
Demand response	Not applied					Max 5% hourly reduction	
Spinning reserve requirements	Day: 1,800 MW Night: 1,000 MW	Day: 2,200 MW Night: 1,250 MW	Day: 2,700 MW Night: 1,600 MW	Day: 2,200 MW Night: 1,250 MW	Day: 2,700 MW Night: 1,600 MW	Day: 2,200 MW Night: 1,250 MW	Day: 2,700 MW Night: 1,600 MW
Transmission Infrastructure	TEİAŞ TYNDP 2026 as starting point						

4. Impact of Doubling (40 GW) and Tripling (60 GW) Wind and Solar on System Planning and Operation

This section presents the main findings of the modeling analysis and compares the results of the scenario calculations. Starting from the Base Case scenario – 20 GW of installed wind and solar PV capacity by 2026 – we analyze the effects of doubling and tripling wind and solar installations relative to the Base Case scenario. These include:

- the effects on the power generation mix and the share of wind and solar;
- the effects on residual load, ramping requirements for hydro and thermal plants, and reserve needs;
- regional supply and demand balance per region and interregional power flows;
- investment in additional transmission system capacity to resolve structural congestions;
- redispatch levels necessary for safe system operation; and
- the need for and extent of wind and solar power curtailment.

Next, we assess options of how the system integration of wind and solar can be facilitated to reduce congestions and redispatch while making the whole system more resilient and secure. We analyze the benefits of a balanced distribution of wind and solar across the country based on capacity and demand. Then we test different options for increasing the flexibility of the power system as a whole. These include the introduction of distributed batteries and large pumped storage hydro plants and making the system more flexible by modernizing thermal power plants and introducing a demand response mechanism.

4.1. Base Case: 20 GW of solar and wind capacity by 2026

4.1.1. Generation mix

In the Base Case scenario, wind (40 TWh) and solar PV (11 TWh) total around 12% of power generation. Together with hydro and geothermal, the overall share of renewable energy generation amounts to 35% by 2026. Lignite contributes 18% (81 TWh), followed by hard coal (16%), gas (15%) and nuclear (12%). Power is also imported from neighboring Bulgaria, Greece (via ENTSO-E) and Georgia (Figure 24).

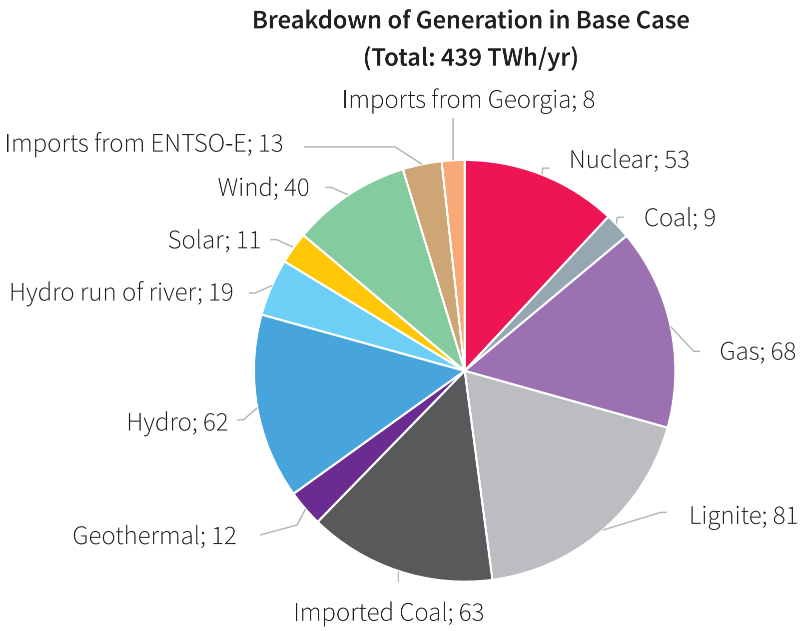


Figure 18. *Breakdown of the total generation mix according to the Base Case scenario, 2026*

Full load hours differ by technology and position in the merit order. Geothermal and nuclear have the highest utilization rate, at 97% and 88%, respectively, followed by imported coal and lignite, at 71% and 70%, respectively. Local coal utilization is at 46%, while gas is only 27%.

4.1.2. Reserve requirements

Maximum hourly contribution of wind and solar to the power supply is 45%. When including run-of-river hydropower, the third non-dispatchable source of electricity, that number increases to 52%. All these cases occur during the public holiday period, which in 2026 begins in mid-March. Low demand during the holiday period drives up wind and solar output.[85]

Maximum hourly ramp rate in the Base Case is 10.8 GW. This is caused by steeply increasing demand during the morning hours. Required reserve capacity, provided mainly by gas and hydropower plants, amounts to 1,800 MW.[86]

4.1.3. Interregional power flows

The largest share of demand is centered in the western part of the country, where most urban centers and industry are located, and in Southeast Anatolia, where electricity demand is mainly driven by agriculture. The three western regions Trakya, West Anatolia and Northwest Anatolia account for 51% of overall demand, while Southeast Anatolia makes up almost 15% of demand.

In terms of supply and demand, there is an annual balance in Southeast Anatolia, considerable oversupply in the West and East Mediterranean regions (driven by hydro and import coal power) and undersupply in Trakya, Northwest Anatolia and Central Anatolia (necessitating high levels of power imports).

In terms of supply and demand, there is an annual balance in Southeast Anatolia, considerable oversupply in the West and East Mediterranean regions (driven by hydro and import coal power) and undersupply in Trakya, Northwest Anatolia and Central Anatolia (necessitating high levels of power imports). As the 2015 blackout showed, this west-east imbalance can have negative impact on system reliability.

As seen in Figure 19. Regional generation/load balance and inter-regional exchange according to the Base Case scenario, 2026 the main power flows are directed from east/southeast to west/northwest. The main driver for the power flow from the East Mediterranean area is the new large nuclear power plant in this region. In West Anatolia, the second largest power exporting region, the flows are driven by a balanced mix of wind, lignite, gas and coal.

[85] Although the maximum of renewable energy supply/demand ratio is relatively high, the average ratio is similar to the other hours. As during the bayram periods, demand is very flat and reserve falls 50%.
[86] For more on the reserve calculation, see Annex 2.

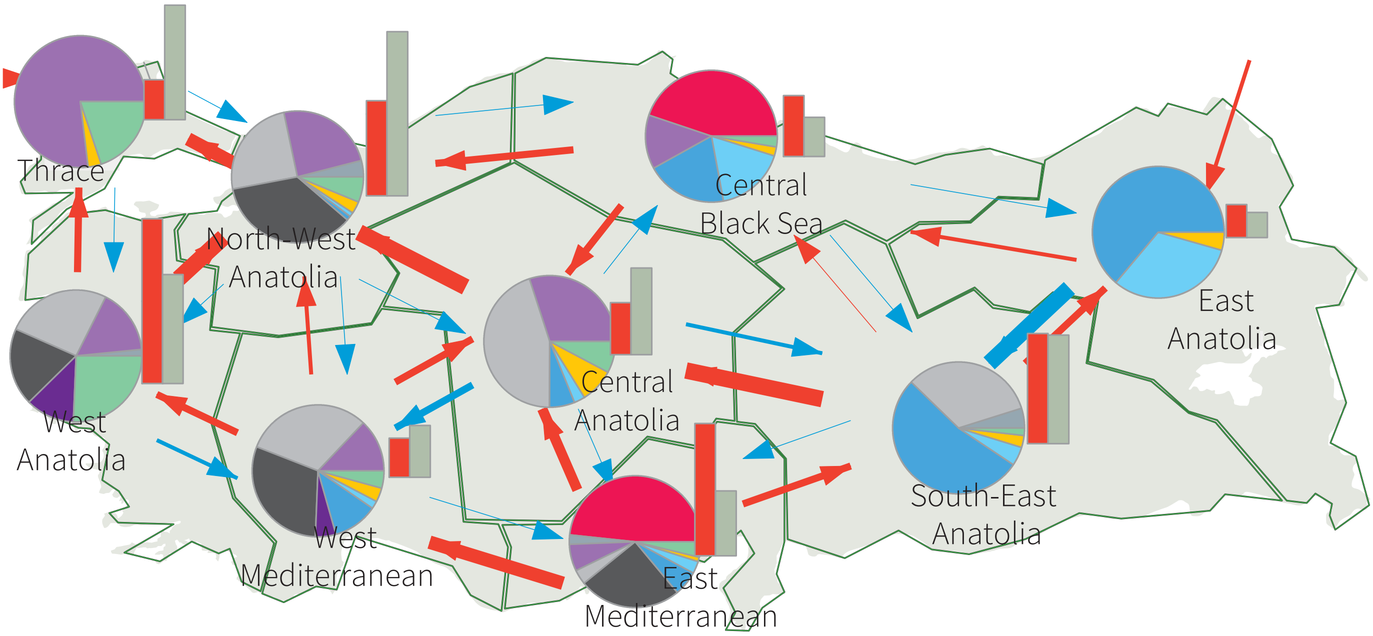


Figure 19. *Regional generation/load balance and inter-regional exchange according to the Base Case scenario, 2026*

4.1.4. Transmission capacity investment

As in the past decade, the growth of Turkey's power system requires further substantial investments in the transmission system.

As in the past decade, the growth of Turkey's power system requires further substantial investments in the transmission system. In 2016, circuit length of the 400 kV system was 21,000 km, and circuit length of the 154 kV system was 38,700 km. According to TEİAŞ's TYNDP Plan for 2026, ~8,300 km additional 400 kV lines will be built. For the 154 kV system, planning only goes to 2021; for these five years, ~5,800 km additional 154 kV lines are planned.[51] The modeling carried out for the Base Case arrives at similar results, with some shift of invest from 154 kV to 400 kV: ~8,900 km of new 400 kV lines, 8% above the TEİAŞ value, and 4,900 km of additional 154 kV lines for 2021–2026.

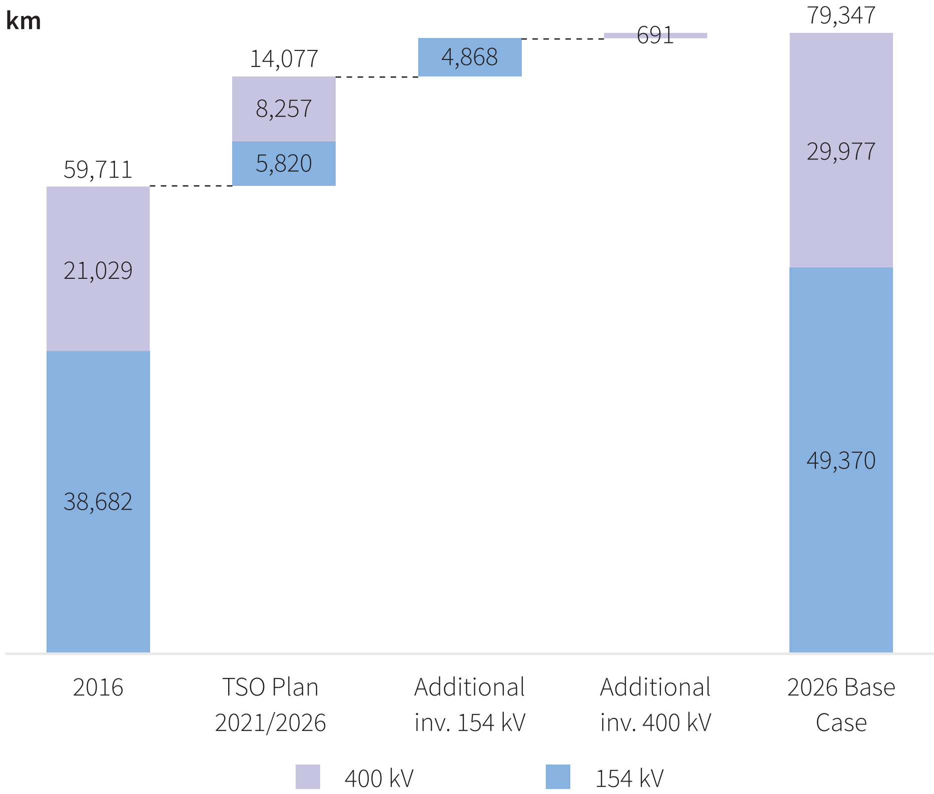


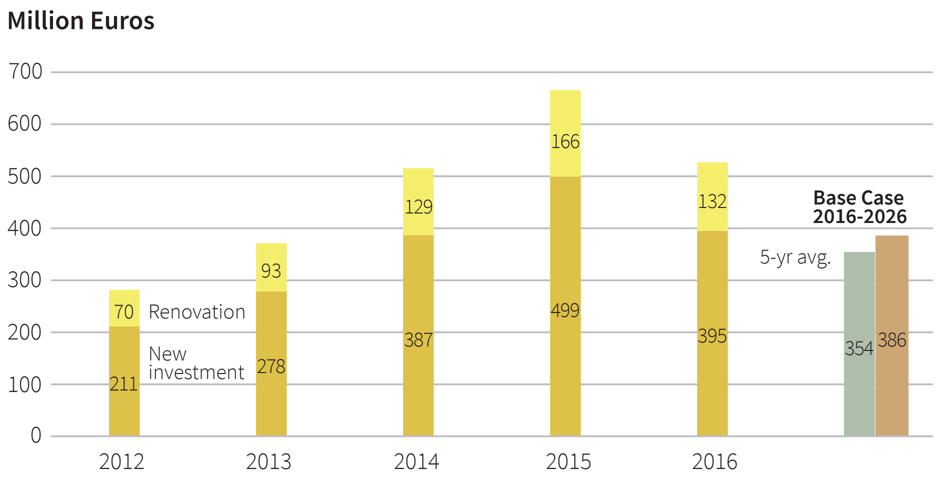
Figure 20. *Transmission grid investment plans of TEİAŞ and additional investments for the Base Case scenario 2026*

As of 2016, there were 301 stations in place, and 51 planned by the TSO; in the model, we identified another 10 stations for the entire 10-year horizon, or 362 stations in total.

As for new transformer stations (400 kV / 154 kV), we arrive at similar results to those of TEİAŞ. As of 2016, there were 301 stations in place, and 51 planned by the TSO; in the model, we identified another 10 stations for the entire 10-year horizon, or 362 stations in total.

Assuming typical investment costs for 400 kV, 154 kV lines and transformer stations in Turkey,[87] the scenario projects overall investment at 3.86 billion € for the 10-year period, or 386 million € per year. To put this figure in perspective, we looked at TEİAŞ investment numbers from past years. TEİAŞ invested between 282 million € and 666 million € in the transmission grid between 2012 and 2016. No public data is available on the breakdown of these totals for new infrastructure and maintenance. Even if we conservatively assume that 25% of the money was spent on maintenance, an annual investment of 386 million € is still only 12 million € over the annual average investment for 2012–2016 and below the average of for 2014–2016 (Figure 21).

[87] The following values are used as standard investment costs: 260,000€ per 1km 400 kV line; 130,000€ per 1km of 154 kV line; and 2,000,000 per 400 kV/154 kV or MV transformers (including substation costs per transformer).



* Total realized investment figures are taken from TEİAŞ;[88] as no public information is available on the ratio of new investment to maintenance costs, a split of 75% / 25% was assumed.[89] This is a conservative figure given the growth of the system in the past decade and the young age of much of the infrastructure.

Figure 21. *Comparison of the realised TEİAŞ investments of with the Base Case scenario investments*

As illustrated in Figure 22, new investment is required throughout Turkey, but most projects are concentrated along the Aegean Sea in West Anatolia, as well as between Central Anatolia, Trakya and Southeast Anatolia. Many new 154 kV lines serve intraregional rather than interregional transmission.

The additional lines are mostly driven by new power plant connections within each region. These are usually caused by increasing demand and/or generation at a particular location in the 154 kV network and its connection to the 400 kV network. Investment in the 400 kV network strengthens existing corridors and is driven by long-distance power flows to Northwest Turkey from new hydro plants in Southeast Turkey and from new nuclear and wind and solar plants in the south.

Figure 22. *Required investments in the transmission grid according to the Base Case scenario, 2026*

[88] See TEİAŞ Turkey's electricity generation and transmission statistics: *https://www.teias.gov.tr/tr/viii-yatirimlar*
[89] Renovation includes only the one-by-one replacement of old equipment with new equipment of the same capacity, no optimization measures or increase in line capacity.

4.1.5. Redispatch and curtailment

In an ideal world, transmission grids would be planned that can accommodate all power flows resulting from market operation at any time of the year, allowing for the most cost-efficient dispatch of power plants throughout the country ("copperplate" approach of a congestion free grid). In reality, situations occur where redispatch[90] is necessary in order to guarantee reliable system operation, i.e. avoiding congestions and guaranteeing reserve capacity from fast-response power generators. In many countries, a certain share of redispatch together with wind and solar curtailment is considered more cost efficient than building a transmission system to handle extreme cases[91] that only occurs during few hours of the year.

In 2016, annual redispatch in Turkey was 12.1 TWh, or 4.4% of overall demand. In the Base Case scenario, this share remains at about the same level, 4.8%. In absolute terms, redispatch increases to 21 TWh, as annual generation increases from 278 to 440 TWh. Redispatch does affect the generation mix, however: gas use increases by ~5 TWh while lignite decreases by ~2 TWh and imported coal and coal fall by ~1.5 TWh each. There is no need for curtailment.

Positive redispatch orders are most frequent in the densely populated and industrialized northwest and western parts of Turkey, where they relax the interregional flow corridors from Central Anatolia, West Anatolia and the Central Mediterranean region.

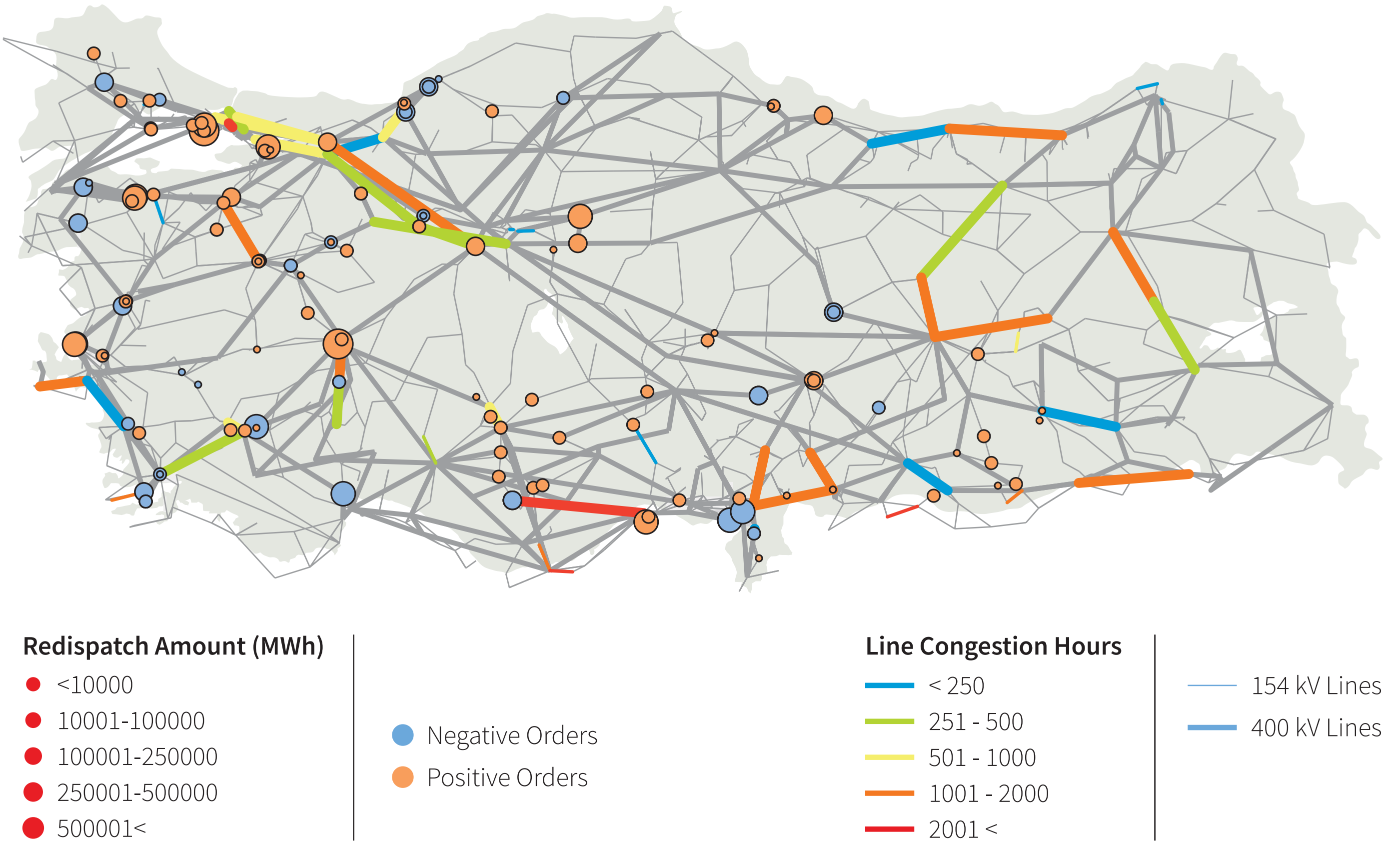


Figure 23. *Annual congestion levels and thermal re-dispatch orders according to the Base Case scenario, 2026*

[90] Redispatch occurs when plant power output changes to avoid operational problems caused by dispatch orders.
[91] *BMWi 2015, An electricity market for Germany's energy transition. Available online at http://www.bmwi.de/English/Redaktion/Pdf/weissbuch-englisch,property=pdf,bereich=bmwi2012,sprache=en,rwb=true.pdf; Yoh Yasuda et al. 2015, International Comparison of Wind and Solar Curtailment Ratio. Accessed at https://community.ieawind.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=52ce6334-ce38-38c9-f210-f3a56ee6aaf5*

4.2. The effects of doubling current planning: 40 GW Wind and Solar Scenario

4.2.1. Generation mix

Increasing the capacities of wind and solar PV from the base scenario with 14 GW of wind and 6 GW of solar to 20 GW of installed wind and to 20 GW of installed solar power in the Doubling scenario raises the annual generated energy of these variable sources from 51 TWh to 90 TWh.[92]

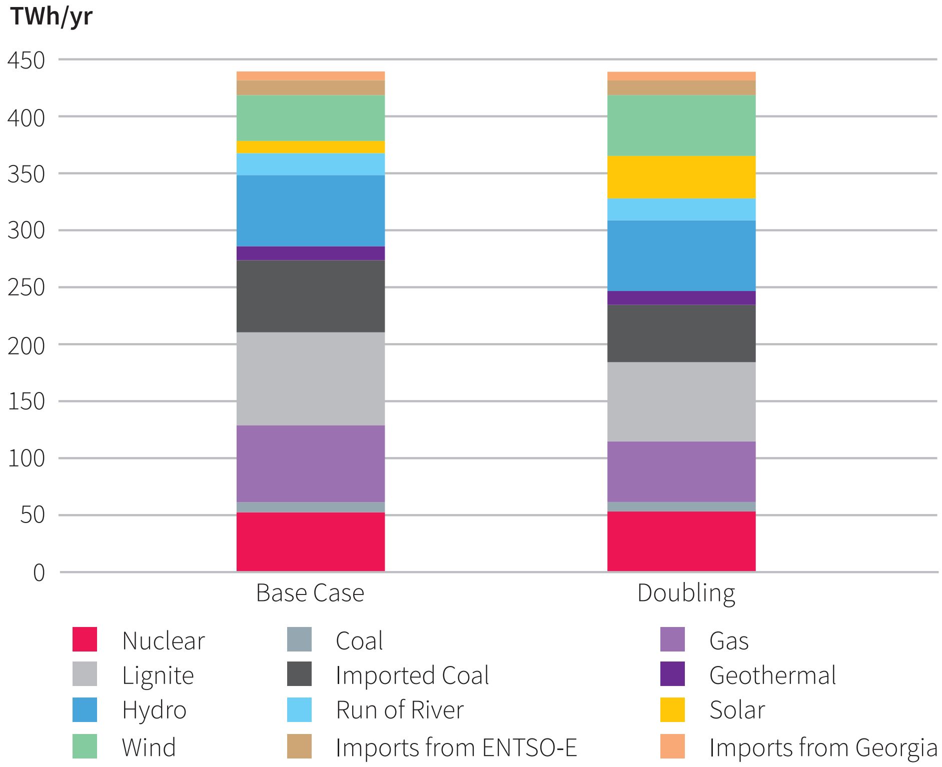


Figure 24. *Total generation mix according to the Base Case and Doubling scenarios, 2026*

The additional 39 TWh of wind and solar displace some gas, lignite and (imported) coal from the fuel mix, each in the range of 12 - 15 TWh.[93] The reduction of gas would be even larger if it wasn't partly reintroduced via redispatch measures for the purpose of flexibility. The remaining sources of electricity, including nuclear power and imported coal, remain almost unchanged. This results in a balanced mix of thermal and hydro generation sources in the Doubling scenario, with hydro, lignite, coal, nuclear and gas all generating power in the order of magnitude of 50 - 70 TWh.

[92] The reason that the doubling of installed capacity does not double power output is not that the resource quality of the added sites is considerably lower. Instead, it is due to the fact that the share of wind and solar capacity is even, whereas it is higher for wind, whose capacity factor is almost 50% higher, makes up a greater proportion in the Base Case.
[93] This is a product of market and network modeling.

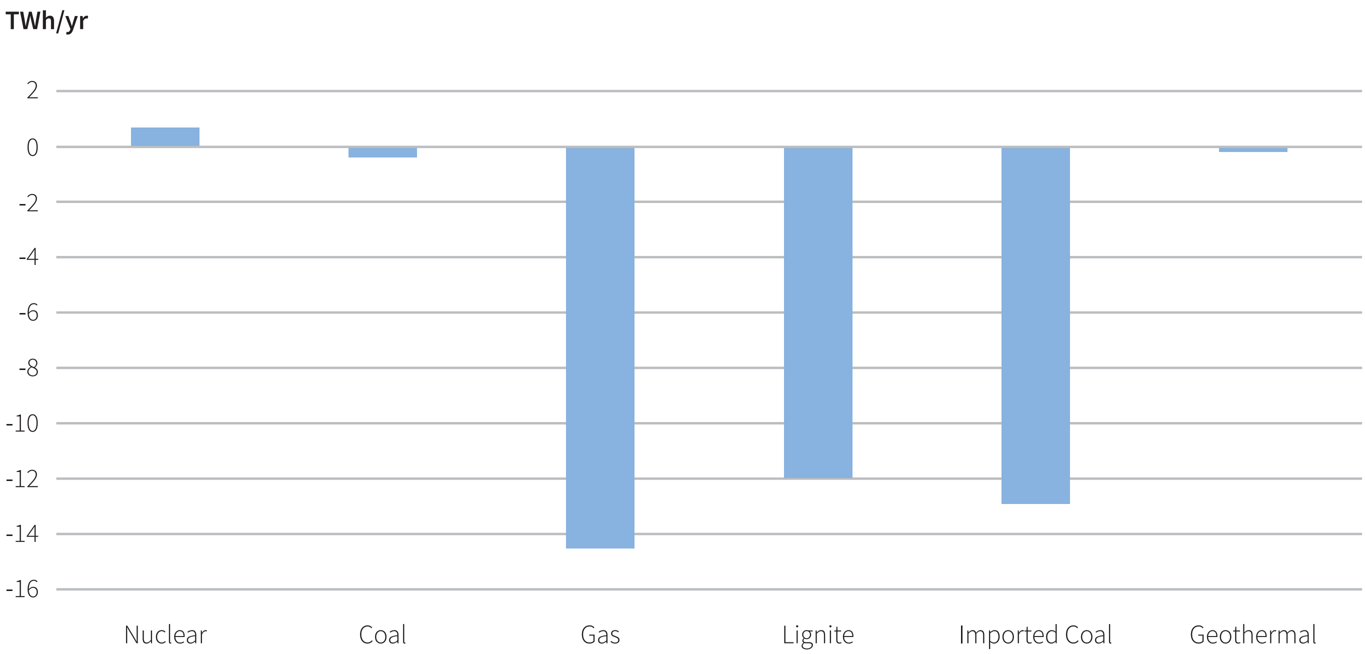


Figure 25. *Changes in total generation by source, Base Case versus Doubling scenarios, 2026*

We did not optimize the power system entirely and instead kept the assumptions on the thermal and hydro generation capacities constant. Due to the higher output of wind and solar, generation from lignite, imported coal and gas is reduced (Figure 25). This lead to a reduction in capacity factors for these power plants, as illustrated in Figure 26. Nuclear generation is slightly higher, as less redispatch occurs.

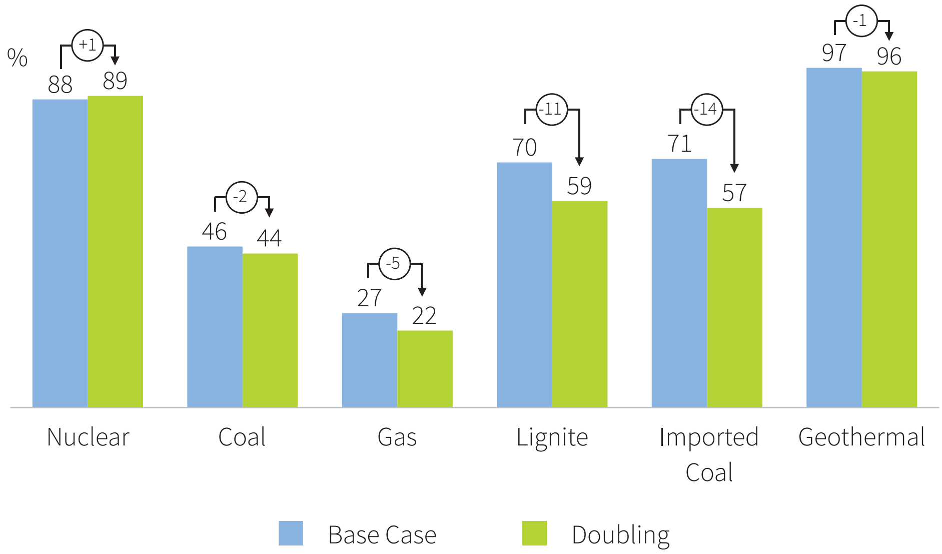


Figure 26. *Changes in capacity factors by source, Base Case versus Doubling scenarios, 2026*

The utilization rate of some gas-fired power plants falls significantly because of the build-up of wind, solar, nuclear and lignite from favorable feed-in conditions. Assessing the impact of increased shares of wind and solar on power market prices and thermal power plant projects was not part of this analysis, however. Only plants with extremely low utilization rates below 500 hours/year were removed from the final modeling run.[94]

4.2.2. Reserve requirements

When doubling wind and solar capacity, the maximum hourly contribution rises steeply from 45% to 89%. Including run-of-river hydropower, the maximum hourly contribution increases to 93%. These extreme cases occur during the Ramazan Bayram period, which in 2026 will begin in mid-March. Low demand during the holiday period drives up wind and solar output, producing a very high wind and solar generation value of 29 GW (only 2 GW below the annual maximum hourly generation). If Turkey's main public holiday periods are excluded, the maximum share of wind and solar is considerably lower.[95]

Despite the steep increase in wind and solar generation shares at certain hours, the maximum hourly ramp rate in the Doubling scenario is actually lower than in the Base Case scenario, declining from 10.8 to 10.4 GW. The reason for this is that there is a positive correlation between the increase of solar generation and early-morning demand. When reserve capacity increases from 1,800 to 2,200 MW, the power system can be operated safely even as variable wind and solar capacity doubles.

4.2.3. Interregional power flows

In this section, we focus on the impact of doubling wind and solar capacity on the regional supply-demand balance, as indicated by interregional power flows. We assume that additional interregional power flows would require additional transmission infrastructure, and a reduction of flows would not.

There are some changes in regional power generation, though. Trakya continues to depend on power from neighboring regions, as decreased gas generation in the region compensates for more wind and solar power. In West Anatolia, the supply deficit falls; and in West Anatolia and the East Mediterranean area, the supply surplus drops. On the other hand, reduced power generation in the Northwest Anatolia and increased power generation in Southeast Anatolia both have a negative impact on the balance in these regions. Hence, the doubling of wind and solar PV at the most attractive wind and solar locations across the country does not have a major impact on the supply-demand balance in these regions.

[94] In the model, the power plants planned for 2026 in the Base Case, that have less than 500 hours of annual utilization have been removed because we assumed that these would not be built. As a result, gas capacity falls from 28.1 GW to 27.3 GW, eliminating 800 MW of the planned 3.7 GW of new gas capacity. In reality, additional thermal power plants may not be built in the Doubling scenario.

[95] Although the maximum renewable energy/demand ratio is relatively high, the average ratio is similar to other hours. As during the Turkish holiday periods, demand is very flat and the reserve falls by 50%.

Table 6. *Regional generation and demand*

Region Generations (TWh)	Base Case	Doubling	Demand
Trakya	23.0	22.1 ↓	65.9
N-West Anatolia	54.7	46.6 ↓	94.4
West Anatolia	94.8	93.0 ↓	62.7
Mid-Anatolia	29.9	34.7 ↑	49.8
West Mediterranean	22.6	29.0 ↑	29.8
Mid-Black Sea	35.1	34.2 ↓	22.6
East Anatolia	19.0	19.4 ↑	14.5
South-East Anatolia	63.4	68.3 ↑	62.5
East Mediterranean	76.1	71.3 ↓	37.3

As in the Base Case, the main power flows in the Doubling scenario move toward the western and northwestern parts of Turkey. The main differences are a reduction of flows from the West to East Mediterranean regions and a slight decrease in flows from Central Anatolia and the East Mediterranean region to Southeast Anatolia, where solar PV generation improves the supply-demand balance when (seasonal) hydro generation, the main power source in this region, is low (Figure 27. Regional generation/load balance and inter-regional exchange for Doubling scenario, 2026).

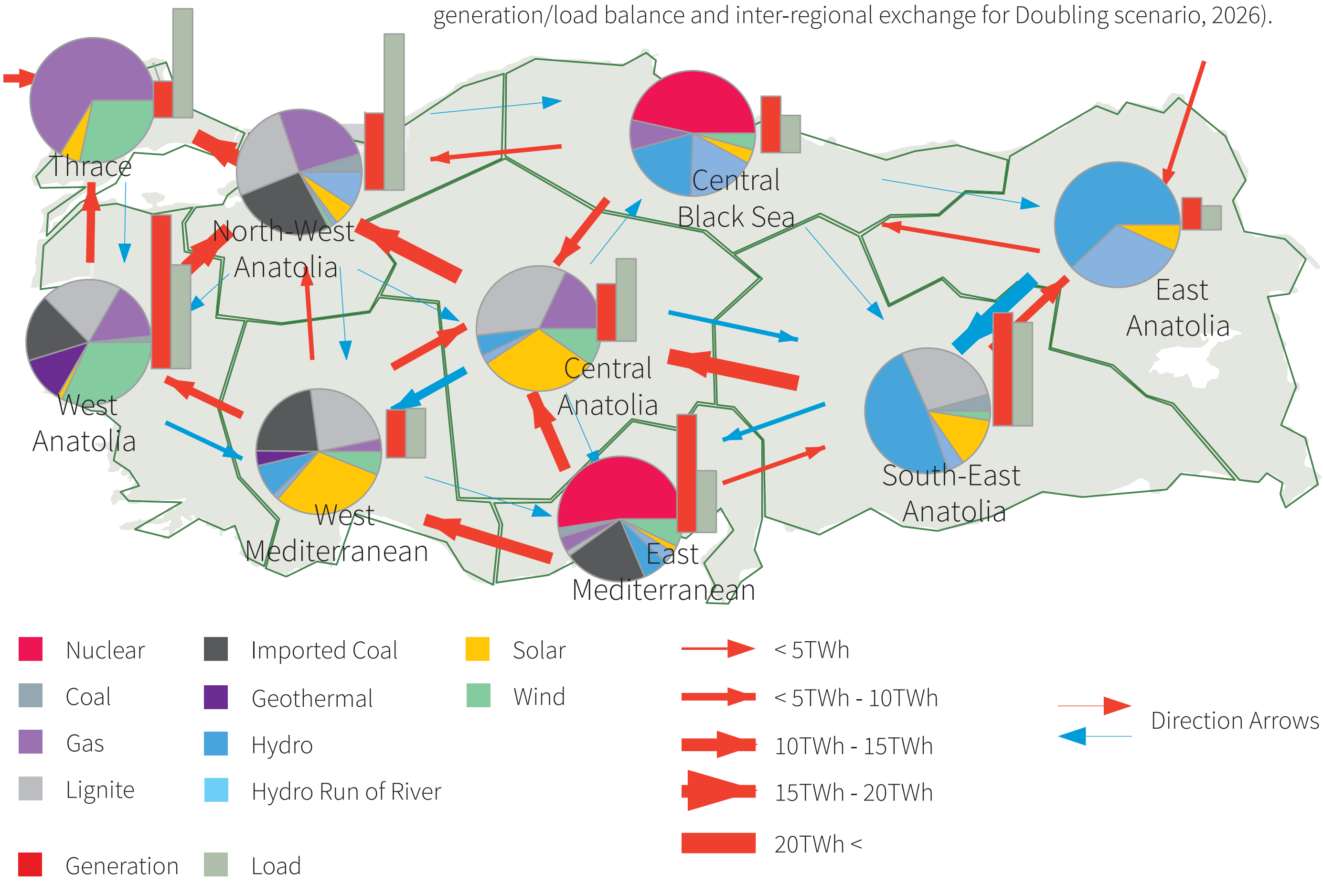


Figure 27. *Regional generation/load balance and inter-regional exchange for Doubling scenario, 2026*

4.2.4. Transmission capacity investment

In line with the high level of similarity between interregional power flows in both the Base Case and Doubling scenarios, the enhanced transmission system in the Base Case scenario provides the necessary infrastructure for the Doubling scenario.[96] Therefore, no additional infrastructure investment is needed to double the share of wind and solar capacity from 20 GW to 40 GW.

4.2.5. Redispatch and curtailment

In the Doubling scenario, somewhat more redispatch (+ 2.5 TWh) is required than in the Base Case scenario for power system security (Figure 28). The increase in redispatch is driven by the need for additional flexibility in the Doubling scenario due to the higher share of wind and solar. The share of redispatch in overall generation – 5.3% – remains close to that in the Base Case (5%).

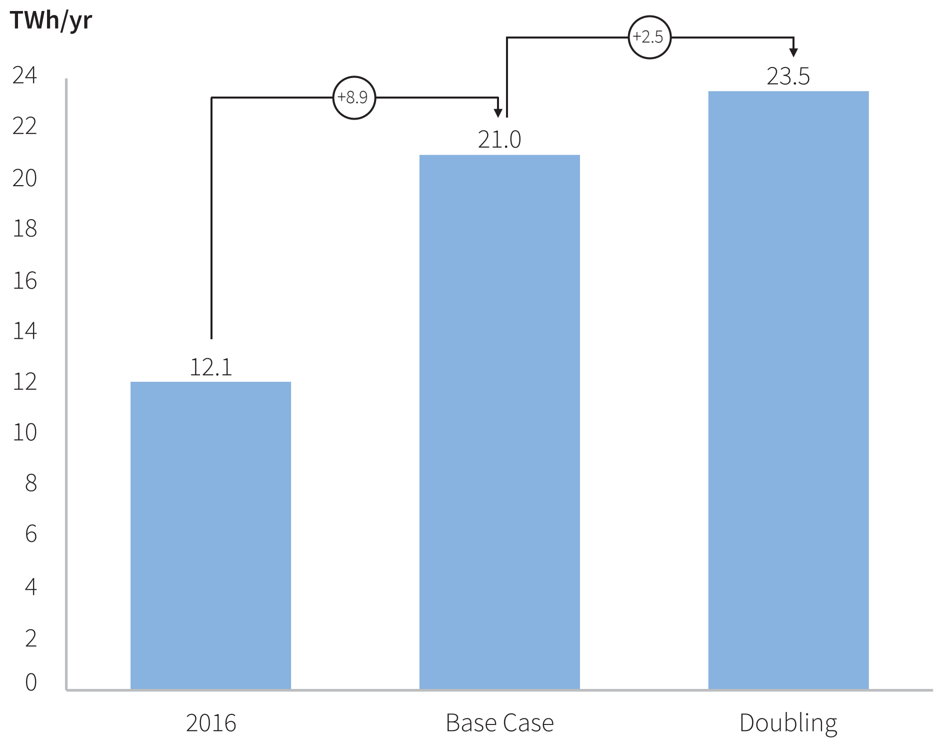


Figure 28. *Redispatch in 2016 according to the Base Case and Doubling scenarios in 2026*

When comparing the effects of redispatch on generation sources, however, there is a stronger technology shift discernable in the Doubling scenario. Although the overall redispatch value is only slightly higher, the shift from lignite and import coal to gas is almost twice as high, increasing from 5 TWh to 10 TWh. There are two main factors that create this difference. As the renewable energy infeed increases, the market-based dispatch provides for reduced utilization of gas, which is the most expensive generation technology. As flexibility needs increase with higher wind and solar generation, however, the needed capacity for fast-response generation also increases. This necessitates gas generation to come back online.

[96] While some minor differences in the new transmission lines between the scenarios would be optimal, keeping the same transmission system facilitates comparison. The only variable is the amount of redispatch necessary to cope with congestions and reserve requirements.

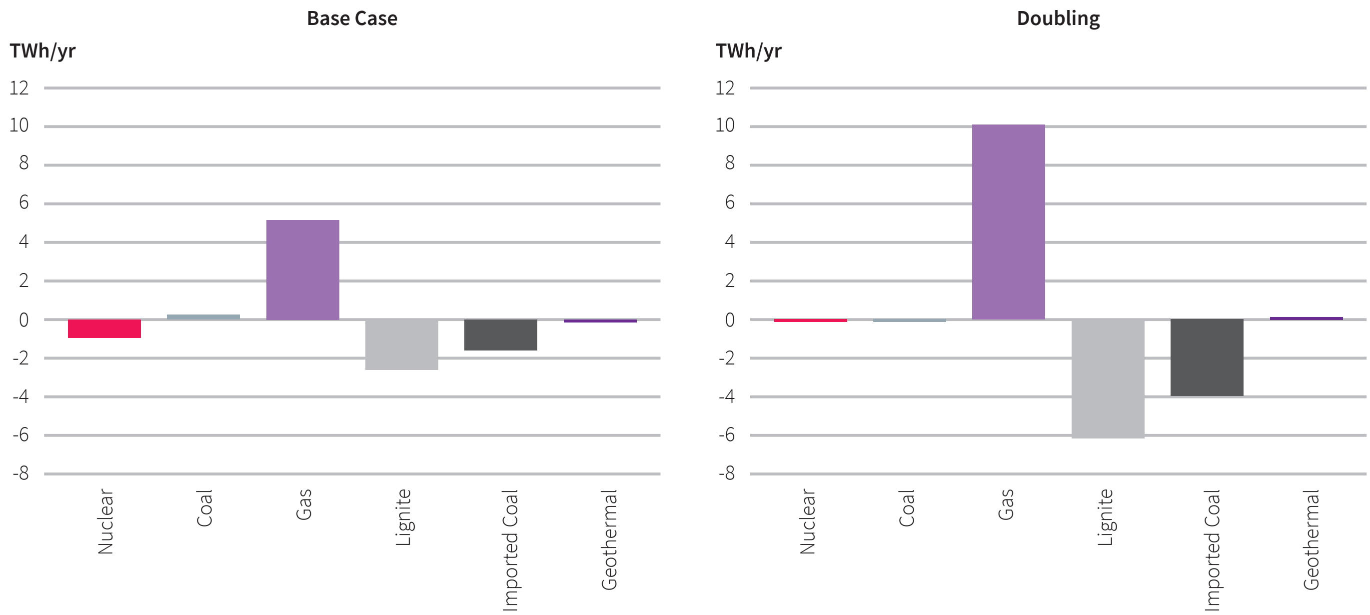


Figure 29. *Changes in generation due to redispatch according to the Base Case and Doubling scenarios, 2026*

Positive redispatch orders are most frequent in the densely populated / industrialized northwest and western parts of Turkey. In some cases, these can significantly relieve congestion on the transmission corridors from Central Anatolia, West Anatolia and the Central Mediterranean region to Trakya and Northwest Anatolia. This can be explained by the increase in reserve requirements from gas-fired plants in these regions. Occasionally, positive and negative orders are observable at very close locations. New gas-fired plants satisfy reserve requirements by reducing generation (or shutting down) other plants.

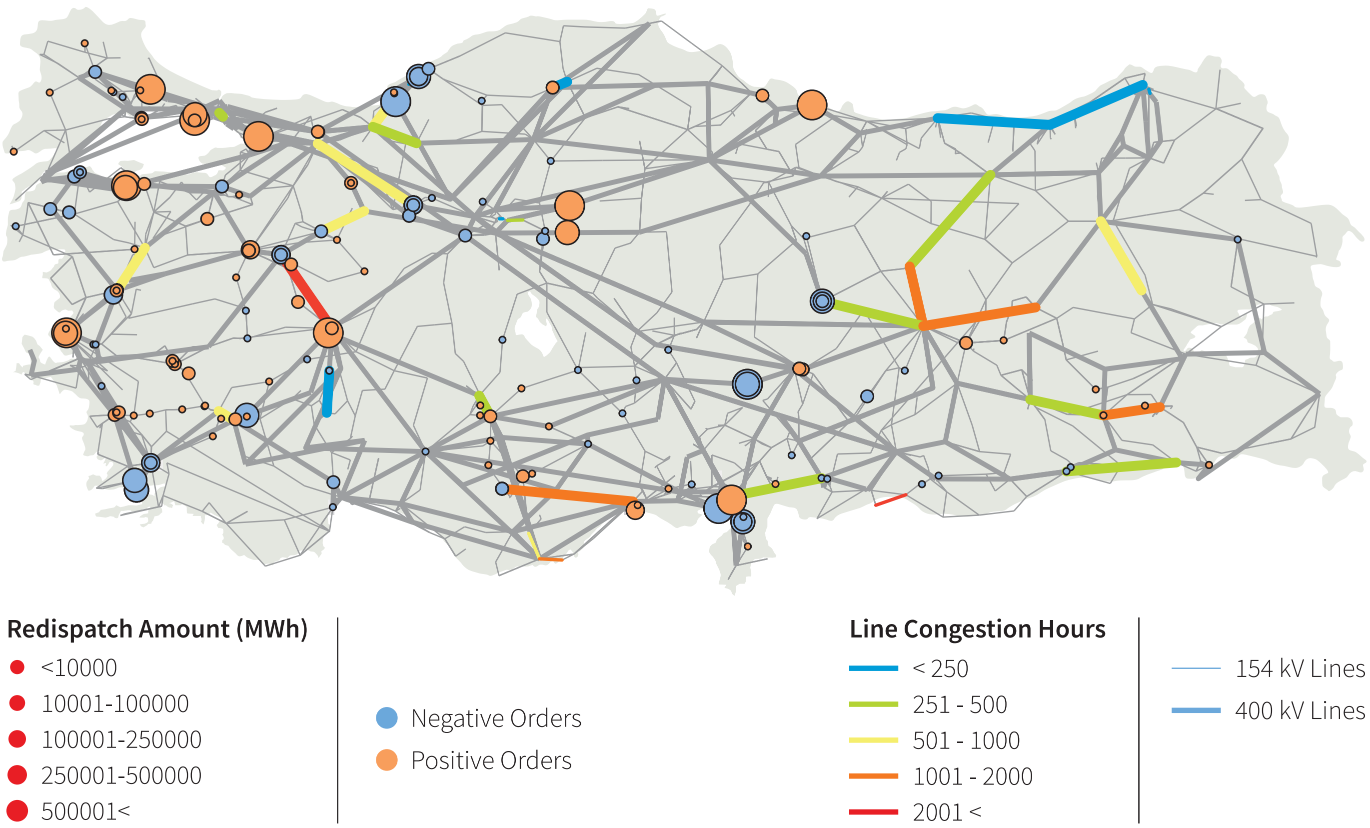


Figure 30. *Annual congestion levels and thermal re-dispatch orders according to the Doubling and Tripling scenarios, 2026*

There is no need for curtailment, except possibly for a few hours of high RE feed-in during the holiday periods. But this amount is negligible when spread out over an entire year.

In sum, this analysis has found that the development of the transmission infrastructure for 2026 as planned by TEİAŞ's TYNDP can accommodate up to 40 GW of wind and solar capacity. No significant curtailment would result, and redispatch would only increase slightly, from 20 TWh to 22.5 TWh, which is still in the range of current redispatch values in Turkey (~5% of total generation).

4.3. The effects of tripling current planning: the 60 GW Wind and Solar scenario

In our second analysis, we assessed the impact of tripling current wind and solar planning to 60 GW, with 30 GW for each wind and solar PV.

4.3.1. Generation mix

In the Tripling scenario, annual generated energy from wind (74 TWh) and solar (55 TWh) reaches 129 TWh, up from 90 TWh in the Doubling scenario and 51 TWh in the Base Case scenario. The share of wind and solar in the energy mix increases to 31%. When including hydro and geothermal (which remain nearly constant at 81 TWh and 11 TWh, respectively), renewables make up 53% of overall power generation.

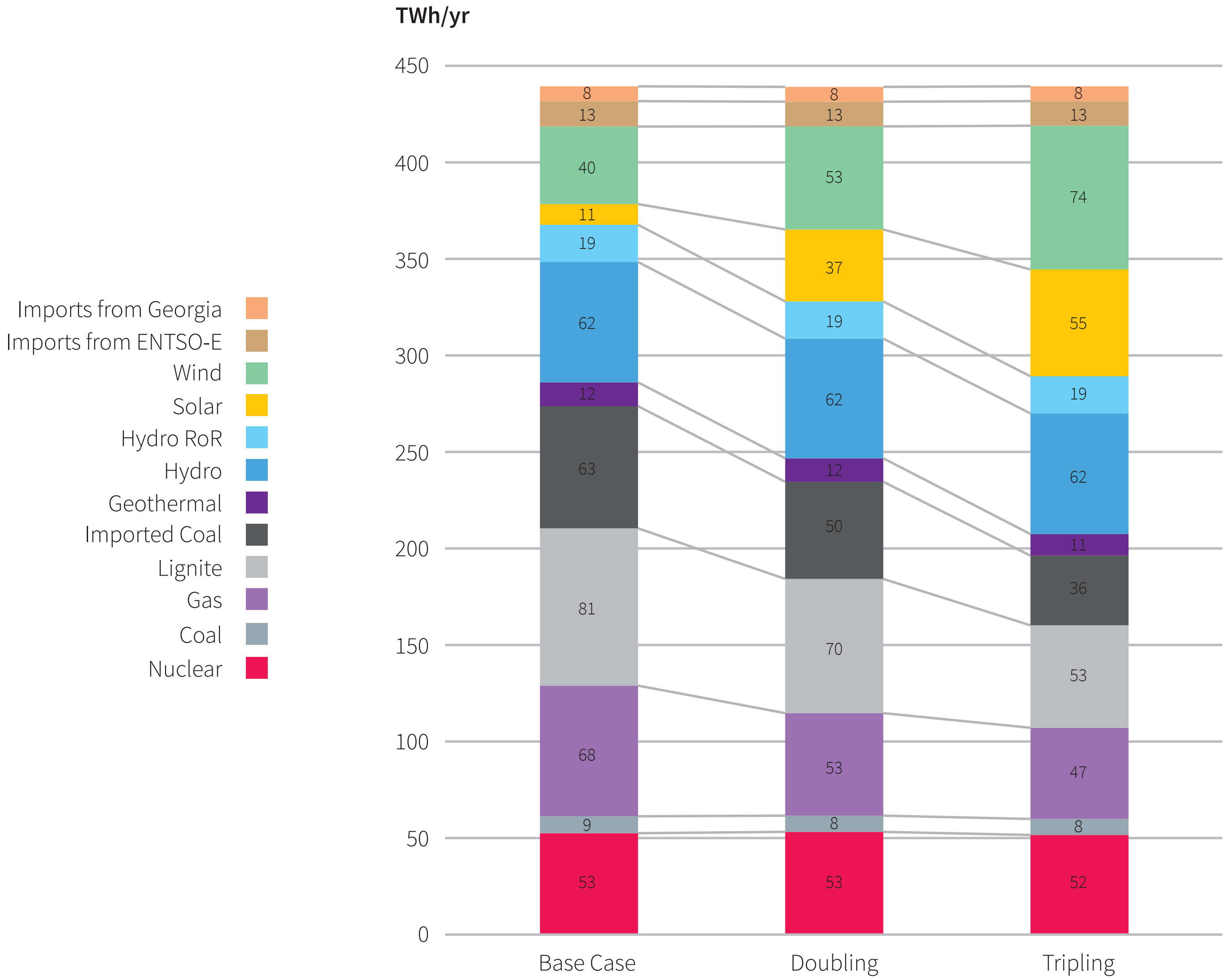


Figure 31. *Total generation mix according to the Base Case, Doubling and Tripling scenarios, 2026*

The additional 39 TWh of wind and solar (as compared to the Doubling scenario) leads to a further reduction of lignite (- 17 TWh), (imported) coal (- 14 TWh), gas (- 6TWh) and nuclear (- 1 TWh). The reduction of gas is much lower than that of lignite and coal, indicating that it may be difficult to reduce the share of gas below 11%, as the flexibility of gas-fired power plants will be needed by the system as no alternatives exist. Consequently, combined coal and lignite generation decreases to below 100 TWh, while nuclear and gas remain stable at around 50 TWh each.

As explained in section 4.2.1, thermal generation capacity was kept constant for each scenario because the impact of lower utilization on market prices and investment decisions was not part of this analysis, with the exception of plants that were not in operation in 2016, but reach less than 500 full load hours in the simulation.[97] Full load hours of lignite and import coal fall well below 50%, as illustrated in Figure 32.

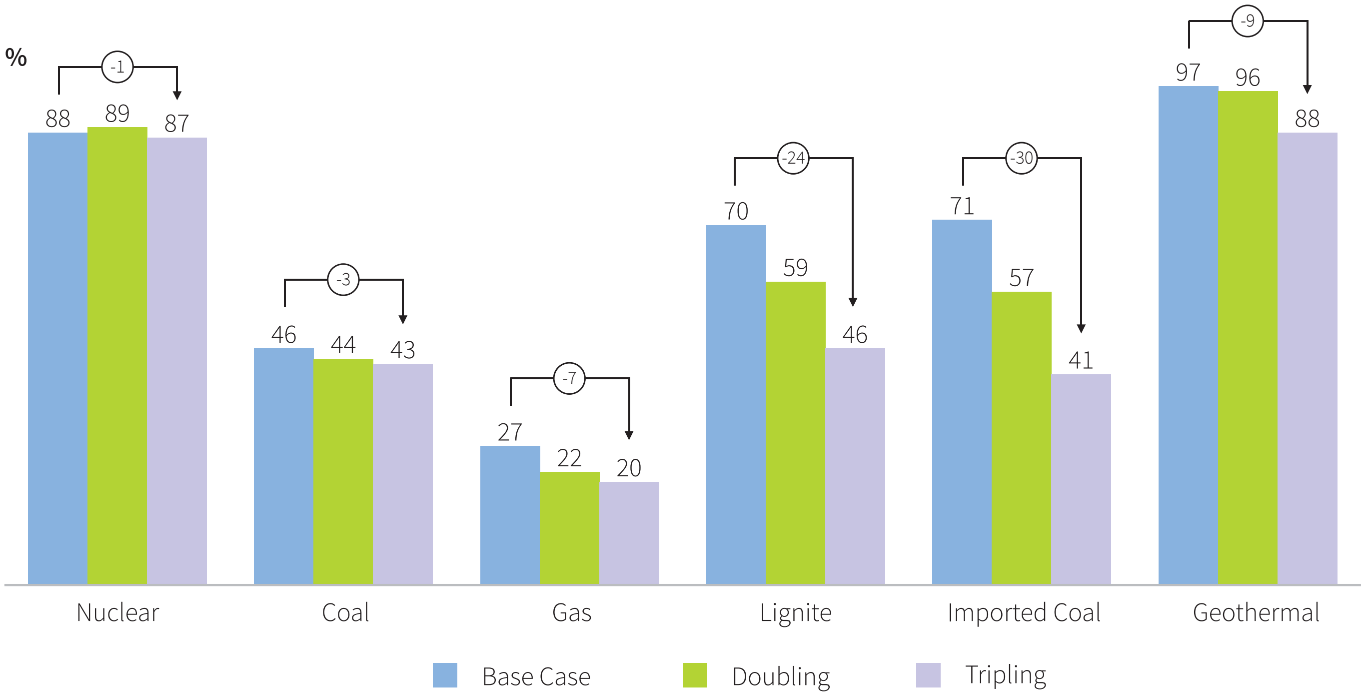


Figure 32. *Capacity factors by source, Base Case, Doubling and Tripling scenarios, 2026*

Obviously, this raises the question as to how much thermal capacity would disappear if a total of 60 GW wind and solar capacity would be installed. The answer to this question will depend on many issues and lies beyond the scope of this study. If – just to show the effect - the full load hours of the Base Case scenario were taken as a benchmark, thermal capacity would decrease considerably: In the Doubling scenario, gas capacity would decrease by 5.6 GW, lignite and import coal by 2 GW each. In the Tripling scenario, gas capacity would decrease by 8 GW, and lignite and import coal by about 4.5 GW each.[98]

[97] New generation under 500 full load hours was removed from the model. In the Tripling scenario, this led to the removal of 1.8 GW of gas and 200 MW of lignite generation capacity relative to the Base Case.
[98] We calculate an alternative installed capacity figure for Doubling and Tripling scenarios utilizing the generated energy in these scenarios and full load hours of the Base Case scenario. The alternative installed capacity is equal to annual generated energy divided by the full load hours of the Base Case. As renewable energy penetration increases, the energy generated by thermal sources is reduced. Assuming the full load hours of thermal plants in the Base Case scenario, alternative installed capacity is calculated.

4.3.2. Reserve requirements

When tripling wind and solar capacity, maximum hourly share increases from 45% in the Base Case to 131% (and even to 138% with run-of-river hydropower) during the national holiday season. When the national holiday periods with particularly low demand are excluded, the maximum share is lower, at 97%.[99]

In line with the increase in wind and solar generation shares at certain hours, the maximum hourly ramp rate in the Tripling scenario increases from 10.8 GW to 14.3 GW. Reserve capacity needs within Turkey, in line with current practice – and based on the support of the ENTSO-E system – increase from 2,200 MW to 2,700 MW and are largely fulfilled by gas-fired power plants and hydropower plants based on the availability of water at particular hours. The reserve declines for national holiday periods as in the Doubling scenario. Some curtailment occurs as well (see Annex 2 for details).

4.3.3. Interregional power flows

Assessing the main regional imbalances in demand and supply, Trakya and Northwest Anatolia, two of the main demand centers in Turkey, continue to depend on imports from other regions for about 50% of their power. Undersupply in Central Anatolia persists, but it falls from 20 to 10 TWh. On the other hand, West Anatolia continues to have a major surplus of energy (+20 TWh), as does the eastern part of the country (+ 37 TWh, Southeast and East Anatolia combined).

A comparison of the annual supply-demand balance of the Tripling scenario with that of the Base Case and the Doubling Scenarios leads to an interesting observation: the sum of regional imbalances actually falls by about 10%.

A comparison of the annual supply-demand balance of the Tripling scenario with that of the Base Case and the Doubling Scenarios (Table 7) leads to an interesting observation: the sum of regional imbalances actually falls by about 10%. In four regions, the effect is positive; in three regions it is marginal; and only in two regions is it negative. In Central Anatolia, West Anatolia, and East Mediterranean, power imbalances are reduced by about 10 TWh in each region. The larger effect in these regions comes from the increase in wind and solar in the Tripling scenario. It should be noted that although the East Mediterranean region has very high solar irradiation sites, no new solar REDA zones are considered there because of the high agricultural and industrial activities and the limited free space for such facilities. In the Tripling scenario, the only region that is negatively affected in its supply-demand balance is Southeast Anatolia. The increase of solar PV and the extensive share of hydropower create an annual oversupply of 10 TWh. Due to the seasonality of hydro and, partly, PV, there are, in all scenarios, times of the year where power needs to be imported and others where power needs to be exported.

[99] During these extreme hours, some wind or solar generation will need to be curtailed.

Table 7. Regional generation and demand balance

Region Generations (TWh)	Base Case	Doubling	Tripling	Demand
Trakya	23.0	22.1 ↓	21.6 ↓	65.9
N-West Anatolia	54.7	46.6 ↓	46.4 ↓	94.4
West Anatolia	94.8	93.0 ↓	84.1 ↓	62.7
Mid-Anatolia	29.9	34.7 ↑	40.1 ↑	49.8
West Mediterranean	22.6	29.0 ↑	33.2 ↑	29.8
Mid-Black Sea	35.1	34.2 ↓	36.2 ↑	22.6
East Anatolia	19.0	19.4 ↑	20.2 ↑	14.5
South-East Anatolia	63.4	68.3 ↑	72.2 ↑	62.5
East Mediterranean	76.1	71.3 ↓	64.5 ↓	37.3

Although an improved supply-demand balance is observable, the main flow pattern across the network remains similar to the previous scenarios. Neither the solar generation increase in southern regions nor the wind generation increase in western regions is sufficient to change these main flows, as their wind and solar increases are mostly offset by declines in conventional sources in the same regions. However, this observation is valid only for annual energy. Hourly flow on individual transmission lines reaches higher values than in the other two scenarios, which produces larger investment requirements and a more congested network.

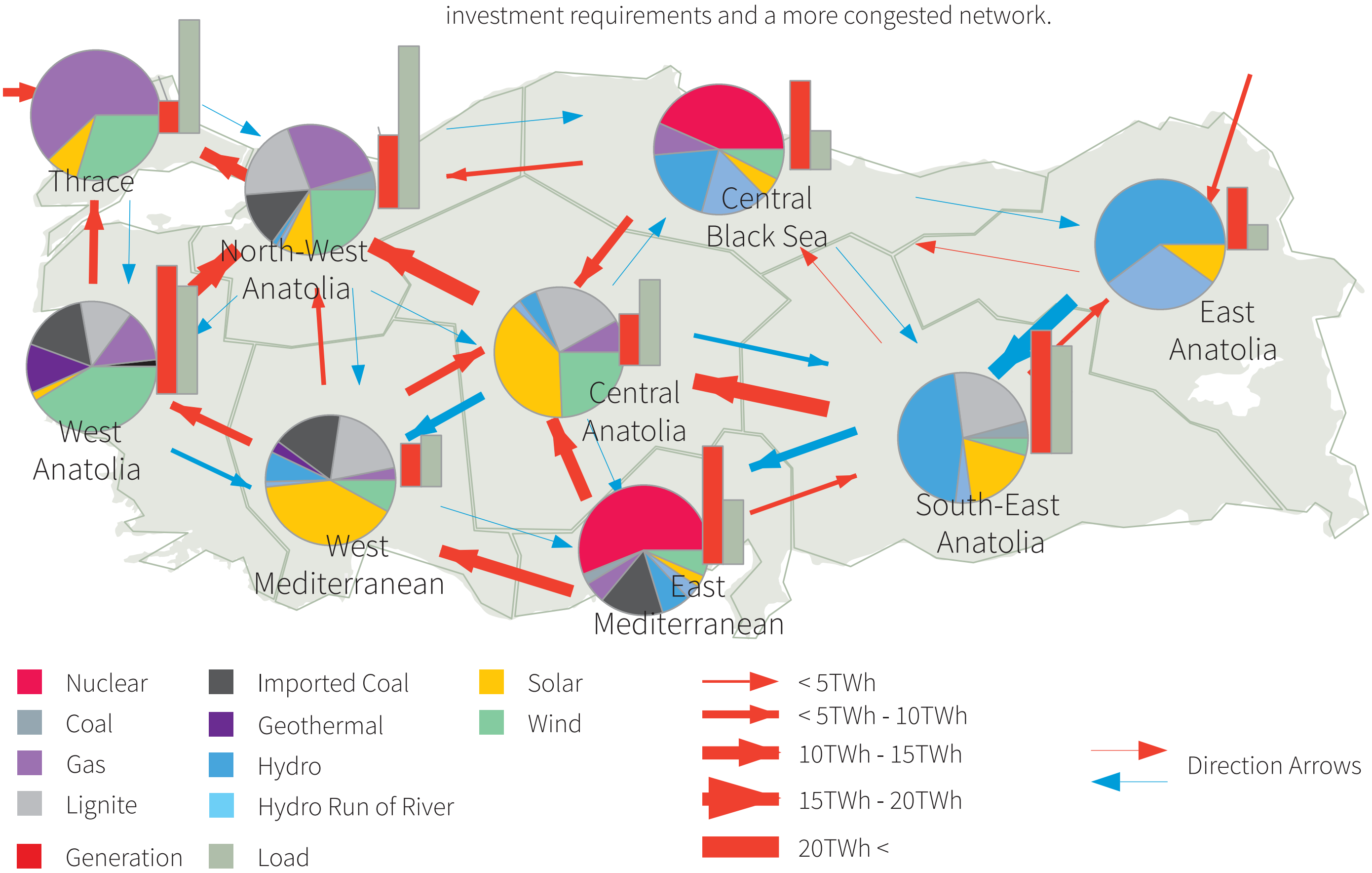


Figure 33. Regional generation/load balance and inter-regional exchange for Tripling scenario, 2026

4.3.4. Transmission capacity investment

The need for additional transmission lines is determined not only by interregional power flows but also by intraregional power flows. While a limited amount of curtailment and redispatch may be more cost-efficient than building new infrastructure, frequent and large congestions and reserve shortages provide an economic rationale for expanding the system.[100]

Tripling solar and wind by adding more capacity at the best wind and solar sites would require additional investment in the grid.

Tripling solar and wind by adding more capacity at the best wind and solar sites would require additional investment in the grid (Figure 34). For the 400-kV-grid, an additional 2,770 km of line are required, 30% more than the Base Case scenario. For the 154-kV-grid, an additional investment of 5,600 km would be needed, an increase of more than 50% over the planned investment. For transformer stations the impact would be lower, with 12 additional units required on top of the 62 stations already planned (+20%).

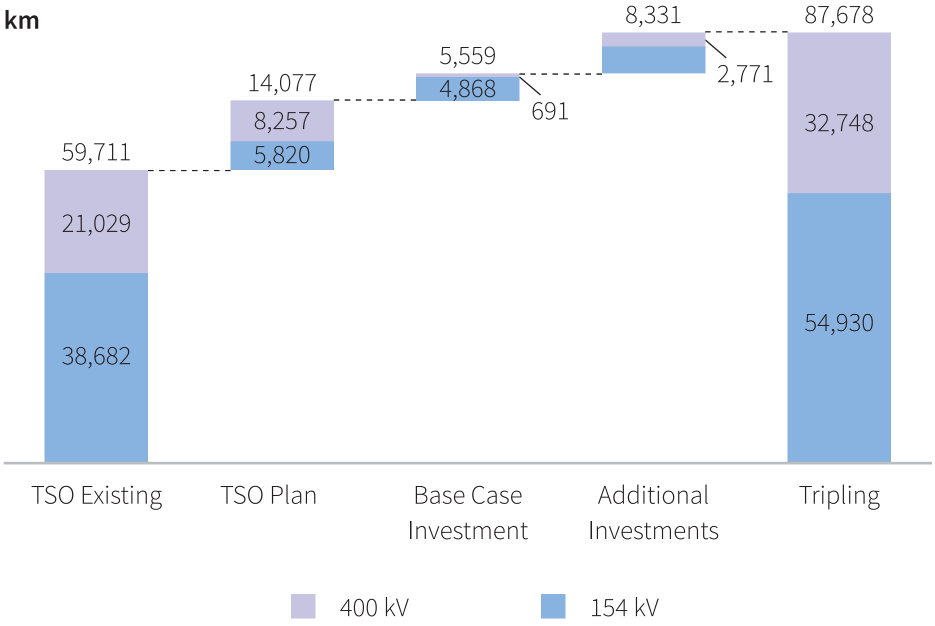
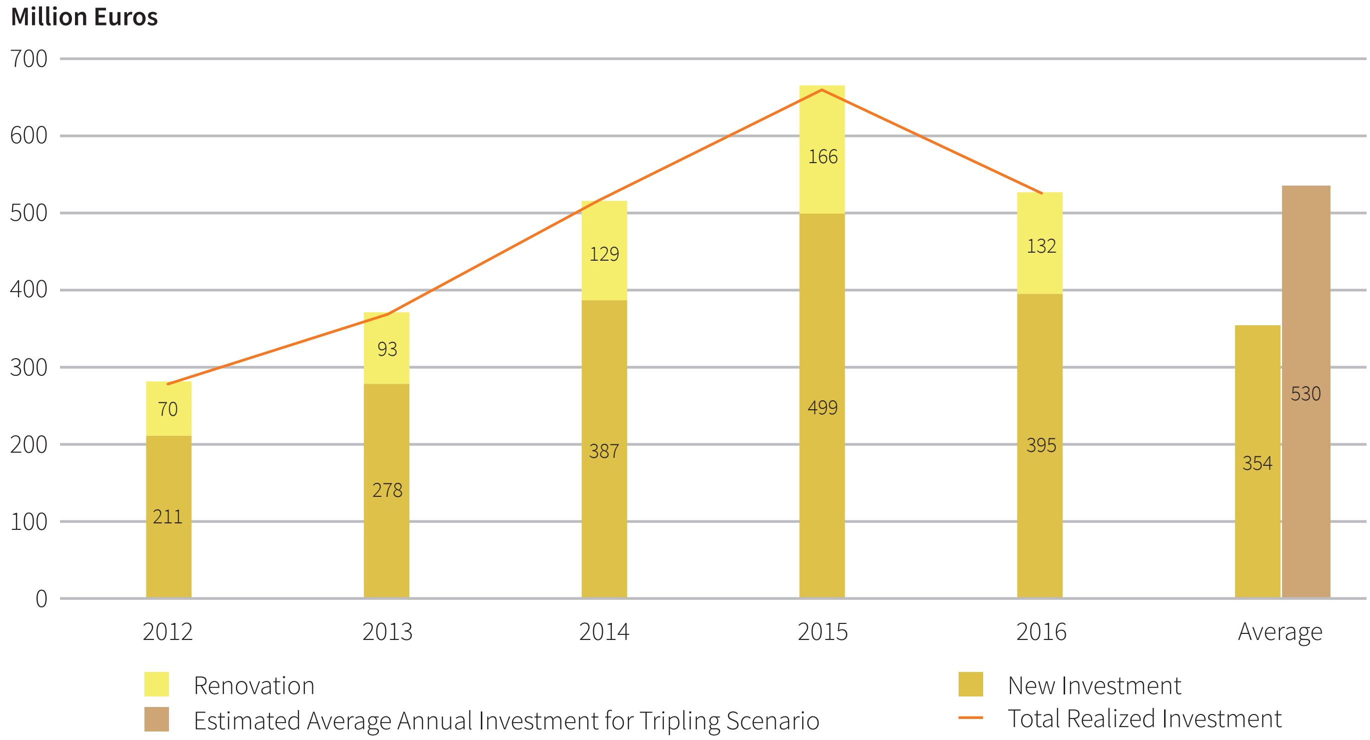


Figure 34. *Transmission grid investments for the Tripling scenario, 2026*

Overall investment costs for adding this infrastructure would be 5.30 billion €, up from 3.86 billion € in the Base Case.

Overall investment costs for adding this infrastructure would be 5.30 billion €, up from 3.86 billion € in the Base Case. This translates into an annual investment of 530 M€, which is 50% higher than TEİAŞ's assumed[101] average investment over the past 5 years.[102]

[100] On the general methodology of proposing additional infrastructure instead of relying on redispatch and curtailment, see Section 3.3 and Section 3.4.
[101] See Section 4.1.4 for details of "assumed average investment".
[102] Annual planned and realised investment figures are available in TEİAŞ website in USD. For the sake of consistency, the currency is converted into EUR using the average annual exchange rate from *"https://evds2.tcmb.gov.tr"*



* Total realized investment figures are taken from TEİAŞ,[103] though no public information was available about the ratio of new investment and renovation investment. Given the high increase in demand and the major network investment in the last decade, renovation investment is assumed to be no larger than 25% of annual investment.

Figure 35. *Comparison of the realised TEİAŞ, investments with the Tripling scenario investments*

Most investment in the 400 kV grid will have to take place in Northwest Anatolia, strengthening capacity for power flows from West Anatolia and Northwest Anatolia to Trakya, as well as in the East Mediterranean and Southeast Anatolia regions. This is mainly due to the high feed-in of solar power in the REDA zones in the southern areas to load centers in northwestern Turkey. As for the 154-kV-grid, considerable additional investment would be needed across the entire country due to the many new generation feed-in points added to the network, which is not consistent with the initial design.

Figure 36. *Required investments in the transmission grid identified based on security and reliability criteria according to the Tripling scenario, 2026*

[103] *TEİAŞ statistical information system available at: https://www.teias.gov.tr/tr/turkiye-elektrik-uretim-iletim-istatistikleri*

4.3.5. Redispatch and curtailment

Despite the additional transmission investment in the Tripling scenario, the need for redispatch increases to 34.4 TWh (Figure 37). This is 13.4 TWh above the Base Case scenario value, an increase by more than one-third, with redispatch amounting to 7.8% of overall demand. In addition, 2.8% of wind and solar generation (3.6 TWh) must be curtailed. The specific curtailment rate is 1.0% for solar and 4.0% for wind. Curtailment and / or redispatch need to be implemented during more than 1,500 hours of the year, at different levels and locations. In general, curtailment is localized along the western coast and in the southern Marmara region for wind and distributed mostly among REDA zones for solar (Figure 39).

Over the year, there are 17 hours (41 hours with the run-of-the-river hydropower) during which the generation of wind and solar exceeds demand, and 161 hours (280 hours with run-of-the-river hydropower) during which it exceeds a share of 75%.

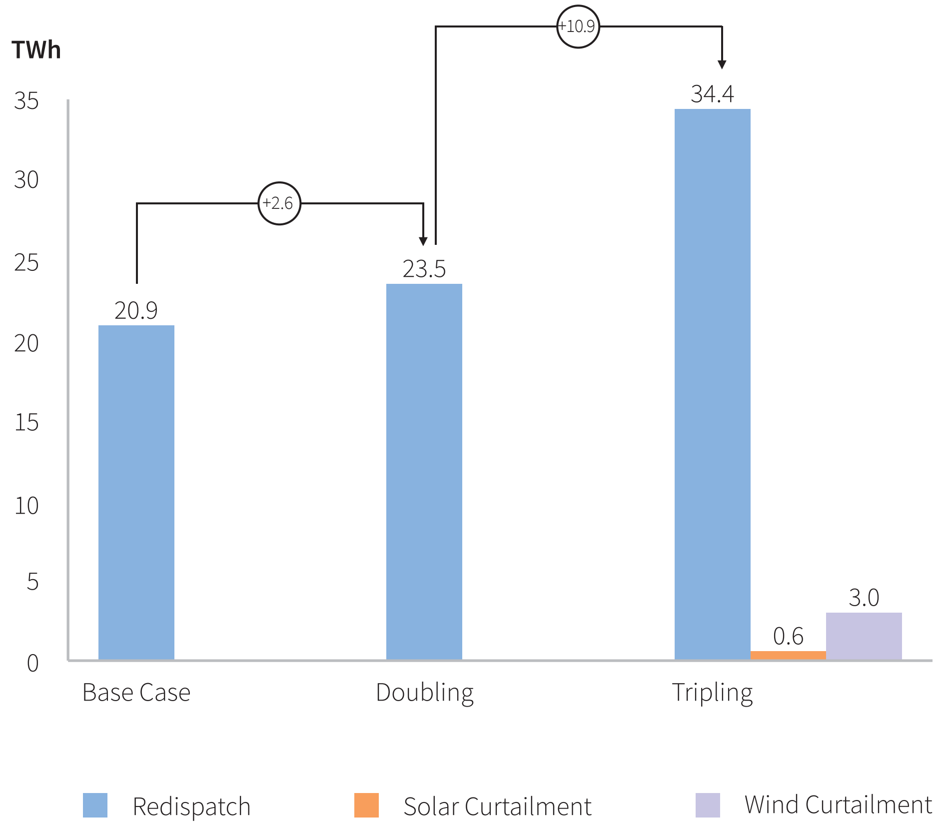


Figure 37. *Redispatch according to the Base Case, Doubling and Tripling scenarios, 2026*

The redispatch figures clearly show the need to frequently adopt the most efficient dispatch as identified in the market, in order to arrive at a feasible dispatch from an operational point of view (Figure 37).

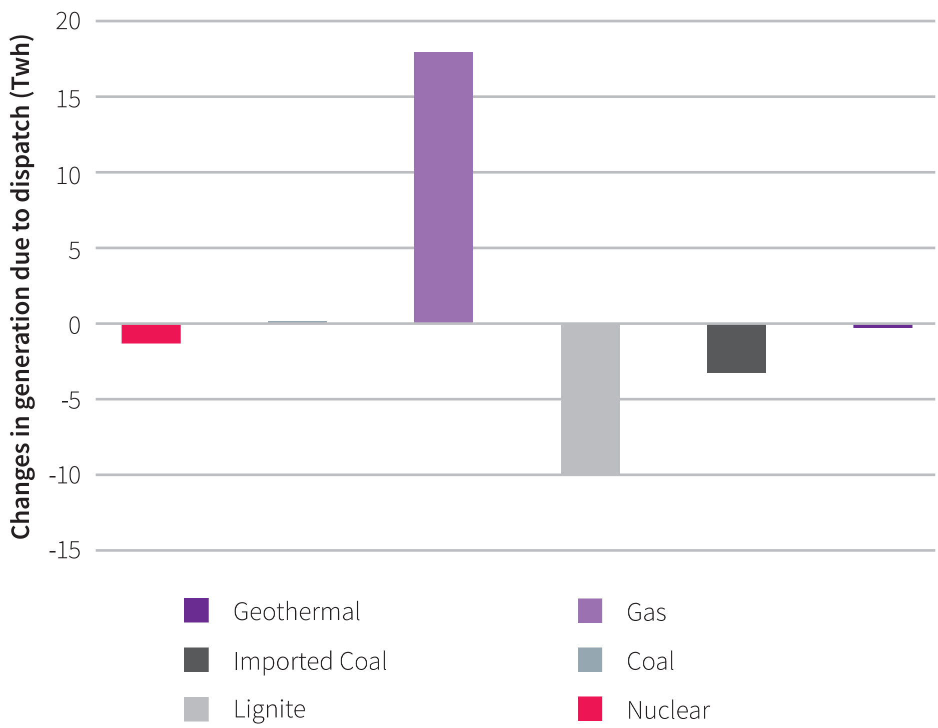


Figure 38. *Redispatch according to the Base Case, Doubling and Tripling scenarios, 2026*

In the Tripling scenario, positive redispatch orders are even more centralized in Trakya and around Marmara Sea, while most of the negative dispatch orders are located in Northwest, West and Central Anatolia regions to relieve grid congestions. Outside of these regions, positive redispatch orders for gas-fired plants occur mostly on account of reserve requirements, which require a reduction of power generation from lignite and imported coal (Examples of this can be found in Southeast Anatolia and in the East Mediterranean region).

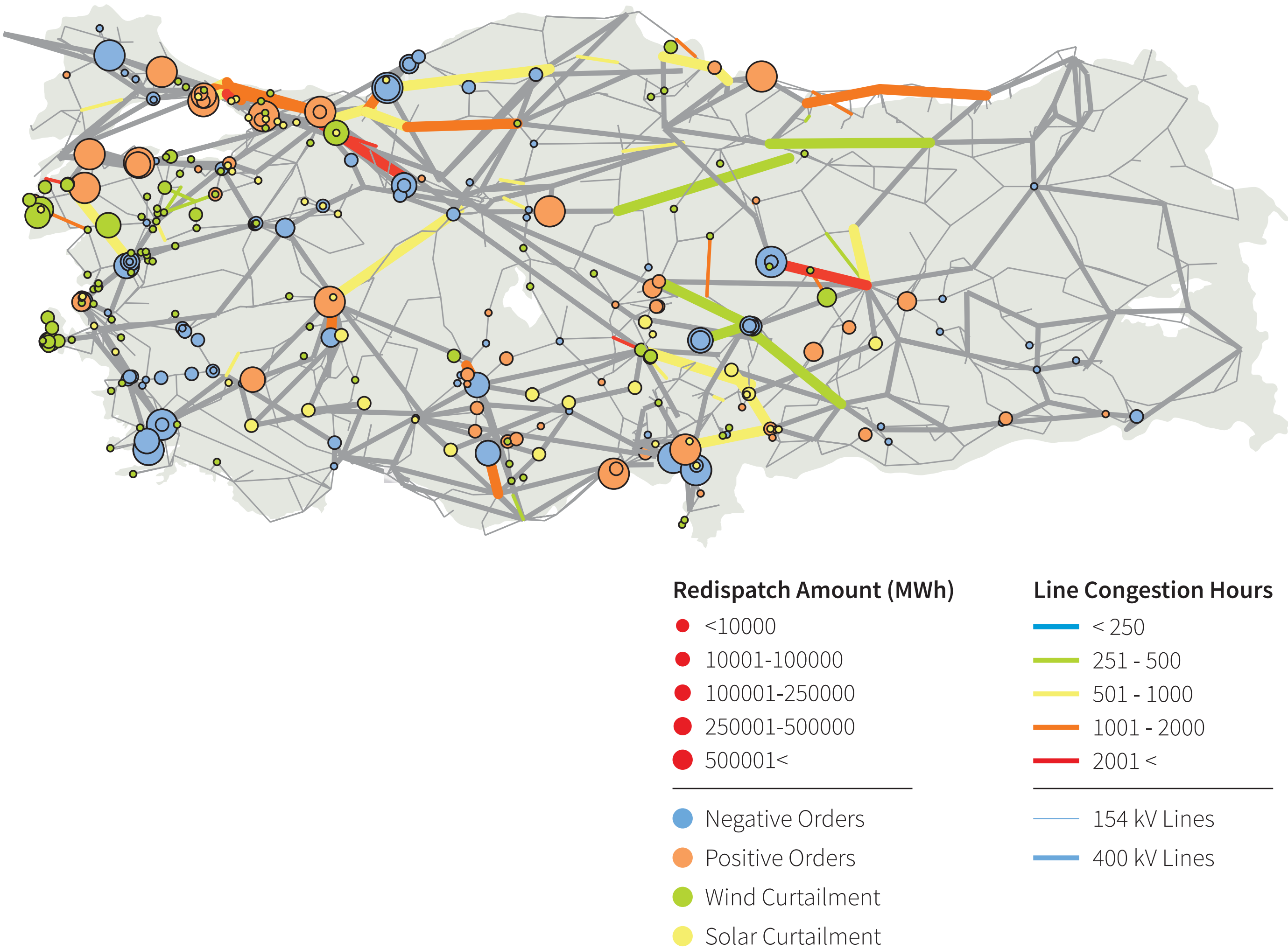


Figure 39. *Annual congestion levels and thermal re-dispatch orders after transmission grid investments according to the Tripling scenario, 2026*

5. Benefits of System-Friendly Wind and Solar Allocation and Increasing Flexibility

5.1. Distributing solar and wind more widely across Turkey

In our strategy analysis, we have assessed the impact of distributing solar and wind generation more widely across the country, both for the Doubling and Tripling scenarios (system-driven allocation). This more system-driven approach emphasizes the smoother distribution of wind and solar plants with regard to wind speed and solar irradiation quality and considers local demand and substation capacity.[104] For solar, the scenario assumes that no additional REDA projects will be implemented. For wind, 5.8 GW of wind generation (by the end of 2016) was installed already, mostly along the Aegean coast. Because these are fixed, only a limited capacity is free for a more balanced allocation across Turkey. Since West Anatolia is a region not only with excellent wind conditions but also high demand, the effect of this allocation method is smaller than for solar.

The difference in allocation of wind and solar[105] between the default scenario and the strategy is shown in Figure 40 and 41.

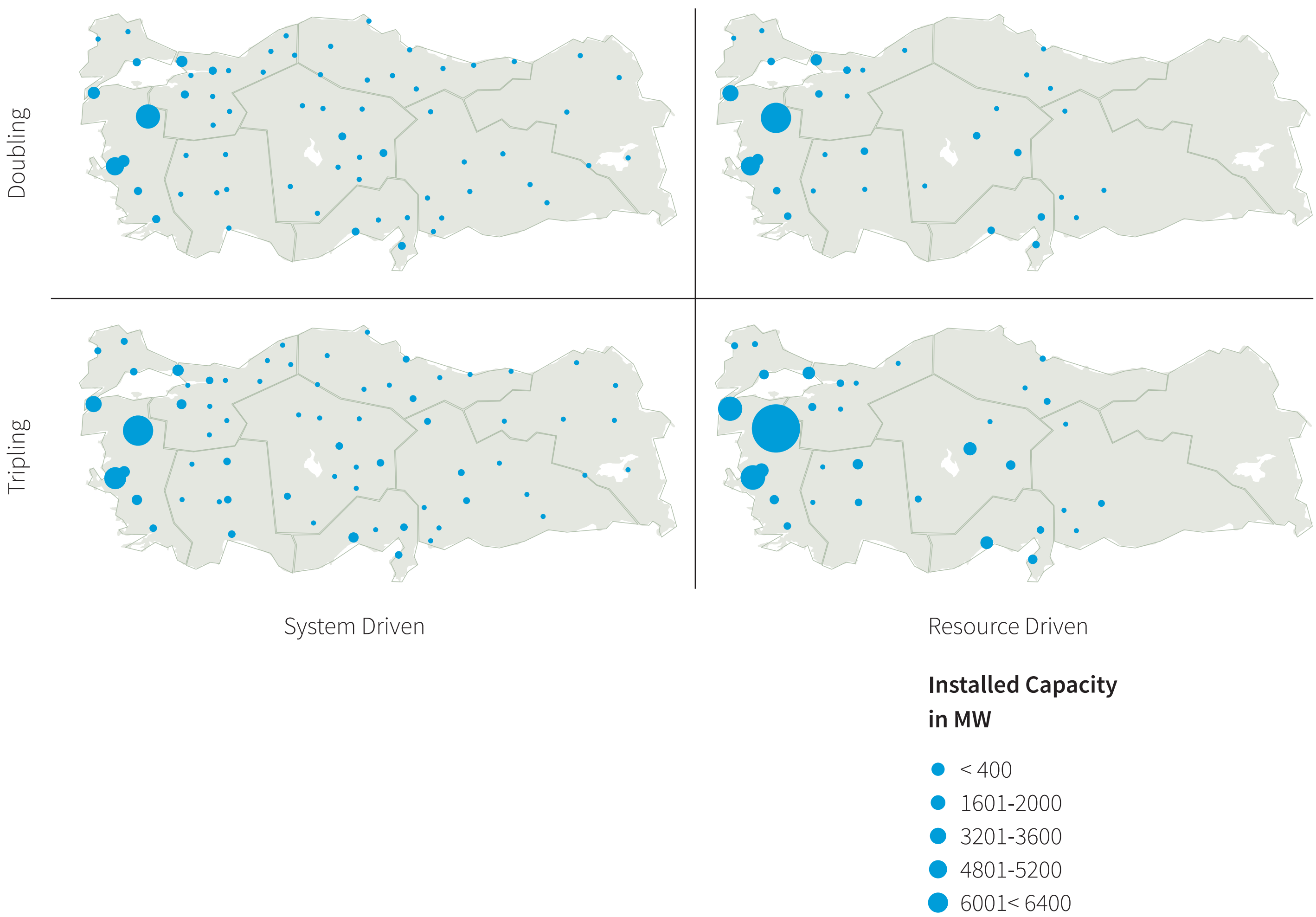


Figure 40. *Comparison of wind capacity allocation in the resource-driven and system-driven strategies, 2026*

[104] *Please see Annex 2 for more details.*
[105] *Please see Annex 2 for more details.*

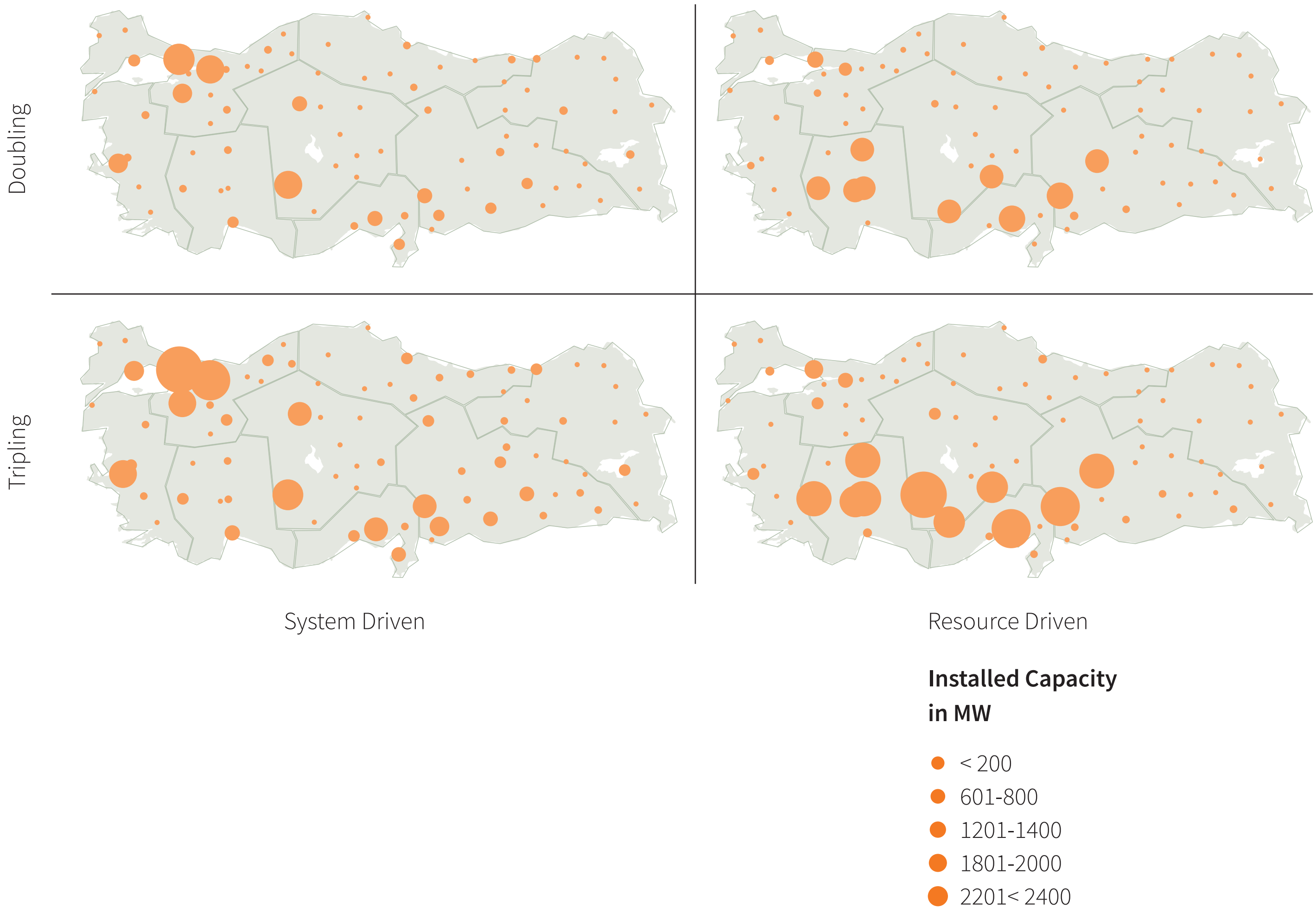


Figure 41. *Comparison of solar capacity allocation in the resource-driven and system-driven strategies, 2026*

5.1.1. Effect on the Doubling scenario

5.1.1.1. Regional changes to wind and solar capacities

In this strategy wind investment decreases in the East Mediterranean region, in Trakya and in West Anatolia, and increases in all other regions. With the exception of West Anatolia, where the decrease is about 1.3 GW, changes in all other regions remain in a bandwidth between -390 MW and +550 MW.

Distribution effects for solar generation are considerably higher in the system-driven approach. Only in two regions, Southeast Anatolia and East Mediterranean, are they below 200 MW, while in the remaining seven regions changes are no lower than 950 MW. Both in central Anatolia and the western Mediterranean regions, the decrease of solar generation capacity is above 3 GW.

In total, wind and solar capacity decreases in southcentral Turkey and along the Aegean coast (though only slightly). This drop is offset by an increase in all four northern regions, and some slight additions of wind capacity in Southeast Anatolia (Figure 42).

What is not visible on the regional scale but needs to be borne in mind as well is the fact that there is also a considerable redistribution of wind and solar capacities within the regions.

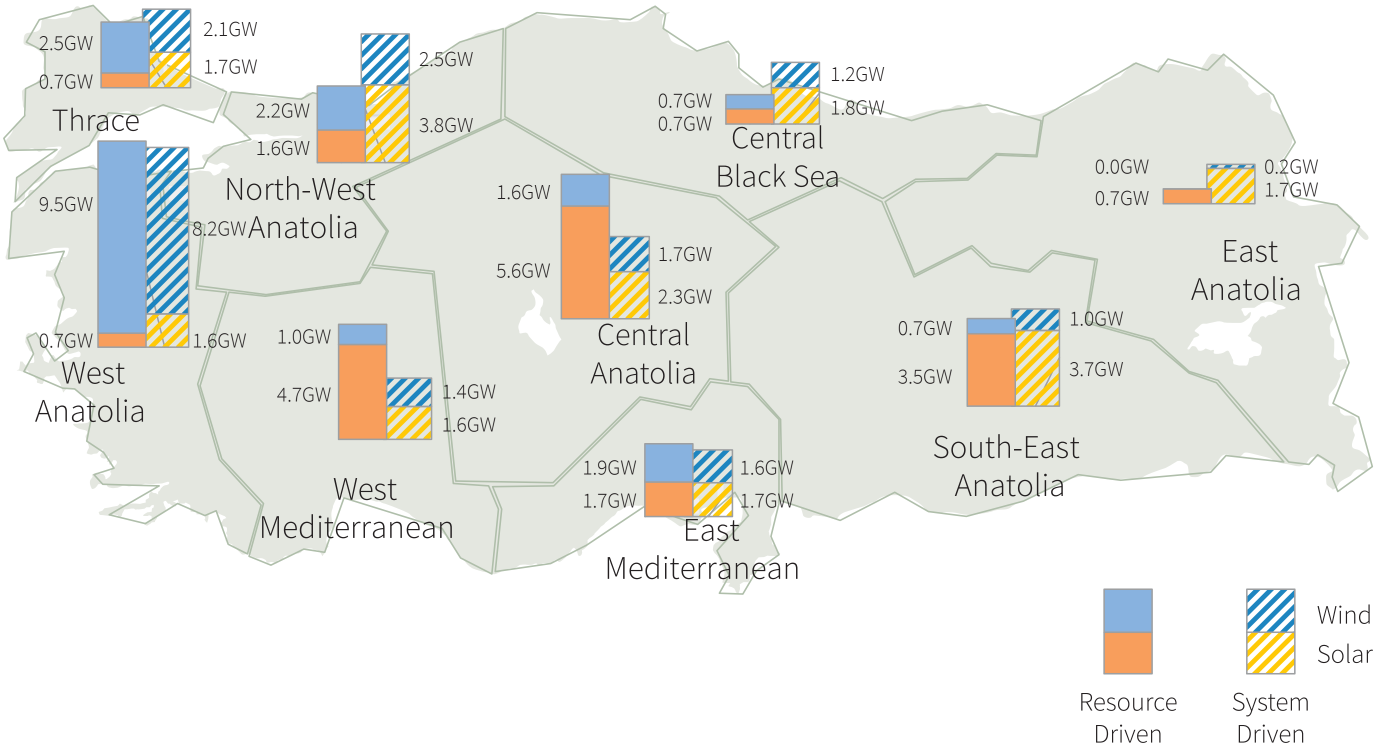


Figure 42. *Allocation of wind and solar capacities in the resource-driven and system-driven strategies according to the Doubling scenario, 2026*

5.1.1.2. Capacity factor and ramp rates of wind and solar

The more balanced distribution of wind and solar PV capacity leads to some reduction in generation output, from 90.6 TWh per year to 87.3 TWh per year, as some attractive sites are substituted by others with slightly reduced capacity factors. Reduction is about 1.8 TWh in solar and 1.5 TWh in wind generation. The capacity factor for both technologies is rather low, dropping from 21.3% to 20.2% in solar and from 30.5% to 29.6% in wind. The impact on the levelised cost of generation of wind and solar when these are allocated at more system-friendly locations in Turkey is, therefore, negligible.

One advantage of spreading weather-dependent generation capacities across geographies is a more balanced generation curve. Indeed, the maximum hourly ratio of wind and solar to demand falls from 89.4% to 86.9%. The same is true when looking at maximum hourly ramp rates, which drops only by about 50 MW (0.5%). Although the change in maximum values is small, the days with strong impact in net load (Figure 43) facilitate system integration.

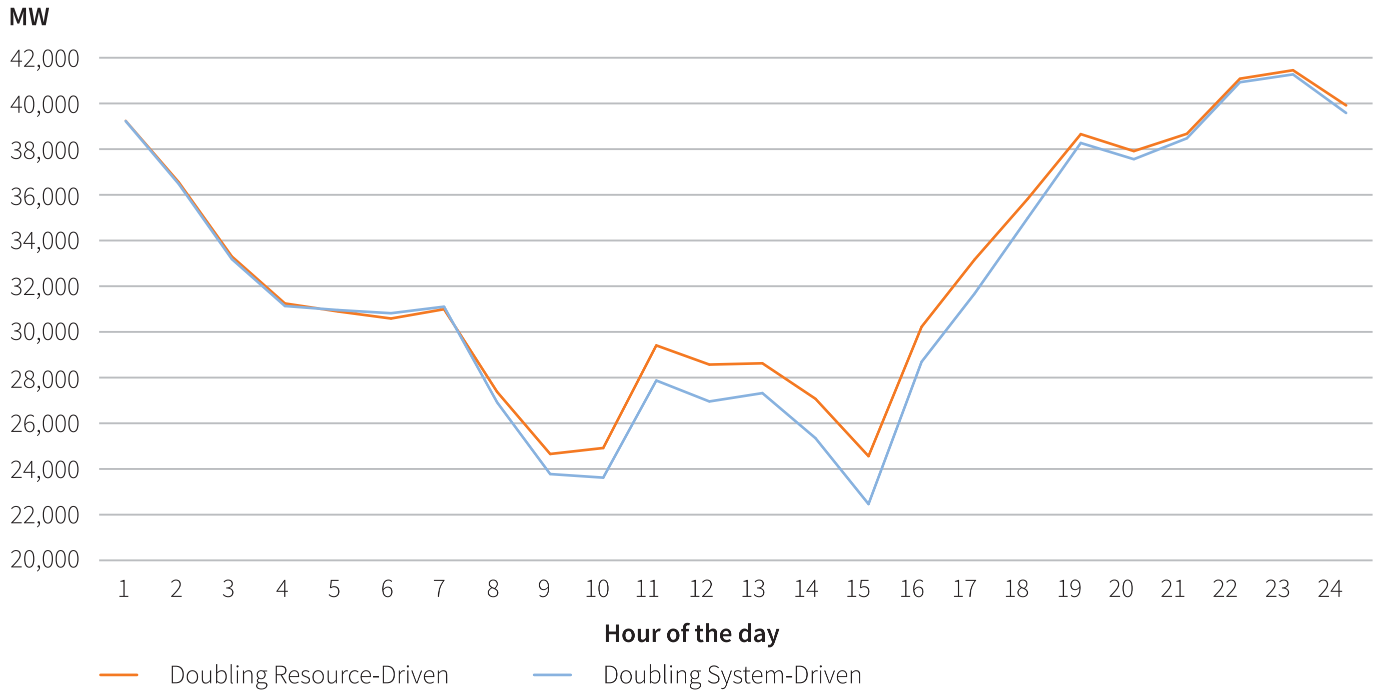


Figure 43. *Net load deviation example; difference between resource-driven and system-driven strategies*

5.1.1.3. Transmission investment and redispatch

The effects on transmission capacity requirements (tested in separate modeling runs) are limited. For ease of comparison, therefore, we maintained the 2026 transmission infrastructure in the Base Case scenario. This allows us to use redispatch values as the main indicator for the effect of distributing solar and wind. In this strategy redispatch can be reduced from 23.5 TWh to 21.8 TWh. Thus, redispatch for the Doubling scenario rises only 0.7 TWh above the value in the Base Case scenario while remaining below 5% of annual demand (Figure 44).

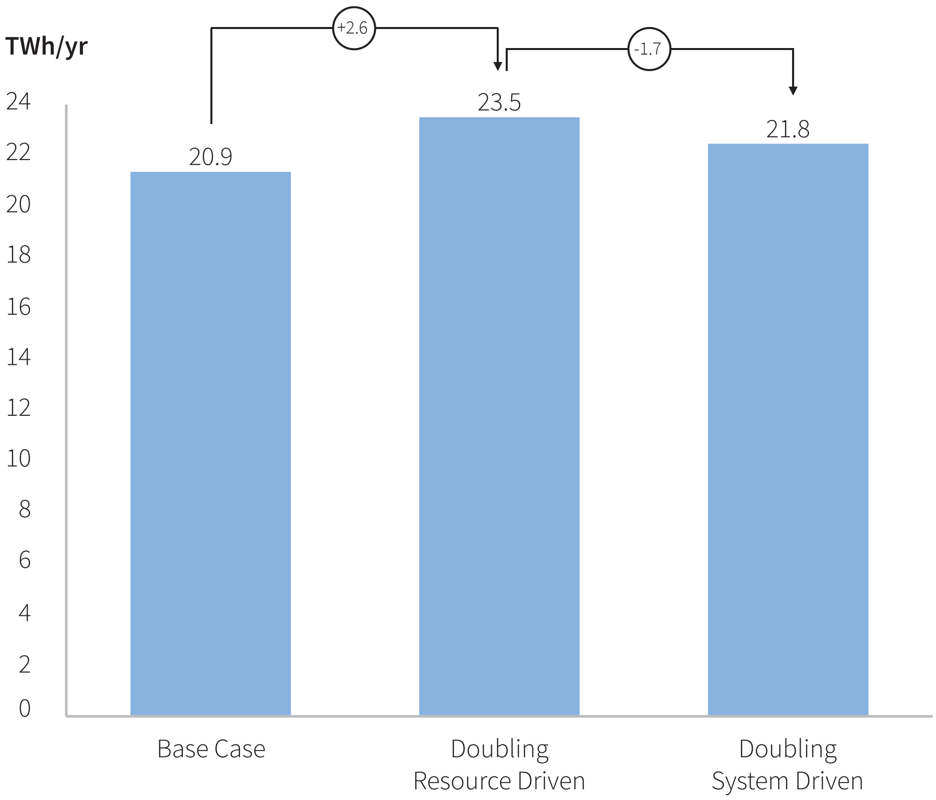


Figure 44. *Redispatch according to the Base Case and Doubling scenarios for resource and system-driven strategies*

There are tangible effects in distributing 40 GW of wind and solar more widely across Turkey: wind and solar generation is slightly more balanced, and system integration is improved.

In sum, we see that there are tangible effects in distributing 40 GW of wind and solar more widely across Turkey: wind and solar generation is slightly more balanced, and system integration is improved. As the redispatch reduction shows, doubling solar and wind capacity is still possible with the same transmission infrastructure and the same redispatch volumes, provided that wind and solar capacities are allocated in a system-friendly manner. The negative impact on wind and solar levelised cost of generation is negligible.[106]

5.1.2. Effect on the Tripling scenario

5.1.2.1. Regional changes of wind and solar capacities

In this strategy analysis, 11 GW of the total 60 GW of installed wind and solar capacity are shifted to other regions. This shift is driven by the same pattern as in the Doubling scenario: a strong reduction mainly in Central Anatolia and in West Mediterranean. The main increase of generation occurs in Northwest Anatolia, in Central Black Sea and, to a lesser extent, in East Anatolia and Trakya.

Two-thirds of the 5 GW regional shift in wind investment is due to a decrease in the main wind region of West Anatolia (-3.4 GW) along the Aegean Sea. Another 1.7 GW of wind capacity declines in Trakya and East Anatolia. Wind capacity increases in all other regions, with Central Black Sea (+1.5 GW) and West Mediterranean (+1.1 GW) taking the largest shares of additional capacity.

The distribution effects for solar generation are twice as high (10 GW).[107] As in the Doubling scenario, solar installation is reduced heavily in two neighboring regions, Central Anatolia and the West Mediterranean (~-5 GW each). The main beneficiary is Northwest Anatolia (+3.4 GW), where demand is high. All four northern regions – Trakya, Northwest Anatolia, Mid Black Sea and East Anatolia – see an increase of solar capacity by 1.5 GW. In the Tripling scenario, Central Anatolia and the West Mediterranean are the two leading solar regions; in the system-driven strategy approach, Northwest and Southeast Anatolia take the lead (Figure 45).

What is not visible on the regional scale but needs to be borne in mind is the considerable redistribution of wind and solar capacities within the regions. The reason that the redistribution does not appear is that it occurred on a substation level, especially in the 154 kV grid system.

[106] In order to arrive at recommendations on the location of future wind and solar investment, losses in economic efficiency would have to be weighed against overall system benefits. This was not part of the scope of this study, though we do provide the input and datasets needed for future analysis.
[107] The overall switch still is only 11 GW due to the fact that changes of wind and solar generation partly offset each other.

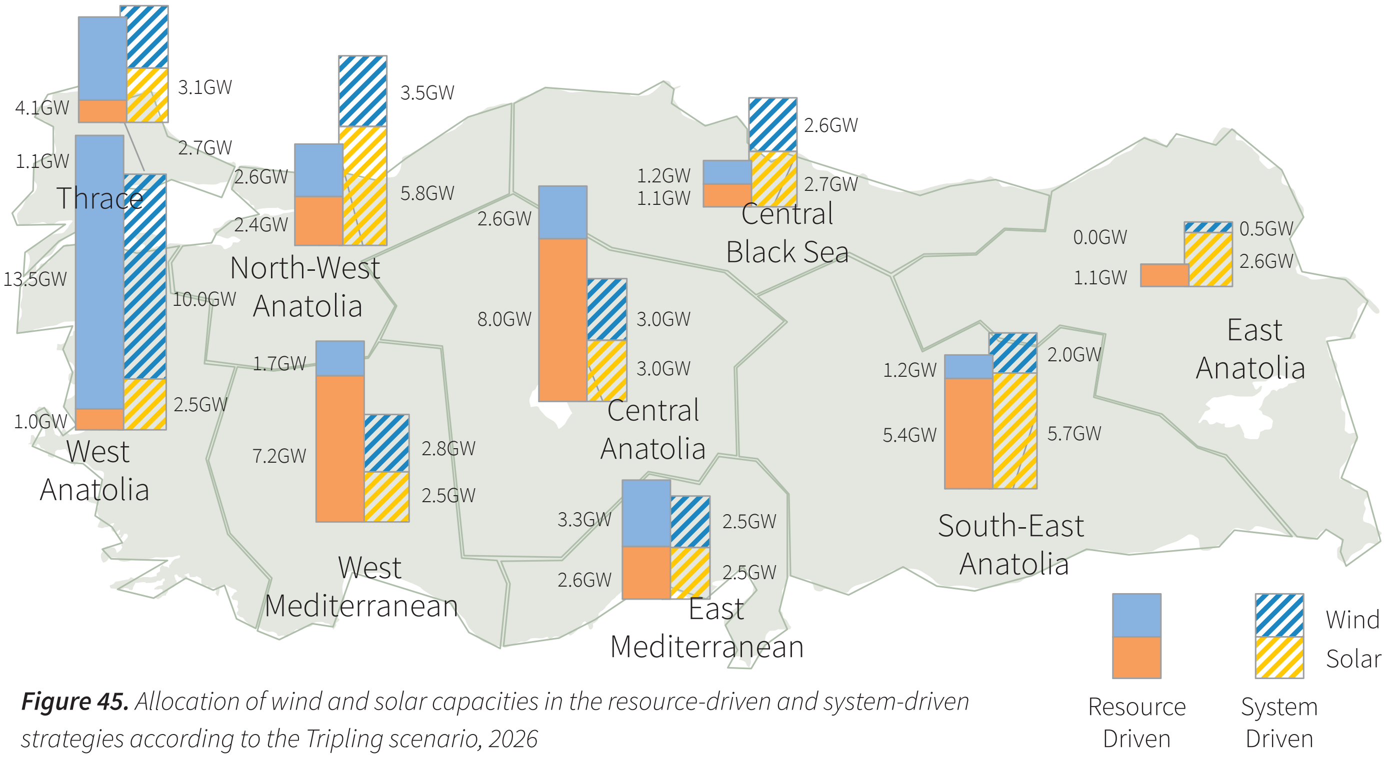


Figure 45. *Allocation of wind and solar capacities in the resource-driven and system-driven strategies according to the Tripling scenario, 2026*

The system-driven allocation of wind and solar also has a balancing effect, with the maximum hourly share of wind and solar in overall demand declining from 131.5% to 126.2%.

5.1.2.2. Effects on the capacity factor and ramp rates of wind and solar

The more balanced distribution of wind and PV capacity reduces generation output from 129.8 TWh per year to 125.4 TWh per year. Reduction is about 2.6 TWh in solar, and 1.8 TWh in wind generation. Capacity factors go down only slightly for both technologies: from 21.1% to 20.1% in solar, and from 28.3% to 27.6% in wind. The reason is that, while site quality decreases steeply from the few top sites (around 10 GW) to the second tier, the second tier nevertheless contains many locations with very attractive conditions for wind and solar.

The system-driven allocation of wind and solar also has a balancing effect, with the maximum hourly share of wind and solar in overall demand declining from 131.5% to 126.2%. The reduction in the maximum hourly ramp rate falls by about 100 MW, from 14.3 to 14.2 GW (-0.7%). Nevertheless, there are many days with a strong positive impact on net load, as shown in Figure 46.

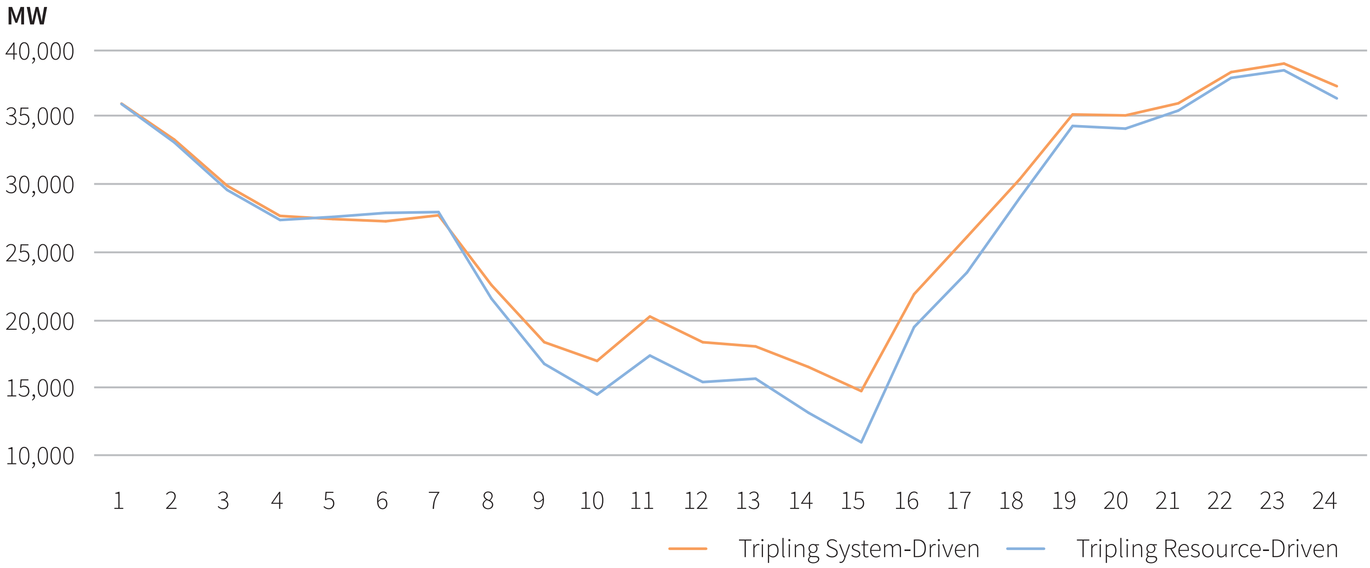


Figure 46. *Net load deviation example; difference between resource-driven and system-driven strategies*

5.1.2.3. Transmission capacity investment, redispatch and curtailment

Compared with the default scenario, the Tripling scenario has a considerable reduction in congestion and, by extension, in the need to supply additional transmission infrastructure.

To recapitulate, we already identified the need for another 8,300 km of new transmission infrastructure, 2,700 km of 400 kV lines and 5,600 km of 154 kV lines on top of that in the Base Case investment. Thanks to a more system-friendly distribution of solar and wind investment, two-thirds of these investments could be saved. Indeed, compared with the Base Case scenario, 700 km of additional 400 kV lines and 2,000 km of additional 154 kV lines would suffice to integrate 60 GW of wind and solar capacity in the grid (Figure 47).

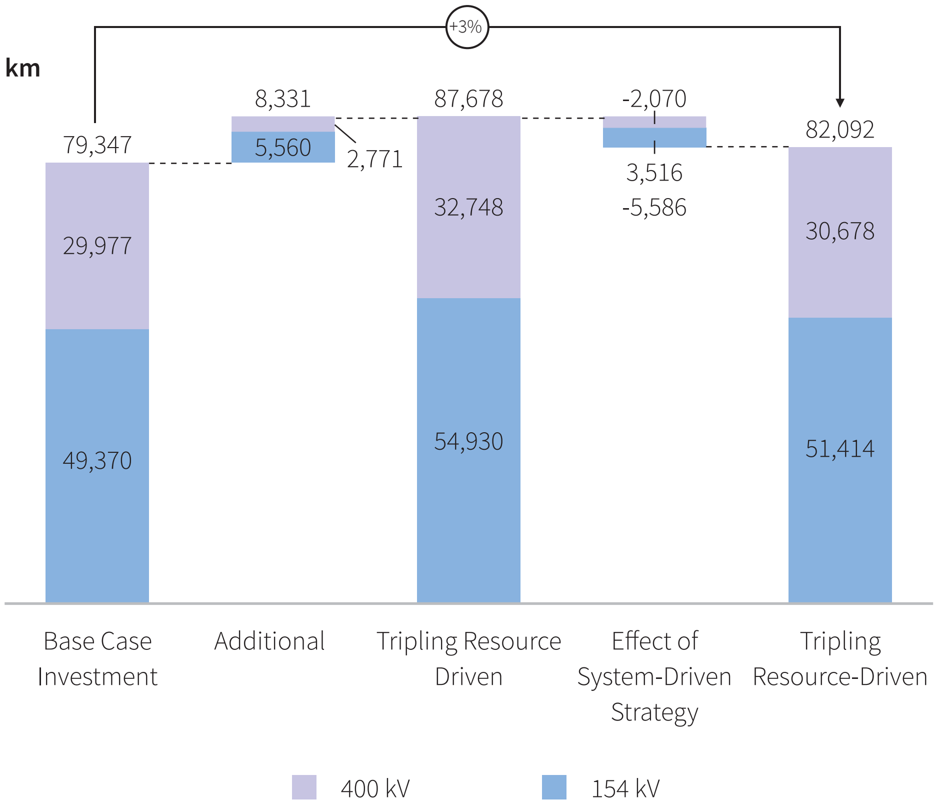


Figure 47. *Comparison of transmission grid investments for the Tripling scenario, 2026*

The potential to reduce grid expansion requirements across Turkey can clearly be seen on the maps displayed in Figure 48.

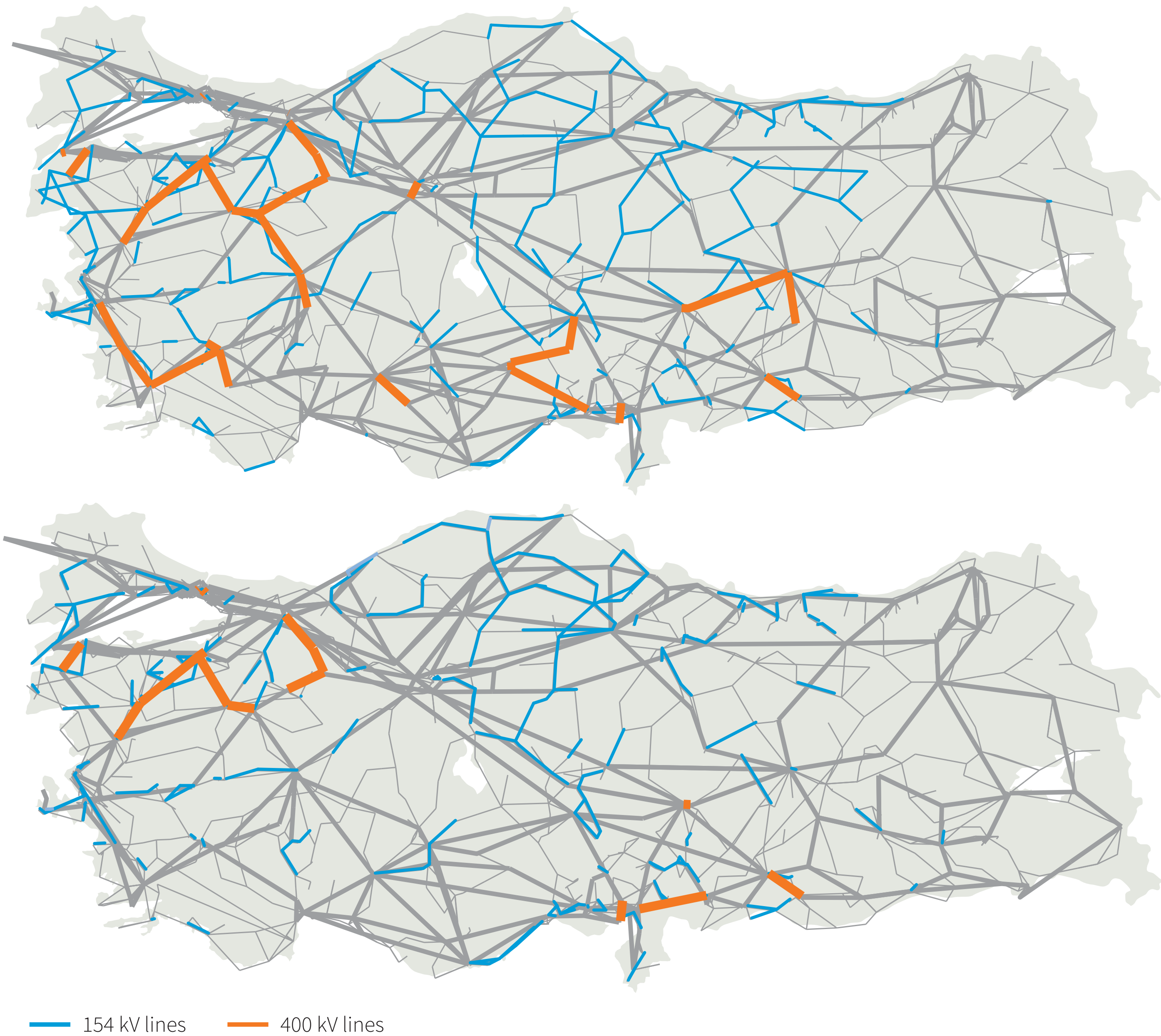


Figure 48. *Comparison of investment needs for resource-driven and system-driven strategies according to the Tripling scenario*

These infrastructure requirements (Figure 48) show an investment over the ten-year period of 4.3 billion €, which is 1 billion € below the Tripling scenario (resource-driven) and 400 million € above the Base Case scenario. An annual average investment of 430 million € would be only 21% higher than TEİAŞ's average investment for the past five years.[108]

Despite transmission grid reduction, there is nevertheless a remarkably positive effect: redispatch falls by more than 5 TWh, from 34.4 TWh to 29.1 TWh. This value is still well above the Base Case and Doubling scenarios, which are slightly above 20 TWh, and is considerably higher than the current level. Reducing it further would require substantially more transmission investment or additional power system measures to facilitate system integration. The changes in redispatch and are given in Figure 49 and Figure 50. As wind and solar generation is distributed more widely throughout the grid, congestion falls in almost all network elements. Redispatch reduction is most visible in the northwestern region of Turkey.

[108] See Section 4.1.4 for details of "assumed average investment".

In the Tripling scenario, frequent **curtailment** – totaling 3.6 TWh annually – is necessary to safely operate the system. The effect of distributing solar and wind better has a remarkably positive effect on curtailment, which decreases to below 1 TWh. The effect is particularly positive on wind generation, where curtailment is reduced by almost 80%, from 3,000 GWh to 640 GWh.

The distribution of curtailment is displayed in Figure 49 and Figure 50. Power distribution greatly reduces wind generation curtailment in the West and North West. Further, as generation is shifted towards demand centers, solar generation curtailment (observable in the southern regions) falls as well.

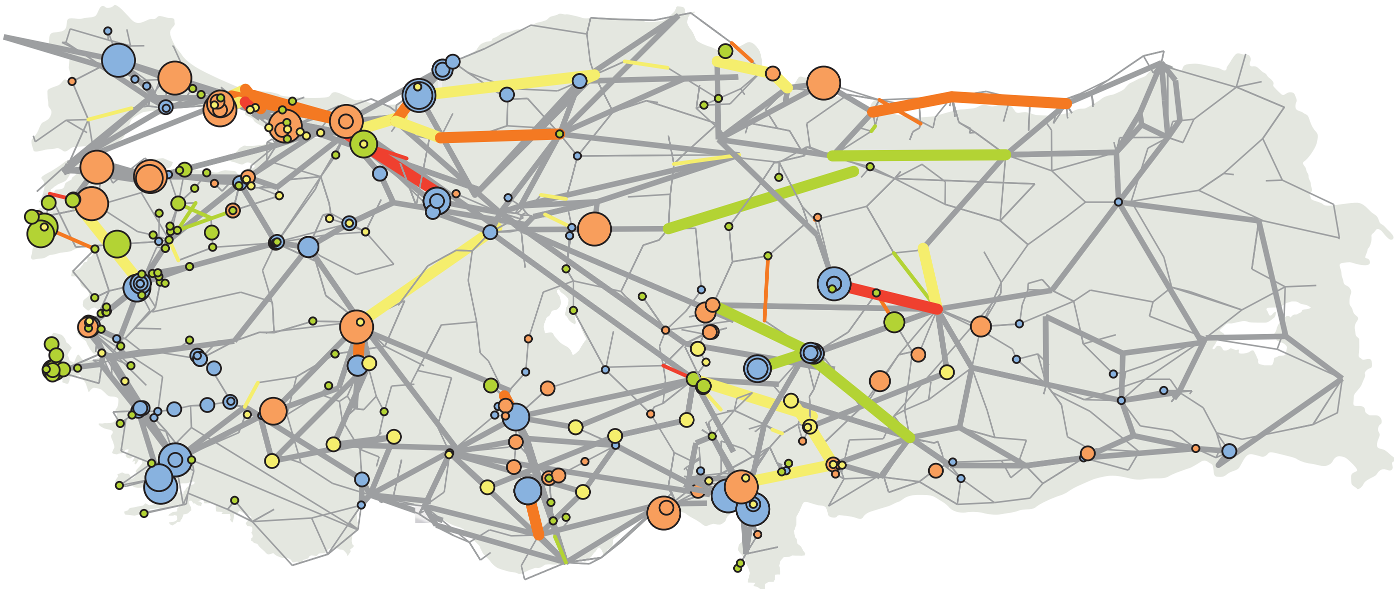


Figure 49. *Redispatch, network constraints and curtailment locations for resource-driven strategy according to the Tripling scenario*

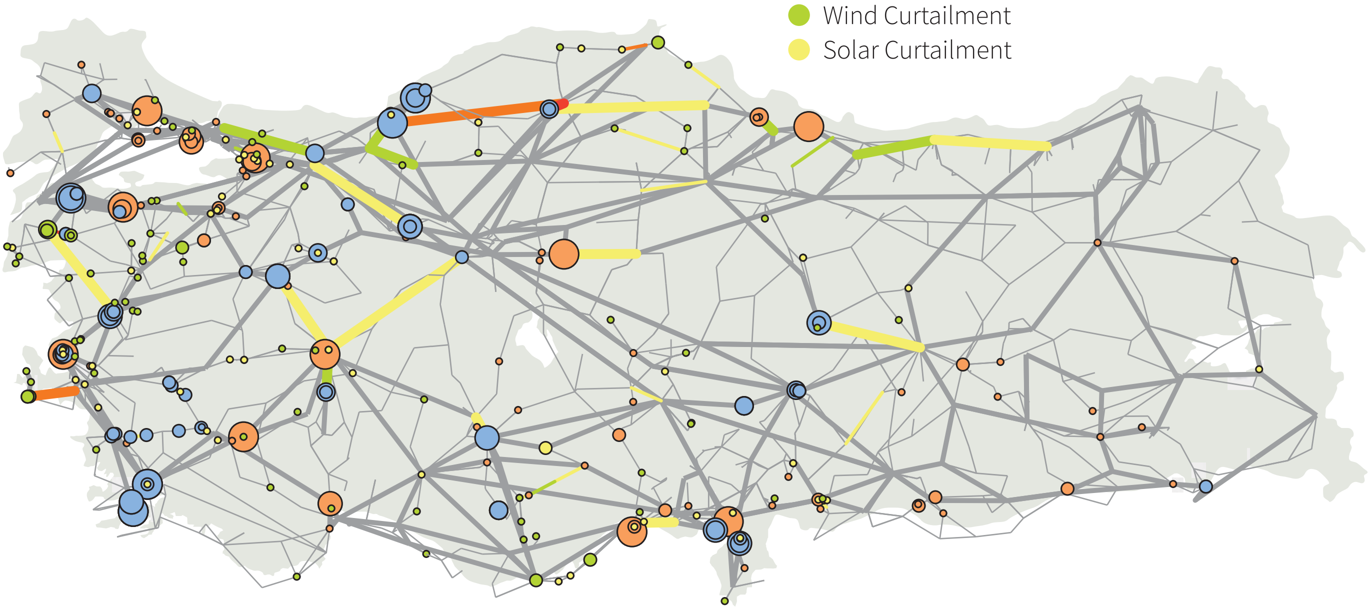


Figure 50. *Redispatch, network constraints and curtailment locations for system-driven strategy according to the Tripling scenario*

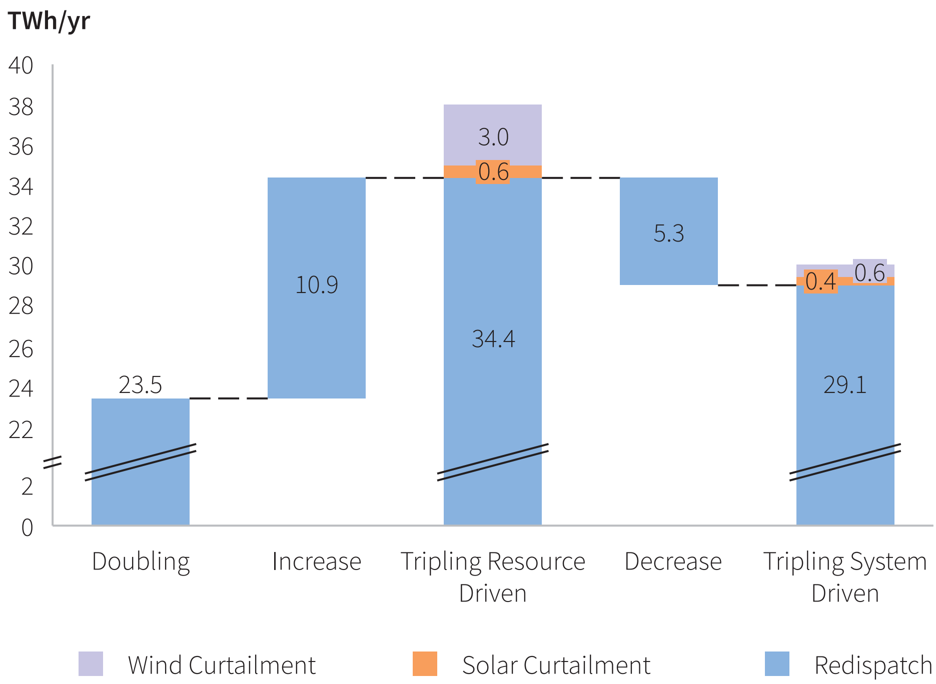


Figure 51. *Comparison of redispatch and curtailment, resource-driven versus system-driven strategy according to the Tripling scenario*

In conclusion, a more balanced distribution of wind and solar across Turkey produces significant benefits when a large share (above 20–25% of annual generation) of renewables technology is in place.

In conclusion, a more balanced distribution of wind and solar across Turkey produces significant benefits when a large share (above 20–25% of annual generation) of renewables technology is in place. Additional transmission investment needs fall by more than 60%, curtailment levels decline by more than 80% and redispatch drops by 15% (Figure 51). Nevertheless, the high redispatch values continue to be a challenge, and an indication that additional system flexibility is needed. This aspect will be addressed in more detail in Section 5.2.

5.2. Increasing flexibilities in generation, storage and demand

In a second strategy, we assessed the impact of adding generation and demand flexibility as well as storage options. We made the following changes to the assumptions in the default scenarios:

a) Storage capacity: We assume an added 2 GW of capacity providing +/- 700 MW of secondary frequency control reserve.
   a. What supplies the storage is a 1,400 MW pumped storage power plant near the Gökçekaya hydropower plant in Northwest Anatolia, made up of four 350 MW turbines. It is assumed that each of these four units is able to supply +/-100 MW of secondary frequency control reserve.
   b. Another source of storage is 600 MW of distributed batteries.[109] These batteries are assumed to provide +/-300 MW of secondary frequency control.

b) Generation flexibility: We assume that 12 GW of existing lignite and coal power plants will be rehabilitated to speed up ramping (reaching full load in one hour), decrease minimum load (stable operation down to 50% of P_{max}) and provide a frequency control reserve (up to 10% of P_{max}).[110]

c) Demand response: We assume that demand at any HV/MV substation can be reduced by up to 5% of default demand at a specific hour and location.

[109] The technical details and modelling assumptions for storage are described in Section 3.6.
[110] These are the assumptions applied in the default scenario for all power plants to be added to the system between 2016 and 2026.

Flexibility in 21st century power systems

Operation flexibility – the ability of a power system to respond to change in demand and supply – is a characteristic of all power systems. Flexibility is especially valued in twenty-first century power systems, which contain higher levels of grid-connected variable renewable energy (primarily, wind and solar).[111]

Flexibility options such as hydro and thermal generation fleets with fast ramp up / ramp down capability, demand response instruments, and storage options allow TSOs to better cope with rapidly changing feed-in levels of wind and solar generation. Several studies address how hydro and fast-response natural gas power plants greatly facilitate the integration of variable types of Renewables such as wind and solar power by providing flexibility and storage capabilities.[112] For instance, the high share of wind power that has developed in Denmark over the last 25 years provided an early incentive for increasing the **flexibility of thermal power plants.** From the power plants' perspective, the high fluctuation in residual load associated with wind power generation has steep load gradients. It also requires fast start-ups at low cost and a very low level of minimum stable generation. Consequently, Danish coal power plants that were originally designed as base load units became some of the most flexible power plants in Europe.[113]

In an ideal world, grids would be planned in such a way so as to avoid all congestion, providing sufficient grid capacity for any supply and demand situation. A large feed-in of wind and solar power, which peaks a few hours each year, may mean that the **redispatch** of conventional generation or the curtailment of renewable generation is cheaper than building (rarely used) additional lines.

Storage is another flexibility option that may balance supply and demand. Storage devices can be grouped into three categories:

- Hydropower plants with a storage dam for reducing generation
- Pump storage hydraulic power plants for shifting generation and consumption
- Batteries for shifting generation and consumption

Dynamic line rating, HVDC implementation and topology modification have also been applied in power systems to reduce transmission infrastructure investment. They are briefly explained below.

Dynamic line rating:

Current limits of overhead lines are restricted by thermal capability. The temperature of the conductors depends on the electric current, the ambient temperature, the wind speed and direction, and solar irradiation. The frequently assumed values of 35 °C and 0.6 m/s wind speed often lead to an underestimation of actual current limits. An adaptive determination of limits based on actual weather conditions could increase the transport capability by up to 25–30%. This approach is called dynamic line rating.

HVDC implementation:

High-voltage DC technologies are particularly beneficial for the transportation of electric energy over long distances thanks to its absence of reactive power losses. Moreover, converter stations (voltage source converters) are capable of an independent control of active and reactive power, which could be utilized to ensure voltage stability and congestion management in the AC grid. By contrast, HVDC lines are very costly. Hence, investment decisions should be evaluated for individual cases.

Topology modification:

Topology modifications are a frequently used low-cost measure for controlling active and reactive power flows and relieving congestions in the transmission network. Typical topology modifications include the activation and deactivation of branches, changing busbar assignments and opening and closing busbar couplers. The modelling of topology modifications is very complex due to the high number of different combinations. Moreover, switching elements may fail, endangering network security.

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[111] *NREL 2014: Flexibility in 21st century power systems.*
[112] *DNV GL 2015: The hydropower sector's contribution to a sustainable and prosperous Europe.*
[113] *Agora Energiewende 2015: The Danish experience with integrating variable renewable energy.*

5.2.1. Effect on the Doubling scenario

In our first simulation, the flexibility options were applied to the resource-driven Doubling scenario. The aim was to identify the impact on the generation mix, on system requirements, on transmission capacity and on redispatch.

5.2.1.1. Storage use, generation mix and system requirements

Storage is used to help balance supply and demand as well as to avoid congestions and provide frequency control. The total utilized energy (store and generate) is 1.25 TWh for pump storage and 0.92 TWh for batteries, which produces utilization factors of 13.7% and 40% for pump storage and batteries, respectively. The main differences between the storage options are the size of the units, their efficiency factor (described in section 3.6) and their position in the grid. It should be noted that a certain portion of storage capacity is allocated for frequency control reserve. Similar to a generation facility, the portion allocated for frequency control is not utilized as generation or as load.

Pump storage is actively utilized about 2,800 hours a year (30% of the time) and is based on the efficiency assumptions and cost curves of conventional units, which indirectly determine the price difference between day and night. The resulting price differences do not cause heavy pump storage activation for economic reasons because of the relatively low efficiency factor and relatively low-price differences in the simulations.[114] The main drivers of pump storage are network constraints. This fact should be kept in mind when evaluating the commitment hours and utilization factor of pump storage.

The batteries distributed in the network are utilized more than pump storage. The regional utilization factors range across 18 percentage points (the difference between maximum and minimum regional average utilization), with higher utilization in congested regions and lower utilization rates in more relaxed regions. These utilization factors also indicate more effective locations for storage investments (Figure 52). Batteries, given their relatively high efficiency, are more affected by price differences but, like pump storage, are mainly driven by network constraints.

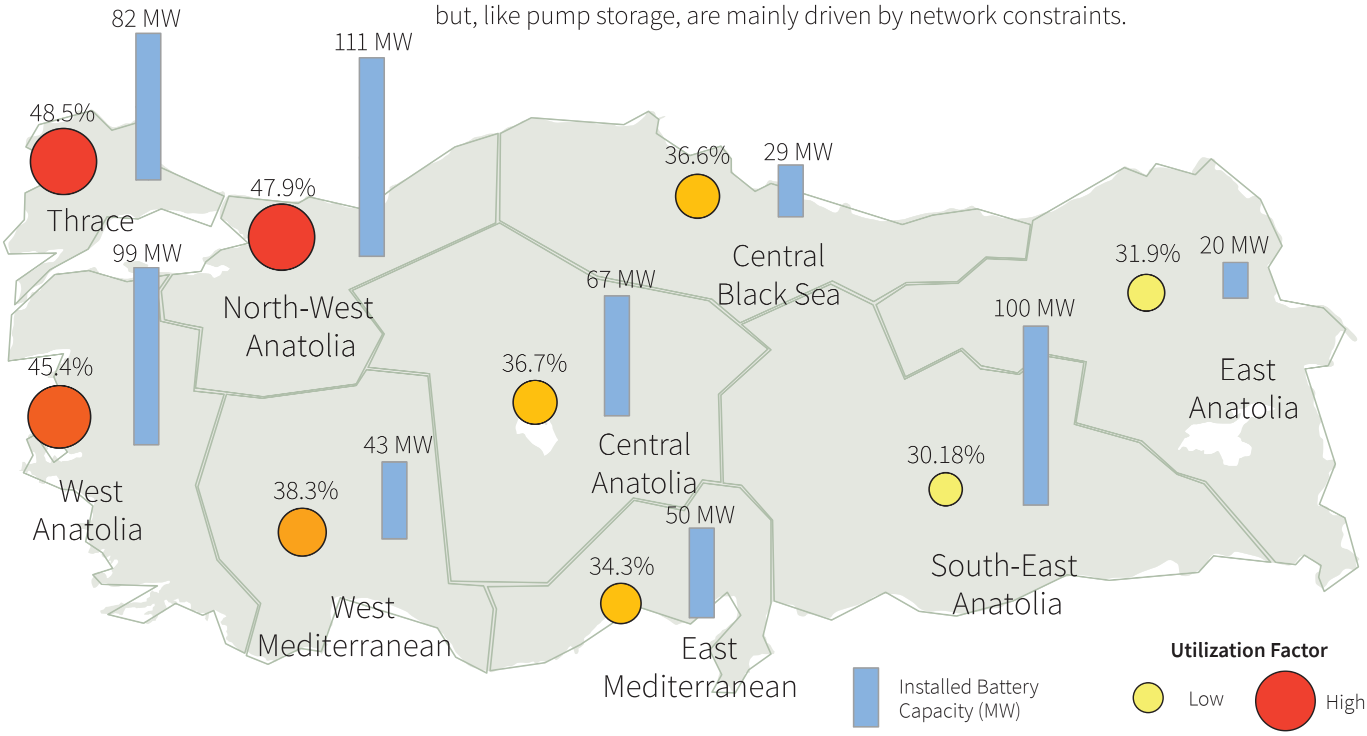

***Figure 52.** Regional distribution of capacity and capacity factors of battery storage*

[114] Different cost curve assumptions with higher day-night cost differences may result in a higher utilization of pump storage as well.

Reserve requirements are 2,200 MW in the Doubling scenario. Almost one-third, or 700 MW, is provided by batteries, reducing the need for gas plant generation.

The effect on the generation mix is hence straightforward. Storage provides additional flexibility which would otherwise be provided by gas-fired power plants.

Storage provides additional flexibility which would otherwise be provided by gas-fired power plants (reducing gas generation by 5.1 TWh to 48 TWh). Lignite-fired power plants benefit the most, increasing their generation by 3.3 TWh to 72.8 TWh (Figure 53).

Flexibility also relaxes hourly ramps for conventional units. The hourly ramps may decline up to 2,000 MW for specific hours, for an annual average of 75 MW. This relaxation allows smoother transitions from day to night and from night to day between technologies.

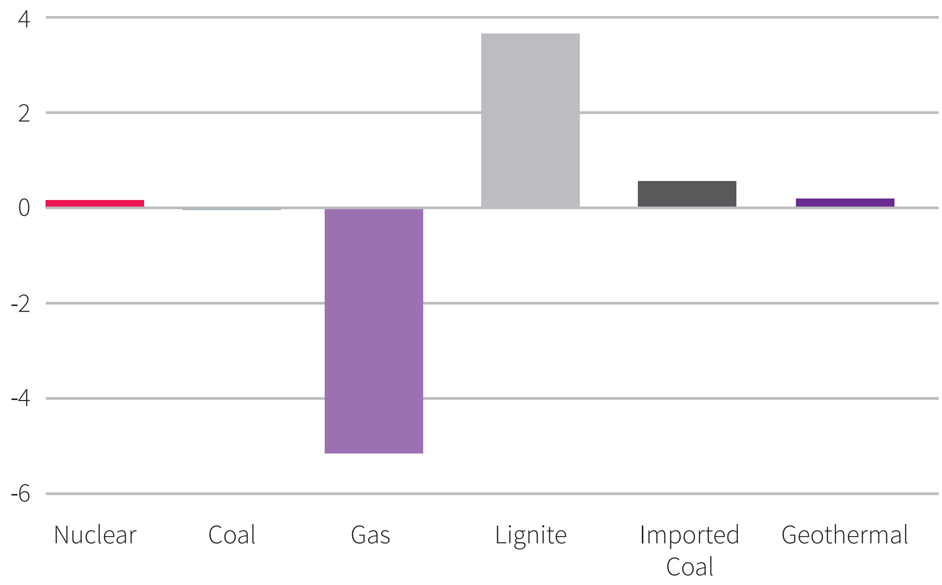

Figure 53. *Difference in total generation mix for the Doubling scenario with and without flexibility strategy*

5.2.1.2. Transmission capacity and redispatch

For ease of comparison, the transmission infrastructure as identified in the Base Case and Doubling scenarios was kept constant. (In reality, some transmission investment may be omitted.) The change in redispatch quantifies the benefits of flexibility on the transmission system.

Thanks to the extra storage, redispatch falls from 23.5 TWh to 10.2 TWh, i.e. by 13.3 TWh or more than 50%. This is below the absolute, and far below the relative, levels from 2016 (2.3% versus 4.6%)*.

** In a different strategy the effect of adding storage only (1.4 GW of pumped hydro plant and 600 MW of distributed batteries) was tested for the Doubling scenario. The effects of storage options on redispatch are remarkable. Redispatch falls from 23.5 TWh to 11.9 TWh, i.e. by 11.6 TWh or almost 50%. This is even below the level we saw in 2016 in absolute terms, and well below 2016 values in relative terms (2.7% versus 4.6%).*

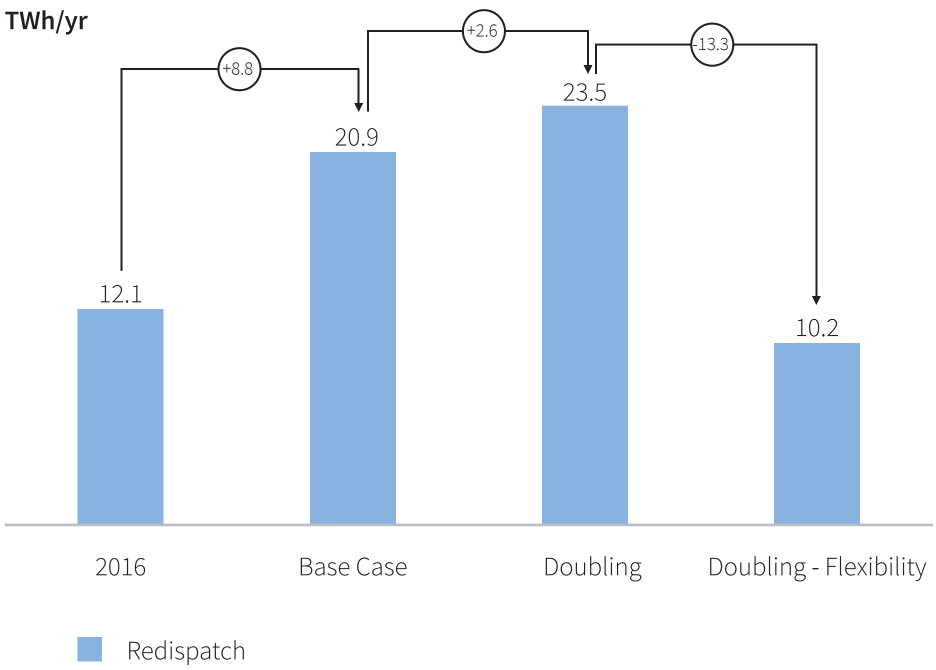

Figure 54. Redispatch comparison of 2016 and the Doubling scenario with and without storage strategy in 2026

As for the regional distribution of redispatch orders, most of the congestion in the no-flexibility scenario disappears, though some minor congestion occurs in the West and South of Turkey.

The drop in redispatch is driven by two main factors: the support of storage systems for the frequency control reserve and the effective utilization of storage systems for relaxing contingencies.[115]

[115] As a certain level of storage is utilized for reserve, the reserve capacity needed from conventional plants declines. This effect reduces the redispatch amount required for sufficient reserves by either decreasing the generation of an already dispatched unit or by starting a new unit and ramping it up to its minimum stable operation level (including its required reserve). The relationship between congested energy and the redispatch needed to eliminate congestion is not linear. Due to the characteristics of meshed grids it is possible that considerably more redispatch energy will be needed than represented by the congested energy. Because the battery systems are distributed throughout the network, however, it is possible to activate the most effective devices to resolve the contingencies. As seen in Figure 55 (and compared with Figure 30), the geographical distinction between positive and negative dispatch orders are more distinct. That is, the location-specific congestion that can be controlled effectively with storage is resolved and the congestion affecting large areas stands out more. But even these congestions will benefit from the effective utilization of storage systems.

Effects on the distribution grid of increasing wind and solar
The economic aspects covered in this analysis are limited to the investment of the transmission grid and the battery storage systems. Nevertheless, when supply and demand grow, investment in the distribution system is required as well. The investment needs for the distribution network are generally higher than those for the transmission grid, as the distribution network is much larger. In Turkey, by the end of 2016, the transmission grid comprehended 61,269 km of lines, while the length of the distribution network was 1,102,508 km (933,158 km of this was overhead lines, the rest underground cable). In 2016, investments for the distribution network were more than twice as high as those for the transmission grid (1.1 billion € versus 0.5 billion €).[116] The "Milli Enerji ve Maden Politikası" that was released in 2017 highlights the continuation of this for until 2023 (1.0 billion € and 0.6 billion € on average per year for distribution and transmission, respectively).[117] According to the recent assessment by TÜSİAD that covers the entire period between 2016-2030, the total investment needs would rise to on average 2.2 billion € per year (1.6 billion € for distribution and 0.6 billion € for transmission on average per year).[118] These estimates are in line with this study's findings and they also show the scale of the distribution grid investments that may come with growing demand for electricity.

Assessing the distribution grid investment needs in detail, is even more complex than for the transmission grid.[119] Yet, some general considerations can be made: Distribution investments are not strongly impacted by long-distance power transport, as electricity distribution occurs by nature more on the sub-regional level. The challenge and associated cost of integrating renewables into the distribution grids largely depend on local supply-and-demand ratios for renewables (and their smart planning) and on the ability of distribution system operators to monitor and control the feed-in of wind and solar.[120]

Investment for distribution grids may increase if the capacity of solar PV systems integrated was larger than the local demand, as demand is currently the dimensioning criterion for the capacity of the distribution system. On the lowest voltage level, costs would thus be sensitive to solar PV system size. According to an assessment of the IEA, for systems of up to 2.5 kW the impact of investment needs in distribution grids on electricity generation costs would remain below USD 2/MWh; for larger systems of around 4 kW they could be increase up to USD 10/MWh. However, with distributed storage and other advanced management systems, these costs may actually be much lower.[121]

[116] *EMRA (2017) Elektrik Piyasası 2016 Yılı Piyasa Gelişim Raporu; an exchange rate of 3.8 TL/EUR was assumed.*
[117] *http://www.enerji.gov.tr/tr-TR/Bakanlik-Haberleri/Milli-Enerji-Ve-Maden-Politikasi-Tanitim-Programi*
[118] The TÜSIAD numbers are based on considering a total installed capacity of 17 GW onshore wind by 2027 and 12.5 GW solar PV by 2030; an exchange rate of EUR 0.92/ 1 USD was assumed. http://tusiad.org/tr/tum/item/9986-tusiad-dan-enerjiye-3d-formulu-ile-yilda-34-milyar-dolar-ek-katma-deger-vizyonu
[119] See: *https://www.agora-energiewende.de/fileadmin/Projekte/2014/integrationskosten-wind-pv/Agora_Integration_Cost_Wind_PV_web.pdf*
[120] *E-Bridge, IAEW, OFFIS, 2014: Verteilernetzstudie (Distribution grid analysis), Study for the German Ministry for Economics and Energy, Management Summary (English). See: https://www.bmwi.de/Redaktion/DE/Publikationen/Studien/verteilernetzstudie.html*
[121] See: *https://www.iea.org/publications/freepublications/publication/The_power_of_Transformation.pdf*

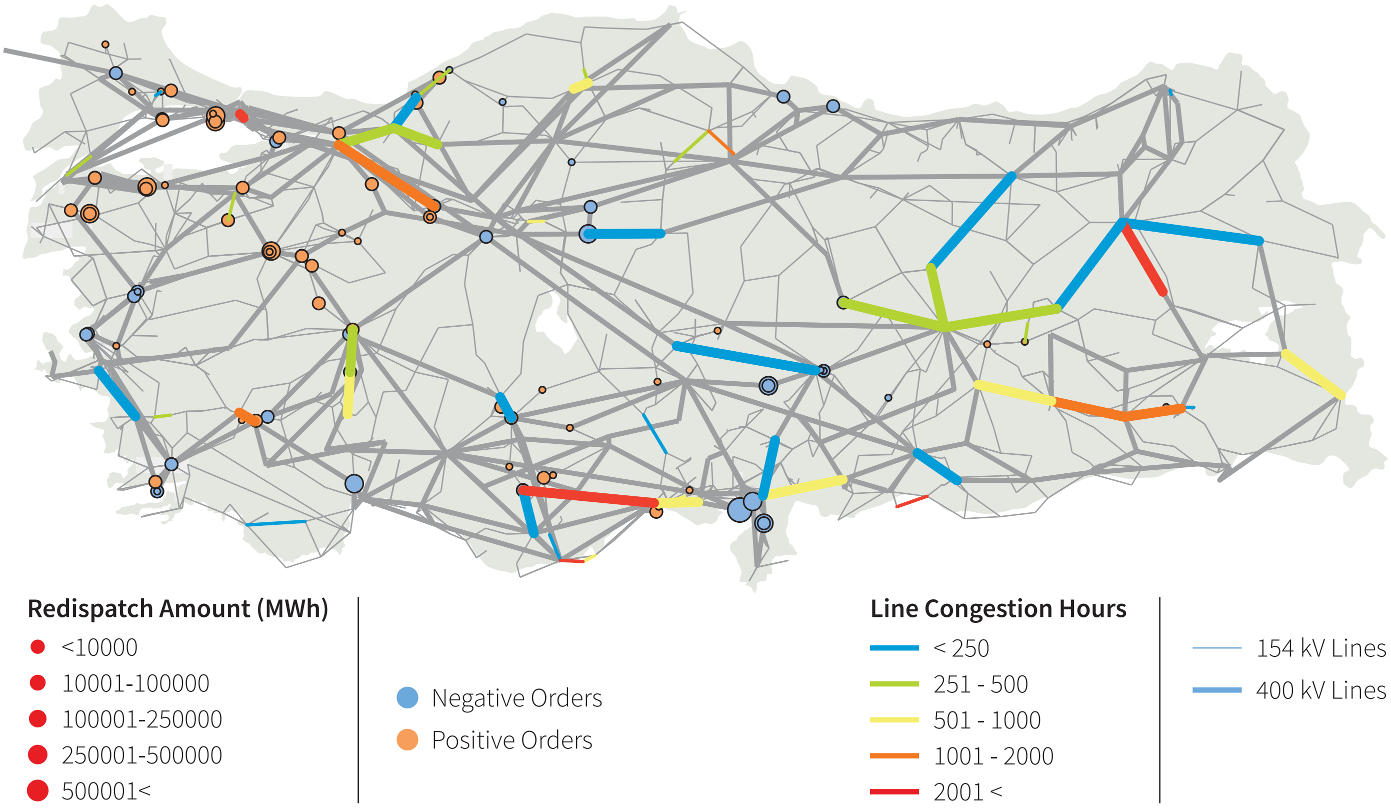

Figure 55. *Annual congestion levels and thermal redispatch orders according to the Doubling scenario for resource-driven flexibility strategy, 2026*

5.2.2. Effect on the Tripling scenario

In the Tripling scenario, the effect of adding flexibility was tested on the system-driven allocation strategy, which provides considerable benefits in terms of lowering transmission capacity requirements.

In the Tripling scenario, the effect of adding flexibilities was tested on the system-driven allocation strategy, which as shown in section 3.2, already provides considerable benefits in terms of lowering transmission capacity requirements. Our aim was to assess how a better allocation of renewables generation and a better system design can meet the challenge of integrating 30% and more variable renewables.

5.2.2.1. Generation mix and system requirements

The total utilized energy (stored and generated) is 1.4 TWh for pump storage and batteries, which corresponds to utilization factors of 16% and 52%, respectively. The main differences between the storage options are unit sizes, their efficiency factors (described in section 3.6) and their positions in the grid. It should be noted that a certain portion of storage capacity is allocated for the frequency control reserve. As with a generation facility, the portion allocated for frequency control is not utilized as generation or load.

The pump storage is actively utilized more than 3,700 hours in the year, which is more than 43% of the time. The fact that the utilization factor is rather low (16%) indicates that in the case of parallel battery installation the assumed capacity of the pump storage (1.4 GW) would exceed the needs of the network.

Once again, the distributed batteries are utilized more than pump storage. As renewables are distributed in this scenario, the regional average utilization factors are within two percentage points of each other (the difference between average maximum and minimum regional utilization), much lower than in the default scenario. The maximum and minimum utilization of individual storage devices are 60% and 45%, respectively.

As flexibility is provided by a variety of system elements – thermal plants, storage and demand – the importance of gas as a balancing technology diminishes. The output of renewable energy sources remains unchanged: the share of wind and solar is 28.6%; including run-of-river hydro, variable renewables make up 33% of output. Total renewables (including hydro and geothermal) provide 49.6% of generation. Altogether, lignite (+5 TWh), import coal (+4 TWh) and nuclear (+1TWh) generation increases by 10 TWh, while gas decreases by 10 TWh. Consequently, the share of coal totals 25.1%, while the share of gas is only 8.5%.

Figure 56. *Generation mix according to the Tripling scenario, 2026*

These shifts are obviously reflected in the full load hours of the power plants (Figure 57). While the capacity factors of nuclear and geothermal remain constantly high at around 90%, the lignite capacity factor exceeds 50% and hard coal utilization is at about 45%. By contrast, the utilization of gas-fired power plants falls to 16%. The parallel expansion of nuclear, lignite and renewables – all ahead of gas in the merit order – will undercut the economics of gas-fired generation in the power system.

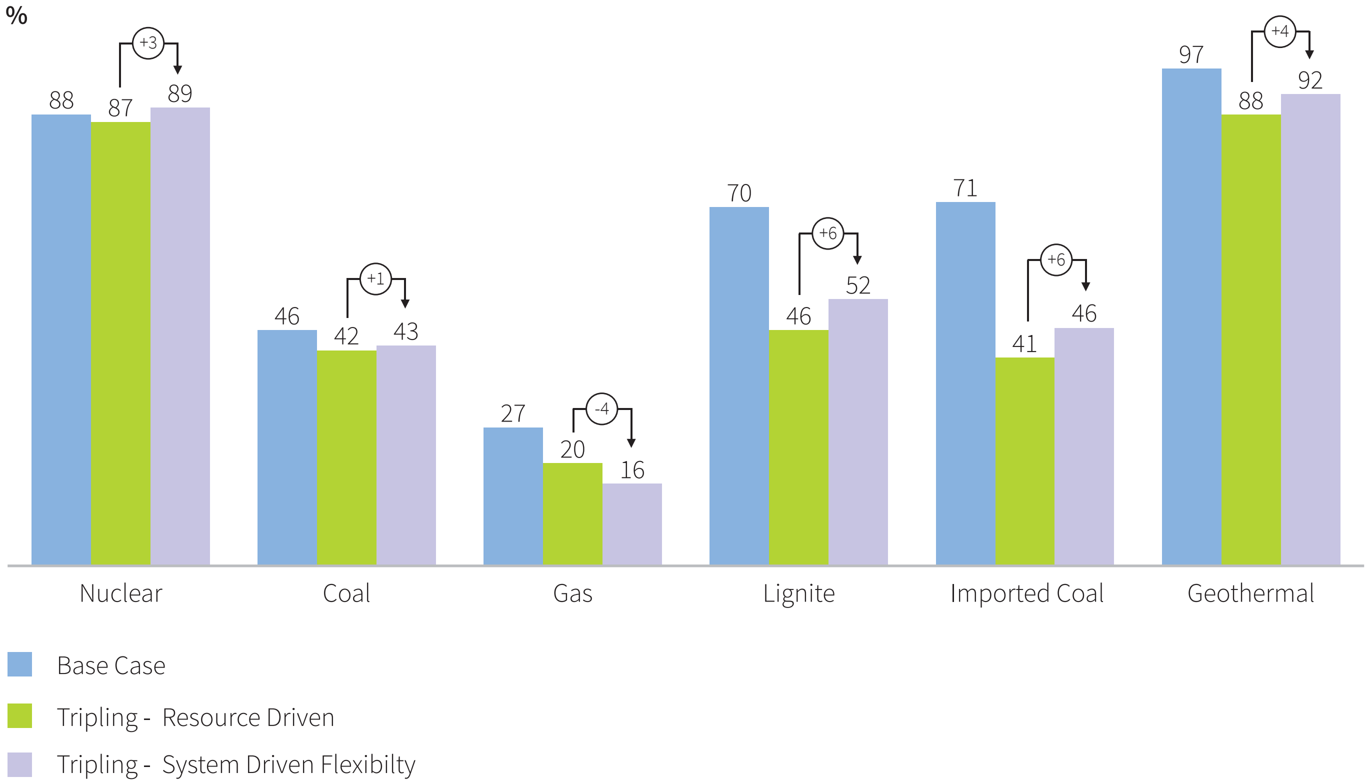

Figure 57. *Capacity factors by source according to the Base Case and Tripling scenarios, 2026*

Figure 58 provides a sample period 29 June to 1 July when the high feed-in of wind and solar requires ramping down of thermal, including nuclear generation and curtailment. The example clearly shows individual hours when curtailment is increased, but the total amount of curtailment declines when wind and solar are optimally allocated. Furthermore, at specific hours, gas generation and reductions of nuclear generation fall as well.

Once flexibility options and storage devices are introduced, curtailment in the sample day drops to almost zero. Moreover, nuclear generation stays almost flat while gas generation falls further thanks to reserve capacity provided by overhauled older thermal units.

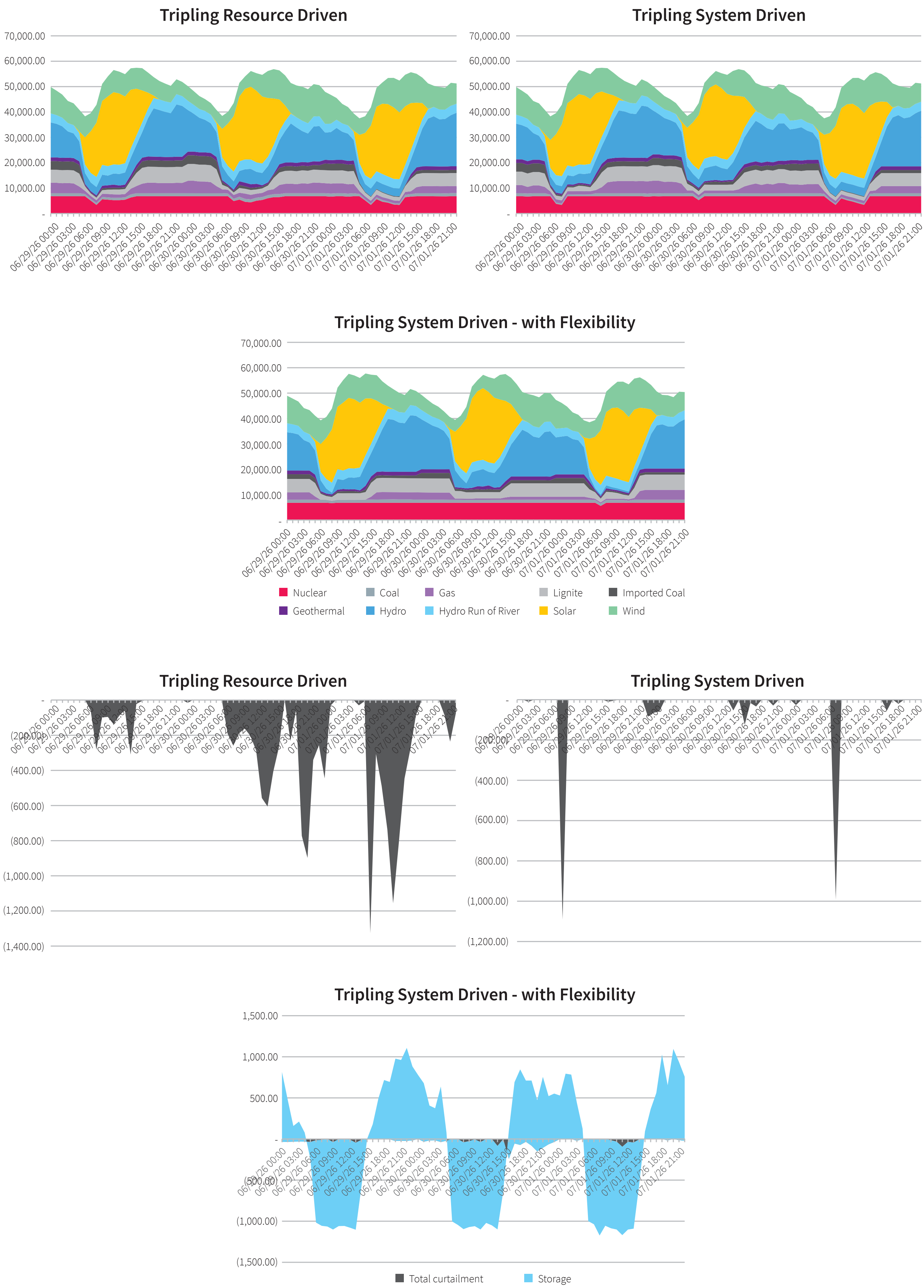

Figure 58. *Ramp change according to the Tripling scenario, 2026*

Additional flexibility also relaxes hourly ramps for conventional units. Specifically, hourly ramps fall by up to 4 GW for specific hours (from 11 GW to 6.6 GW), with an annual average of 95 MW. This relaxation permits smoother transitions from day to night and from night to day between technologies.

Reserve requirements, which were calculated at 2,700 MW for the Tripling scenario, can be covered in part by batteries and pumped hydro storage plants, which provide up to 700 MW of reserve capacity. Further, all the units in the thermal generation park (including existing lignite and coal plants) can provide reserve services. These additional reserve options do much to reduce the number of redispatch orders (see sections 4.3.5 and 5.1.2).

5.2.2.2. Transmission infrastructure and redispatch

Once again, changes in redispatch and curtailment quantify the positive effect of increasing system flexibility. Transmission investment – for the sake of simplifying the comparison - is assumed to remain the same as in the Tripling scenario with system-driven allocation strategy.[122]

The reduction in redispatch that can be achieved beyond the Tripling scenario with system-driven allocation strategy - is remarkable (Figure 59). Despite the high shares of non-dispatchable generation (28% wind and solar, 5% run-of-river (RoR)), redispatch diminishes by 15.7 TWh, from 29.1 to 13.4 TWh. Redispatch in absolute terms is roughly the same level as that of today; in relative terms, it is well below today's value (3.1% versus 4.4%). The amount of curtailment drops by an additional 0.1 TWh below that of the system-driven allocation scenario.

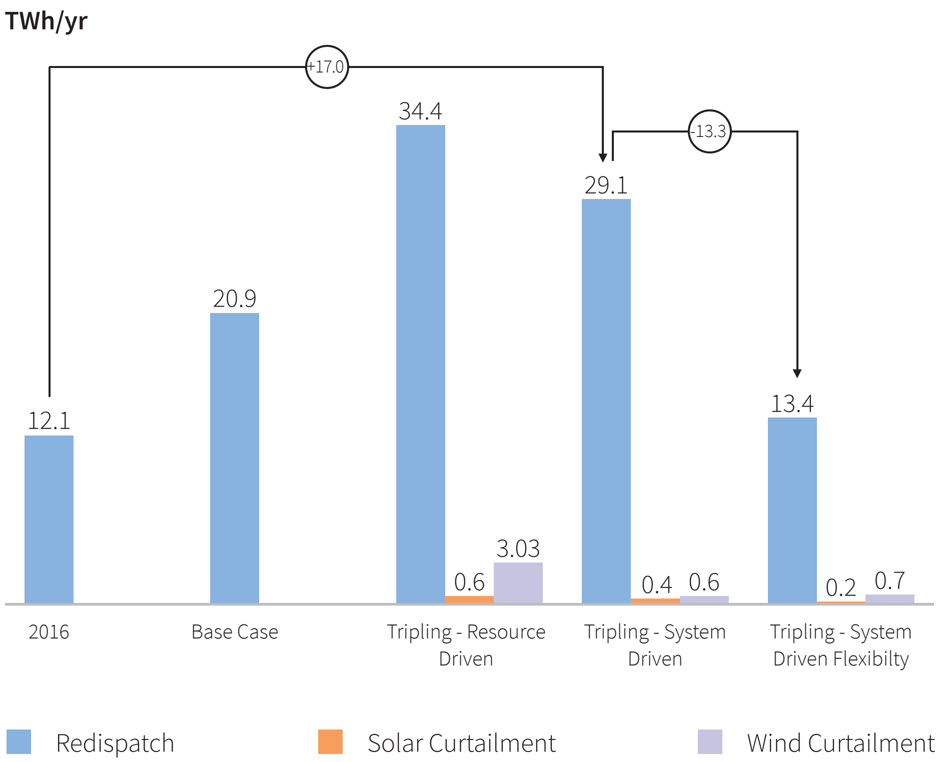

Figure 59. *Comparison of redispatch and curtailment according to the Tripling scenario, 2026*

[122] In practice, however, some of the infrastructure investment may not be required in a more flexible system.

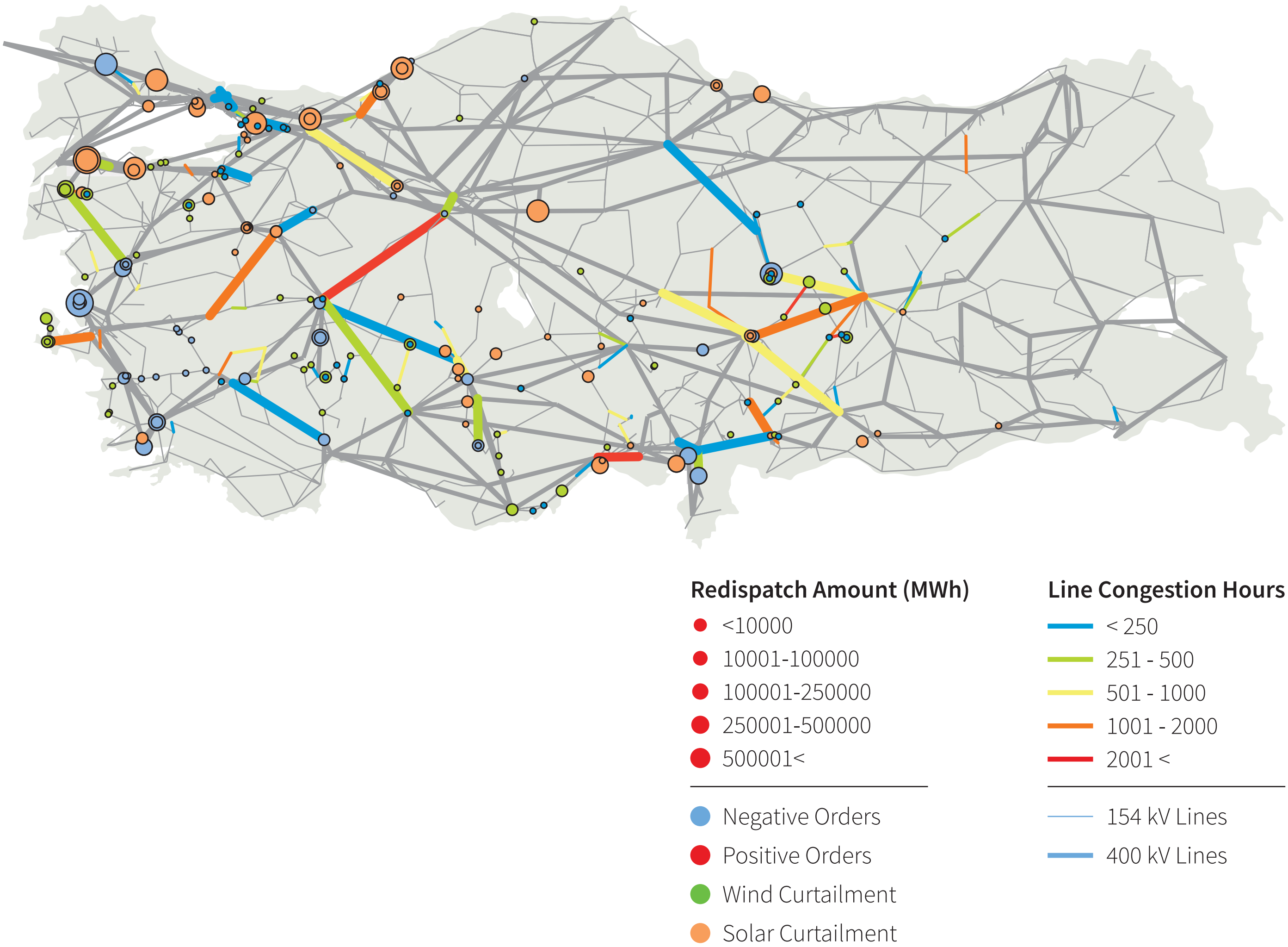

Figure 60. *Redispatch, congestion and curtailment map according to the Tripling scenario, 2026*

As seen in Figure 60 (and compared with Figure 49 and Figure 50), redispatch falls significantly in the southwest region of Turkey, with a slight shift in congested lines. Wind and solar generation stays at very low levels – negligible, even, in the case of solar.

In sum, we identified and quantified a set of measures for the secure operation of Turkey's power system with more than 50% renewables (of which one-third comes from variable wind, solar and RoR). If renewable power site location, thermal generation, and demand response were all optimized for system flexibility and integration, the transmission infrastructure upgrade could be kept to a minimum. Adding a limited expansion of infrastructure in the 400 kV grid (+700 km, i.e. +10%) and the 154 kV grid (+ 2,000 km, +20%) could reduce redispatch well below current levels while keeping solar and wind curtailment to below 1 TWh, which is less than 1% of their annual generation.[123]

[123] As mentioned before, in order to optimize the whole system, it is essential to weigh saved transmission investment and redispatch against additional investment for generation and storage. As studies on other systems have shown, though, Renewables integration cost that take all elements into account are much lower than often assumed. For an overview to this discussion, see: *https://www.agora-energiewende.de/fileadmin/Projekte/2014/integrationskosten-wind-pv/Agora_Integration_Cost_Wind_PV_web.pdf*

6. Conclusions and Recommendations

Renewable energy technologies are playing an increasingly important role in Turkey's power system. By the end of 2017, the share of renewables in total electricity generation stood at 29%. Most of this, however, is hydro energy; wind power makes up 6%, while solar PV is at 1%. Yet, wind and solar have been making news recently thanks to their rapidly declining costs and their plentiful supply in Turkey. In 2017, solar and wind auction prices ranged between USD 3–6 cents/kWh, making them cost competitive with fossil fuel-based generation. In 2016, wind and solar projects with a total capacity of around 5 GW were licensed under various tariff schemes in Turkey; a total of 3.2 GW of new capacity was added in 2017. These developments are part of the government's strategic plan to decrease the trade account deficit and promote local value creation in the Turkish energy sector.

Integrating higher shares of wind and solar efficiently in Turkey's power system is feasible. Yet it requires systematic planning if it is to address crucial issues such as balancing, grid congestion and flexibility. Other countries have managed to integrate a high share of renewables in their power systems, but one must keep in mind the particular circumstances of each system with regard to geography, resource availability, capacity mix, and market dynamics. This study investigated the specific factors that shape the Turkish power system.

The analysis shows that doubling the total installed wind and solar generation capacity to 40 GW by 2026 is feasible without aadditional investments in the 400 kV and 154 kV transmission infrastructure.

The analysis shows that doubling the total installed wind and solar generation capacity to 40 GW by 2026 is feasible without additional investments in the 400 kV and 154 kV transmission infrastructure (beyond that already planned by TEİAŞ). Doubling capacity would raise the share of wind and solar to 21% and the total renewables share to 42% by 2026. Tripling the capacity to 60 GW is also achievable, the study found, provided that grid integration strategies are introduced. These strategies include the use of flexibility technologies and the placement of wind and solar plants closer to demand centres.

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Various options for facilitating the integration of variable renewables have been identified and implemented in countries with higher shares of wind and solar, such as Germany, Denmark, Ireland or California. One option is exploring the benefits of a system-driven allocation of renewable energy generation units in the place of purely resource-driven allocation. Such an approach takes local demand and grid capacity into account when selecting wind and solar locations. As there is an abundance of areas with excellent solar and wind in Turkey, such an approach would decrease power output only negligibly. Increasing system flexibility through storage, adding more flexible thermal power plants and improving demand response can help further drive down grid-related costs. The study specifically considered the introduction of a large pumped hydro plant (1.4 GW) and 600 GW of small-scale decentralized batteries, the overhaul of older thermal power plants (for more flexible ramp rates and reduced minimum load) and the use of demand response mechanisms that can reduce demand by up to 5% during times of limited generation availability. The study found that these strategies have a significant positive impact on reducing the need for additional transmission infrastructure and the need for the redispatch and curtailment of wind and solar in all scenarios.

This study, the first of its kind for Turkey, provides important insights on creating a modern, efficient and robust power system. It has identified the benefits of integration

This study, the first of its kind for Turkey, provides important insights on creating a modern, efficient and robust power system.

strategies for transmission grid planning and grid operations. These need to be assessed against the additional costs for, say, renewables generation, storage, thermal plant rehabilitation or demand response programs. An increase in wind and solar capacity will also have an impact on the thermal generation park, requiring less investment and a different technology mix.

This study is the first step in developing a roadmap that addresses all relevant aspects and stakeholders affected by higher shares of solar and wind. Such a roadmap is crucial if Turkey is to continue its energy transition, changing the way energy is produced, distributed and consumed. It will also be important to support the changing roles and responsibilities of the actors in a power system with high shares of renewables. The transition will only be successful with an approach that balances new technologies with novel approaches to renewable integration through market design, business models and financing. The following recommendations describe the starting point for such a roadmap:

(i) **Energy planners** need to refine this study's scenarios by assessing the impact of other relevant issues such as energy demand growth, the mix of generation technologies, regional variations and the synergies between renewables and energy efficiency. As the analysis shows, supply cannot be planned in isolation from demand; this requires identifying suitable planning methods. Such planning will also need to consider the capacity factors of the power plant fleet, new locations, and transmission and distribution needs, including the coupling of markets with the neighbouring countries of Georgia, Bulgaria and Greece.

(ii) **Transmission and distribution systems** need to employ sophisticated data forecasting and management systems to handle the increasing need for (fast-response) flexibility. In addition, incentives will be needed to ensure system inertia provision, power dispatching and local load control.

(iii) **VRE units** will need to supply services that were once provided by conventional units, such as voltage control, frequency response and operational reserves. Power system operators must understand whether and to what extent these can be integrated into the Turkish power system.

(iv) **Regulators** must reassess existing procedures for addressing the needs of a power system that is becoming more complex due to the increasing number of generators and new grid options such as mini-grids and smart grids.

(v) As Turkey puts more emphasis on distributed generation, **consumers** – households, farmers, communities, industries, commercial companies – will have new responsibilities in generating, consuming and selling electricity. When combined with smart-grid technologies, consumers will also play a key role in improving power system flexibility through demand-side management and behind-the-meter distributed storage technologies.

(vi) Traditional **financing models,** where large investors play a major role in the energy sector, must be complemented by smaller investors, including project developers, corporate actors and households. It is important that Turkey identify which new models – green bonds, early-stage venture capitals, etc. – are best suited for this purpose.

(vii) Turkey's power system must consider the new **business models** that are emerging on the market. One is the so-called virtual power plant, which combines distributed generation and demand response. With the introduction of intelligent generation, distribution and supply technologies, data collection and management have gained momentum. This requires the use of novel ICT technologies for the energy transition.

(viii) Energy transition has been positively impacted by innovations in **market design.** Renewable energy markets were initially stimulated by the introduction of feed-in-tariffs. With declining renewables costs, this scheme is now being supplemented with and at times replaced by auctions, resulting in very attractive prices for wind and solar power. New market instruments and regulations will need to be developed to support continued investment in renewable capacity, integrate system resources and provide and reward system flexibility.

ANNEX 1. Overview of Turkey's Power System

This section presents an overview of the Turkey's power system pertinent to the study. It provides key data on the generation and transmission infrastructure and operation of Turkey's power system. This includes the generation fleet and electricity demand of the country in 2016, and an outlook to 2026 in terms of demand forecast and generation capacity development. In addition, operation of the day-ahead wholesale electricity market in Turkey, existing capacity and penetration levels of renewable energy in the country, and incentives for renewable energy installments by private investors are addressed. These data and operational rules are essential inputs for the analysis performed in the study.

GDP growth rates between 6% (before the financial crisis in 2009) and 4.5% (since 2009) have translated into an electricity demand increase of 7% annually during the first decade, and 4-5% in recent years.

A-1.1. Electricity demand and power generation

Turkey has been one of the fastest growing economies in the world in the 21st century. GDP growth rates between 6% (before the financial crisis in 2009) and 4.5% (since 2009) have translated into an **electricity demand** increase of 7% annually during the first decade, and 4-5% in recent years. Gross electricity consumption in Turkey has increased from 175 TWh in 2006 to 278 TWh in 2016. Peak load, which was 27.5 GW in 2006, almost reached 44 GW by the end of 2016[13]. The development of peak demand and gross electricity consumption between 2006 and 2016 are presented in Figure 61.[124]

Electricity demand in Turkey peaks in the summer. Peak power demand season in Turkey switched from winter to summer in 2008, due to increasing and widespread utilization of air conditioning for summer cooling, as well as irrigation of agricultural land.[125] As electricity is still widely used for heating in winter, the winter peak is only about 5% lower than the summer peak. Demand is more and more centralized in urban conglomerates in the center-West and West of the country, a trend that is bound to continue.[126]

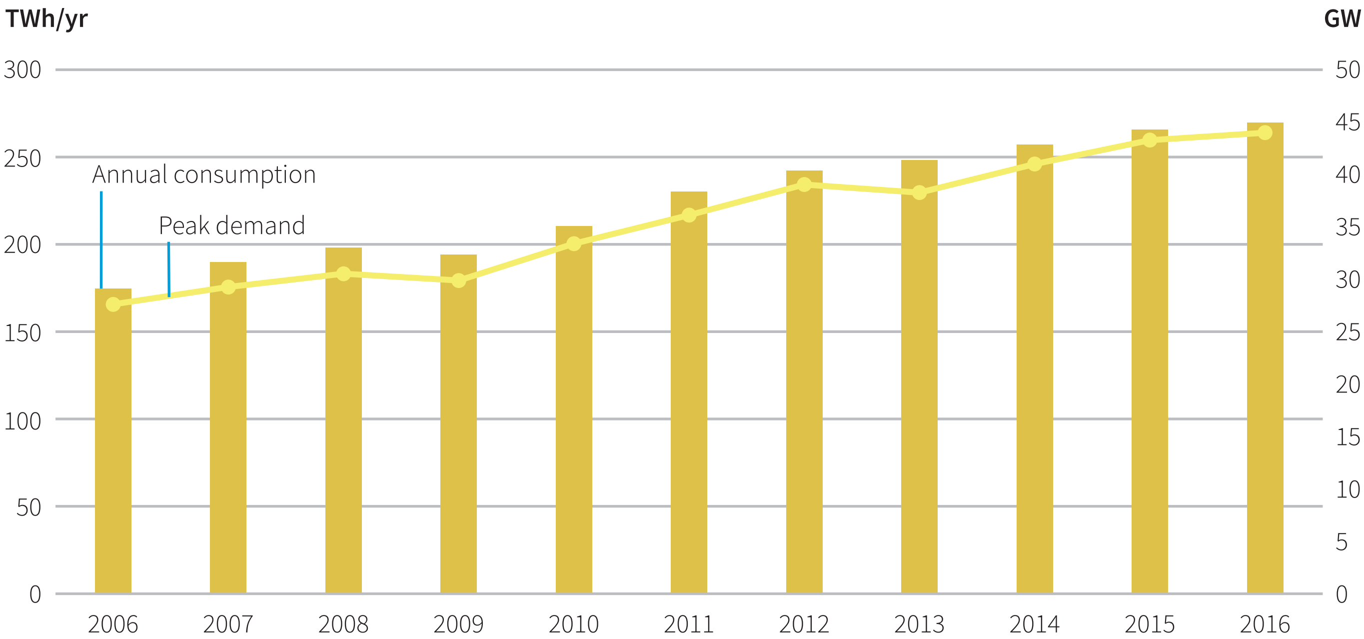
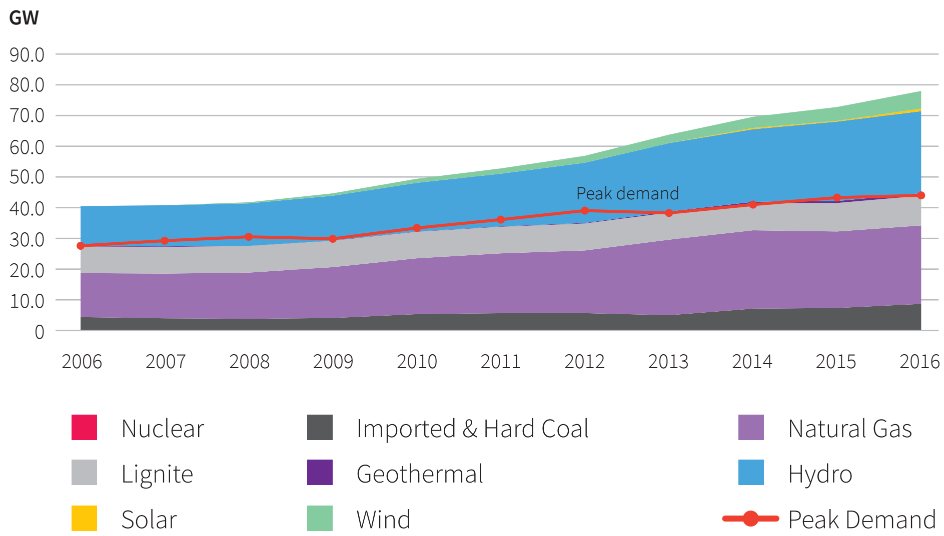


Figure 61. *Peak demand and gross electricity consumption, 2006-2016*

[124] *TEİAŞ Planlama ve Stratejik Yönetim Dairesi Başkanlığı, "10 Yıllık Talep Tahminleri Raporu (2017-2026)", available at: https://www.teias.gov.tr/sites/default/files/2017-06/10Y%C4%B1ll%C4%B1kTalepTahminleriRaporu2016%282 %29.pdf*
[125] *O. B. Tor and M. Shahidehpour, "Crossroads of Power: Coordinating Electricity and Natural Gas Infrastructures in Turkey," IEEE Power & Energy Magazine, Vol. 12, Issue 6, Nov-Dec 2014, pp. 49-62.*
[126] As no reliable forecast data on how demand may further change in terms of geographic distribution or distribution throughout the day, the same pattern as in 2016 data was kept for the modeling analysis.

Generation capacity even outstripped demand growth and went up from 32 GW in 2002 to 77.8 GW at the end of 2016[10]. The remarkable additions to the generation park, which came to a large extent from private investments enabled by the liberalization of the power market, has swept away concerns about undersupply in the market, and has led to considerable overcapacities. As most of the growth of the past decade was due to investment in large hydro and gas fired power plants, Turkey's power generation park is dominated by hydro (26. 7 GW) and natural gas (25.5 GW) plants, followed by lignite (9.3 GW) and hard coal (8.5 GW); all lignite and 1 GW of hard coal fired power plants are fueled by local resources, while most hard coal power plants operate on imported fuel (7.5 GW). Development of peak demand and installed capacity in terms of primary sources is presented in Figure 62.

When it comes to the output of the plants, thermal generation features more prominently, due to higher full load hours of coal and lignite plants in particular. The generation mix 2016 was dominated by natural gas power plants (33%), lignite and coal (31%); hydro contributed 25% to overall supply[127]. Contribution of the different power generation sources is illustrated in Figure 62.



Breakdown of Generation in 2016
(Total: 269.8 TWh)

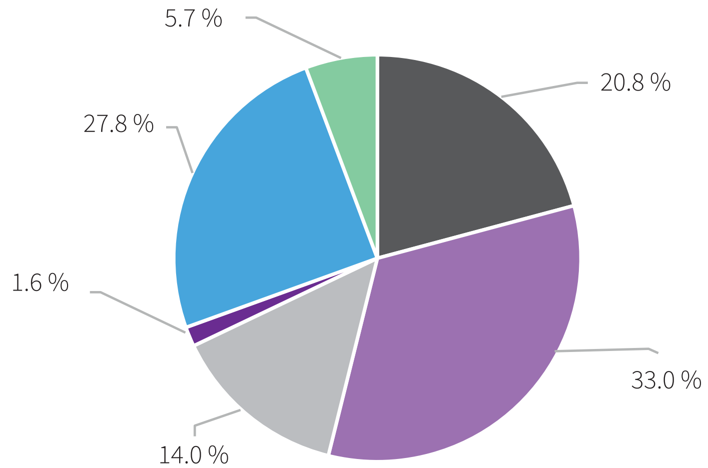


Figure 62. *Breakdown of total installed capacity (top) and electricity generation (bottom) by source, 2016*

[127] *https://www.teias.gov.tr/tr/elektrik-istatistikleri*

It should be noted that capacity factors[128] for hydro generation vary considerably year-by-year as seen in *Figure 63*[129], due to varying precipitation levels (snow and rainfall); in this regard, 2016 can be considered as an average year.

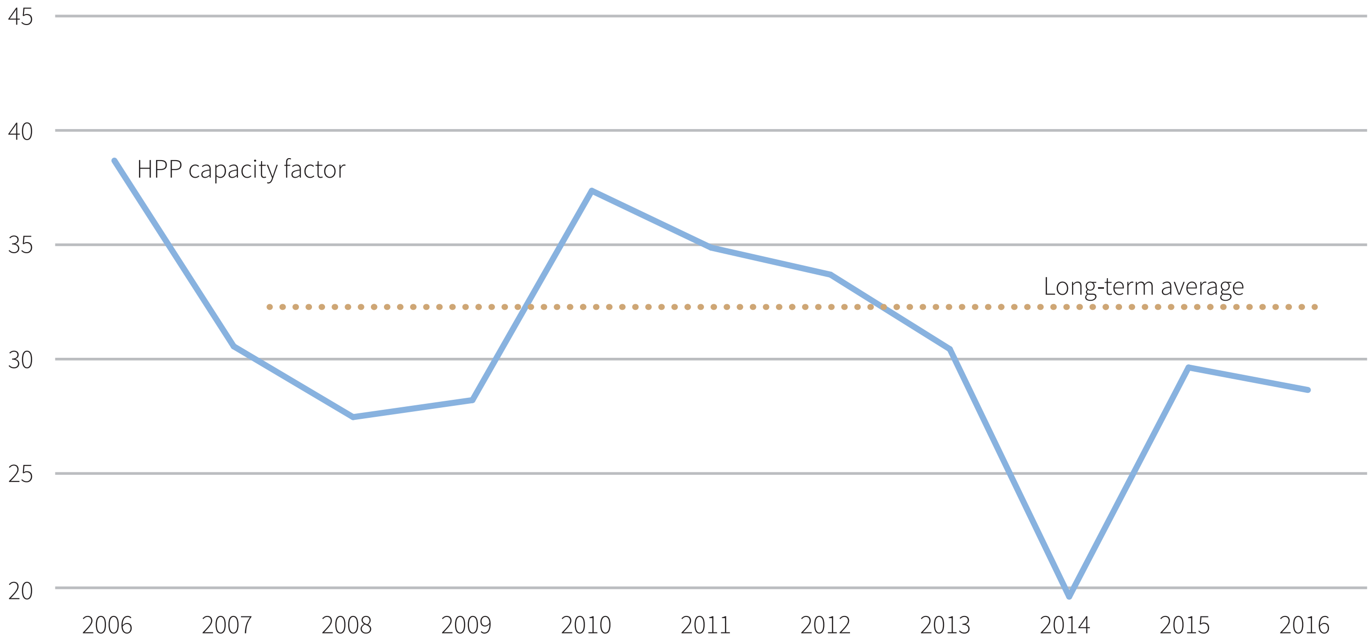


Figure 63. *Average capacity factor of hydropower plants and the long-term average, 2006-2016*

Turkey has excellent **solar, wind and hydro resources**. The wind atlas in Figure 64 below, Rüzgâr Enerjisi Teknik Potansiyelleri Atlası (REPA), was published by the Ministry of Energy and Natural Resources in 2016.[130] While there is a considerable variation of wind resources across the country, wind speeds above 7 m/s (80m_{AGL}) can be found in almost all regions of Turkey. Particularly attractive conditions are present in the Aegean, Marmara, and Eastern Mediterranean regions; these are also the areas where most wind power projects have been realized and are planned by developers. The Ministry of Natural Resources and Energy estimates the potential for attractive wind power generation with wind speeds above 7.5 m/s, measured at 50 m above ground, to be at 48 GW.[119] Taking into account the rapid technology and cost development, which allows wind power to be generated economically also at less ideal wind speeds below 7.5 m/s, the actual economic potential may actually be substantially higher than this figure.[131]

[128] Capacity factor is the ratio of electricity generated for the time considered, to the energy that could have been generated at continuous full-power operation during the same period
[129] *TEİAŞ Türkiye Elektrik Üretim-İletim İstatistikleri, https://www.teias.gov.tr/tr/turkiye-elektrik-uretim-iletim-istatistikleri/2015*
[130] *YEGM Rüzgâr Enerjisi Teknik Potansiyelleri Atlası REPA: http://www.eie.gov.tr/YEKrepa/REPA-duyuru_01.html.*
[131] Most wind power plants currently under construction in Turkey use turbines in the 3 MW range, which usually have hub heights of 120m and above; in particular above more rugged surface, wind speeds strongly increase with height; cf. *http://www.tureb.com.tr/files/tureb_sayfa/duyurular/2017_duyurular/subat/turkiye_ruzgar_enerjisi_istatistik_raporu_ocak_2017.pdf; https://www.agora-energiewende.de/fileadmin/downloads/publikationen/Agora_Kurzstudie_Entwicklung_der_Windenergie_in_Deutschland_web.pdf;*

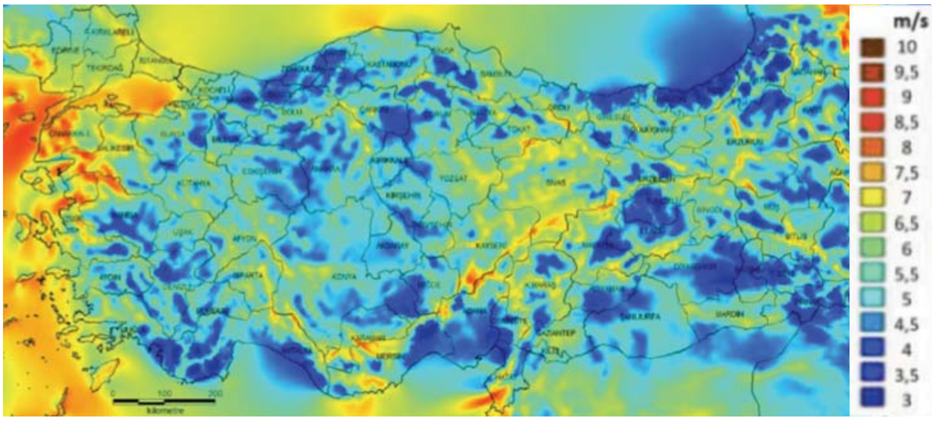


***Figure 64.** Wind speed atlas of Turkey (50 meters height and 200 meters resolution)*

Installed capacity of the wind power plant has increased from less than 1 GW in 2009 to almost 6 GW by the end of 2016, as presented in Figure 65[132]. Between 2013 and 2015, annual new installations were close to 1 GW, and, in 2016, for the first time, well above 1 GW.[133]

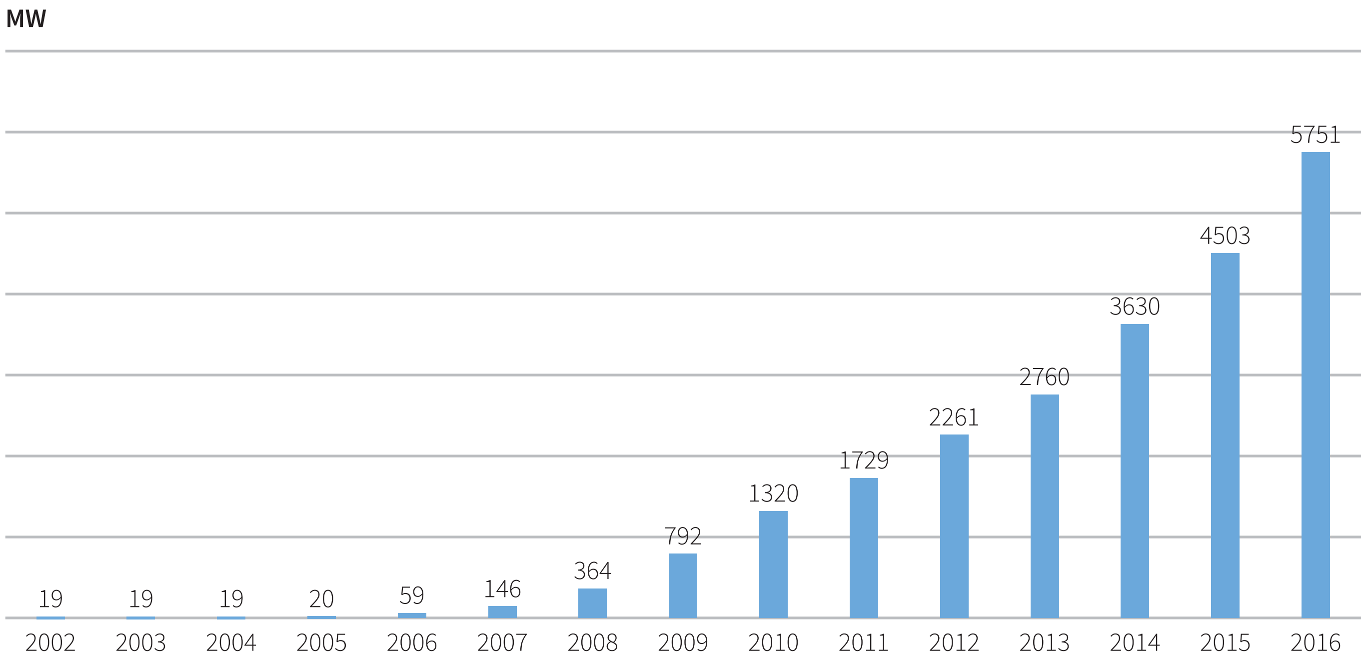


Figure 65. *Development of total installed wind power capacity in Turkey* [134]

A solar resource map of Turkey is presented in Figure 66. It demonstrates the attractive solar conditions across the country: Even in the North, in the Istanbul and Black sea areas, solar irradiation is consistently above 1,400 kWh/m^2/year. In the South, these values go up to 1,700 to, at maximum 2,000 kWh/m^2/year, with particularly attractive areas in the Mediterranean, Southern and South-Eastern Anatolian regions.

[132] *https://www.teias.gov.tr/tr/yayinlar-raporlar/sektor-raporlari*
[133] *In july 2017, 808 MW of Wind power plants were under construction, and another 2900 had been licensed, according to Turkish Wind Energy Association 2017, Wind Energy Statistics Report (http://www.tureb.com.tr/files/tureb_sayfa/duyurular/2017_duyurular/agustos/turkiye_ruzgar_enerjisi_istatistik_rapor_temmuz_2017.pdf)*
[134] *Ministry of Energy and Natural Resources (http://www.enerji.gov.tr/tr-TR/Sayfalar/Ruzgar)*

Figure 66. *Solar irradiation map*[135]

It should be noted that this range of irradiation is considerably higher than in many countries around Europe with higher installed solar capacities, as can be seen in Figure 67. Average solar irradiation in Turkey is second only to small island states Malta and Cyprus, and Portugal and Spain, but higher than the values of other Mediterranean countries such as Greece and Italy.

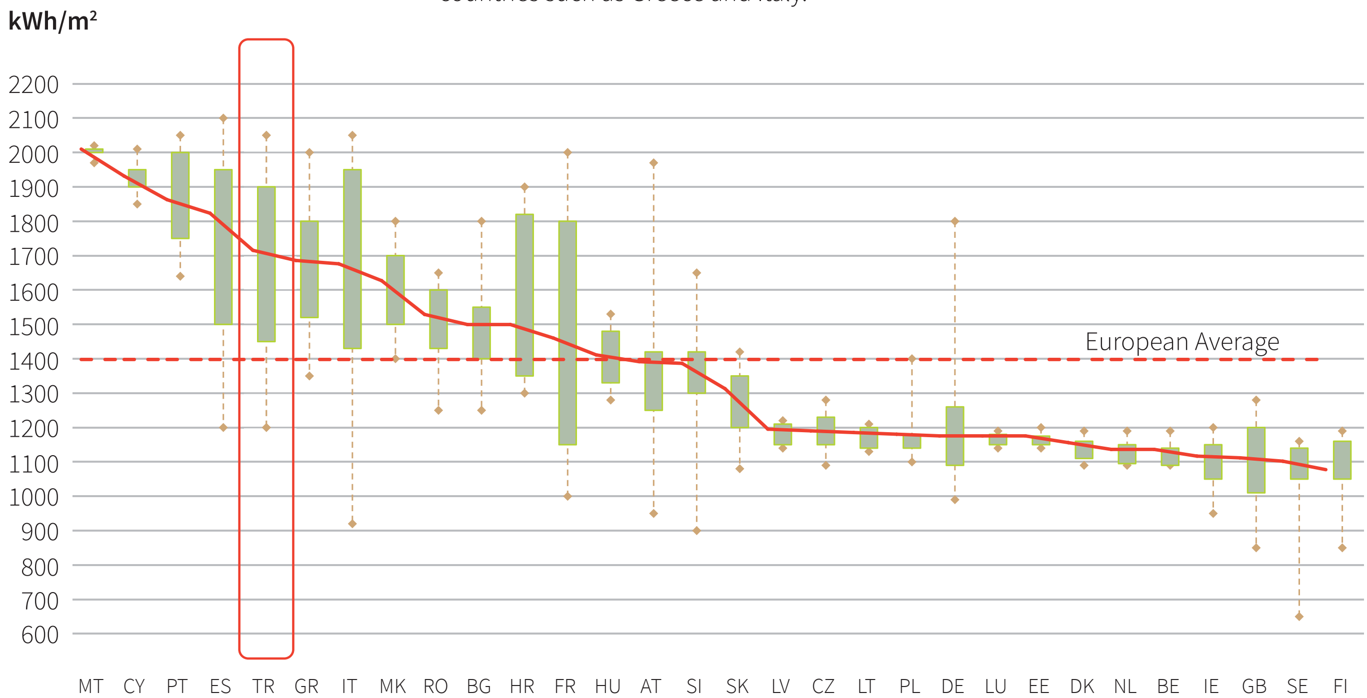


Figure 67. *Comparison of solar irradiation for selected countries (red: country average, box: 90% of areas, dashed: maximum and minimum)*[136]

Despite these very attractive solar resource conditions and considerable investor interest, until very recently, very few PV installations had been implemented in Turkey. Total installed capacity of PV was only about 300 MW by the end of 2015. However, recently, installations have picked up considerably: In 2016, more than 650MW were installed, followed by 550 MW additional capacity in the first half of 2017, with the Solar association GÜNDER estimating new installations to exceed 1 GW for the first time in this year[137]. To the largest extent, these are 1 MW installations, as investments up to this size do not require a lengthy licensing process.

Despite these very attractive solar resource conditions and considerable investor interest, until very recently, very few PV installations had been implemented in Turkey.

[135] *YEGM Güneş Enerjisi Potansiyel Atlası: http://www.yegm.gov.tr/MyCalculator/Default.aspx*

[136] *European solar irradiation map, European Commission Joint Research Centre Institute for Energy and Transport Photovoltaic Geographical Information System (PVGIS) "http://www.eborx.com/download/en/data/European-Solar-Irradiation-kWh-m2.pdf"*

[137] *International Solar Energy Society – ISES Turkey (GÜNDER) website: http://gunder.org.tr/*

A-1.2. Power market and (re-)dispatch in Turkey

The Electricity Market Law (EML) of 2001 established a wholesale electricity market in Turkey[138]. The EML envisioned a market design based on bilateral contracts as the best way to achieve competition in the Turkey's power industry (EMRA, 2003). After the enactment of EML, the EMRA was established, and previously vertically integrated segments of generation and transmission were unbundled.

The electricity market is based on a power exchange (PX) market operated by Energy Exchange Istanbul (EXIST). The main function of this market is to identify an economically optimal dispatch of available power generation: As generators bid at their marginal cost, a merit order is created, and generators receive production orders according to their offers, until demand of that specific hour is met. Network and reliability constraints are ignored in this day-ahead market clearing[139].

The example in Figure 68 illustrates the identification of the market clearing price (MCP), which is determined on an hourly basis in the day-ahead market, based on the bids of generators and requests of consumers in the market for this hour. The intersection points where demand requests and generator bids meet corresponds to the MCP for that hour.

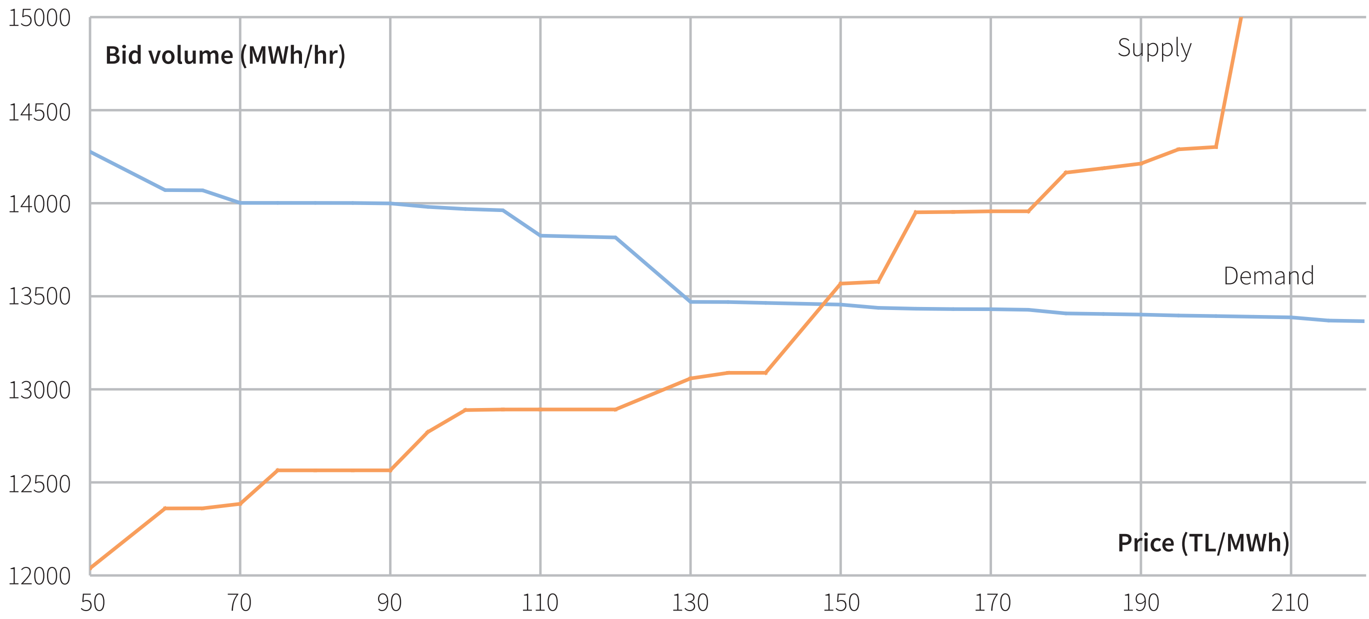


Figure 68. *Day ahead market clearing for a specific hour*[140]

Security and reliability criteria are taken into account only in a second step, after market clearing: Final commitment and dispatch of power plants are determined by the national dispatch center (NDC) of TEİAŞ in day-ahead and intra-day balancing markets, as illustrated in Figure 69[141]. The security criterion, laid out in the grid code[142], is based on the N-1 contingency criteria: In case of failure of any single network equipment, undisturbed operation of the entire needs to be guaranteed. In addition, reliability criteria need to be fulfilled, including the availability of sufficient amounts of spinning reserves, as defined by regulations introduced by ENTSO-E.[143]

[138] *EMRA: The Electricity Market Application Handbook www.EMRA.org.tr*
[139] *Day-ahead energy market: methodology for determination of market clearing price https://www.epias.com.tr/wp-content/uploads/2016/03/public_document_v4_released.pdf*
[140] *EPİAŞ Transparency platform, EPİAŞ 2017: https://seffaflik.epias.com.tr/transparency/*
[141] *TEİAŞ Türkiye Elektrik Piyasası: https://teias.gov.tr/tr/yayinlar-raporlar/piyasa-raporlari*
[142] *Grid code available at: http://www.EMRA.org.tr/TR/Dokumanlar/Elektrik/Mevzuat/Yonetmelikler*
[143] *ENTSO-E Network Code on Load Frequency Control and Reserves (LFCR): https://www.entsoe.eu/major-projects /network-code-development/load-frequency-control-reserves/Pages/default.aspx*

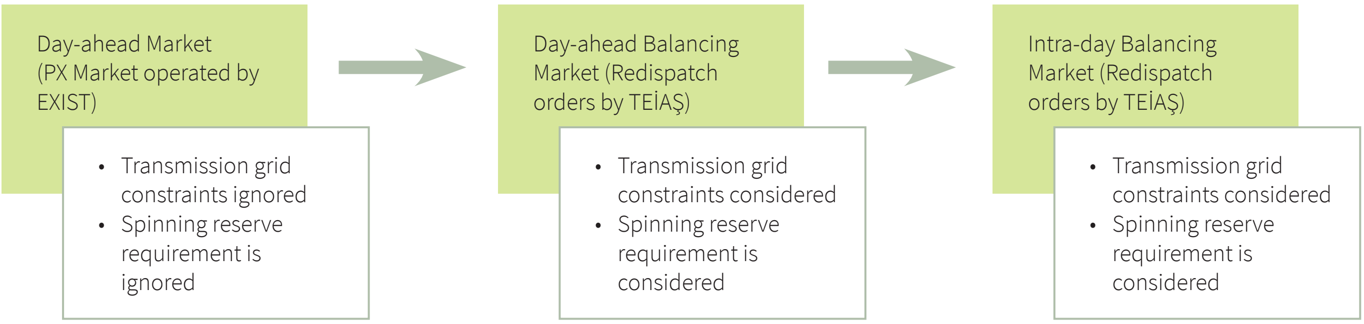


Figure 69. *Responsibilities of TEİAŞ in PX day-ahead and intra-day balancing markets*

Three different kinds of redispatch and commitment orders are given, if necessary, for either achieving supply-demand- balance at this hour (called “Code 0” order), for avoiding network constraints due to branch overloading (congestion) (“Code 1” order) or for meeting spinning reserve requirements (“Code 2” order). According to the current market rules, redispatch costs are defined as system marginal prices (SMP) and allocated to all market participants according to their consumption and peak demand level in power purchase agreements. Redispatch orders according to the different codes mentioned on a sample day, January 21, 2017 are presented in Figure 70[144].

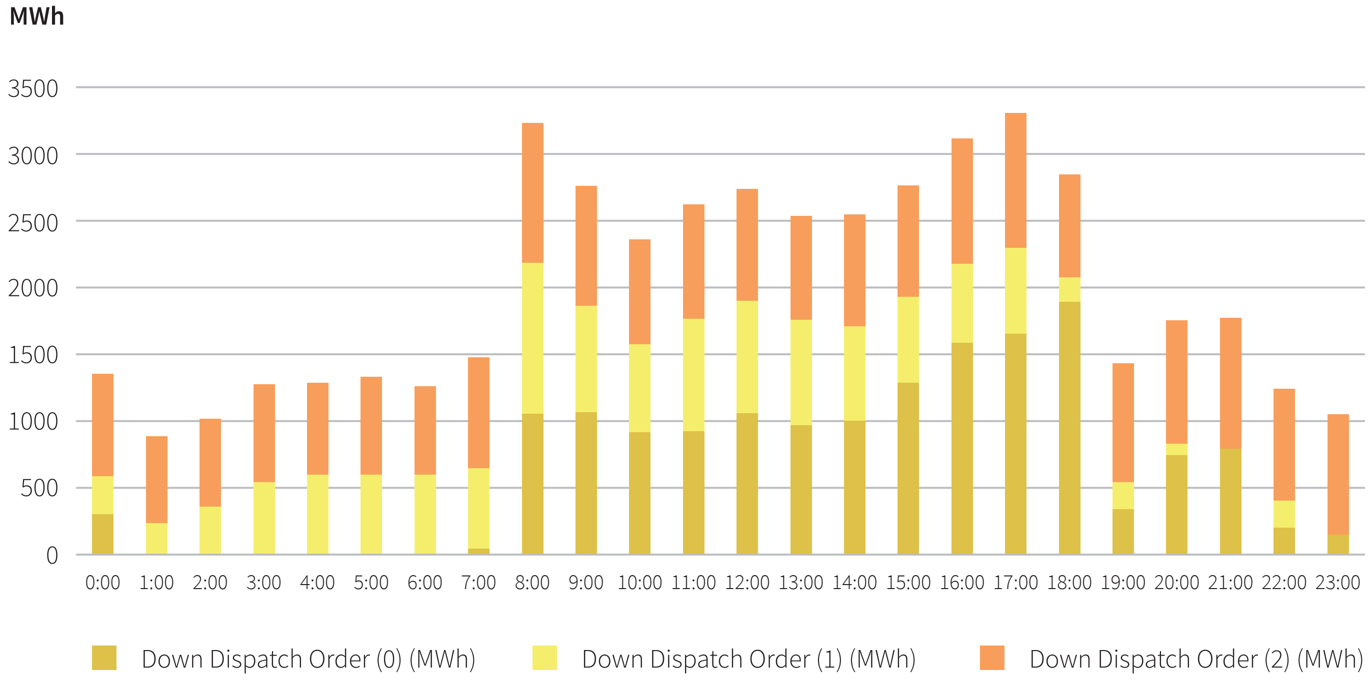


Figure 70. *Redispatch orders on January 21, 2017*

As system operator, TEİAŞ takes an active role in managing its operational costs by redispatching resources in short-term markets (day-ahead and intra-day balancing markets) based on market participants’ bids for balancing the system load, managing congestion, and maintaining system security and reliability.

[144] *EXIST EPİAŞ Transparency Platform: https://seffaflik.epias.com.tr/transparency/*

A-1.3. Main characteristics of Turkey's electricity transmission system

The transmission grid is the backbone of power systems, connecting the different regions of the country, enabling long distance power transport, for example of hydropower generated in the East of the country, to main demand center in the Western part. In Turkey, it is composed not only of the 400 kV system, but important transmission functions are also covered by the 154 kV system[145], as illustrated in Figure 71. Therefore, both systems are analyzed in this study. The state-owned company TEİAŞ is the sole owner of transmission assets in Turkey and responsible for both new investments in the transmission infrastructure, as well as system operation. Since it is a monopoly, the company is regulated by EMRA by means of a cost-based revenue cap approach.[146]

Figure 71. *Map of high voltage transmission network, interconnections, thermal and hydropower plants (source: TEİAŞ)*

TEİAŞ is required to safely operate and expand its system according to the needs of market participants. In order to carry out its duties, TEİAŞ prepares detailed investment plans and a capital expenditure budget. The plans and the corresponding budget are reviewed by the regulatory authority of Turkey. The proposed annual investment cost is recovered through use-of-transmission system charges (i.e. access charges)[147].

Turkey is largely self-reliant in terms of electricity supply, while exchange with neighboring countries does balance supply and demand locally.

Turkey's total electricity import and export amounts in 2016 were 6.4 TWh and 1.4 TWh, respectively[10]. That is, net import is 5 TWh, which corresponded to 1.8% of total consumption (278.4 TWh) in 2016. Turkey is largely self-reliant in terms of electricity supply, while exchange with neighboring countries does balance supply and demand locally.

The electric power system of Turkey has been synchronized with the ENTSO-E through 400 kV transmission lines with Bulgaria (two lines) and Greece (one line) since September 2010. Main advantages of the interconnection with the ENTSO-E system include grid frequency stability and sharing of spinning reserves among the ENTSO-E countries. The thermal capacity of the lines exceeds 1,500 MW however the transfers are limited due to dynamic concerns and network constraints within Balkan region[148].

[145] *TEİAŞ 2016: http://www.teias.gov.tr*
[146] *EMRA Lisans Yönetmeliği: http://www.EMRA.org.tr/TR/DokumanDetay/Elektrik/Mevzuat/Yonetmelikler/Lisans*
[147] *EMRA Use-of-transmission system charges: http://www.EMRA.org.tr/TR/Dokumanlar/TDB/Elektrik/IletimTarifesi*
[148] *O B Tör, C Gençoğlu, Ö Tanıdır, M E Cebeci, N Güven, "Investigation of necessary Transmission Enforcements at the Balkan Region of ENTSO/E in the sense of Inter-area Oscillations after Interconnection of Turkey," ELECO 2011, 7th International Conference on Electrical and Electronics Engineering, 1-4 December 2011, Bursa, Turkey, pp. 7-12.*

To the East, interconnections do exist with neighboring countries Syria, Iran, Iraq and Georgia. However, systems are not synchronized and interaction with these systems can therefore be controlled: The electric power export to Iraq and Syria and the import from Iran are through isolated 400 kV systems. The power exchange with Georgia started in 2014 through controllable, high voltage direct current (HVDC) back-to-back converters located close to the border.

For planning purposes and in order to identify grid reinforcements, TEİAŞ applies N-1 contingency criteria for 400 kV and 154 kV networks for summer and winter peaks, as well as spring minimum load periods.

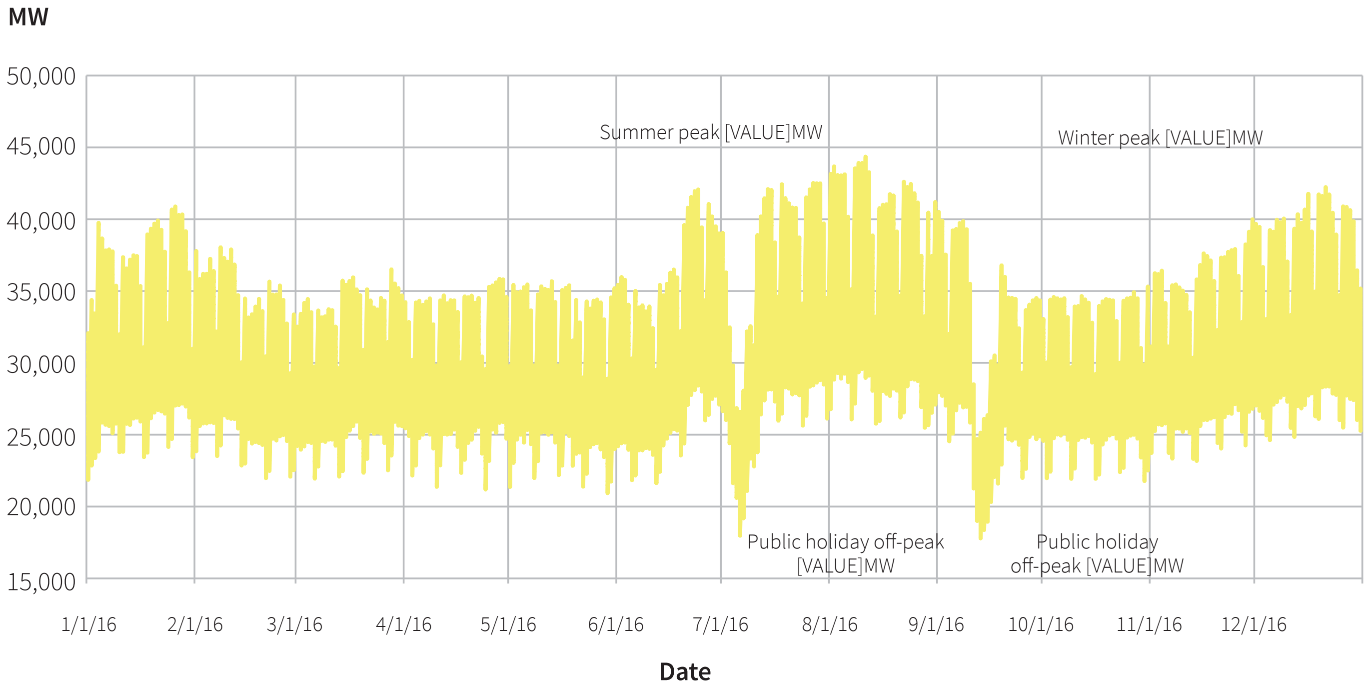


Figure 72. *Summer and winter peak and religious holiday off-peak demands, 2016*

Another characteristic of the Turkey's power system is that it has relatively large load deviations, mainly due to the use of steel arc furnaces.[149] Arc furnaces, which require generation capacity of several hundred megawatts during the melting process, are widely distributed in the country. They commonly cause random and sharp changes in load which affect the power flows on interconnection lines and area control error (ACE) in Turkey. Total change in power flows on the interconnectors of Turkey between Greece and Bulgaria sometimes exceeds 900 MW in less than 30 seconds, particularly when these large industrial loads are coinciding. These load changes are balanced by overall ENTSO-E rotating inertia until the frequency control via automatic generation control (AGC) acts. These rapid changes in the demand forces TEİAŞ to utilize a large amount of frequency control reserve. Accordingly, the operators constantly monitor and are very sensitive to available reserve in the up/down direction as well as the changes in demand. Therefore, keeping sufficient spinning reserve and flexible generation is a major concern of the TSO.[150] The study addresses this concern by calculating and modeling required fast spinning reserve requirements in order to satisfy ENTSO-E frequency control performance criteria.[151]

[149] *Ö. Tanıdır, O. B. Tör, "Accuracy of ANN based day-ahead load forecasting in Turkey's power system: degrading and improving factors," Neural Network World, 4/15, 2015, pp. 443-456.*
[150] *This concern was explicitly addressed by TEİAŞ during the stakeholder meetings.*
[151] *ENTSO-E Secretariat, "ENTSO\E Operational Handbook, P1 – Policy 1: Load-Frequency Control and Performance [C]]", 2004, available at: https://www.entsoe.eu/publications/system-operations-reports/operation-handbook/Pages/default.aspx*

A-1.4. Regulatory framework for Renewable energy investment

In its vision for 2023, government of Turkey has set several targets for the renewable part of the energy sector. The primary target aims to increase the share of renewable energy resources for electricity generation to at least 30 by year 2023. Specifically, the following RE targets were set:

- 34 GW capacity of hydro;
- 20 GW capacity of wind;
- 5 GW capacity of solar;

The main requirement to reach these targets is to support renewable generation in the electricity market. In order to achieve this, significant reforms have been undertaken since 2005, when the first law on renewable energy was enacted, as shown in *Figure 73.*[152]

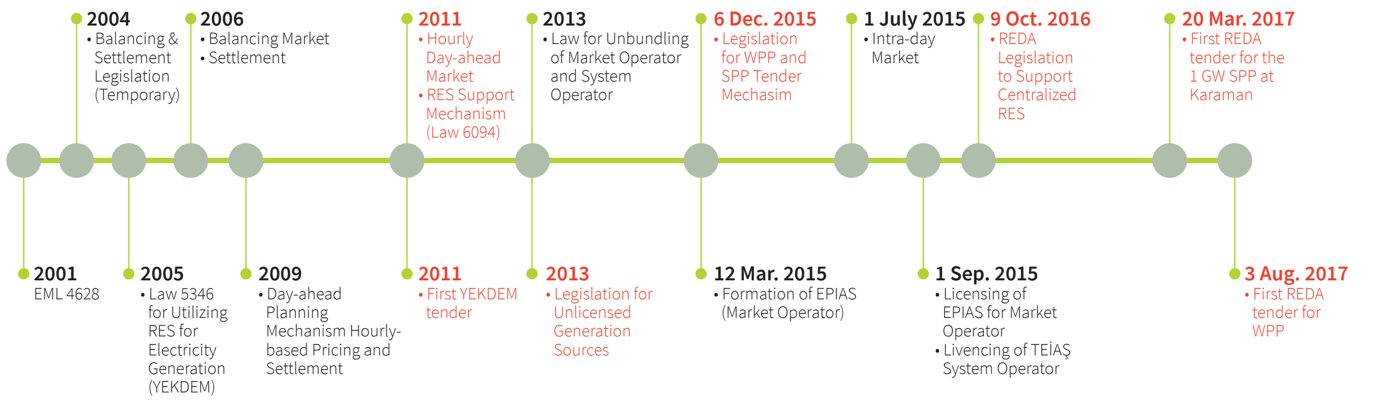


Figure 73. *Turkish Electricity Market Reforms and Laws, 2001-2017*

Investments in renewable energy technologies remained limited between 2005 and 2010, as the regulatory environment and in particular feed-in tariff levels were considered not attractive enough by investors. In order to encourage investment, the government of Turkey decided to amend the existing Law No. 5346 in 2010, which provided for more attractive feed in tariffs. Under the Law No. 6094, technology-specific feed-in tariffs (FiT) were introduced. Accordingly, FiTs have been provided to renewable energy facilities that were commissioned before 31 December 2020 for a period of ten years with the tariff levels (quoted in US dollars to avoid exchange rate risk) shown in Table 8.[153] Additionally, local content bonuses are offered to encourage local value creation (see Table 8).

Table 8. *Feed in tariffs after Law 6094 in 2011*[154]

Renewable Energy Type	Feed-in Tariff (USD ct/kWh)	Domestic production support (USD ct/kWh)	Total (USD ct/kWh)
Hydro	7.3	2.3	9.6
Wind	7.3	3.7	11
Geothermal	10.5	6.7	20
Biomass	13.3	9.2	22.5
Solar	13.3	5.6	18.9

[152] *TEİAŞ: https://www.teias.gov.tr/tr/yayinlar-raporlar/piyasa-raporlari*
[153] *IEA 2016: Energy Policies of IEA Countries: Turkey 2016 Review.*
[154] *YEGM: Law No 5346: Utilization of RES for the Purpose of Generating Electrical Energy. http://www.eie.gov.tr/yenilenebilir/y_mevzuat.aspx; local content support is limited to five years.*

In 2013, EMRA, announced the renewal of renewable energy support mechanism (YEKDEM). The retail companies assigned by EMRA have been required to purchase the produced electricity from manufacturers which are subject to this mechanism. Renewable energy investors may select annually in October, whether they will operate under the day-ahead market regime in the following year (which also yields balancing requirements) or prefer direct sale according to the FiT plan (instead of trading on the market, and free of balancing requirements). With high market prices in the past, most wind and hydro investors had originally opted to operate under the market regime; however, since 2015 (Figure 74), when wholesale prices dropped below FiT levels, they have moved almost entirely under the FiT regime.

USD cents/kWh

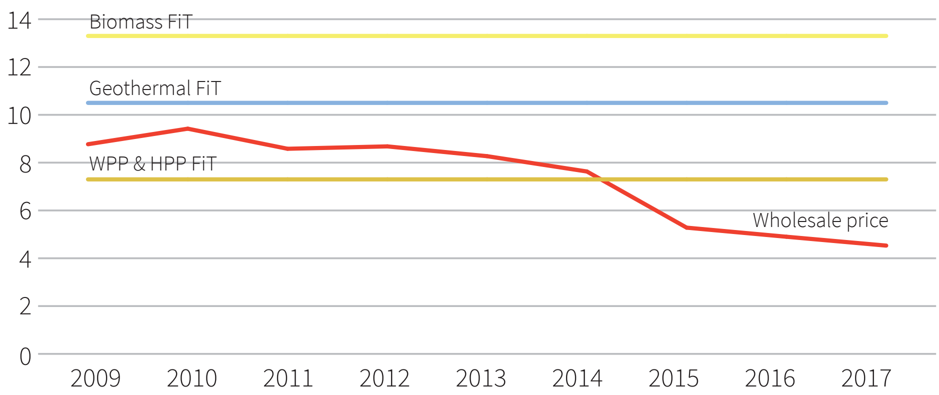


Figure 74. *Average wholesale market prices and the FiT, 2009-2017*[155]

According to Turkey's market regulation, power plants that have an installed capacity greater than 1 MW are required to obtain a generation license from the EMRA. Generation facilities with a maximum installed capacity of 1 MW can benefit from the feed-in tariffs without having to undergo the enduring licensing procedure. The auction regime for grid connection in particular has become a major bottleneck for larger solar investments. This is due to the fact that bidders, initially focused on securing grid connection entitlements because of the limited number of capacity, then delayed implementation as they waited for further PV system price decreases which would make their offers economically viable. As a consequence, almost all solar investment up until now fell under this "unlicensed regime".

Supplementary incentives set for all renewable energy generation investment include an 85% discount in the treasury and lease fees for 10 years after commissioning; 99% discount for the licensing fee and the annual license fee for first 8 years of operation; grid connection priority and VAT / custom taxes exemptions.

Although the support scheme has increased investment in renewable energy generation in Turkey, there are still major barriers that cut investments short.

Although the support scheme has increased investment in renewable energy generation in Turkey, there are still major barriers that cut investments short. These relate to the short period of feed in tariffs of 10 years (in many countries, FiT cover 15-20 years) and uncertainty on the period post-2020. The fact that renewable energy generators, who participate in the YEKDEM, do not have balancing responsibility, increases overall system cost and weakens the cost argument in favor of Renewables in the discussion.

[155] The annual average exchange rate is utilized to calculate the wholesale price as USD via following data sources; https://evds2.tcmb.gov.tr, https://rapor.epias.com.tr/rapor/xhtml/ptfSmfDonemlik.xhtml

In 2017, a new investment model for renewables, REDA mechanism, was introduced in order to bring costs down for Renewables generation and incentivize local manufacturing of renewable generation assets in Turkey. Public and government-owned land that is categorized as highly suitable for the renewable energy generation may be defined as REDA. Within REDA, a large generation capacity of either wind or solar (1 GW in the first two tenders) is assigned to a single private consortium through tenders. Beyond the size of the investment, which shall allow for economies of scale, investors benefit from additional exemptions:

- Renewable energy investments shall be exempt from customs tariff and value added tax for their investment costs (imported solar panels are not within the incentive scope);
- Lower license fees (only 10% of licensing fees) and annual license fee exemption for the first eight years of the operations;
- Network connection priorities;
- Simplified project preparation and land acquisition procedures;
- For the first ten years of the investment and operation periods, an 85% discount is applied to the cost of right of easement, usage right and rent.

REDA tenders in 2017 are in line with Turkey's domestic and renewable energy strategy.

REDA tenders in 2017 are in line with Turkey's domestic and renewable energy strategy.[156] The wind tender resulted in a highly competitive electricity price of USD 3.48 ct/kWh.[157] This compares to USD 10.3 ct/kWh under the YEKDEM regime and is 40% below 2017 spot market price.

The 2017 tender for the 1 GW Karapınar solar PV REDA, won with USD 6.99 ct/kWh. Within the scope of the Karapınar solar power project, a plant with a production capacity of a minimum of 500 MW of photovoltaic modules per year will be built in Turkey and research and development (R&D) activities will be carried out for the next 10 years [158].

[156] *Electricity market and security of supply adequacy strategy document (2009) http://www.enerji.gov.tr/File/?path=ROOT%2F1%2FDocuments%2FBelge%2FArz_Guvenligi_Strateji_Belgesi.pdf*
[157] Recent (25-29/12/2017) pre-license applications for new wind investment competition results in negative prices for almost 90% of the allocated capacity. The minimum price was -2.87 $cent/kWh
[158] *http://www.enerji.gov.tr/*

ANNEX 2. Methodology and key assumptions

A-2.1. Market simulation approach and key inputs

This section presents details of the market simulation approach in the study. In the market simulation, supply-demand balance of the power system is satisfied hourly for the entire target year 2026 at minimum cost of generation through an optimization process as illustrated in Figure 75. Staying consistent with the Turkey's day-ahead PX market, network security and reliability constraints and spinning reserve requirements are not considered in the market simulation. Main inputs and outputs of the market simulation are presented in Figure 75.

Input

- Cost curves of thermal power plants (NGPP, CPP, LPP, NPP)
- Short and long-term technical constraints of conventional power plants (Thermal PPs & HPPs)
- Time series total demand for the target year 2026 in hourly resolution
- Time series renewable energy generation for target year 2026 in hourly resolution
- Location of RES: Resource-driven and system-driven approaches, separetely

Market Simulation

- Minimum cost of generation for the target year 2026 (PX market based on merit order)
- Security constraints ignored (Congestions)
- Reliability constraints ignored (N-1 contingency and spinning reserves)

Output

- Market clearing for the target year 2026 in hourly resolution
- Commitment and dispatch of conventional generators in hourly resolution (Thermal PPs and HPPs)
- Cost of generation in hourly resolution
- Amount of renewable energy curtailment, if any, in hourly resolution

Figure 75. *Key inputs and outputs of the market simulation*

The objective function of market simulation is to minimize operation cost of generation along the entire target year 2026. It is formulated by (1)[159]

$$Min \sum_{i=1}^{N_g} \sum_{t=1}^{N_t} [C_1(P(i,t)) * I(i,t) + S(i,t)] \qquad (1)$$

The first term inside the bracket is the production cost, $C_1(P(i,t))$ which is calculated as the product of the heat rate (MBTU/h) and the unit's fuel cost ($/MBTU). The second term represents the start-up cost of the units which depends on the length of time that the unit has been off. The start-up cost is defined as (2):

$$S(i,t) = 1(i,t) * [1- I(i,t-1)] * \left[\alpha_i + \beta_i * \left(1 - exp\frac{-x^{off}(i,t)}{\tau_i}\right)\right] \qquad (2)$$

The prevailing constraints of the market simulation are as follows.

• System real power balance:

$$Min \sum_{i=1}^{N_g} (P(i,t)) * I(i,t) = P_D(t) \qquad t=1, \ldots N_t \qquad (3)$$

• Unit generation limits:

$$P_{gmin}(i) \leq P(i,t) \leq P_{gmax}(i) \qquad i=1, \ldots N_g \qquad t=1, \ldots N_t \qquad (4)$$

[159] *Shahidehpour, H. Yamin, Z. Li, "Market Operations in Electric Power Systems," Wiley, 2002.*

• Thermal unit minimum starting up/down times:

$$[X^{on}(i,t) - T^{on}(i,t)] * [I\,(i,t\text{-}1) - I\,(i,t)] \geq 0 \tag{5}$$

$$[X^{off}(i,t\text{-}1) - T^{off}(i,t)] * [I\,(i,t\text{-}1) - I\,(i,t)] \geq 0 \tag{6}$$

• Ramping constraints:

$$P\,(i,t) - P\,(i,t\text{-}1) \leq UR\,(i) \quad \text{as unit ramps up} \tag{7}$$

$$P\,(i,t\text{-}1) - P\,(i,t) \leq DR\,(i) \quad \text{as unit ramps down} \tag{8}$$

Other constraints of the objective function (1) are described in the following sub-sections.

A-2.2. Network simulation approach and key inputs

Network simulation represents the role of the TSO, TEİAŞ, in determining a suitable transmission network and system operation that guarantees security and reliability of the power system. Security is satisfied by ensuring supply-demand balance without any overloading of lines and transformers in the transmission grid. Reliability of the network is satisfied by ensuring N-1 contingency and providing necessary spinning reserves. A flowchart of the network simulation approach utilized in this study is presented in Figure 76. As illustrated in the flowchart, market simulation output, which is an 8760-hour time series unit commitment and generation dispatch for the target year 2026, is given as an input to the network simulation.

In addition to renewable energy curtailment, load shedding is also considered as an option to relax congestions in the network. Cost of load shedding is assumed to be the highest among the others in the merit order. Renewable energy curtailment cost follows the load shedding cost.

Input	Market Simulation	Output
• Market simulation constraints • Market simulation output for the target year 2026 in hourly resolution (Commitment and dispatch of conventional power plants) as an initial operating point of the conventional generators • Grid data (400 kV and 154 kV transmission network • Time series demand of substations for the target year 2026 in hourly resolution	• Minimum cost of generation re-dispatch for the target year 2026 • Security constraints considered (Congestions) • Reliability constraints considered (N-1 contingency and spinning reserves)	• Final commitment and dispatch of conventional generators (Thermal PPs and HPPs) for the target year 2026 in hourly resolution) • Cost of generation and re-disptach in hourly resolution • Amount of renewable energy curtailement and/or load shedding, if any, in hourly resolution • Allocation of spinning reserves on conventional PPs •Congestion level of transmission branches (lines ad transformers) in hourly resolution •Transmission investment requirements induced by network security and reliability constraints

Figure 76. *Main flowchart of network simulation*

As the system becomes more congested, the system operator would consider the alternative of incorporating the network flow constraints in the unit commitment formulation to minimize the violation and the related costs of the normal operation of the system.

The objective of network simulation is to obtain a unit commitment schedule at minimum production cost without compromising the system reliability. The reliability of a system is interpreted as satisfying two functions: adequacy and security. An adequate amount of capacity resources must be available to meet the peak demand (adequacy), and the system must be able to withstand changes or contingencies on a daily and hourly basis (security). The traditional unit commitment algorithm determines the unit schedules to minimize the operating costs and satisfy the prevailing constraints such as load balance, system spinning reserve, ramp rate limits, fuel constraints, multiple emission requirements and minimum up and down time limits over a set of time periods. The scheduled units supply the load demands and possibly maintain transmission flows and bus voltages within their permissible limits. However, in circumstances where most of the committed units are located in one region of the system, it becomes more difficult to satisfy network constraints throughout the system. As the system becomes more congested, the system operator would consider the alternative of incorporating the network flow constraints in the unit commitment formulation to minimize the violation and the related costs of the normal operation of the system.

The following approach is implemented in the study. Network simulation decomposes the scheduling formulation into a master problem and a sub-problem based on the Benders de-composition[144]. The master problem involves calculating unit commitment, by augmented Lagrangian relaxation, using the prevailing constraints but omitting the network constraints. Given a certain unit commitment schedule, the sub-problem performs one of the following tasks:

1. Minimizes the network violations. For a linearized network, such as the one used in this study, the sub-problem is decoupled into two smaller sub-problems corresponding to transmission and voltage constraints. The transmission sub-problem seeks to minimize transmission flow violations for the steady state and *n*-1 contingencies by unit generation.
2. Minimizes the expected unserved energy (EUE). The sub-problem takes into consideration the forced outage rates of committed generating units and in-service transmission lines, and correspondingly adjusts the available control facilities to minimize EUE.

In both tasks, Benders cuts are generated if any violation is detected in the sub-problems. Via Benders cuts, the unit commitment in the master problem is solved iteratively to provide a minimum cost generation schedule while satisfying all constraints.

The objective function and constraints of network simulation are completely the same as those of the market simulation (1)-(8). In addition to (1)-(8), following system constraints are included to the problem:

• System Spinning Reserve Requirements

$$\sum_{i=1}^{N_g} r_s(i,t) * I(i,t) \geq R_s(t) \qquad t=1,\ldots N_t \tag{11}$$

$$r_s(i,t) = \min\{10 * MRS(i), P_{gmax}(i) - P(i,t)\} \tag{12}$$

where,

• Transmission Flow Limit from Bus *k* to Bus *m*

$$-P_{km}^{max} \le P_{km}(t) = f(P(t) \le P_{km}^{max} \qquad t=1, \ldots N_t \tag{13}$$

where $\boldsymbol{P}(t)$ is real power generation vector at time *t*.

• Reactive Power Operating Reserve Requirement

$$\sum_{i=1}^{N_g} Q_{gmax}(i) * I(i,t) \ge Q_D(t) \qquad t=1, \ldots N_t \tag{14}$$

• Reactive Power Generation Limits and Load Bus Balance

$$Q_G^{min} I(t) \le Q_G(t) = F_1(V) \le Q_G^{max} I(t) \qquad t=1, \ldots N_t \tag{15}$$

$$Q_L(t) = F_2(V) \qquad t=1, \ldots N_t \tag{16}$$

where $\boldsymbol{I}(t)$ is unit commitment status vector at time t.

• System Voltage Limits

$$V^{min} \le V \le V^{max} \tag{17}$$

A-2.3. Main modeling assumptions

A-2.3.1. Parameters constant in all scenarios

A-2.3.1.1. Demand and peak load

Average annual demand and peak load increase between 2016 and 2026 is estimated at 5.13%, based on the combination of top-down and bottom-up approaches along with trending techniques.[160] Total consumption and peak demand of the country are estimated at 439 TWh and almost 70 GW, respectively, up from almost 280 TWh and 44.5 GW in 2016. Hourly resolution of demand is illustrated in Figure 77. It follows today's distribution, with the exception of the two main Islamic holiday seasons, which move throughout the calendar year, shifting by 10-11 days / year. Minimum daily load is determined by these two main religious holiday periods, as demand of the country decreases significantly during these periods.[161] They were set accordingly for the year 2026.

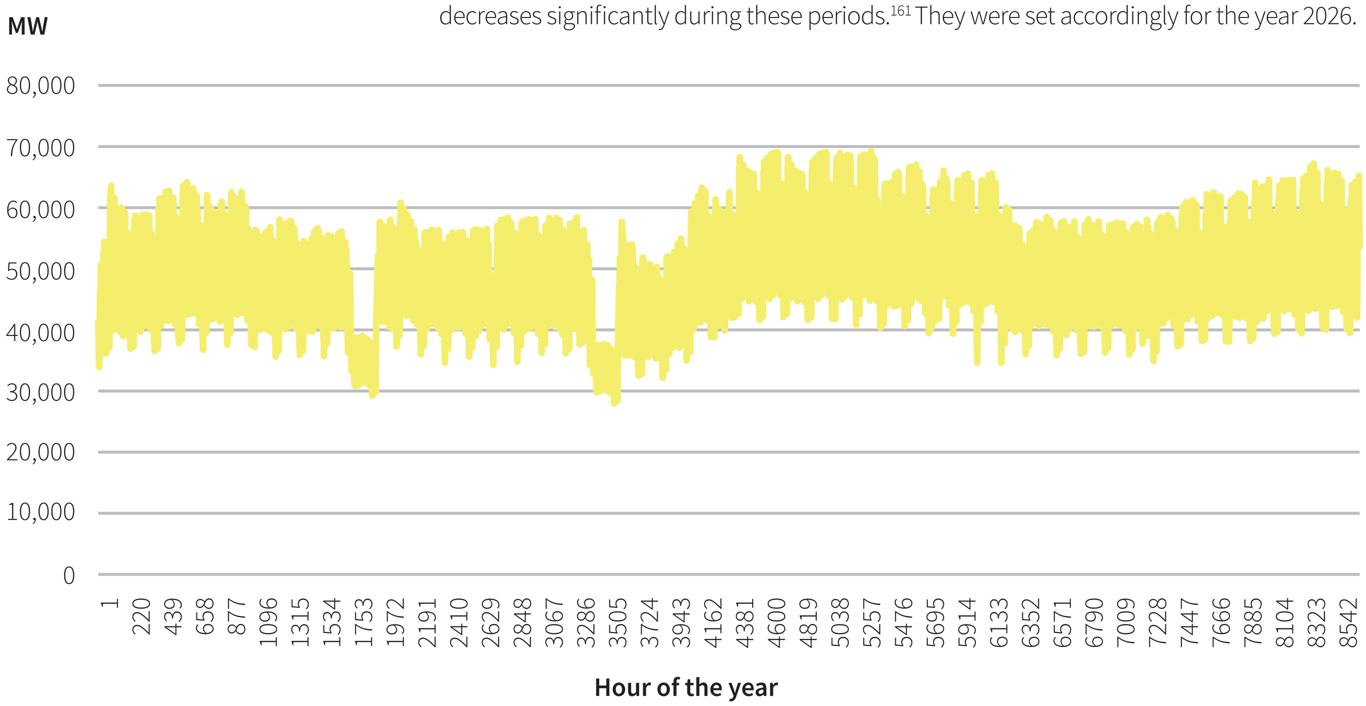


Figure 77. *Total demand estimation of Turkey in 2026 with time series approach*

[160] *F. Tursun, M. E. Cebeci, O. B. Tör, A. Şahin, H. G. Taşkın, A. N. Güven, "Determination of zonal power demand S-curves with GA based on top-to-bottom and end-use approaches," IEEE PES ICSG 2016.*

[161] *These periods are important for this study in the sense that RES generation might needs curtailment based on the level of RES generation.*

A-2.3.1.2. Merit order of power plants

In order to model a realistic dispatch of the power plants required for the grid analysis a merit order is identified for the study based on SRMC of the power plants. For this purpose, the absolute generation cost of power plants is not at the center, but, instead, relative cost of the power plants. SRMC depends on the primary energy source, capacity, and age of the power plants. Figure 78 shows the SRMC intervals assumed in the study for different types of power plants. In defining the SRMC intervals for the same type of power plants, the following assumptions were made: The larger the capacity, the lower the SRMC (economy of scale), and: The younger the power plant, the higher its efficiency. This assumption ensures that, for the same fuel type of power plants, those power plants built more recently are more efficient than the older ones. SRMCs are determined plant by plant based on these general assumptions.

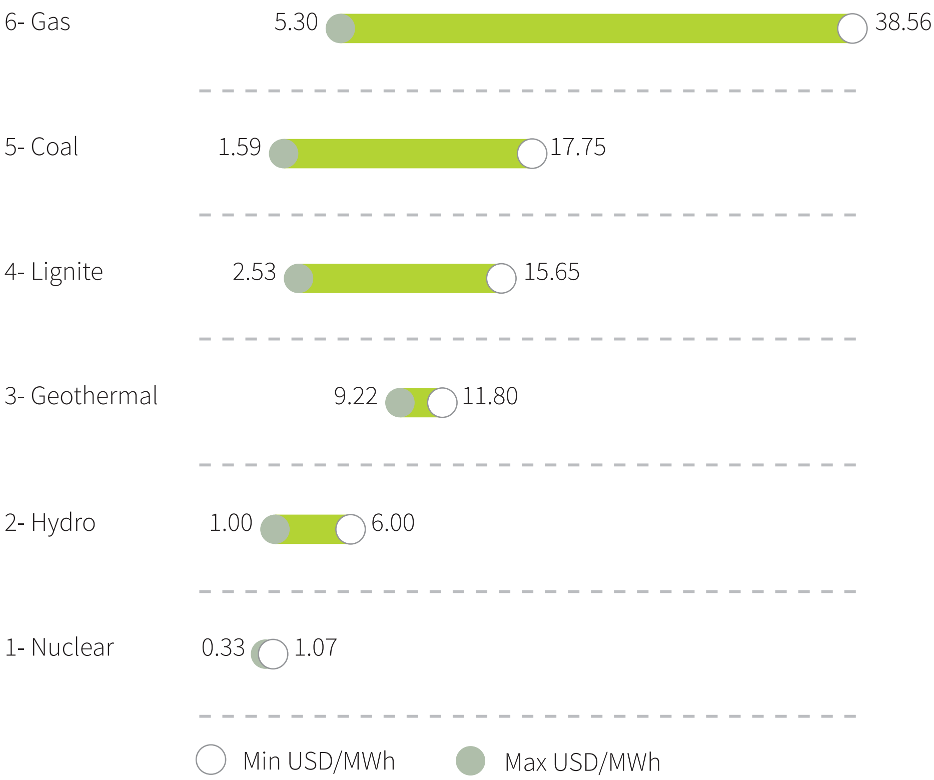


Figure 78. *Short-run marginal costs intervals of the power plants assumed for 2026*

Additional assumptions made in determining the SRMCs of the power plants are listed below:

- Generator cost curves of conventional power plants are assumed to be linear, and therefore, SRMCs (derivative of cost curve) are constant independent from the generation amount. The same SRMCs are considered in market and network simulations.
- **Wind and Solar Plants:** SRMC of renewable energy are assumed to be at the bottom of the merit order with zero cost. Their generation is modelled as negative load (i.e., feed-in).
- **Hydropower Plants:** SRMCs of hydropower plants are assumed to be zero. However, long-term energy constraints of hydropower plants are considered in market and network simulations. Thereby, cost of hydropower plants are induced from operating them non-optimally under their long-term energy constraints.

- **Nuclear Power Plants:** Long-term bilateral purchase agreements with nuclear power plants are considered in determining the SRMCs. They are lower than SRMC of thermal power plants. Therefore, nuclear power plants are at the bottom of the conventional thermal power plants in the merit order.
- **Conventional power plants excluding NPPs and HPPs**: They are sorted in merit order plant-by-plant according to their SRMCs. Depending on the availability of data, historical MCPs published by EXIST[162] and hourly utilization of different technology clustered power plants are considered in estimating the SRMCs of power plants. SRMCs of open cycle gas turbine power plants are at the top of the natural gas power plants in the merit order. The commitment of the government to give incentives to lignite power plants is considered by assuming the maximum SRMC of LPPs under the maximum SRMC of ICPPs in the merit order.

As indicated in Figure 78, SRMCs of some natural gas power plants are lower than that of old coal and lignite power plants due to capacity, size or efficiency. Nevertheless, maximum SRMC of the natural gas power plant (USD 38.56/MWh) is higher than the maximum SRMCs of both coal and lignite power plants (USD 17.75/MWh and USD 15.65 /MWh, respectively).

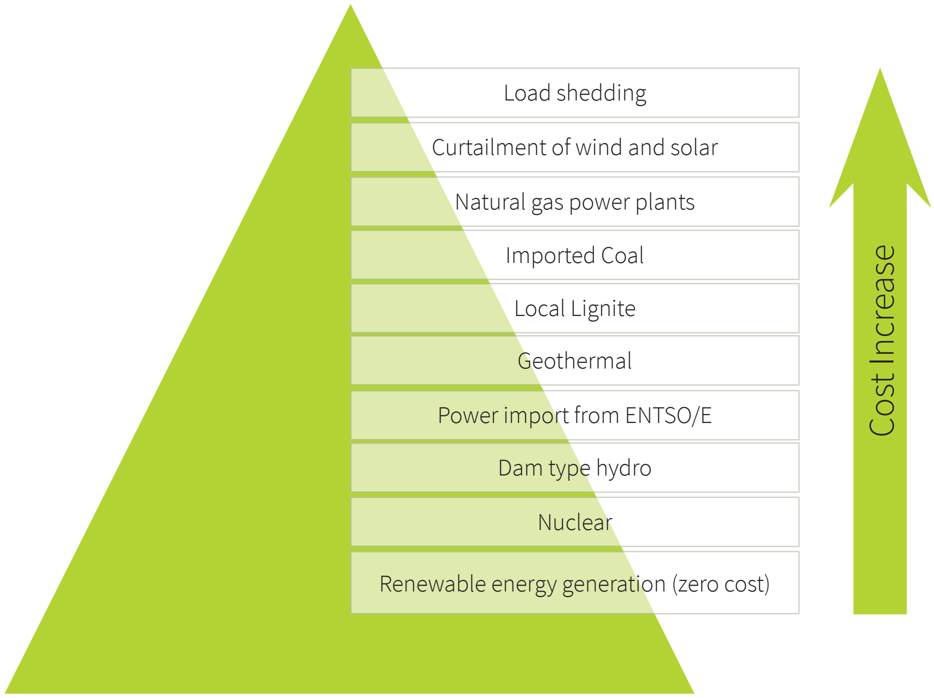


Figure 79. *Merit order of the generators in terms of short-run marginal costs for 2026*

A-2.3.1.3. Long-term constraints of hydropower plants

An example of hydraulic coupling data utilized in the study is presented in Figure 80. The hydraulic coupling affects the generation ability of an hydropower plants due to its impact on the reservoir. This impact is converted into energy constraints that limits the generation of the plant based on the generation of upstream plant plus the available water in the reservoir. For this purpose, the efficiency of the hydropower plants are assumed to be constant for simplification of calculation.

[162] *EPİAŞ transparency platform, "https://seffaflik.epias.com.tr/transparency/"*

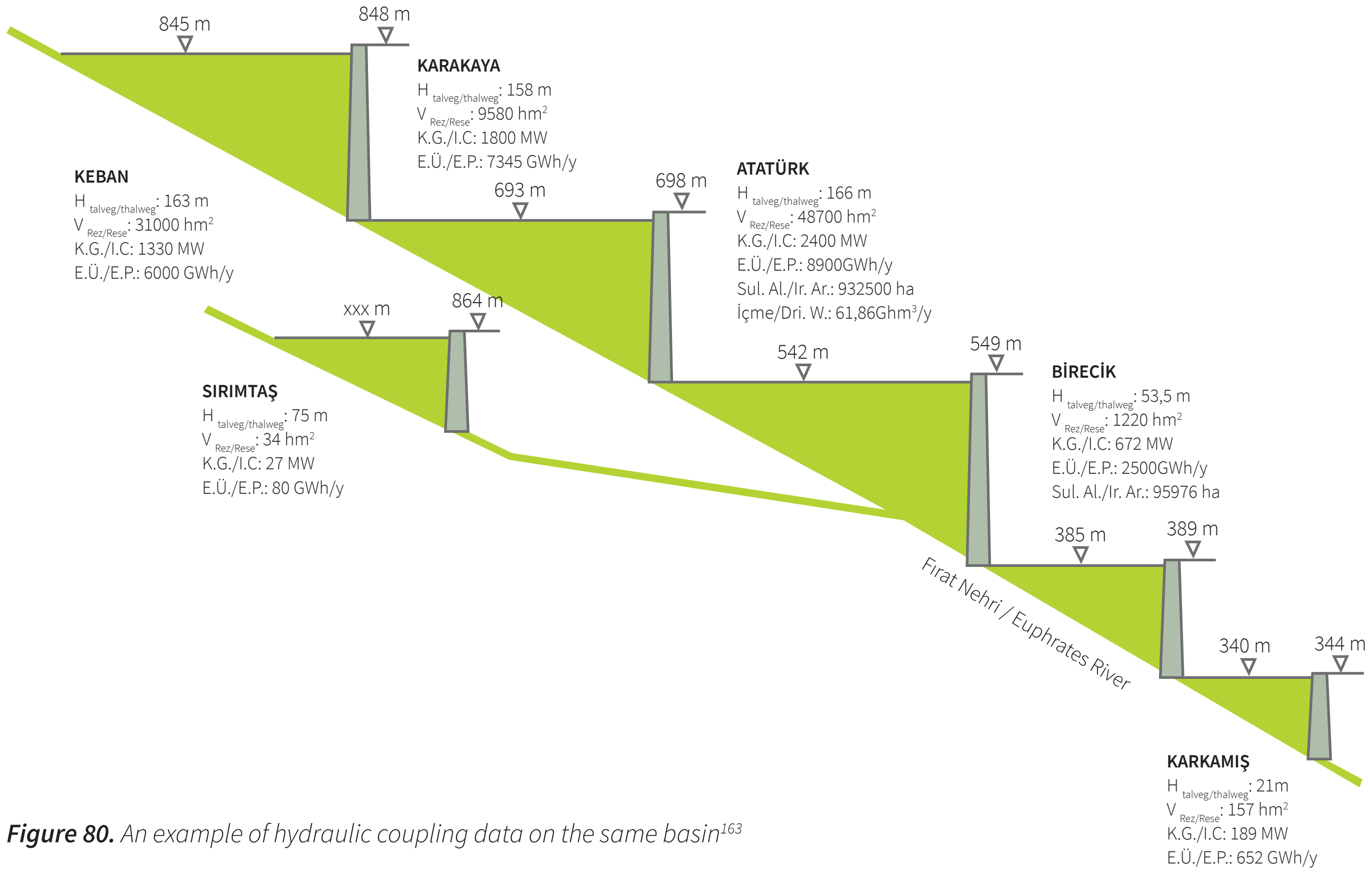


Figure 80. *An example of hydraulic coupling data on the same basin*[163]

A-2.3.1.4. Natural gas power plants curtailment

In scenarios where renewable energy curtailment is not an option, the renewable energy generation is modelled as an uncontrollable power injection whose values are pre-calculated, whereas for scenarios where the renewable energy curtailment is activated, the renewable energy generation is modelled by controllable and cost-effective plants whose maximum generation is limited by pre-calculated renewable energy generation for each hour and for each plant. Hence, the plant generation is limited by the actual wind/solar capacity at a particular hour and the algorithm (based on network constraints and/or reserve requirements) allows for reducing the output of the plant.

A-2.3.2. Parameters that vary depending on the scenario

A-2.3.2.1. Spinning reserve requirements

Generation and demand, in synchronous power networks, must be balanced for proper operation of the system. This balance is constantly monitored and any imbalance due to network events, dispatch changes by market or forecast errors maintained by automatic controllers of individual units, centralized control systems and manually by the dispatcher, the details of which are explained in ENTSO-E policies.[164] Further, the control performance is also addressed by performance indices.

In Turkey's electricity market, primary and secondary reserves are provided by conventional power plants. Primary reserve is compulsory while secondary reserves are provided by the market.

In Turkey's electricity market, primary and secondary reserves are provided by conventional power plants. Primary reserve is compulsory while secondary reserves are provided by the market. Hydropower plants and gas fired power plants, which have fast ramp-up/down capability, are given priority in the secondary reserves.

[163] *Dams of Turkey, International Comission on Large Dams Turkish National Committee, 2014, available at: http://www2.dsi.gov.tr/barajlar_albumu/files/assets/basic-html/index.html#1*

[164] *ENTSO-E Secretariat, "ENTSO\E Operational Handbook, P1 – Policy 1: Load-Frequency Control and Performance [C]", 2004, available at: https://www.entsoe.eu/publications/system-operations-reports/operation-handbook/Pages/default.aspx*

As "minimum reserve requirement" is one of the inputs of Network Simulation, the differences between reserve requirements of individual scenarios should be defined based on the frequency control performance criteria.

During the interconnection process with ENTSO-E, TEİAŞ realized various adaptations, rehabilitations and improvements on these plants and the AGC system in the scope of two cascading EU funded projects.[165,166] Through these projects and utilizing ENTSO-E policies, frequency control performance indices and success criteria are defined by TEİAŞ and ENTSO-E Project Group. Based on the defined success criteria, TEİAŞ performed various studies to improve the performance indices either via controller modifications or reserve amount adaptations [167,168]. However, as the intermittent generation in the network increases because of renewable energy installments, these performance indices will be affected and adaptation in reserve amount will be necessary to satisfy the success criteria. As "minimum reserve requirement" is one of the inputs of Network Simulation, the differences between reserve requirements of individual scenarios should be defined based on the frequency control performance criteria.

• Frequency Control Performance Criteria of ENTSO-E for Turkey

The general principles for performance indices and success criteria of frequency control are described in detail in ENTSO-E policies[149]. However, based on the characteristics of interconnection and network structures of neighboring countries, the success criteria can be adapted. Accordingly, nine specific performance indices are defined by the ENTSO-E project group [169,170] based on:

- Frequency (mean, standard deviation)
- Unscheduled exchange power (mean, standard deviation)
- ACE (mean, standard deviation, various absolute value limit for a defined percentage of time)

For only four of these indices, success criteria defined:

- Average of absolute values of hourly ACE values should be less than 20 MW
- Standard deviation of hourly ACE values should be less than 120 MW
- Absolute values of ACE should be less than 100 MW for 33% of the time
- Absolute values of ACE should be less than 175 MW for 10% of the time

The most challenging performance criteria was the "Absolute values of ACE should be less than 175 MW for 10% of the time ($Abs(ACE)_{\%90} < 175$ MW)" [171] given the rapid changes in total demand of Turkey due to arc-furnaces which can cause more than 700 MW exchange power deviation in less than 20 seconds.

[165] *Republic of Turkey Prime Ministry Under Secretariat of Treasury Central Finance and Contracts Unit, "Project Number: TR 03 03 03; Complementary Technical Studies for the Synchronization of the Turkey's Power System with the UCTE Power System", 2003*
[166] *Republic of Turkey Prime Ministry Under Secretariat of Treasury Central Finance and Contracts Unit, "Project Number: TR 07 02 05; Rehabilitation of the frequency control performance of Turkey's Power System for Synchronous Operation with UCTE", 2007*
[167] *Ö.Tanıdır, M.E.Cebeci, C.Gençoğlu, O.B.Tör, "A strategy to enhance AGC performance of power systems that suffer inter-area oscillations and a case study for Turkey's power system", Elsevier International Journal of Electrical Power & Energy Systems, Volume 43, Issue 1, December 2012, Pages 941-953*
[168] *TUBITAK UZAY Power Systems Department, "Performance Evaluation of the AGC System of Turkey during ENTSO/E CESA Trial Interconnection Period", 2011*
[169] *ENTSO-E Turkey Interconnection Project Group, "Methodology of evaluation of the performance of Secondary Control in EPS of Turkey", 2010*
[170] *ENTSO-E Turkey Interconnection Project Group, "Workshop Report: Observations on the AGC Performance and Structure"*
[171] *ENTSO-E Turkey Interconnection Project Group, "Minutes of Meeting, Project Group for Connection of Turkey to the Continental Europe Synchronous Area 28th Meeting", 2011, Istanbul*

• **Reserve Requirement Determination**

For determination of reserve needs, ENTSO-E policies recommends four options[149]:
- Empiric Noise Management Sizing Approach
- Probabilistic Risk Management Sizing Approach
- Largest Generation Unit or Power Infeed
- Extra-ordinary Sizing of Reserves

The determined reserve from the first three options were not enough for the satisfaction of success criteria defined by the ENTSO-E working group[155]. Accordingly, the AGC reserve is gradually increased until the criteria are satisfied. As the deviation in demand reduces at night hours and the available reserve from online units is limited, TEİAŞ preferred to reduce the AGC demand at night hours without violating the success criteria. The final utilized values are:
- 1,200 MW for day hours
- 700 MW for night hours

The network can still maintain performance indices based on this reserve scheme. However, as the amount of renewable energy increases in the network as in 2026 scenarios, the hourly changes in Net-Demand also increases. Accordingly, the reserve amount is expected to be increased based on the ratio between the hourly changes in Net-Demand of 2016 and 2026.

For these calculations, EPİAŞ data; hourly demand for 2016 (Figure 81) is utilized[172] together with the calculated/assumed hourly demand/renewable energy generation for each scenario in 2026 in a two-step calculation methodology.

• **Step-1:**
Initially, the current situation is assessed in detail. The annual hourly Net-Demand for 2016 and corresponding hourly Net-Demand changes are calculated.

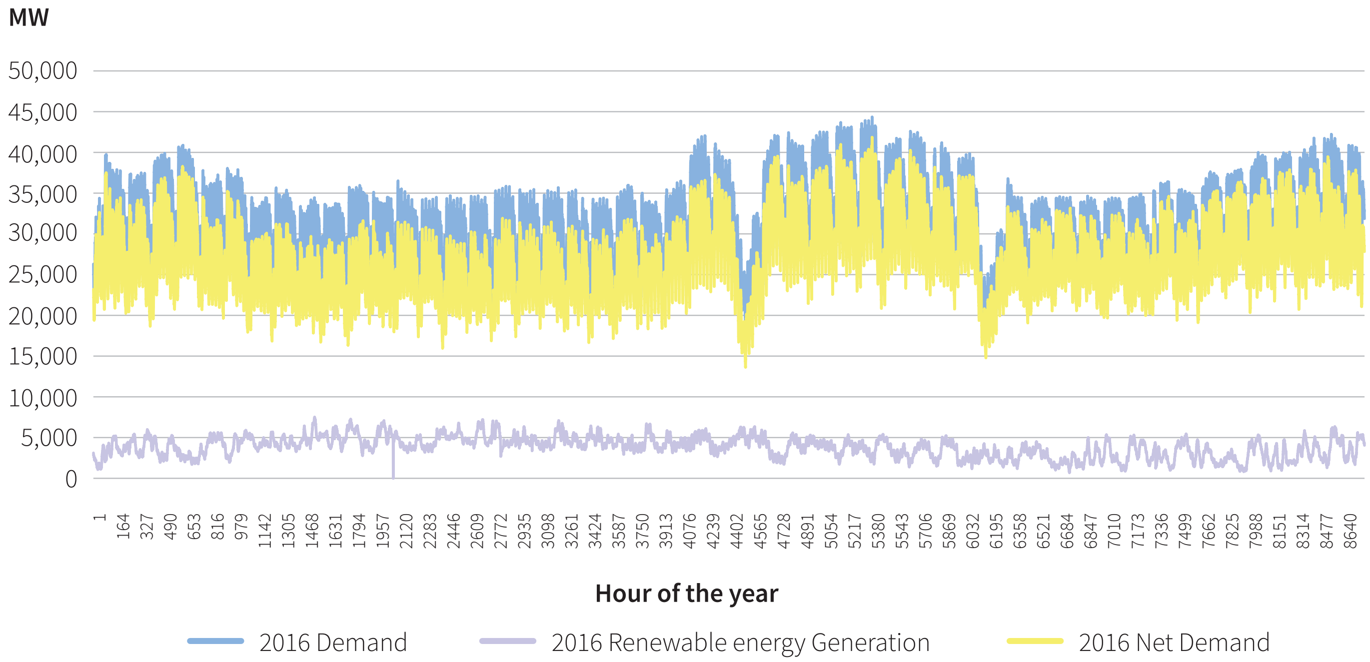


Figure 81. *Demand, Net-Demand, and renewable generation in 2016*

[172] EPİAŞ Transparency Platform [Online]. Available at: https://seffaflik.epias.com.tr/

The “hourly Net-Demand change versus duration” curve is generated to calculate the maximum hourly change at 90% of the time (Figure 82). The ratio of current reserve amount to this value is used as a reference parameter.

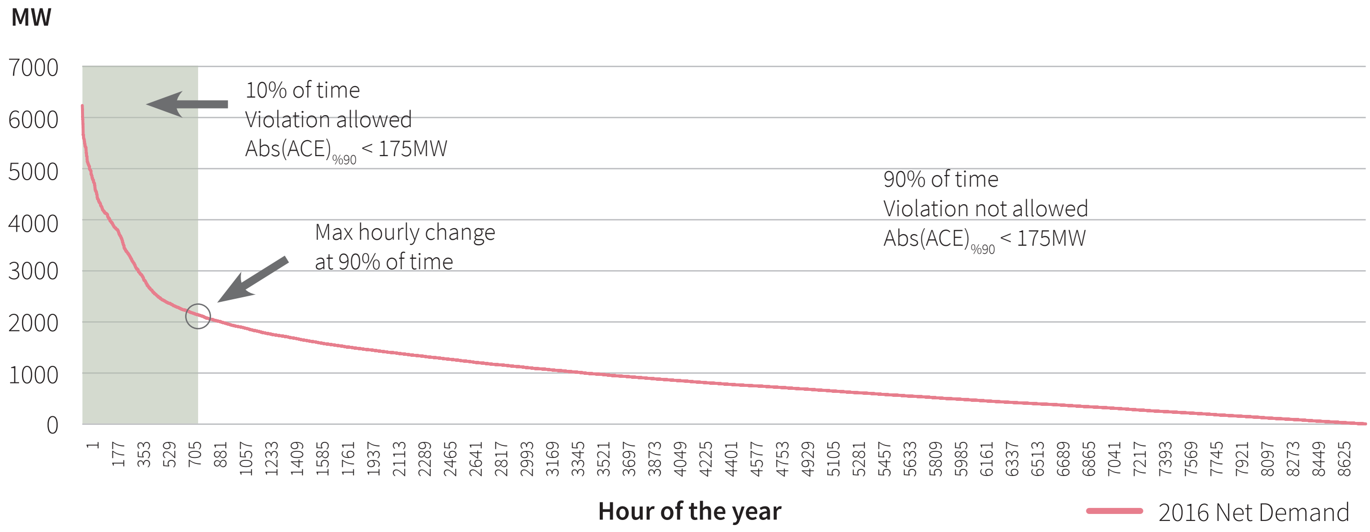


Figure 82. *Hourly Net-Demand change versus duration for 2016*

• **Step-2:**

Similarly, the same Net-Demand calculation is performed for all scenarios. As seen in Figure 83, the hourly changes increase with the increase of renewabl energy capacity.

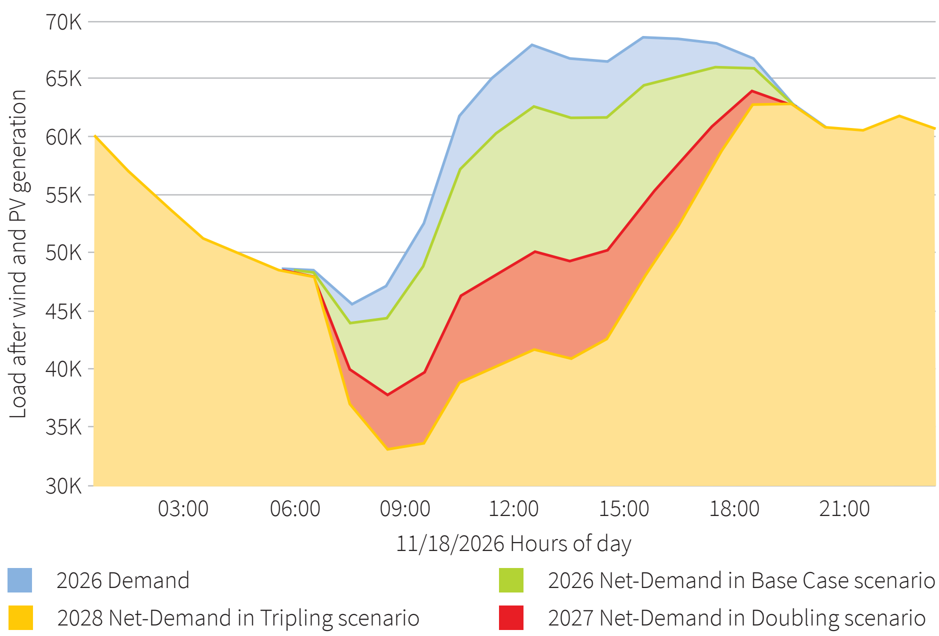


Figure 83. *Daily Net-Demand in year 2026 for different scenarios*

The “hourly Net-Demand change – duration” curve is generated for each scenario (Figure 84). The average of resource-driven and system-driven cases is utilized for comparison purposes (i.e., the reserve need kept constant for different cases in each scenario). Finally, the maximum hourly change at 90% of time is calculated for each scenario. Using the ratio between maximum hourly change at 90% of time and utilized reserve amount in 2016 (with a +/-5% range for rounding numbers), the reserve requirements are calculated for each scenario (Table 9). The ratio between day time and night time reserve of 2016 is considered to calculate reserve amount at night time.

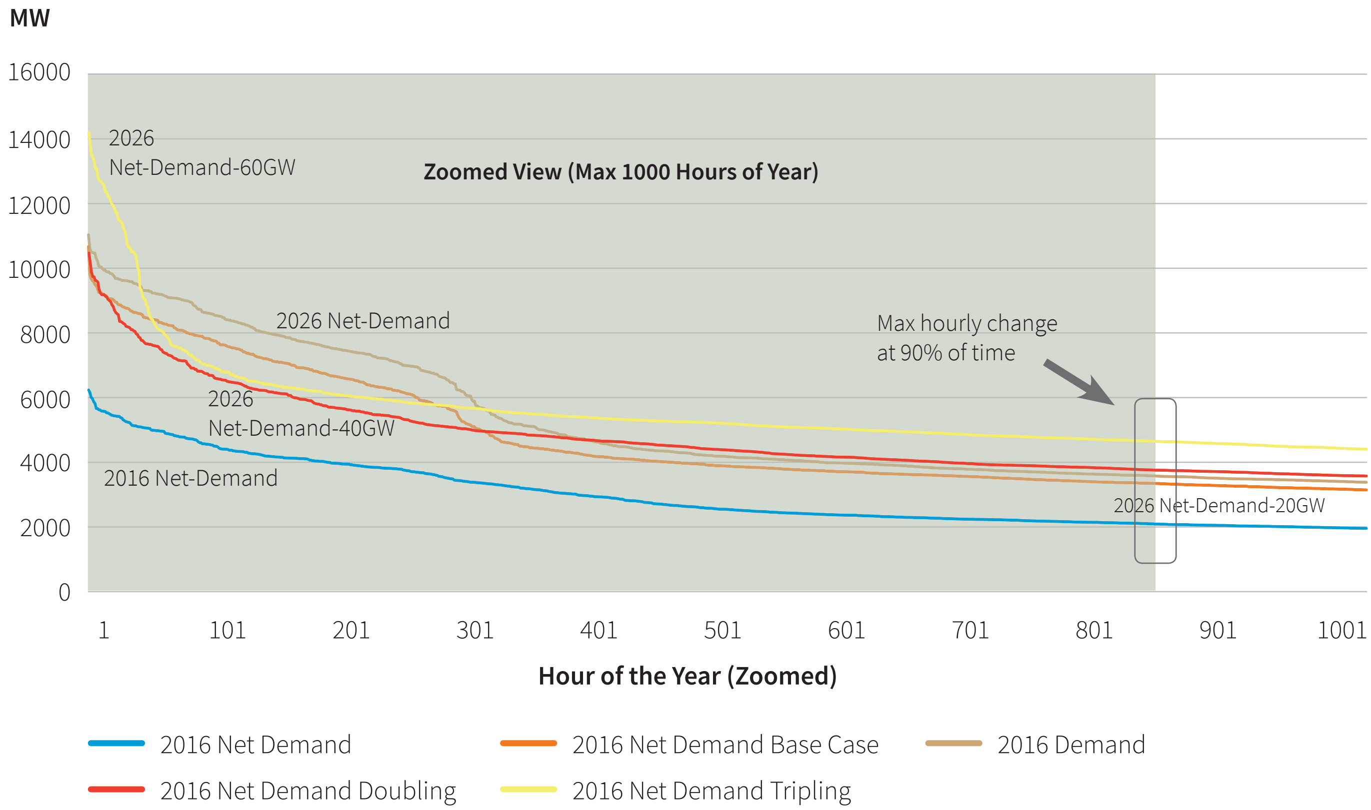


Figure 84. *Hourly Net-Demand change versus duration for all scenarios in 2026*

Table 9. *Reserve requirement calculation results*

Scenario / Status Quo	Peak Hourly Deviation of Net Demand (MW)	Maximum Hourly Deviation of Net Demand at 90% of Time (MW)	Reserve Day Time (MW)	Reserve Night Time (MW)
2016	6,389	2,054	1,200	700
2026 20 GW	10,672	3,291	1,800	1,000
2026 40 GW	10,470	3,718	2,200	1,250
2026 60 GW	14,194	4,591	2,700	1,600

ANNEX 3. Hourly Wind and Solar Power Generation Calculation Details

A-3.1. Wind Power Plants:

The calculations have three stages; initially the capacity factors of approximately 6kmx6km areas are determined and the infeasible locations are eliminated. For each location an average of 20 MW installed capacity is considered, due to the space requirements between turbines[173]. Secondly, the calculated capacity factors are utilized together with existing wind output measurements to estimate an hourly generation profile for each location. Finally, the predefined installed capacity is emplaced among the grid with alternative methods to determine resource-driven scenarios and system-driven strategies.

- Determination of capacity factors:
  For capacity factor determination, the following data is utilized:
    - Temperature data
    - Pressure data
    - Direction data
    - Speed data

Using direction and speed data, a Weibull probability distribution is determined. Then the turbine power curve is adapted based on the air density data which is calculated via temperature and pressure data. Using the Weibull probability distribution and adapted power curve, the capacity factors are calculated for individual areas as given in Figure 85. Based on the calculations, the wind capacity factor map is generated as given in Figure 86.

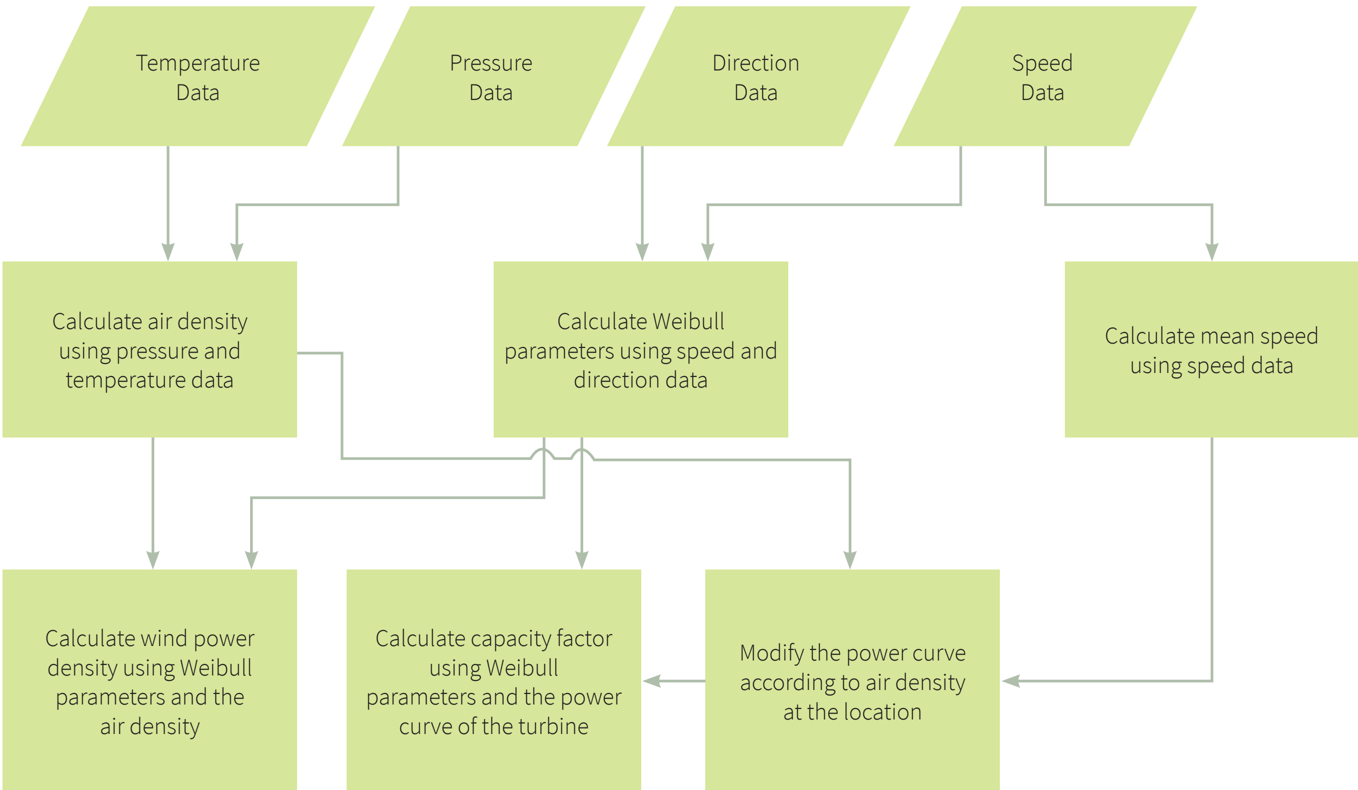


Figure 85. *Methodology for estimating time-series wind power density of wind power plants*[174]

[173] *D. G. L. Johnson, "Wind Power Plants: Turbine Placement," in Wind Energy Systems, Manhattan, KS, University Reprints, 2006, pp. 9.1-9.4*

[174] *Hale Çetinay, "Determination of Wind Power Potential and Optimal Wind Power Plant Locations in Turkey," Master Thesis, Middle East Technical University, May 2014.*

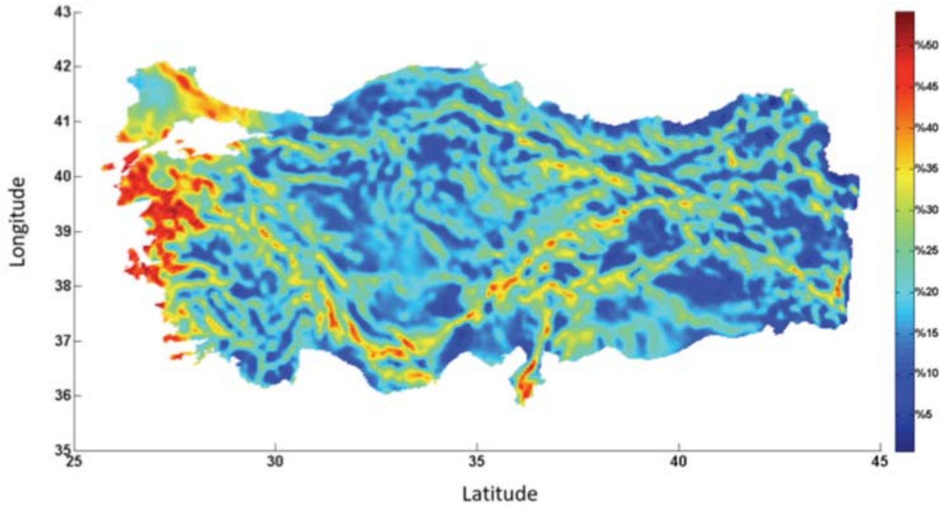


Figure 86. *Wind capacity factor map determined based on the methodology*

A set of locations are excluded from calculations due to:

o Sites with altitudes higher than 2,000 mt
o Terrain above light ruggedness[175]
o Land restrictions (settled areas, airports, nature protection zones)

Based on the exclusion criteria, the capacity factor map is changed as given in Figure 87.

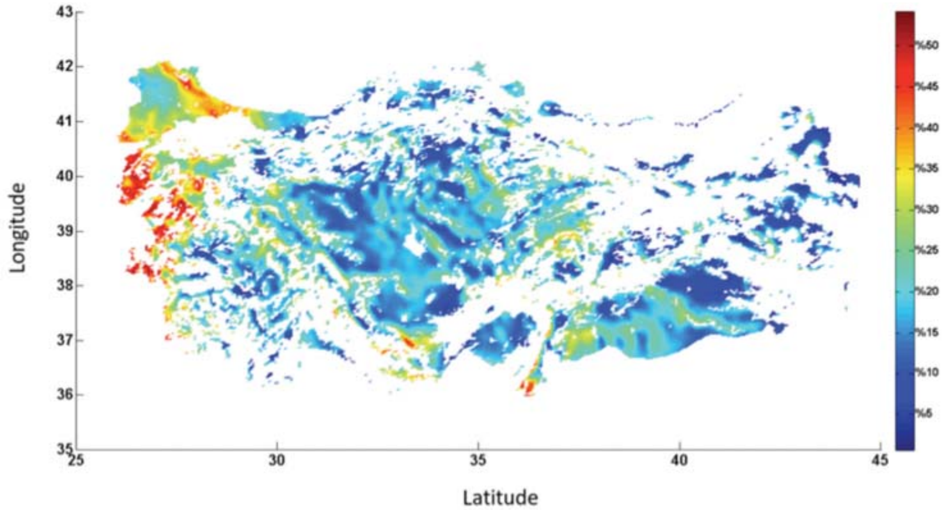


Figure 87. *Wind capacity factor map of Turkey after eliminating the restricted zones*

- Determination of hourly generation:

In order to determine hourly generation for each new plant location, the Virtual Wind Farm (VWF) model is utilized[176]. The model acquires wind speeds at 2, 10 and 50 m above ground at each MERRA grid point, interpolates speeds to the specific geographic coordinates of each wind farm using LOESS[177] regression, extrapolates speeds to the hub height of the turbines at each site using the logarithm profile law;

[175] *Riley,S.J., DeGloria,S.D., Elliot,R., "A Terrain Ruggedness Index That Quantifies Topographic Heterogeneity", Intermauntain Journal of Sciences, Dec 1999*

[176] *I. Staffell and S. Pfenninger, 2016. "Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output". Energy, 114, 1224–1239.*

[177] *I. Staffell and S. Pfenninger, 2016. "Supplementary Material to Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output." Energy, 114, 1224–1239.*

and then converts speeds to power outputs using manufacturers' power curves, which are smoothed to represent a farm of several geographically dispersed turbines. The calculated characteristic is calibrated to represent the capacity factor calculated specifically for the location.

- Location of installed capacity:

The main approach for selecting new wind power plant locations is mainly based on capacity factors at the relevant location. The capacity factors are converted to per unit values based on the maximum value. The capacity factors below 20% are considered as infeasible investments and excluded for capacity emplacement.
The installed capacity additions are defined by distributing the amount of installed capacity in two separate ways:

  - System-Driven Approach: Capacity factor of each location is mapped between 0 to 1 based on the maximum and minimum values of the variable set (i.e., max(capacity factors list) = 1p.u., min(capacity factors list) = 0p.u.) as indexes. The capacity factor indexes in each location are scaled up linearly to the desired total installed capacity.
  - Resource-Driven Approach: In order to concentrate the generation to higher capacity factor locations, the linear mapping of capacity factor index is adapted by taking the squares of the values. The adaptation of linear mapping with the squares of capacity factor indexes is not applied to get a linear relation between capacity factors and installed capacities. Thus, the installed capacity is distributed more widely.

Thus, for each location an installed power value is determined. Considering this installed power and previously calculated hourly profile, a power injection curve for each location is determined. These power injections are aggregated in HV substations as total wind injection in each substation. The resulting total hourly generation is given in Figure 88.

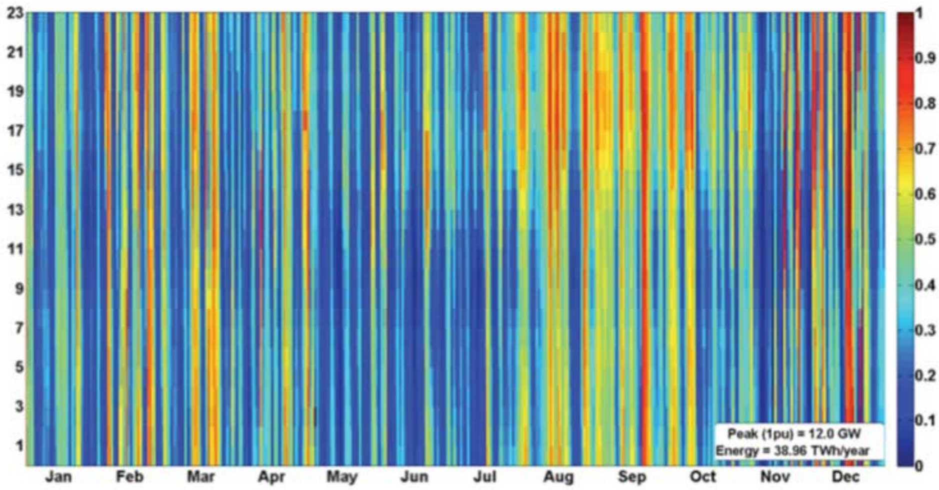


Figure 88. *Times series power generation of wind power plants in 2026 (Per unit power generation based on maximum total power output by date and time for Base Case scenario, resource-driven)*

A-3.2. Solar Power Plants:

The calculations have three stages; firstly the hourly solar power generation at the locations of all substations (approximately 800 points) are determined. Secondly, the calculated hourly generation is converted into capacity factors for determined points, and the rest of the capacity factors are interpolated based on the determined values. Finally, the predefined installed capacity is emplaced among the grid with alternative methods to determine resource-driven scenarios and system-driven strategies.

- Determination of hourly generation profiles:

Although wind generation is prone to significant changes in small distances (<20km), solar generation is more uniformly distributed based on the geographic location. Hence, instead of a high resolution 5kmx5km grid-based approach, a substation-based approach is utilized, assuming that the solar generation within 20-30km distance of a substation does not change significantly.

In order to calculate the generation levels at substation locations, the Global Solar Energy Estimator (GSEE)[178] model is utilized. The input is the satellite data from NASA with hourly intervals and spatial resolution of 50km x 50km. The data set covers 1979 to present. The calculations are performed in four steps as given in Figure 89:

- The irradiance at substation locations are calculated via linear interpolation from measured satellite grid cells.
- The diffuse irradiation is determined via clearness index depending on the day of the year.
- The irradiance on the inclined panel is calculated.
- The temperature dependence of panel efficiency is included in calculations considering ambient temperature, effect of irradiance and factor of free standing for cooling.

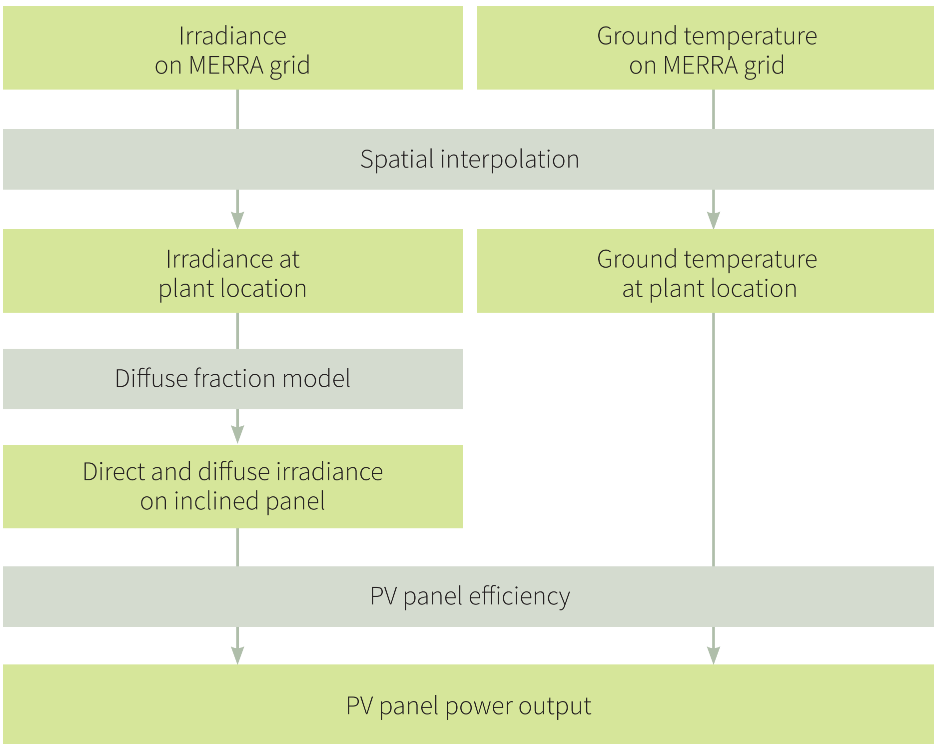


Figure 89. *Overview of the approach used to model PV power output*

[178] *S. Pfenninger and I. Staffell, 2016. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy, 114, 1251–1265.*

- Determination of capacity factors:

After the substation location hourly generation calculations, the resulting values are converted to capacity factors. These capacity factors of approximately 800 points are used as reference and the high-resolution capacity factors for Turkey are generated via interpolation as given in Figure 90.

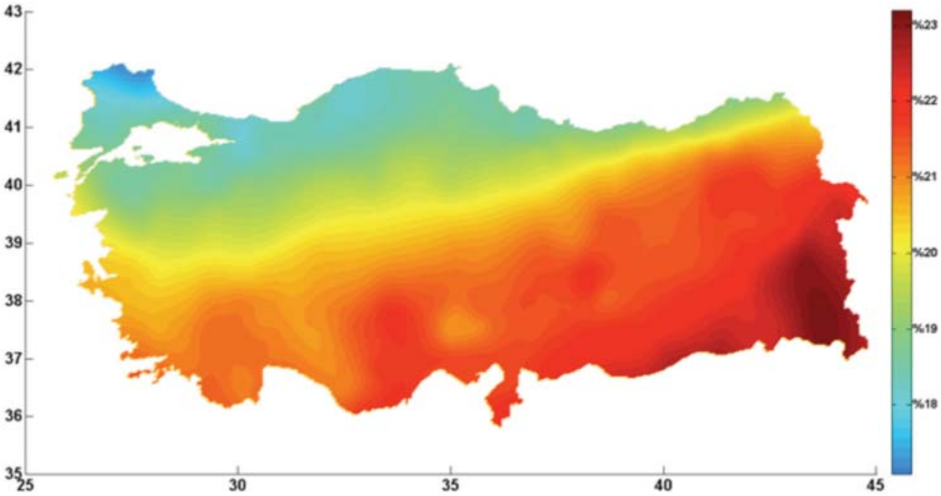


Figure 90. *PV capacity factor map of Turkey*

A set of locations are excluded from calculations due to:

o Sites with altitudes higher than 2,000 mt

o Terrain above light ruggedness[179]

o Land restrictions (settled areas, airports, nature protection zones)

Based on the exclusion criteria, the capacity factor map is changed as given in Figure 91.

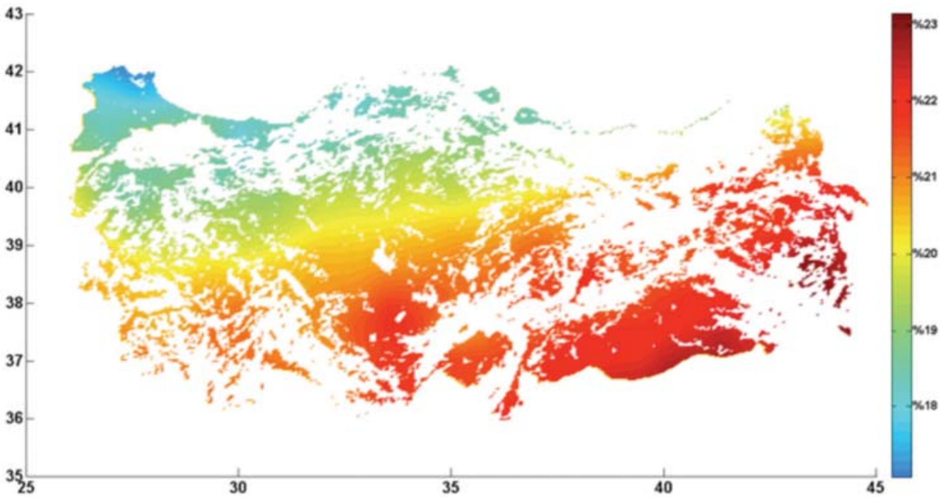


Figure 91. *PV capacity factor map of Turkey (restricted locations are eliminated)*

Once the capacity factors for all locations and the available locations for installment are determined, the capacity limitation for all substations are ascertained.

[179] *Riley,S.J., DeGloria,S.D., Elliot,R., "A Terrain Ruggedness Index That Quantifies Topographic Heterogeneity", Intermauntain Journal of Sciences, Dec 1999*

- Emplacement of installed capacity:

Two separate methodologies are applied similar to wind power plant case; resource-driven and system-driven approaches:

- Resource-Driven: In this approach;
    - Base Case scenario is considered to have a single REDA zone with 1 GW capacity
    - In other scenarios, it is assumed to create 10 new REDA zones (each having equal capacity and covering 60% of the total solar power plant capacity in the scenario) in Turkey as given in Chapter 3.

  The rest of the installed capacity is distributed based on two variables:
    - Load level at the substation
    - Capacity factor of the substation

Both variables are mapped between 0 to 1 based on the maximum and minimum values of the variable set (i.e., max(capacity factors list) = 1p.u., min(capacity factors list) = 0p.u.) as indexes. In order to concentrate the generation to higher capacity factor locations, the linear mapping of capacity factor index is adapted by taking the squares of the values. Finally, load and capacity factor indexes are added with 50% higher weighting factors for capacity factor to create an installed capacity index. The installed capacity indexes are scaled up to the desired installed capacity (5 GW in Base Case scenarios and remaining 40% in Doubling and Tripling scenarios), considering the capacity limits of the substations.

o Distributed approach: In this approach; no new REDA zones are assumed and the capacity factor index mapping is done linearly in the installed capacity index calculations.

A-3.3. Run-of-river hydropower plants

The plant regimes are modelled as uncontrollable generation into all scenarios in the same way as given in Figure 92, which displays the daily and seasonal distribution of hydro resources. Following the annual pattern (2016) of snow melting and high precipitation in spring, run of river hydro generation peaks between mid-April and mid-June; during May, levels are consistently above 80% of max capacity, while they drop to 20-40% during the period September to January.

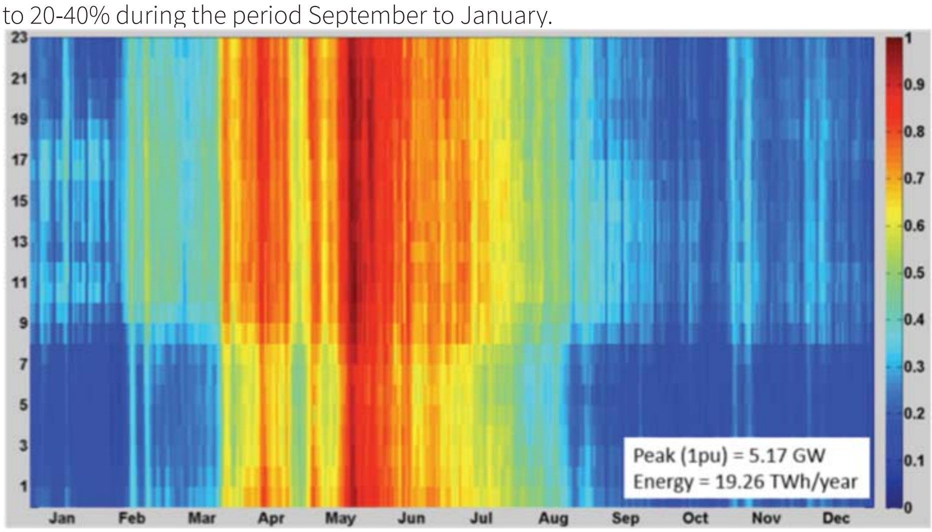


Figure 92. *Times series power generation of run-of-river power plants, 2026 (8760 hours) (Per unit power generation based on maximum power output by date and time)*

ANNEX 4. 2016 Redispatch Calculation Details

Redispatch; is the adaptation of the generation levels of individual generators that are determined by the market to the physical limitations of the network and operational requirements. Three different kinds of redispatch (and commitment) orders are used:

- Supply-demand balance at any hour ("Code 0"): Due to forecast errors before the market clearing, unplanned generator outages after the market clearing and/or any other reason that results in an imbalance between generation and load has to be compensated immediately. The orders that are used for maintaining the supply-demand balance are called Code-0 orders.
- Network constraints due to branch overloading (congestion) ("Code 1"): As the power market does not consider the physical topology, the market results may create overloading on certain elements in the network. In order to ensure the security of the network, the overloads are supposed to be relaxed by the redispatch orders of TSO. Further, TSO also has to maintain the reliability by considering the potential loss of a network element and its impacts on the loadings of other branches and transformers. Accordingly, additional redispatch orders might be necessary. All these redispatch orders for security and reliability are considered as Code 1 orders.
- Spinning reserve requirements ("Code 2" order): The spinning reserve is another concern of TSO while operating the network. The amount of spinning reserve a unit can provide is determined based on its ramp rate and dispatch level, as well as it maximum and minimum operation levels. If the spinning reserve of generators that is committed and dispatched based on market clearing results is not sufficient, the TSO is forced to make redispatch and commitment if necessary to maintain spinning reserve requirement.

The utilized analysis approach does not include the Code 0 part, as in the simulation studies the day ahead forecast errors and the events between market clearing and actual operation are not considered. Accordingly, the sum of all up and down orders are equal for each hour in order to maintain the supply-demand balance.

For the sake of consistency, only actual Code 1 and Code 2 redispatch commands of TSO in 2016 are supposed to be considered. However, the sum of up and down orders of Code 1 and Code 2 are not zero for several hours in 2016. This can have two reasons:

- The up/down orders of Code 1 and/or Code 2 were compensated by down/up orders of Code 0
- The up/down orders of Code 1 and/or Code 2 were compensated with forecast errors and/or events that result in supply demand imbalance

Hence, the redispatch order mismatches are calculated as below:

$$M_i = Code\ 1_i(Up) + Code\ 2_i(Up) - Code\ 1_i(Down) - Code\ 2_i(Down)$$

where, "i"=1…8760 (hours of the year), "M_i": redispatch order mismatches for hour "i".

The total redispatch amount is calculated as follows:

$$R_{Total} = \left[\sum_{i=1}^{8760} Code\ 1_i(Up) + Code\ 2_i(Up) + Code\ 1_i(Down) + Code\ 2_i(Down) + M_i \right] / 2$$

where, "i"=1…8760 (hours of the year), "R_{Total}": Total redispatch for security, reliability and spinning reserve in 2016.

ANNEX 5. Generation park assumptions

A-5.1. Nuclear power plants

According to the strategy document in 2012, the government target is to put a total of 9.2 GW into service by 2026[180], 4.8 GW in Akkuyu, four units of Sinop nuclear power plant with 4.4 GW into service. Due to the complexity in nuclear investment both from a technical and financing point of view, delays in the construction of these plants are widely observed internationally. Similar concerns were raised in the stakeholder workshops. In the modeling, it is commonly agreed by the stakeholders to assume that all four units of Akkuyu nuclear power plant each with 1.2 GW capacity, plus two out of four units at Sinop nuclear power plant each with an installed capacity of 1 GW will be in operation by 2026, adding up to 6.8 GW of nuclear power capacity. This assumption is constant in all scenarios.

A-5.2. Imported coal power plants and local power plants

The majority of coal power plants in Turkey are based on import coal and they are located in the Mediterranean, Aegean, and Black Sea coast regions. Local coal power plants are located at the Black Sea coast region as well. Considering the current license applications to EMRA for new imported coal power plants and ongoing implementation projects, it is commonly agreed by the stakeholders to assume that total installed capacity of import coal power plants will increase to 10.16 GW in 2016 from 7.74 GW in 2016. Total installed capacity of lignite power plants is assumed to be constant (2.19 GW as in 2016), which has been the case for several years indeed. These assumptions are constant in all scenarios.

A-5.3. Lignite power plants

Turkey has significant lignite resources. There are several lignite power plants located in different regions of the country totaling 9.6 GW. The government target in the 2012 strategy document is 30 GW in 2023, in terms of total capacities of imported coal power plants, lignite power plants. It corresponds to 34.5 GW if scaled to 2026 proportionally. Recently, the government of Turkey has declared some incentives for lignite power plants[181]. In order to reduce energy imports, the government is incentivizing the construction of additional lignite generation, despite the relatively low calorific value of lignite in Turkey. This might essentially increase the interest of investors in lignite power plants.

In this study, total installed capacity of lignite power plants is assumed to increase 13.7 GW in 2026 from 9.6 GW in 2016. This assumption along with 10.16 GW imported coal power plants and 2.19 GW lignite power plants (see above), corresponds to 26 GW in total capacity for the 2026. This total amount is consistent with the TEİAŞ investment plans for 2026. The figure reflects the fact that lignite and hard coal power plants are losing their competitiveness in the electricity markets globally, given recent developments in renewable energy installments and concerns of carbon emissions. Current license applications to EMRA, rich lignite regions, and ongoing implementation projects are taken into account in defining locations of the new lignite coal power plants.

[180] *http://www.enerji.gov.tr/tr-TR/Sayfalar/Ulkemizde-Nukleer-Santraller*
[181] *http://www.enerji.gov.tr*

A-5.4. Natural gas power plants

The amount of new gas power plant capacity has been decaying recently in Turkey, given the high cost of gas in comparison with wholesale electricity prices. Moreover, the government has declared its intention to decrease total share of energy production from natural gas power plants gradually, given strong dependency of the country on the import of natural gas. In response, it is commonly agreed by the stakeholders to assume total installed capacity of gas power plants to be 29.23 GW in 2026 (it is 25.90 GW in 2016) consistent with the TEİAŞ projections in Base Case. Current license applications to EMRA, ongoing implementation projects, and gas transmission network investment plans are taken into account in defining locations of the new gas power plants.

In the study, the additional natural gas power plant capacity to the current 25.90 GW capacity is assessed in terms of utilization factors of the new natural gas power plants as follows. Those new natural gas power plants, which are assumed to be put in to service between 2016 and 2026 and that have a utilization factor in the target year 2026 which is below a specific threshold value, are removed from the model. That is, it is assumed that those new natural gas power plants will be subjected to loss of competition against the other power plants due to their low utilization factors, and therefore, they should be removed from the model. This approach will essentially result in different levels of installed natural gas power plant capacity in different renewable energy penetration scenarios if compared to the initial assumption of 29.23 GW installed capacity. Details of the approach are described in section 3.3.

A-5.5. Hydropower plants

The main large dam type hydropower plants in the range of 1,000 to 2,400 MW capacities are located on the Fırat and Dicle rivers at the east and south-east regions of the country. The Çoruh Basin at the north-east region also contains several large hydropower plants. Those hydropower plants are connected to the power system at 400 kV level. Transmission corridors from east to west carry generation of hydropower plants to main demand centers to the west and north-west.

The Karadeniz region of Turkey has significant run-of-river type hydropower plants potential. Capacity factor of the run-of-river type hydropower plants is very sensitive to season and increase to maximum during spring and initial summer periods. Long-term constraints of hydropower plants, including cascaded plants on the same river and storage constraints of hydropower plants, are considered in the study. Details of modeling assumptions are described in Annex 2.

Total installed capacity of hydropower plants (dam type plus run-of-river) is assumed to increase to 37.5 GW in 2026 from 26.61 GW in 2016.

Total installed capacity of hydropower plants (dam type plus run-of-river) is assumed to increase to 37.5 GW in 2026 from 26.61 GW in 2016. Those regions which have rich hydraulic capacity are given priority in defining locations of new hydropower plants.

A-5.6. Geothermal power plants

Currently, total installed capacity of geothermal power plants is only 0.77 GW in 2016. However, Turkey is among those countries which have considerable geothermal capacity. It is commonly agreed by the stakeholders to assume that the current installed capacity will be doubled by 2026. In line with their rich geothermal potential, new power plants are assumed to be installed in the region of southwest Turkey.

ANNEX 6. Comparison of generation park assumptions with international studies

One of the most important assumptions is the generation park that is considered in the study. Although, the political perspectives of the MENR and the technical perspective of TEİAŞ is considered during preparation of the assumptions, other international studies are also investigated in order to assess the similarities and differences in the expected generation park in 2026 as given in Table 10.

Table 10. *Projections of different studies*

<table>
<tr><th></th><th>2016</th><th>2026 Base Case (14/6)</th><th>Government Targets 2023</th><th>ENTSO-E MAF (2025)</th><th>Bloomberg BAU[182] Scenario (2026)</th><th>IBS BAU[183] Scenario (2030)</th><th>BNEF BAU[184] Scenario (2030)</th></tr>
<tr><td>Peak Demand</td><td>44 GW</td><td>69.2 GW</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Consumption</td><td>278 TWh</td><td>439 TWh</td><td>440 TWh</td><td>458.7</td><td>405.0</td><td>480.0</td><td>462.0</td></tr>
<tr><td>Annual Demand Growth</td><td>-</td><td>5.1%</td><td>7.3%</td><td>5.7%</td><td>4.2%</td><td>4.2%</td><td>4.0%</td></tr>
<tr><td>Import Coal</td><td>7.5 GW</td><td>10.2 GW</td><td rowspan="3">30.0 GW</td><td rowspan="2">8.2 GW</td><td rowspan="3">28.6 GW</td><td rowspan="3">30.8 GW</td><td rowspan="3">34.0 GW</td></tr>
<tr><td>Hard Coal</td><td>0.6 GW</td><td>0.6 GW</td></tr>
<tr><td>Lignite</td><td>9.3 GW</td><td>13.7 GW</td><td>10.8 GW</td></tr>
<tr><td>Natural Gas</td><td>25.5 GW</td><td>29.2 GW</td><td>N/A</td><td>27.8 GW</td><td>27.9 GW</td><td>30.6 GW</td><td>27.9 GW</td></tr>
<tr><td>Nuclear</td><td>0.0 GW</td><td>6.8 GW</td><td>9.3 GW</td><td>3.6 GW</td><td>3.4 GW</td><td>6.0 GW</td><td>4.8 GW</td></tr>
<tr><td>Wind</td><td>5.8 GW</td><td>14.0 GW</td><td>20.0 GW</td><td>14.2 GW</td><td>12.7 GW</td><td>18.5 GW</td><td>15.9 GW</td></tr>
<tr><td>Hydro</td><td>26.7 GW</td><td>27.5 GW + 10.0 GW*</td><td>34.0 GW</td><td>36.8 GW</td><td>27.4 GW</td><td>33.6 GW</td><td>27.4 GW</td></tr>
<tr><td>Solar</td><td>0.0 GW</td><td>6.0 GW</td><td>5.0 GW</td><td>6.0 GW</td><td>7.5 GW</td><td>6.9 GW</td><td>10.1 GW</td></tr>
<tr><td>Geothermal</td><td>0.8 GW</td><td>1.5 GW</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Others</td><td>1.7 GW</td><td>1.7 GW</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Total Installed Capacity</td><td>77.8 GW</td><td>111 GW</td><td>N/A</td><td>107 GW</td><td>107 GW</td><td>126 GW</td><td>120 GW</td></tr>
</table>

N/A: Not available
* Run-of-river

As given in Table 10;

- The general tendency of international studies about coal, lignite and import coal plants are consistent with policies of the MENR, which are slightly above the utilized installed capacities.
- The forecast on natural gas power plants, on the contrary, are lower than the considered capacity in the studies which is approximately balancing the total forecasted thermal capacity.

[182] *Bloomberg 2014: TURKEY'S CHANGING POWER MARKETS, White Paper, 18 November 2014*
[183] *IBS Research and Consultancy, www.ibsresearch.com*
[184] *Bloomberg New Energy Finance, "New Energy Outlook 2017", 2017*

- The expectation on nuclear installed capacity is relatively low in the international studies whereas the assumption in the study is closer to targets of the Ministry of Energy and Natural Resources.
- The dam type hydro plants are considered to exceed 27 GW which is consistent with some of the international studies investigated. However, there are other studies that indicate a lower hydropower plant growth.

Abbreviations

ACE	Area Control Error
AGC	Automatic Generation Control
AGL	Above Ground Level
EML	Electricity Market Law
EMRA	Energy Market Regulatory Authority
EXIST	Energy Exchange Istanbul
ENTSO-E	European Network of Transmission System Operators for Electricity
EMRA	Energy Market Regulatory Authority of Turkey (EPDK)
EU	European Union
FiT	Feed-in Tariff
GDP	Gross domestic product
GHI	Global Horizontal Irradiance
GPP	Geothermal Power Plant
GW	Gigawatt
HPP	Hydraulic Power Plant
HV	High Voltage (>36 kV)
HVDC	High Voltage Direct Current
ICPP	Imported Coal Power Plant
IRENA	International Renewable Energy Agency
LCOE	Levelized Cost of Energy
LHCPP	Local Hard Coal Power Plant
LLPP	Local Lignite Power Plant
LV	Low Voltage (400 Volt)
MAF	Mid-term Adequacy Forecast
MCP	Market Clearing Price in the Day-ahead Market
MV	Medium Voltage (1 kV < MV < 36 kV)
MW	Megawatt
N-1	Reliability Criteria
NDC	National Dispatch Center at TEİAŞ
NGPP	Natural Gas Power Plant
NPP	Nuclear Power Plant
NTC	Net Transfer Capacity (MW)

Pmin	Technical minimum operating point of power plants when committed
PV	Photo-voltaic
PX Market	Power-exchange Market
REPA	Renewable Energy Potential Atlas
RES	Renewable Energy Source
RoR	Run of river hydropower plant
SMP	System Marginal Price in the Balancing Market
Sp	Sub-process
SPP	Solar Power Plant
SRMC	Short Run Marginal Cost
TEİAŞ	Türkiye Elektrik İletim A.Ş. (Turkey's state-owned TSO)
TSO	Transmission System Operator
TWh	Tera Watt hour (1 Tera (T) = 1000 * Giga (G) = 1000 * Mega (M) = 1000 * Kilo (k)
TYNDP	Ten Year Network Development Plan
WPP	Wind Power Plant
YEGM	Renewable Energy Directorate of Turkey (in Turkish abbreviations)
REDA	Renewable Energy Designated Areas (REDA)
YEKDEM	Renewable energy support mechanism (in Turkish abbreviations)
C_i (.)	Cost function of unit *i*
S (i,t)	Start-up cost of unit *i* at time *t*
N_g	Number of units
N_t	Number of time periods (8760 hour)
I (i,t)	Commitment state of unit *i* at time *t*
i	Unit index
t	Time index
α_i	Integrated labor starting-up cost and equipment maintenance cost of unit *i*
β_i	Starting-up cost of unit *i* from cold conditions
$x^{off}(i,t)$	Time duration for which unit *i* has been OFF at time *t*
$x^{on}(i,t)$	Time duration for which unit *i* has been ON at time *t*
$T^{on}(i)$	Minimum ON time of unit *i*
$T^{off}(i)$	Minimum OFF time of unit *i*
τ_i	Time constant that characterizes unit *i* cooling speed

P (i,t)	Generation of unit *i* at time *t*
P_D (i,t)	Total system real power load demand at time *t*
P_{gmin} (i)	Minimum generation of unit *i*
P_{gmax} (i)	Maximum generation of unit *i*
UR (i)	Ramp-up rate limit of unit *i*
DR (i)	Ramp down rate limit of unit *i*
C_t	Country consumption at year *t* (GWh)
P_t	Peak demand of the country at year *t* (MW)
a_c ,b_c	Coefficients of least square method for $_{Log(Ct)}$
a_p ,b_p	Coefficients of least square method for $_{Log(Pt)}$
$\varepsilon_{t,c}$	Errors in projection at year t for $_{Log(Ct)\ (GWh)}$
$\varepsilon_{t,p}$	Errors in projection at year t for $_{Log(Pt)\ (MW)}$
NTC	Net Transfer Capacity (MW)
r_s (i,t)	Contribution of unit i to spinning reserve at time t
R_s (t)	System spinning reserve requirement at time t
MSR (i)	Maximum sustained ramp rate of unit i (MW/min)
P_{km}^{max}	Upper limit for power flow of line k–m
P_{km} (t)	Power flow of line k–m at time t
P (t)	Real power generation vector at time *t*
Q_{gmax} (i)	Maximum reactive power unit i can provide
Q_D (t)	Total system reactive power load demand at time t
Q_G^{min}	Reactive power generation vector lower limit at time t
I (t)	Unit commitment status vector at time t
Q_G (t)	Reactive power generation vector at time t
F_1 (V)	Reactive power function of V for units
Q_G^{max}	Reactive power generation vector upper limit at time t
Q_L (t)	Reactive power load vector at time t
F_2 (V)	Reactive power function of V for buses
V^{min}	System voltage lower limit vector
V	System voltage vector
V^{max}	System voltage upper limit vector

About Istanbul Policy Center at the Sabancı University

Istanbul Policy Center (IPC) is a global policy research institution that specializes in key social and political issues ranging from democratization to climate change, transatlantic relations to conflict resolution and mediation. IPC organizes and conducts its research under three main clusters: The Istanbul Policy Center–Sabancı University–Stiftung Mercator Initiative, Democratization and Institutional Reform, and Conflict Resolution and Mediation. Since 2001, IPC has provided decision makers, opinion leaders, and other major stakeholders with objective analyses and innovative policy recommendations.

About European Climate Foundation

The European Climate Foundation (ECF) was established as a major philanthropic initiative to help Europe foster the development of a low-carbon society and play an even stronger international leadership role to mitigate climate change. The ECF seeks to address the "how" of the low-carbon transition in a non-ideological manner. In collaboration with its partners, the ECF contributes to the debate by highlighting key path dependencies and the implications of different options in this transition.

About Agora Energiewende

Agora Energiewende develops evidence-based and politically viable strategies for ensuring the success of the clean energy transition in Germany, Europe and the rest of the world. As a think tank and policy laboratory, Agora aims to share knowledge with stakeholders in the worlds of politics, business and academia while enabling a productive exchange of ideas. As a non-profit foundation primarily financed through philanthropic donations, Agora is not beholden to narrow corporate or political interests, but rather to its commitment to confronting climate change.

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