Integration of Renewable Energy into the Turkish Electricity System

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 decarbonisation of the energy sector via an innovative energy transition platform. It caters to 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 the 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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This report is available for download from www.shura.org.tr. For further information or to provide feedback, please contact the SHURA team at shura@shura.org.tr

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This report and the assumptions made within the scope of the study have been drafted based on different scenarios and market conditions as of the end of 2020. Since these assumptions, scenarios and the market conditions are subject to change, it is not warranted that the forecasts in this report will be the same as the actual figures. The institutions and the persons who have contributed to the preparation of this report can not be held responsible for any commercial gains or losses that may arise from the divergence between the forecasts in the report and the actual values.

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ABBREVIATIONS

AGC	Automatic Generation Control
ARES	Accelerated Renewable Energy Scenario
BAU	Business as Usual
CBA	Cost-Benefit Analysis
CPD	Coal Phase Down
ENTSO-E	European Network of Transmission System Operators for Electricity
EV	Electric Vehicle
GW	Gigawatt
HPP	Hydroelectric Power Plant
HVDC B2B	High Voltage Direct Current Back-to-Back
kV	kilovolt
MCP	Market Clearing Price
MW	Megawatt
NPP	Nuclear Power Plant
NTC	Net Transfer Capacity
O&M	Operation and Maintenance
PV	Photovoltaic
RES	Renewable Energy Sources
RoR	Run-of-River
SRMC	Short-Run Marginal Cost
TEIAS	Turkish Electricity Transmission Company
YEKA	Regulation on Renewable Energy Zones

Key Messages

1. The Turkish government recently underlined its commitment to transform the Turkish economy to carbon neutrality by 2053. The power sector will need to lead the transition by decarbonising before other sectors of the economy. Clean renewable power will enable an accelerated and more efficient decarbonisation through sector coupling and end-use electrification.

2. To meet rapidly rising demand due in no small part to electrification, power supply and end-use infrastructure will require forward planning that emphasizes system reliability and resilience. Decision making will need to focus on maximising system reliability and stability when selecting new wind and solar power plant locations, or which coal-fired power plants to decommission, rather than individual project output.

3. Turkey's current ten-year transmission grid development plan provides a solid foundation for the country's energy transition. Dramatically increasing wind and solar generation while significantly phasing down coal use can be achieved without any additional investments. While operational challenges to balance demand and supply increase in such a scenario, redispatch and curtailment levels remain well below 5% of annual production.

4. The Turkish power system is well prepared to integrate significantly more renewable energy without the need for additional flexibility investments if the potential of existing hydropower, gas and demand side response is fully exploited. Still, some additional flexibility options will be needed once renewables share surpasses 65% of the total generation generation.

5. Strong policies and regulation will provide the right incentives to drive the power system development based on resilience and stability. This includes flexibility incentives on both the supply and demand side; including to unlock the ancillary services that modern wind and solar facilities can provide.

Executive Summary

A. Introduction

The Turkish power system has undergone a remarkable transformation over the past two decades. To meet rapidly rising demand driven by a growing economy and population, Turkey began restructuring its power system in 2001. The liberalization and privatization of the electricity market allowed for private entities to participate in power generation, distribution and supply with the long-term view towards promoting energy security through increasing domestic production capacity and reducing overall power system costs.

Initially, these reforms resulted in significant investments into conventional fossil-fuels. Heavily dependent on imports for natural gas, a mainstay fuel in Turkey's energy mix since the late 1980s, the country has sought to reduce its vulnerability to imported gas by promoting the exploitation of domestic resources and technologies. This drove the expansion of local resources for power generation, including both lignite and renewables, as well as the decision to begin construction on the Akkuyu Nuclear Power Plant, the first in Turkey, with the first unit scheduled for commissioning as early as 2023.

Yet, the rapid development of renewable energy resources has represented the vanguard of Turkey's diversification of its power generation mix. Hydropower played a leading role by covering roughly one-third of total power generation over the past two decades. The past decade, however, has witnessed a mercurial rise of wind and solar power generation. Through a combination of impressive cost declines and an enabling regulatory and financial environment including favourable feed-in-tariffs (YEKDEM), the share of wind and solar in total power generation reached around 12% in 2020, compared to just 1.4% in 2010. Much of this growth has occurred just in the last five years, achieving additions of 4.3 GW wind and 6.4 GW solar power capacities. Today, wind and solar currently make up 18.6% of total installed capacity[1], compared to 6.5% in 2015.

Nevertheless, up until this year Turkey's energy strategy has focused predominately on the security of supply, rather than emissions reductions. The announcement by Turkey's general assembly in October 2021 to target net-zero carbon emissions by 2053 under the framework of the Paris Agreement thus marks a watershed moment for Turkish energy and climate policy. In the wake of these announcements, the focus now shifts to drafting a set of policies and action plans that enable greenhouse gas emissions reductions across the economy, providing a new policy arena for the power system transformation.

Power systems represent the backbone for the decarbonisation for the economy and key tenements to achieving net-zero targets. A key strategy to reducing greenhouse gas emissions in the building, transport, and industrial sectors, is to convert these sectors to use electricity either directly, for example, via the use of electric vehicles or heat-pumps in buildings, or indirectly via hydrogen or synthetic fuels produced from renewable electricity through electrolysis. For this strategy to succeed, the decarbonisation of electricity generation is essential and will require an unprecedented acceleration of renewable energy deployment and the eventual phase-out of fossil-fuels.

[1] As of January 2022. Source: TEIAS report: https://www.teias.gov.tr/tr-TR/kurulu-guc-raporlari

Transmission and distribution grids are the lynchpin connecting clean electricity generation and the decarbonisation of end-use sectors. As new policies and digital technologies help improve energy efficiency across the building, transport and industrial sectors, these end-use areas can increasingly be operationalised to meet supply instead of the other way around. In that sense, power control and dispatch could occur throughout the power system, and transmission grids have the potential to become smart actors within this system, instead of the relatively neutral conduits of the past.

Still, the International Energy Agency warns that the success of the energy transition could be undermined by poor planning and insufficient investments into transmission and distribution grids. While new investments must be made in solar, wind and other low-carbon technologies, additional focus on the evolution and role of transmission networks is paramount.

B. Objectives

This study assesses the potential impacts to Turkey's transmission grid network that could arise due to an accelerated transformation of the power system that is focused predominately on variable renewable energies. It models the evolution of the Turkish power grid, investigates potential operational challenges, and puts a particular focus on the system integration of variable renewables.

The study finds that Turkey's current investment and development plan for its transmission network is well prepared for an even more ambitious expansion of solar and wind resources. Furthermore, an ambitious phase-down of coal use in the power sector is possible without the need for significant additional investments if a holistic and system-driven approach is adopted with respect to future power system planning.

This assessment represents a revision and update to SHURA's 2018 study[2], which employed a similar methodology, but assessed the impacts of a doubling of variable renewable energy capacity from 20 GW to 40 GW by 2026. The previous analysis demonstrated that such an increase in wind and solar capacity was feasible without any additional investments outside of the 2016-2026 Ten-Year Network Development Plan developed by Turkey's transmission system operator (TSO), Türkiye Elektrik İletim A.S. (TEIAS). It also found that further increases in renewables capacity would, however, require substantial additional investment, and did not investigate the extent to which fossil generation capacity, coal, lignite and gas, could be dismantled.

This current study extends the planning horizon to 2030 and considers updated grid planning for 2021 to 2030. It examines a more realistic perspective of how such an ambitious expansion of renewables could impact the availability, use and eventually reduction of existing coal and gas power plants. As such, this current study also builds upon SHURA's 2020 study, 'Optimum electricity generation capacity mix for Turkey towards 2030[3],' and investigates the extent to which certain policy interventions shaping the development of Turkey's power system are feasible from the vantage of system operations and security.

[2] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)
[3] Shura Energy Transition Center. Optimum electricity generation capacity mix for Turkey towards 2030. July 2020 (https://www.shura.org.tr/wp-content/uploads/2020/09/ExecutiveSum.pdf)

Consequently, this study aims to be a first-of-its-kind investigation into the system operation impacts of a comprehensive reduction of coal generation as part of a structured policy strategy to phase down and eventually entirely eliminate coal use in Turkey.

C. Methodology

To achieve this, two comparative scenarios are investigated against a business-as-usual (BAU) baseline that reflects a continuation of current government policies beyond 2023 as well as an updated grid investment and development plan. The Accelerated Renewables scenario (ARES) assumes a significant acceleration of wind and solar deployment, with the combined installed capacity of wind and solar reaching 64 GW in 2030, compared to 37 GW in the BAU baseline. The Coal Phase-Down scenario (CPD) assumes policies such as carbon pricing are introduced that succeed in reducing coal installed capacity to just 5 GW in 2030, a 15 GW reduction compared to the 20 GW currently operational in 2021. Renewable energy displaces displace the decommissioned coal and the installed capacity of wind and solar reaches 74 GW by 2030.

The study models, in granular detail for each hour of the year, the power market and transmission grid network of the entire Turkish power system in 2030. That is, the assessment incorporates a full representation of Turkey's power generating fleet, both existing and planned, allocated to the 400 kV and 154 kV transmission grid system.

Optimal flexibility solutions are identified for each scenario through an iterative approach. First, a simulation of the power market assigns generation dispatch according to real-time market realities but ignores grid constraints. The results of the market simulations are then fed into a detailed model of transmission grid network, which incorporates hourly demand allocated to each individual grid node, i.e., 400 kV or 154 kV substation, to ensure supply always meets demand, to quantify grid constraints, and to identify cost-effective flexibility solutions. Flexibility solutions in this sense are limited to those available to the transmission network and include, for example, investments into expanding the transmission grid, or the redispatch or curtailment of generation. Cross-border interconnections, for example to Bulgaria, Greece or Georgia are also considered, albeit in a simplified manner.

For each scenario, certain assumptions are tested via sensitivity analyses that enable a more detailed investigation of the impact of certain variables. On the one hand, these sensitivity analyses represent a deeper investigation on how the grid stability is impacted by specific conditions of particular concern to grid operation and management stakeholders. For example, one such 'stress-test' in the BAU scenario investigates the coincidence of low-demand with a high share of variable renewable energy technologies, where such conditions could lead to particularly steep ramp rates resulting in a misallocation of supply and demand, and possibly inefficient system operation causing wasteful levels of curtailment and expensive redispatch orders. Another use of sensitivity analyses is used to test the benefits of different flexibility options on system operations. For example, how might grid stability be impacted by the introduction of demand response combined with higher net transfer capacity of interconnections? Finally, sensitivity analyses also permit a closer look at what kind of roles natural gas and renewables might play in a coal phase-down future. Details of the sensitivity analysis are found in Section 5 of this report.

The locations of new wind and solar power plants are identified according to system needs by aggregating new wind or solar capacity and assigning them to grid nodes based on where additional power demand is expected. Generation profiles for wind and solar are taken from spatial historical resource data. Existing hydropower power plants, whose operational constraints are also defined using historical data, are allocated to each grid node and can be operated to provide flexibility services when available.

D. Scenario Framework

The **business-as-usual (BAU)** baseline scenario reflects a continuation of current policies and trends as well as an updated grid investment and development plan for the 400 kV and 154 kV transmission systems for 2021-2030. Total electricity demand in 2030 reaches 460 TWh, and new power generation capacity is added largely by allowing the market to continue to operate under current policies to 2030. As a result, coal capacity increases from nearly 20 GW in 2020 to about 23 GW in 2030, wind grows from 8 GW to nearly 17 GW, and solar increases from 6 GW to 20 GW. Gas installed capacity remains relatively stable at nearly 26 GW. Turkey succeeds in commissioning all four 1,200 MW units of its first nuclear power plant. Sensitivity analysis in the BAU include an investigation of considerably lower demand (360 TWh) and significantly more solar and wind power reaching 64 GW in 2030 (More RES).

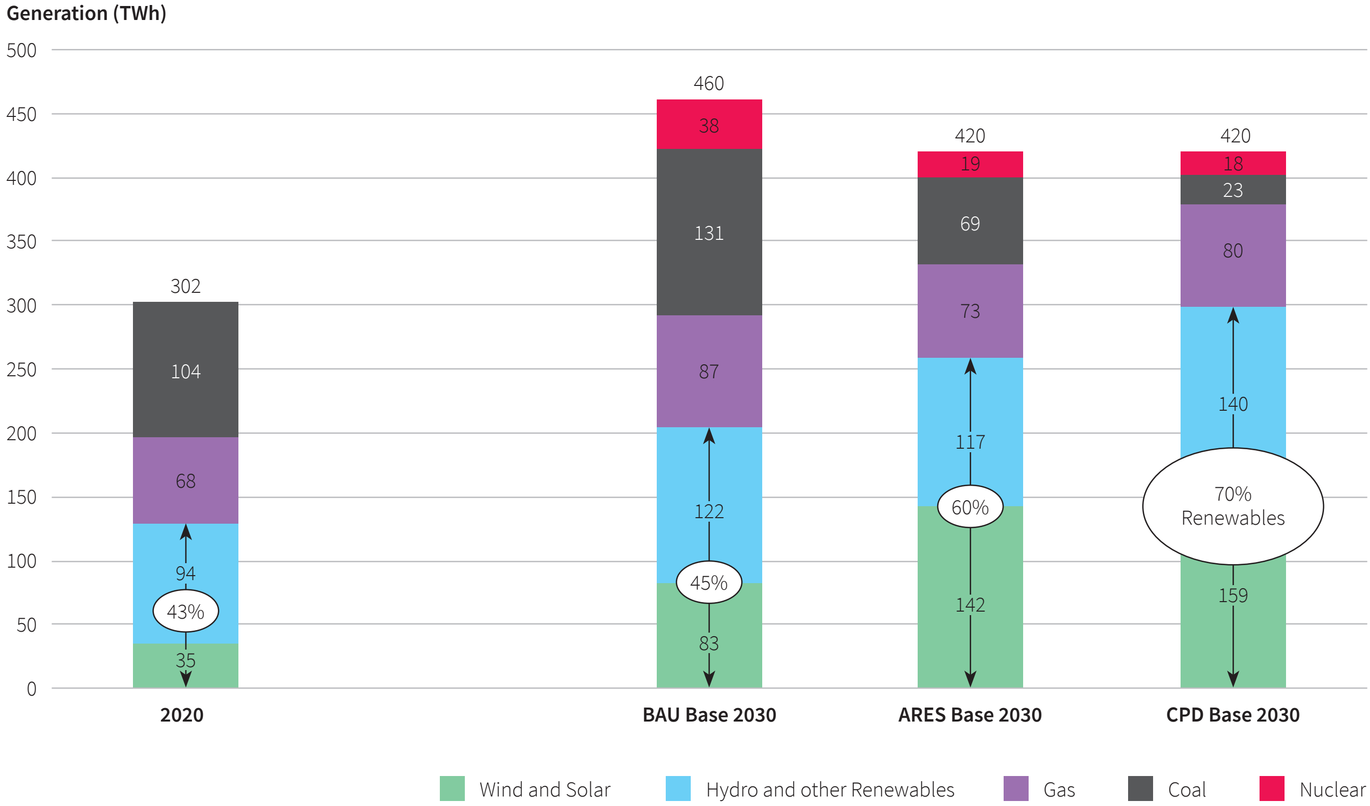
In the **Accelerated Renewable Energy Supply Scenario (ARES),** total demand is reduced by 40 TWh, reaching 420 TWh in 2030, reflecting greater energy efficiency improvements. Supportive policies and regulatory frameworks promoting accelerated renewable energy deployment are assumed to be in place resulting in wind and solar installed capacities reaching 30 GW and 34 GW, respectively. Thermal generating capacity is reduced to avoid over supply, meaning that coal installed capacity drops to 14.5 GW, gas reduces to 23 GW, and only two nuclear units are commissioned by 2030. Additional supply-side flexibility is also promoted in this scenario compared to BAU. ARES incorporates a 1 GW pumped storage hydropower project to provide system flexibility. Sensitivities investigated include the commissioning of all four nuclear units by 2030 (More Nuclear) and more available system flexibility through, inter alia, the addition of a 600 MW battery system (More Flex)

The **Coal Phase-Down Scenario (CPD)** builds further upon the ARES framework. The same energy efficiency improvements and supply-side flexibility actors as in ARES are assumed, with additional flexibility provided by a 600 MW lithium-ion battery energy storage system, the unlocking of spinning reserves from renewable energies, and the activation of demand-side peak-shifting options[4]. Finally, and most importantly, dedicated policies to discourage the use of coal-fired generation are introduced, causing coal capacity to fall to 5 GW in 2030 (3.2 GW import coal and 1.8 GW lignite), with wind (33 GW), solar (41 GW), biomass (5 GW), and geothermal (4 GW) fill the gap. Sensitivity analyses explore which coal projects are decommissioned and how they are replaced. CPD Path 1 emphasizes system resilience where the installed capacity of gas is increased to 25.8 GW from 22.7 GW with respect to the CPD Base. Here, biomass and geothermal drop to 3.3 GW and 2.8 GW, respectively. CPD Path 2 studies the case where imported coal power plants are shut down first and lignite installed capacity is reduced to 5 GW.

[4] SHURA's report on "Sector Coupling for Grid Integration of Wind and Solar" investigates demand side response options in Turkey across buildings, industry, and transport sectors: https://shura.org.tr/en/sector-coupling-for-grid-integration-of-wind-and-solar/

Figure 1 summarises Turkey's energy generation mix in 2030 according to each scenario compared against real generation values occurred in 2020.

Figure 1: *Electricity generation by technology across each scenario*



Continuing along current policies, the BAU generation mix in 2030 shows a relatively similar composition to 2020. The renewable share remains relatively similar, around 45%, while the addition of nuclear marginally displaces fossil-fuel generation, with the gas share of generation reducing to 19% from 23% in 2020, and coal dropping to 28% from 34%.

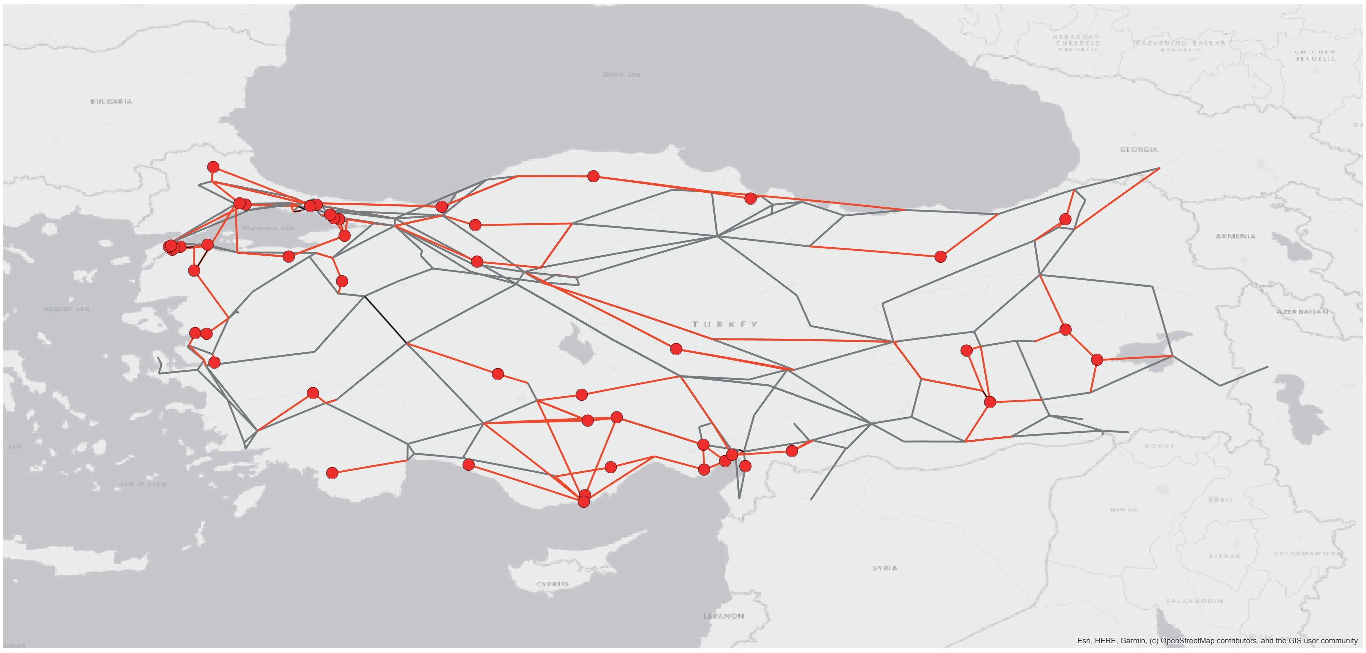
Additional policies supporting renewable energy development mean that renewable energies become the dominant source of power in 2030 in the ARES scenario. The proportion of coal in the energy mix more than halves, contributing just 16% of total generation.

In the CPD scenario only 5 GW of coal remains in the system, comprising of a combination of imported (1.8 GW) and local lignite (3.2 GW). Renewables reach 70% of total generation, and although wind and solar installed capacity is some 10 GW greater than in ARES scenario, their generation remains relatively stable. While gas capacity remains the same in the CPD and ARES scenarios, gas fills the supply flexibility gap in the absence of coal, and its generation share increases from 17% in ARES to 19% in CPD.

D.1. Transmission Investment

Turkey's transmission network development plan is based on government policies and projections of energy demand and is regularly updated to reflect new developments in technology and policies. The current plan includes an ambitious expansion and upgrade of Turkey's 400-kV grid, adding an average of almost 800 km per year up to 2030 that includes new transmission corridors between demand centres in the western regions around Istanbul and new supply locations in Turkey's northeast and south (see Figure 2).

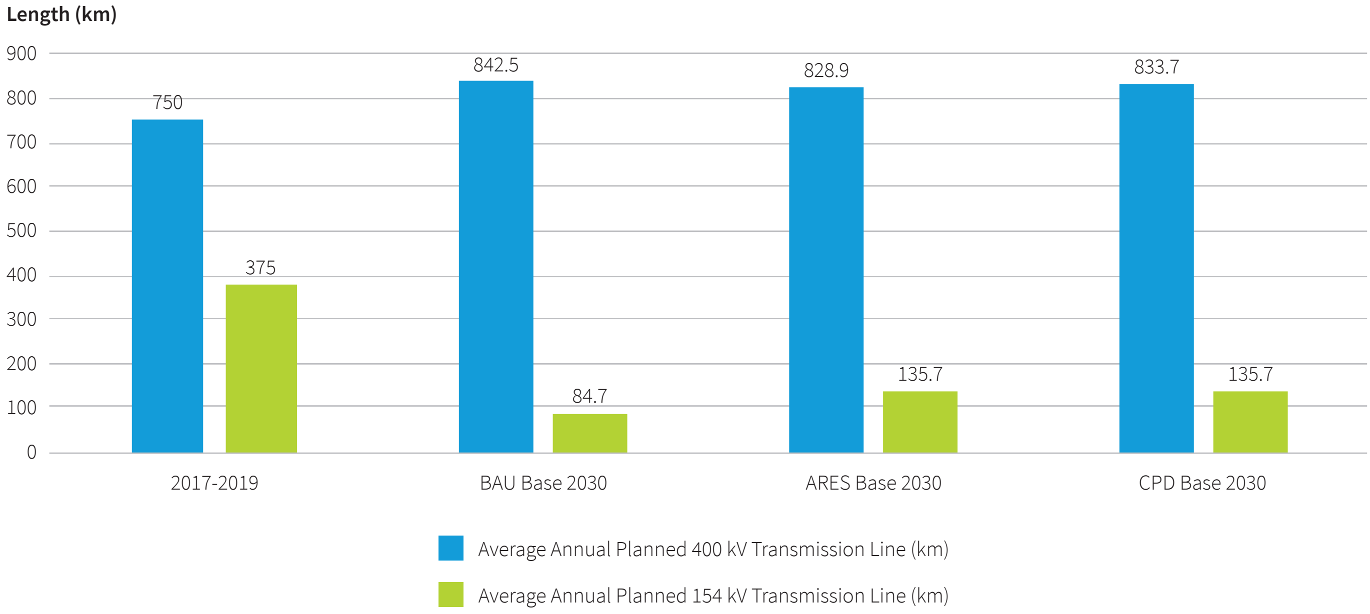
Figure 2: *Map of current (grey lines) and planned (red lines and dots) 400-kV transmission grid as per the updated ten year (2021-2030) prospective network development plan*



The current investment plan also demonstrates compatibility with much higher shares of renewable energy and even a significant reduction in coal generation, but only if the evolution of the power sector takes a system-driven approach that prioritises network stability and security. This assumes that the localisation of new renewable energies may not necessarily coincide with the best available resource or market potential, but rather where the system can best use it – typically closer to demand centres. The same system-friendly approach is assumed to apply to decommissioning decisions regarding coal, and to a lesser extent natural gas, in the CPD scenario. That is, maximising grid benefits may result in the decommissioning of coal projects according to system needs, e.g., reducing redispatch amounts or renewable energy curtailment, rather than other criteria such as promoting local over imported coal.

Still, the significant additions of renewable energy to the system do impact grid expansion planning. The displacement of large-scale thermal generators by more disperse and smaller-scale renewables put a higher onus on the lower voltage (154-kV) grid. As a result, model results demonstrate a reduction of 400-kV grid expansion in the ARES (-13.6 km per year), and CPD (-8.8 km per year) scenarios, relative to the BAU (Figure 3). In contrast, both scenarios would require an additional 51 km per year of 154 kV lines, a total of 510 km after a decade of expansion. Some investment will naturally flow into retrofits and upgrades of existing lines.

Figure 3: *Average annual planned transmission line extensions for the 400-kV and 154-kV networks*



D.2. Flexibility

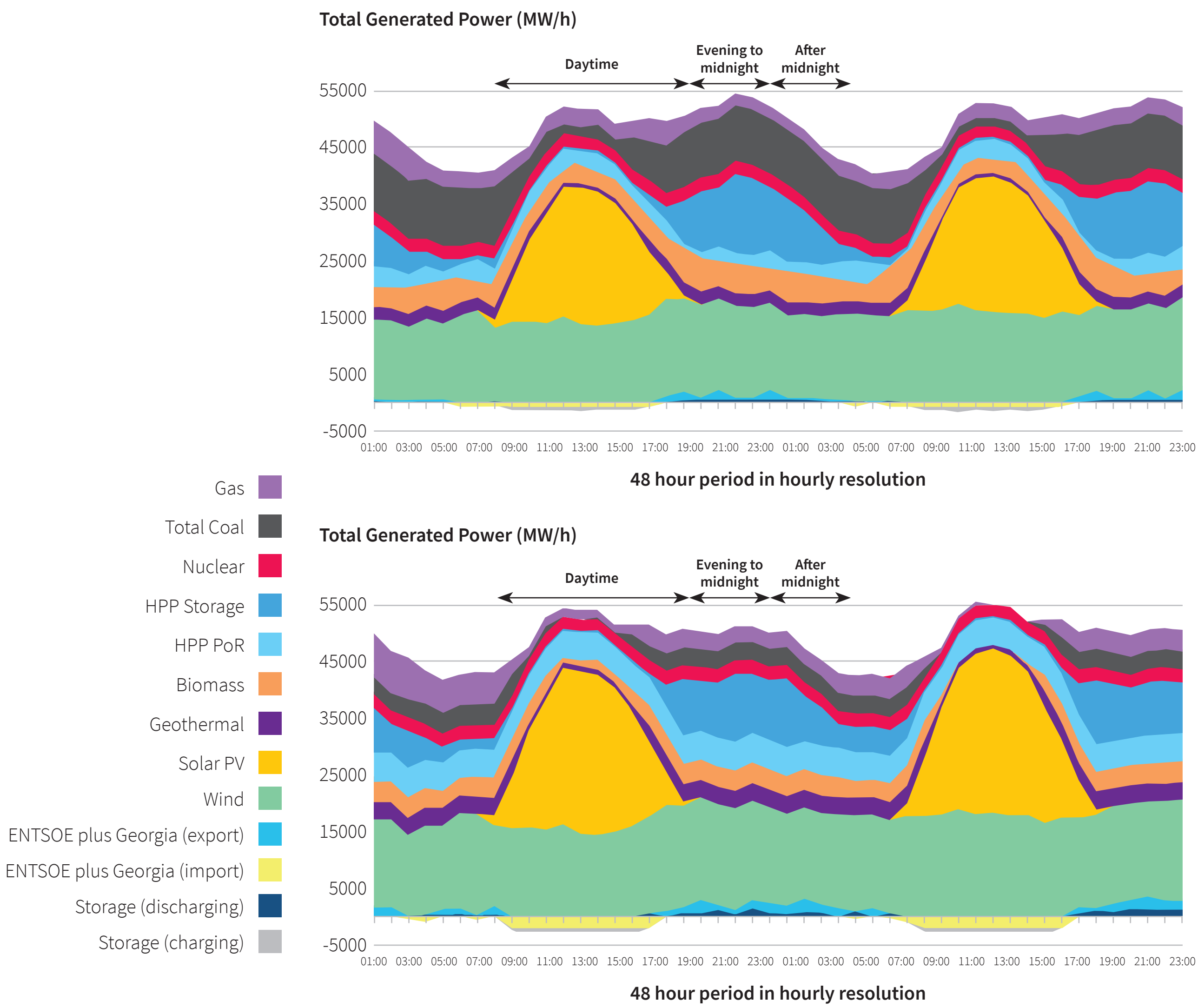
As the contributions of wind and solar PV to power generation continue to grow, system flexibility becomes the new paradigm of the Turkish power system. At low levels of penetration, the variability of wind and solar can, and has been, managed through conventional generators providing the necessary system balancing services. However, as wind and solar continue to grow and eventually displace conventional thermal generators, system operators are faced with managing an increasingly complex system characterised by growing uncertainty and supply-side variability. On top of the measures to expand and upgrade the domestic transmission network, which in effect increases the magnitude and area over which supply and demand are balanced, this study also investigates practical solutions across a broad set of additional flexibility options:

- from the supply side, allowing dispatchable power generators to respond to market signals to ramp generation either up or down;
- from storage technologies, introducing both pumped hydropower and battery energy storage systems;
- from the demand side, allowing for peak shaving to shift demand from peak hours to off-peak hours. As energy end-use sectors increasingly electrify, these sectors can begin to actively participate in balancing the power system; and
- from interconnections to adjacent power systems.

The interaction of different flexibility measures is explored in detail in Figure 4, which simulates total power generation for a typical 48-hour weekday period in spring. During the midday hours, when solar generation is at its peak, hydropower, gas and coal provide flexibility and system balancing services by ramping down generation. Generation from storage hydropower can be reduced considerably, as these are free from coal's minimum generation requirements, aside from needing to generate small amounts to maintain environmental flows in downstream river systems. Storage hydropower has the added benefit of accumulating 'fuel' in its reservoirs during this time due to natural inflows into their reservoirs. Although gas turbines can technically offer more flexibility than coal through quicker ramping and lower minimum generation levels, gas remains online to meet spinning reserve requirements. At the same time, surplus power is used to charge the 1 GW pumped storage and 600 MW battery storage systems, as well as exporting power to neighbouring grids. Flexible and dispatchable generators then ramp up as solar generation drops in the early evening, with storage technologies discharging power back into the grid and the flow of electricity in the interconnectors reversing to import power to the grid.

In the CPD Base scenario (Figure 4, bottom), due to the removal of significant coal capacity from the grid, additional flexibility is provided by the increased interconnection capacity. Gas and hydropower continue to adjust generation to keep supply and demand in balance. The main difference between ARES More Flexibility and CPD Base scenarios in Figure 4 is in the demand profile. The provision of demand-side response in the CPD Base scenario allows the evening demand peak at 22:00 to be 'smoothed' or shifted.

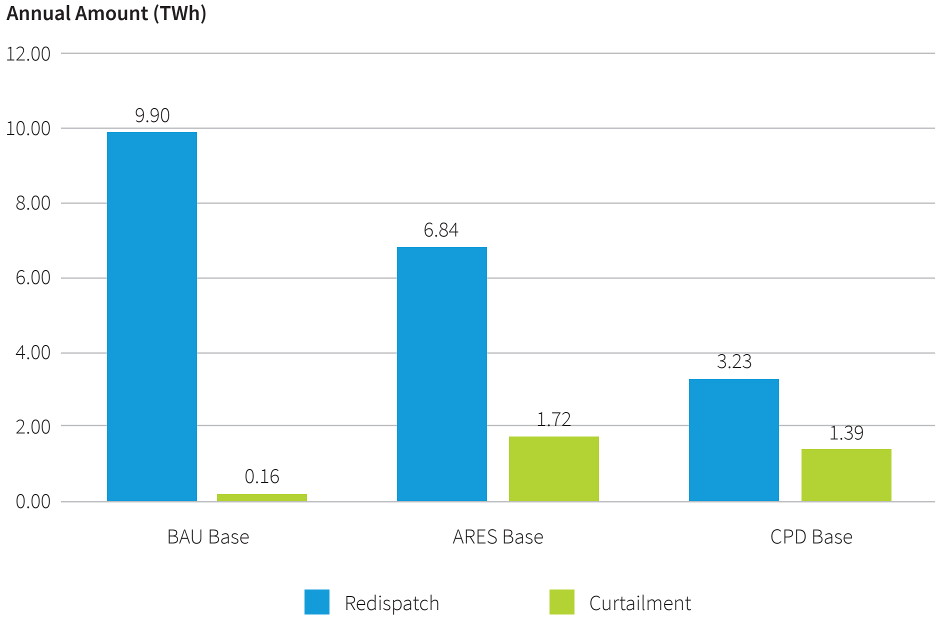
Figure 4: *Power system generation simulation for a typical 48-hour weekday in spring. ARES with additional flexibility sensitivity (Top) and CPD Base with system-driven decommissioning of coal and siting of wind and solar (Bottom).*



D.3. System Operation and Security (Grid Stability)

Grid reliability and security are assessed using two main indicators: curtailment and redispatch. Curtailment is the deliberate reduction in output, typically of a renewable energy generator, below that which could have been produced to resolve a transmission constraint or oversupply. Redispatch is a measure that TSOs take to reduce, avoid, or resolve grid congestion. A redispatch order instructs power plant operators to adjust their planned operation to shift the local distribution of power production while total system generation remains the same. For example, if there is a risk of congestion at a certain point in the grid, operators on one side of the bottleneck are instructed to reduce power production, while operators on the other side will increase their output accordingly. Any redispatch order results in additional costs, as producers who have limited production must be compensated, while those that are called upon to ramp up may do so at costs higher than the market price. A summary of redispatch and curtailment volumes are shown for each scenario in Figure 5.

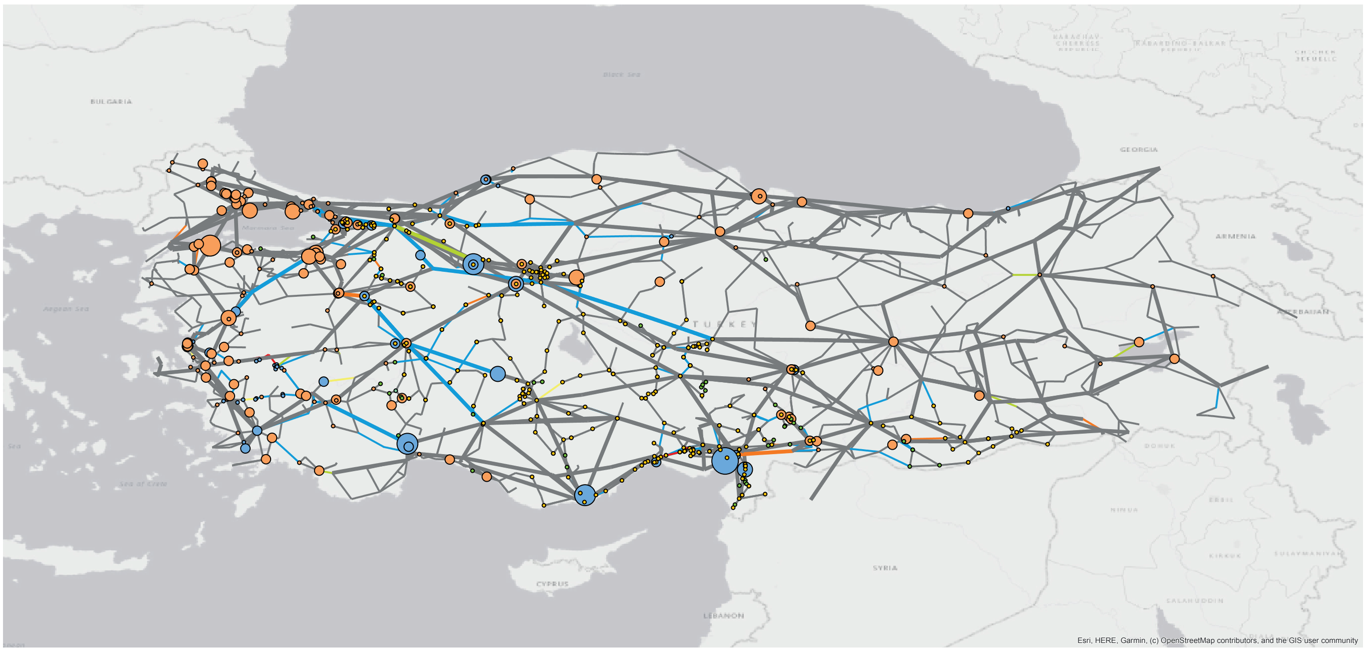
Figure 5: *Redispatch and curtailment levels across all three scenarios*



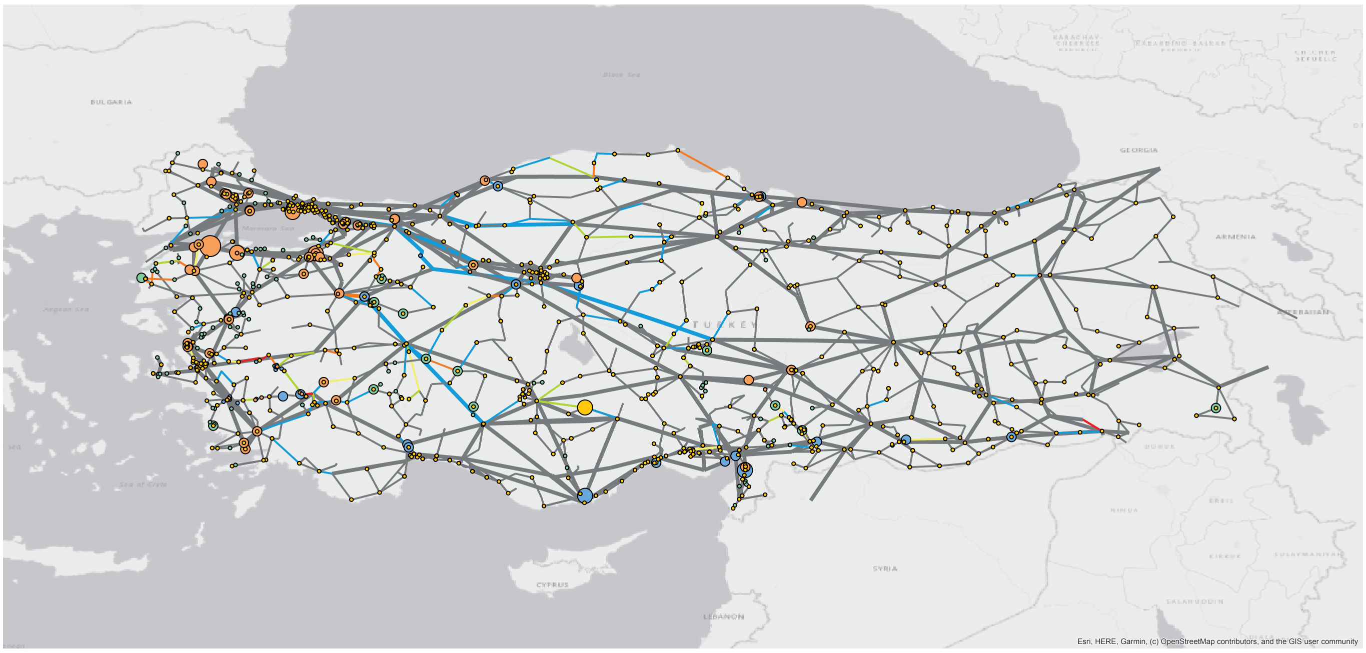
From a grid stability perspective, the current grid investment and development plan provides an adequate foundation for connecting Turkey's main demand centres to areas of supply while also adding further stability and contingency to system operations. This is particularly evident in the BAU scenario, where redispatch volumes are reduced compared to the 3.5% average redispatch amounts between 2018 and 2020. Some redispatch and curtailment remain necessary, yet even with higher and more distributed shares of renewables, redispatch volumes and curtailment are kept within tolerable historical limits. Overall, as wind and solar are deployed in a more distributed and decentralised than their conventional counterparts, redispatch tends to decrease, while curtailment increases slightly. Curtailment remains higher in the ARES scenario compared to the CPD scenario because of the operational constraints forcing coal power to remain online.

Investigating redispatch and curtailment conditions at different sensitivities, higher levels of curtailment and redispatch are needed during conditions of very high variable renewable shares combined with low overall demand and full use of nuclear (see Figure 6). As nuclear can only provide limited flexibility in the absence of flexibility incentives via market signals, in this instance it represents a near 5 GW point-source feed-in to the grid, resulting in redispatch orders along the corridors connecting the NPP in the south of the country to the load centres in the west. Due to this inflexibility, curtailment could also occur along these corridors during instances of low demand and high renewables feed-in, especially if supply-side flexibility actors are unavailable or constrained.

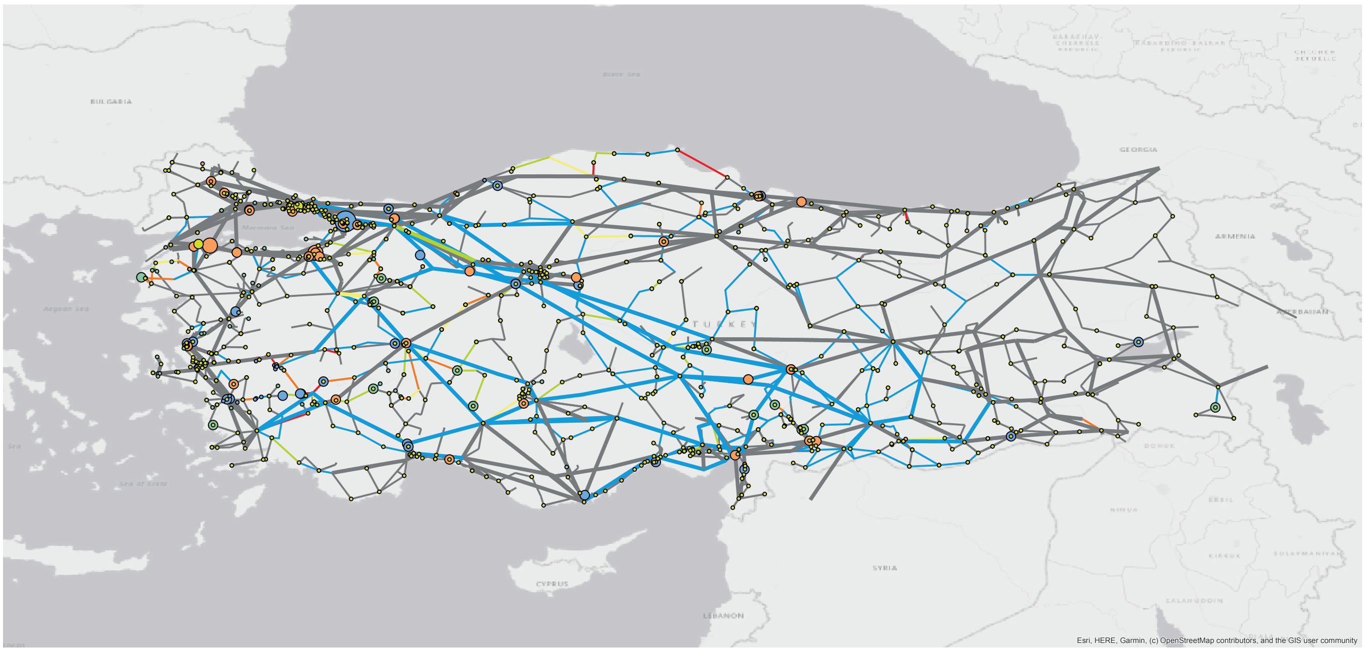
Figure 6: *Transmission line congestion, redispatch and curtailment amounts across the (a) BAU, (b) ARES and (c) CPD scenarios*



(a) BAU Base



(b) ARES Base



(c) CPD Base

Redispatch Amount (MWh)

- <10000
- 10001-100000
- 100001-250000
- 250001-500000
- 500001<

- Negative Orders
- Positive Orders
- Wind Curtailment
- Solar Curtailment

Line Congestion Hours

- No Congestion
- < 250
- 251 - 500
- 501 - 1000
- 1001 - 2000
- 2001 <

- 154 kV Lines
- 400 kV Lines

One of the key factors contributing to system reliability and stability is the location of power plants in relation to where power is consumed. The locations of new renewable energy projects were determined using a system driven approach in which locations were prioritised that already have strong grid connections linking them to major demand centres, rather than concentrating on the best resource potential. Employing such a strategy minimises the need for bulk power transportation on a permanent basis and reduces transmission line congestion, redispatch and curtailment. Figure 6 thus further illustrates how system stability and reliability are improved in scenarios with increasing renewable energy generation. The impact of employing the same strategy to prioritise the decommissioning of coal projects (as in CPD) can be seen when comparing against the CPD sensitivities, which emphasize retaining local over imported coal.

Applied to sources of flexibility, the system-driven approach contributes to further improving overall performance of the transmission system. In this respect, unlocking demand-side flexibility through sector coupling can have a significantly higher benefit to system performance, even if the magnitude of that flexibility is much lower than, for example, a large-scale storage system.

Overall power system performance is impacted by variety of different elements. As Turkey's power system continues to evolve, the interaction of various spatial levels, the interplay of individual technologies, and the use or smart digital communication tools will play an increasingly vital role in ensuring stable and reliable system operations.

Given Turkey's new political commitments to reach net-zero carbon emissions by 2053, the long-term future role of coal in the Turkish power system is relatively clear. Its use will need to be eliminated or at least significantly decreased by mid-century at the latest. However, the power sector represents a backbone for a net-zero economy, and as such will need to lead decarbonization efforts to give other economic sectors the time and clean resources to do so. While coal currently can provide flexibility to the grid it is less suitable in terms of flexibility than other generation sources, such as gas or hydropower. In any case, the primary driver to reduce coal use is to reduce greenhouse gas emissions and improve environmental quality. Appropriate policy and regulatory instruments can guide the gradual decommissioning of coal-fired power plants that consider the location and technical characteristics of these projects and their impact on system reliability.

Gas has long been heralded as a bridging fuel on the way to renewables-based energy systems. Indeed, it has contributed significantly to reducing carbon intensities throughout Europe and the United States by displacing coal-fired generation. In addition to a lower carbon intensity, gas can provide improved power system flexibility over coal in a number of diverse ways, including the ability to more rapidly adjust generation (ramping) and lower minimum loads. It also offers storage over longer timescales through seasonal gas storage. Given Turkey's already large fleet of gas power plants, nearly 25 GW today, gas is already well suited to providing peaking support and filling supply gaps not filled by coal or renewables. At the same time, it remains important for spinning reserves which play a key role in maintaining system stability. However, from a pure market perspective, gas turbines will experience lower utilization as they remain on top of the merit order. Modelling analysis in this study demonstrates that additional gas capacity is not required in any scenario, and only in instances of a coal phase-down and slower than expected renewables growth does gas utilization increase.

Hydropower, especially hydropower systems with large active storage volumes in reservoirs, have traditionally provided significant flexibility to conventional energy systems. Hydropower projects can ramp generation up and down very rapidly compared to nuclear, coal and natural gas, and can also be stopped and restarted relatively smoothly. As such, they provide approximately 30% of the world's capacity for flexible power supply. Nevertheless, hydropower's flexibility and indeed generation contributions are subject to seasonal water availability and droughts which can severely limit their contributions. The Turkish hydropower fleet, the ninth largest in the world with an installed capacity of 31 GW, however, has nearly exhausted its technical and economic potential for future greenfield hydropower. This is reflected in this study, as hydropower capacity does not grow across any of the scenarios, except for the addition of the 1 GW pumped hydropower storage at Gökçekaya. However, additional hydropower capacity and flexibility could still be added, through technical upgrades and modernization at existing projects, as well as converting existing hydropower systems to add pumping capacity for additional demand-side response, if necessary.

Wind and solar are the key technologies for Turkey's energy transition and to achieving its net-zero ambitions. As their share of generation continues to increase, power markets and power systems will need to adjust and evolve around these variable resources. Especially at the large scales of expansion highlighted in the more ambitious ARES and CPD scenarios, their variability can be mitigated by geographical distribution, which will require an expanded low-voltage transmission and distribution grid. In addition, wind and solar demonstrate season complementarity, i.e., average wind speeds are greater in winter months when solar generation is lower. At this point, it will be important that hybrid power plant installations become widespread. Innovations in wind and solar technologies will allow future projects to also offer additional system flexibility services, either by providing spinning reserves or even reactive power to mitigate local grid congestion. In any case, expanding wind and solar will continue to require ambitious and system-oriented policies to ensure their growth.

With the first unit of the Akkuyu Nuclear Power Plant scheduled to come online as early as 2023, Turkey will enter the list of countries around the world using nuclear power as a source of low-carbon and large-scale power generation. From a system stability point of view, nuclear power provides significantly less flexibility than hydropower, coal or gas. As such, as additional units are deployed throughout the scenarios and sensitivities in this study, increased levels of curtailment and redispatch are observed along the transmission corridors connecting the project. Turkey continues to debate the construction of an additional nuclear power plant or comparable size. Although the addition of another 4.8 GW nuclear was not modelled, this study suggests that an additional large point-source of inflexible generation could pose great challenges for system operations.

Overall, Turkish power system and transmission grid is in a good position to absorb significantly higher shares of renewables, up to 70% as in the CPD base scenario. Still, securing system flexibility will become an important cornerstone of power system operations. As this study has shown, flexibility can come from a variety of different sources. From the supply side, the large fleets of gas and hydropower are already well suited and are unlikely to need to grow for this purpose. Even after a coal phase-down, the 5 GW of coal remaining in the system in 2030 will still have to adjust operations around wind and solar.

Due to the high flexibility already in the system, the modelled 1 GW pumped storage and 600 MW battery storage systems provide sufficient additional flexibility, even at 70% renewables penetration as in the CPD scenario. Energy storage systems, if added at key nodes on both sides of a congested transmission line, can reduce redispatch and curtailment by acting as 'virtual power lines'. The storage system on the supply side would absorb surplus generation, while the storage system on the other end, the demand side, would discharge accordingly – and charge when grid capacity allows. This configuration can offer a financially viable alternative to upgrading or reinforcing the transmission grid itself.

It is important to note that behind-the-meter batteries, e.g., for residential purposes or those used in electric vehicles, were not included in this study. Combined with digitisation, behind-the-meter batteries will be critical to providing additional flexibility at local levels.

Innovative configurations of two or more power generators can add flexibility to the grid and help reduce the need for spinning reserves, redispatch or curtailment. Hybrid renewable energy systems that combine one or more renewable energy power plants with other generation or storage units, can increase the efficiency of both systems, while smoothing fluctuations before feeding into the grid, thus reducing the need for spinning reserve capacity and the burden on the TSO. Hybrid systems can be particularly useful when integrating very large renewable energy projects to an already strained grid. Aggregators, on the other hand, can operate many smaller-scale distributed energy resources in concert, and are sometimes referred to as a 'virtual power plant' (VPP). A VPP can act as a single unit, mimicking a traditional power plant with similar characteristics that can participate in wholesale or flexibility markets.

Increasing the number of interconnections to neighbouring grids is an effective and low-cost option to improve resilience of the system. Strengthening the net transfer capacity of interconnections with the European ENTSO-E system via Bulgaria and Greece, with Georgia via high voltage direct current lines are well suited examples. This will, however, also require associated internal grid investments, particularly at the 400-kV level, to maximize the utilization of flexibility on interconnection lines through market coupling and imbalance netting.

The energy transition involves transforming from a largely fossil fuel dominated system towards a sustainable system based on flexible and decentralised renewable energy sources. As a result, the role of transmission system operators is widening to manage an increasingly complex and digitalised systems. While this study provides strong evidence on how the Turkish transmission grid and power system could evolve overtime to meet ambitious climate and net neutrality targets, detailed cost-benefit analysis will be able to help inform short-term investment decisions, especially when choosing diverse types of flexibility measures. In the cost-benefit analysis undertaken in this study, market coupling through interconnections were demonstrated to have the greatest benefit to cost ratio.

1. Introduction

Turkish energy and power systems are currently undergoing a fundamental transformation from a fossil fuel-based system to one in which the majority of the energy supply will be from Renewable Energy Sources (RES). Over the past five years, the share of wind- and solar-based installed capacity has risen from 6.5% to 18.6% after the installation of 4.3 GW of wind and 6.4 GW of solar power capacity[5]. Investors' interest in recent Regulation on Renewable Energy Zones (YEKA) tenders shows that the share of RES will continue to increase. Although the Turkish Electricity Transmission Company (TEIAS) has adjusted its planning and operations, questions and concerns remain as to how the system will cope with an even more ambitious transformation pathway.

According to the SHURA grid study in 2018[6], Turkey can generate 20% of its total electricity from wind and solar by 2026 without negatively impacting the transmission system. Furthermore, planning 40 gigawatt (GW) installed wind and solar capacity is feasible without any additional investment in the transmission system compared to the base scenario. Tripling the installed capacity to 60 GW by 2026 would make solar and wind the largest sources of electricity generation in Turkey, with a total share of 31%, and lead to increased flexibility requirements. The results of the previous SHURA study are promising as it demonstrates the increasing share of RES in Turkey. However, there is a need to update the study given the fact that the dynamics of the Turkish power system are changing rapidly in light of the ongoing energy transition.

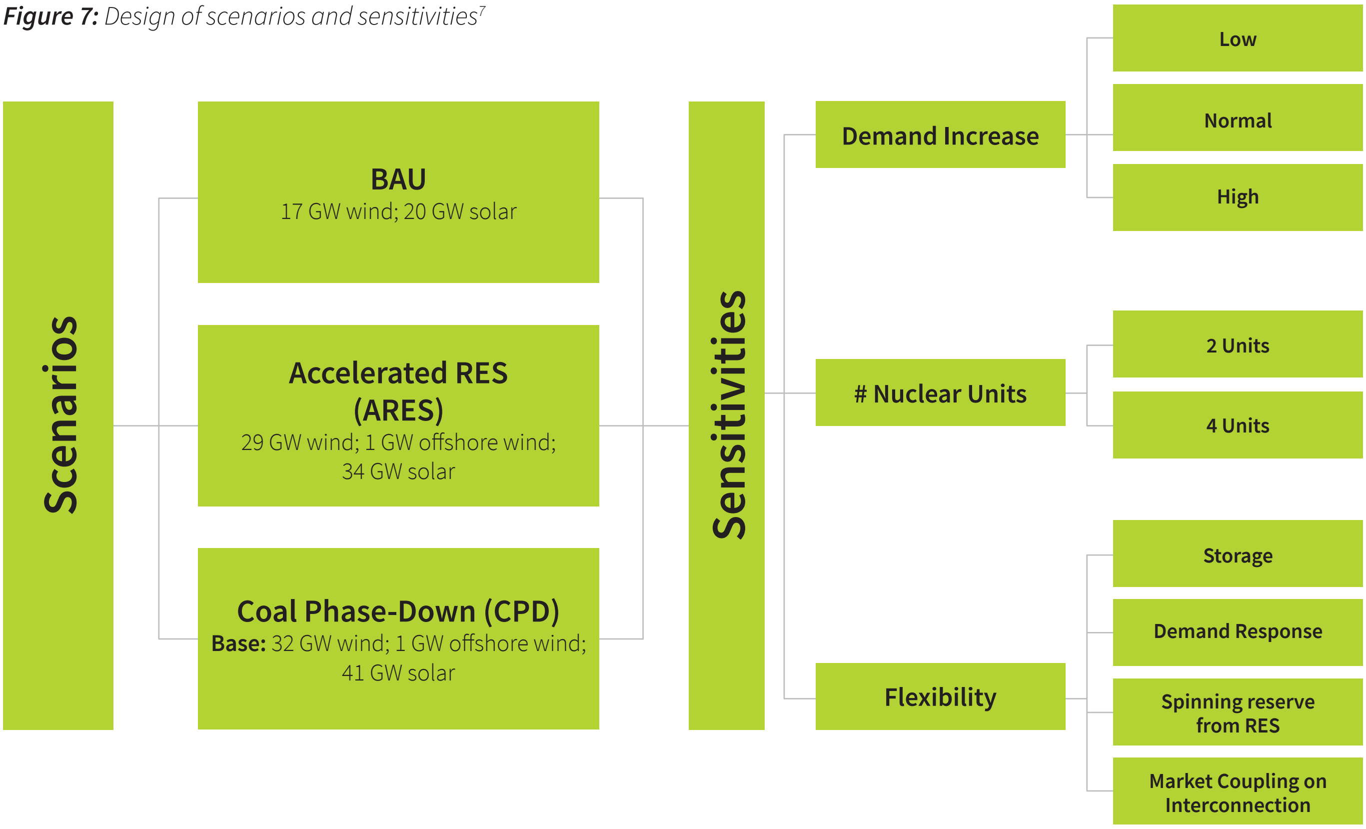
This report presents the results and key outcomes of a new study on the Turkish grid that looks to 2030 as well as key intermediate steps for global decarbonization pathways. This study updates SHURA's previous study from 2018, which highlighted priority areas and informed energy planners, system operators, decision-makers, and key market players on the consequences of higher shares of RES between 2016 and 2026 and what this would mean for transmission investments and integration strategies in Turkey. The new study updates the results for the 2020–2030 period considering Turkey's most recent grid investment plans as well as more ambitious transformation pathways. It aims to address how transmission grid planning is adjusted and what the impact of increasing RES would mean under a gradual coal phase-out.

This study examines three main scenarios: 1) Business as Usual (BAU); 2) Accelerated RES (ARES); and 3) Coal Phase-Down (CPD). For each scenario, market and network simulations are performed for the target year, 2030, with an hourly resolution (i.e., 8,760 hours), ensuring demand is met at any hour of the year at any node in the Turkish transmission system under grid constraints. In addition, scenario-specific stress tests were implemented through a wealth of sensitivity analyses, such as alternative demand development, different speeds of nuclear units coming into operation, and different types and levels of flexibility options, as illustrated in Figure 7.

A key factor in determining the three main scenarios was the share of RES, in particular wind and solar. This share is at its lowest in the BAU scenario (solar + wind: 37 GW), which represents the projections and assumptions of key public stakeholders in Turkey, such as TEIAS and the Ministry of Energy and Natural Resources. Combined solar and wind installed capacity is 64 GW (29 GW wind, 1 GW offshore wind, and 34 GW solar) in the ARES scenario, while the share of RES in the CPD scenario reaches 74 GW given the replacement of coal-fired capacity with renewables (32 GW wind, 1 GW offshore wind, and 41 GW solar).

[5] As of January 2022. Source: TEIAS report: https://www.teias.gov.tr/tr-TR/kurulu-guc-raporlari
[6] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)

Figure 7: *Design of scenarios and sensitivities*[7]



Consecutive market and network simulations are carried out in this study. Market simulations represent the day-ahead wholesale market in Turkey. The main outputs of the market simulations include unit commitment and generation dispatch of power plants under the assumption of a merit order. The generation fleet is modelled for each scenario separately. New power plants are assumed to be cost effective if compared to existing ones with the same technology. To determine the removal of power plants from the system (e.g., fossil fuel-based power plants in the CPD scenario), the priority is to decommission older power plants that are far from the main demand centers. In addition, the priority is to shut down power plants that have a relatively low-capacity factor. Grid constraints, including overloading and N-1 contingency, are ignored in the market simulations as in the current day-ahead wholesale market in Turkey.

The results of the market simulations are given as an input in the network simulations in order to quantify grid constraints and address trading off proper solutions, including the redispatch of power plants, grid investments, and flexibility measures based on the approach in the previous Shura study. Cost-benefit analyses (CBA) compare the value of flexibility solutions and grid investment requirements addressed in the scenarios. Investment and operational costs of grid plans and flexibility solutions are considered in the CBA, including redispatch costs based on market clearing price (MCP) under the merit-order assumption, curtailment costs of RES, capacity payments to gas power plants that have a low-capacity (utilization) factor (below a threshold assumption) but are critical for the grid in terms of providing flexibility (ramp up/down capability), and carbon price. Benefits are quantified in terms of the impacts of the solutions on the average MCP and relative change in the average costs of the solutions in terms of EUR/MWh among different scenarios.

[7] See Appendix 1 for details of the scenarios and sensitivities considered in this study.

The report is organized as follows. Section 2 presents the methodology considered in the study. The scenarios and sensitivities addressed in the study are outlined in Section 3. Modeling details and key assumptions made in the study are described in Section 4. The results of the study are investigated in Section 5 through illustrative tables and figures. Conclusions and key recommendations drawn from the study are summarized in Section 6. A comparison of the scenarios in terms of key assumptions is presented in Appendix 1. The assumptions made in modeling the capacity payment mechanism for power plants that have a low-capacity (utilization) factor but are critical for the grid in terms of providing flexibility (ramp up/down capability) are provided in Appendix 2.

2. Methodology

The first step in the methodology is the identification of scenarios as depicted in Figure 8. This is followed by modeling the day-ahead wholesale market in Turkey and market simulations, respectively. Market and network simulations are key components in the methodology (Figure 9). For each scenario, market simulation results are given as an input in the network simulation in order to quantify grid constraints, if any, and provide effective solutions based on trading of short-term operational solutions (e.g., redispatch of conventional power plants) and long-term planning solutions (e.g., grid investments). For this, the cost of investment (EUR/km/year) and the cost of congested energy (EUR/km/year) are compared. The details of the approach undertaken in the CBA are presented in the previous SHURA study[8]. Market and network simulations of scenarios are followed by sensitivity analyses. CBA is the final step. The details of the CBA analyses and the key indicators considered in the study are described in Section 4.

Figure 8: *Flowchart of the modelling and analysis process*

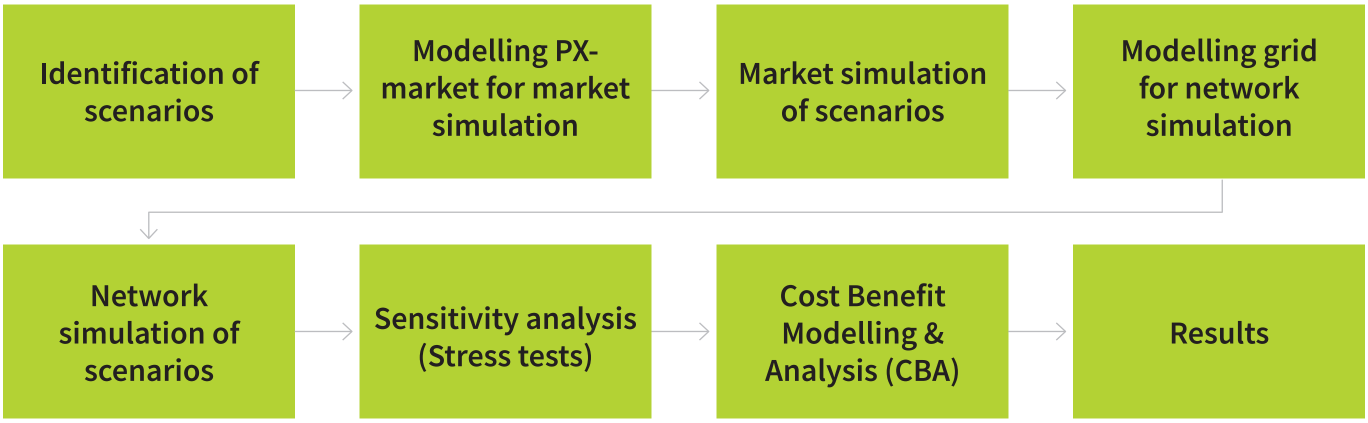
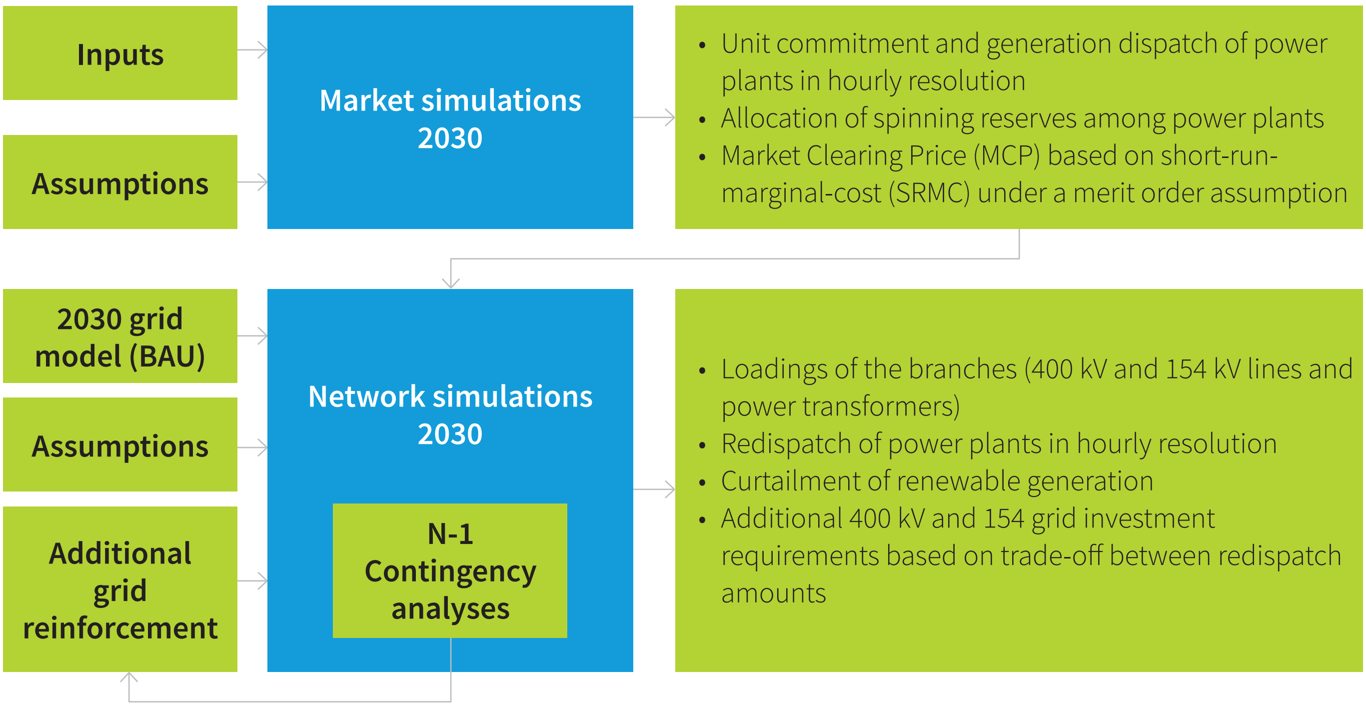


Figure 9: *Market and network simulations*



[8] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)

Market simulations in the study represent the day-ahead wholesale market in Turkey (i.e., market clearing by ignoring grid constraints)[9]. The key inputs, assumptions, and outputs of the market simulations are summarized in Figure 10. Key inputs include total power plant capacity by type, merit order of conventional power plants, hourly total demand profile of the grid along the target year (i.e., 2030), and spinning reserve constraints.

Figure 10: *Key inputs, assumptions, and outputs of the market simulations*

Key Inputs

- System total demand profile in hourly resolution
- Generation fleet of conventional power plants (coal, lignite, gas, nuclear)
- Merit order in SRMC (gas, coal, lignite)
- Weekly energy constraints of HPPs Storages
- Generation profiles of wind, solar, run-of-river generation and others
- Spinning reserve requirement
- Generator constraints (Pmax/min, ramp up/down, etc.)

Market Simulation (Hourly resolution)

Outputs

Senario-based:

- Unit commitment and generation dispatch of power plants in hourly resolution
- Allocation of spinning reserves among power plants
- MCP based on merit-order assumption on an hourly resolution

Key Assumptions

- Network constraints ignored
- Wind, solar, run-of-river generation, “other” plants → negative load (feed-in)
- Wind, solar, run-of-river, other types generation profiles →scaling from historical generation profiles based on capacity fleet
- HPP Storage → weekly energy constraints from historical records
- Gas, coal, lignite merit order → based on SRMC
- Nuclear → maintenance during minimum demand periods
- System demand profile → scaling based on avg. annual increase ratio in %.
- Distributed renewable sources → Distributed to HV substations as negative loads
- Scenario-based generation capacity fleet
- Interconnections → NTC & merit order (SRMC)
- Flexibility options
- Spinning reserve requirement will be adjusted considering increase in renewable generation

Spinning reserve constraint is modeled in the market simulations according to the recent change in the ancillary service tender mechanism in Turkey. Spinning reserves had been procured in the day-ahead market (i.e., short-term) until 2018.[10] However, they have been procured based on long-term contracts since then. The main reason for this is to mitigate high-bid prices for ancillary services in the day-ahead market. Under this approach the total amount of redispatch orders is reduced as discussed in the results.

[9] M. E. Cebeci, O. B. Tor, et. al., “Consecutive market and network simulations to investigate investment and operational requirements for RES penetration scenarios,” IEEE Trans. on Sus. Ener., Vol. 10, No: 4, Oct. 2019.
[10] Therefore, in the previous study of Shura, spinning reserve constraint was modelled in network simulation.

Figure 11: *Key inputs, assumptions, and outputs of the network simulations*

Key Inputs

- Market simulation inputs
- Market simulation outputs
- Current grid model (2020)
- Grid investment plans by TEIAS

2030 Network Sim. (Hourly resolution)

Outputs

Senario-based:

- Grid reinforcement requirements
- Redispatch of power plants in hourly resolution
- Loadings of the branches (400 kV and 154 kV lines and power transformers)
- Lines with N-1 restriction issues.

Key Assumption

- Additional 400 kV and 154 kV grid investment requirements based on trade-off between redispatch amounts
- Load profiles at high-voltage (HV) substation level in the reference grid model (2020) are scaled to 2030, based on total demand forecast
- DC load flow
- Location of new RES: network-driven approach
- Location of new gas: network-driven approach
- Location of new lignite: source-driven approach
- Location of new HPP: source-driven approach

The results of the market simulations are given as an input in the network simulations in order to quantify grid constraints and find effective solutions including redispatch of fast power plants and grid investments. The key inputs, assumptions, and outputs of the network simulations are summarized in Figure 11. As indicated in the figure, the location of new RES and gas power plants is driven by system needs, which was a key finding from the previous SHURA study[11] and is being implemented in Turkey today through YEKA mechanisms.

[11] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)

3. Scenarios and Sensitivities

Three main scenarios are addressed in this study. The share of RES, in particular wind and solar, is the key factor in differentiating between each scenario.

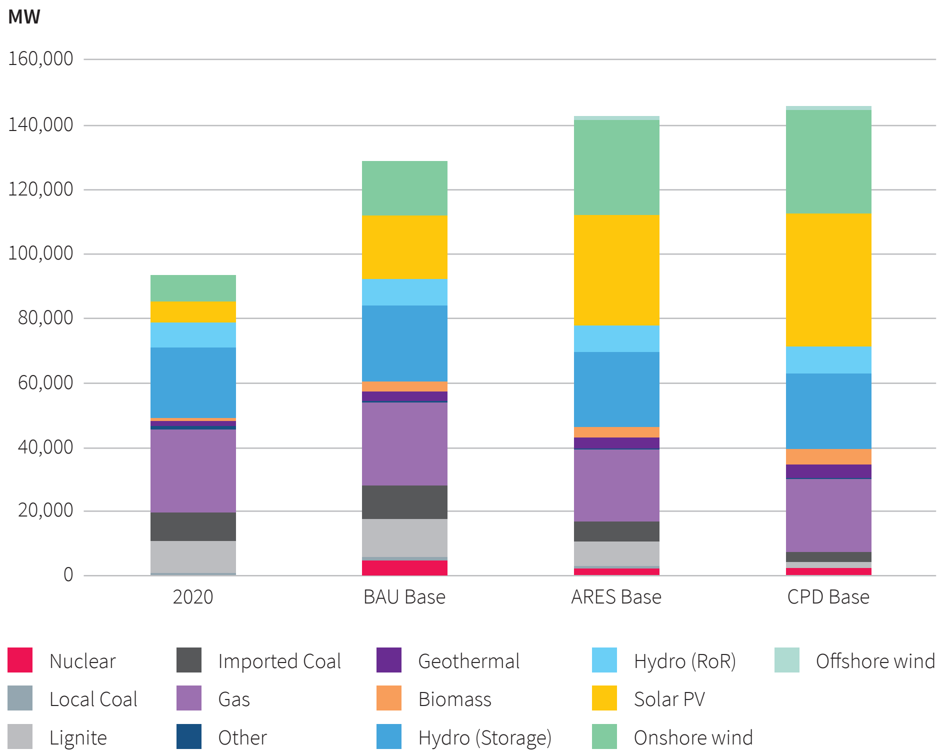
- **Business as Usual (BAU):** Combines the projections and assumptions of different public stakeholders in Turkey such as the Ministry of Energy and Natural Resources[12] and TEIAS. The key figures in the 2030 BAU scenario in comparison with the 2020 figures are summarized in Table 1 and Figure 12. The installed capacities for wind and solar are almost 17 GW and 20 GW, respectively, in the 2030 BAU scenario.
- **Accelerated RES (ARES):** The share of RES in total generation in the ARES scenario is higher than in the BAU scenario, with wind and solar installed capacities reaching 30 GW and 34 GW in 2030. Compared to the BAU scenario, the total installed capacities of thermal power plants (gas, lignite, and imported coal) are reduced (Figure 12) to mitigate oversupply. In addition, total demand is assumed to be 40 TWh less than that of the BAU scenario, reflecting greater energy efficiency improvements.
- **Coal Phase-Down (CPD):** In the CPD scenario (Paths 1 and 2)[13], in which most of the coal-based electricity generation capacity considered in the BAU scenario is not utilised and the resulting difference in supply is provided by the renewable energy sources. In this scenario, the combined installed power capacity of wind and solar energy reaches its highest level (74 GW). It is assumed that the total electricity demand is the same as in the ARES scenario.

Table 1: *Key figures in 2030 according to the BAU Base scenario in comparison with the 2020 grid*

Parameter	2020	2030 BAU Base scenario
Annual consumption (gross) (TWh)	303	460
Peak demand (MW)	45,210	72,000
Total Installed capacity (MW)[14]	93,207	128,541
Nuclear	0	4,800
Natural Gas	25,632	25,845
Imported Coal	8,967	10,267
Local Coal	811	918
Lignite	10,097	11,993
HPP (DAM + Run-of-river)	29,790	31,700
Wind	8,077	16,679
Solar PV	6,361	19,796
Geothermal	1,515	2,884
Biomass	869	3,289
Other[15]	1,088	370

[12] Strategic Plan for 2019 – 2023. Turkish Ministry of Energy and Natural Resources https://sp.enerji.gov.tr/ETKB_2019_2023_Stratejik_Plani.pdf
[13] CPD Base, CPD Path 1, and Path 2 differ in terms of imported coal, lignite, geothermal, and biomass installed capacity. See Appendix 1 for details.
[14] TEIAS Installed Capacity Report – September 2020 (https://www.teias.gov.tr/tr-TR/kurulu-guc-raporlari)
[15] Other types includes co-generation, asphaltite, fuel oil, LNG, and naphtha.

Figure 12: Total installed capacity by type (2020, 2030 BAU, 2030 ARES Base and 2030 CPD Base)



An overview of the scenarios and sensitivities is presented in Figure 13. Sensitivity analyses in the BAU scenario are designed as stress tests under low-demand conditions with respect to the BAU Base scenario; 1) "Low Demand" sensitivity; 2) "No Flex. on NTC" sensitivity (no flexibility is assumed on the net transfer capacity (NTC) of the interconnections under low demand); 3) "More RES" sensitivity; and 4) "Less Gas PP" sensitivity (gas installed capacity reduced if compared to "More RES" sensitivity). These sensitivities correspond to challenging scenarios outlined in TEIAS's report, particularly at minimum loading hours when RES generation is the highest and RES generation curtailment could be indispensable depending on the flexibility level of the grid.

The logic behind the sensitivity analyses in the ARES scenario is to gradually increase the flexibility of the grid with respect to the ARES Base scenario. These analyses aim to see how the increase in grid flexibility affects redispatch and RES curtailment requirements under the ARES scenario, which has more RES capacity than the BAU. Finally, sensitivity analyses in the CPD scenario represents two different pathways for coal phase down under different levels of gas power and RES capacity (i.e., CPD Path 1 and CPD Path 2 with respect to the CPD Base scenario)[16]. A comparison of the scenarios and sensitivities in terms of key assumptions is made in Appendix 1. Details of the key assumptions made in the scenarios and sensitivity analyses are described in the following section.

[16] CPD Base, CPD Path 1, and Path 2 differ in terms of imported coal, lignite, geothermal, and biomass installed capacity. See Appendix 1 for details.

Şekil 13: *Overview of the scenarios and sensitivities*[17]

Scenarios & Sensitivities

Business As Usual (BAU)

BAU Base	Low Demand	No Flex. from NTC	More RES	Less Gass PP
• Gas ≈ 26 GW • Solar & Wind ≈ 37 GW • Lignite ≈ 12 GW • Imported Coal ≈ 10 GW • Demand 460 TWh • Geothermal ≈ 2.8 GW • Biomass ≈ 3.3 GW • Flexible NTC 1,200 MW	"BAU Base" with: • 360 TWh demand	"BAU Low Demand" with: • No flexibility from NTC	"BAULow Demand" with: • More Solar & Wind (≈64 GW)	"BAU Low Demand" with: • Less Gas PP (≈16 GW)

BAU Sensitivities
(Stress tests)

Accelerated RES (ARES)

ARES Base	4 Nuclear Units	More Flexibility	Demand Response	More Flex. on NTC
• Gas≈ 23 GW • Solar & Wind ≈ 64 GW • Lignite ≈ 7.5 GW • Imported Coal ≈ 6 GW • Demand 420 TWh • Geothermal ≈ 2.8 GW • Biomass ≈ 3.3 GW • 2 Units Akkuyu NPP • 1000 MW Pump Storage • Flexible NTC 1,200 MW	"ARES Base" with: • 4 units at Akkuyu NPP	"ARES Base" with: • 600MW Battery • Reserve from Solar & Wind	"ARES More Flexibility" with: • Demand response	"ARES Demand Response" with: • More flexible NTC (2,750 MW)

ARES Sensitivities
(Gradual increase in flexibility)

Coal Phase Down (CPD)

CPD Base	CPD Path 1	CPD Path 2
• Gas≈ 23 GW • Solar & Wind ≈ 74 GW • Lignite ≈ 1.8 GW • Imported Coal ≈ 3.2 GW • Demand 420 TWh • Geothermal ≈ 4 GW • Biomass ≈ 5 GW • 2 Units Akkuyu NPP • Flexibility: "ARES More Flex. on NTC"	"CPD Base" with: • Gas≈ 26 GW • Solar & Wind ≈ 74 GW • Lignite ≈ 1.8 GW • Imported Coal ≈ 3.2 GW • Geothermal ≈ 2.8 GW • Biomass ≈ 3.3 GW	"CPD Path 1" with: • Gas≈ 26 GW • Solar & Wind ≈ 64 GW • Lignite ≈ 5 GW • Imported Coal ≈ 0 GW • Geothermal ≈ 2.8 GW • Biomass ≈ 3.3 GW

CPD Sensitivities
(Alter. pathways)

[17] Change in assumptions are being shown in green

4. Modelling and Key Assumptions

This section presents the details of key assumptions made in the modelling of scenarios and sensitivities.

4.1. System demand projection and profile

TEIAS's projection figures for total annual gross demand (including technical losses) are presented in Table 2[18] in comparison with demand projections made in the study. Total gross consumption in 2030 is assumed to be 460 TWh in the BAU Base scenario, which is consistent with the baseline assumptions in the recent Shura report.[19] Demand projection in the ARES and CPD scenarios are assumed to be 420 TWh considering more energy efficiency[20] with respect to the BAU Base scenario. Compared to BAU Base, improvements in energy efficiency and accelerated end-use electrification impact total demand by -48 TWh and +8 TWh, respectively, in the ARES and CPD scenarios. Therefore, total demand in the ARES and CPD scenarios is 40 TWh (-48+8) less than that of the BAU Base scenario. Total demand is assumed to be 360 TWh in the low-demand sensitivities under the BAU scenario, similar to TEIAS's low-demand scenario. As seen in Table 2, demand projections in different scenarios and sensitivities addressed in this study cover TEIAS's high- and low-demand projection range.

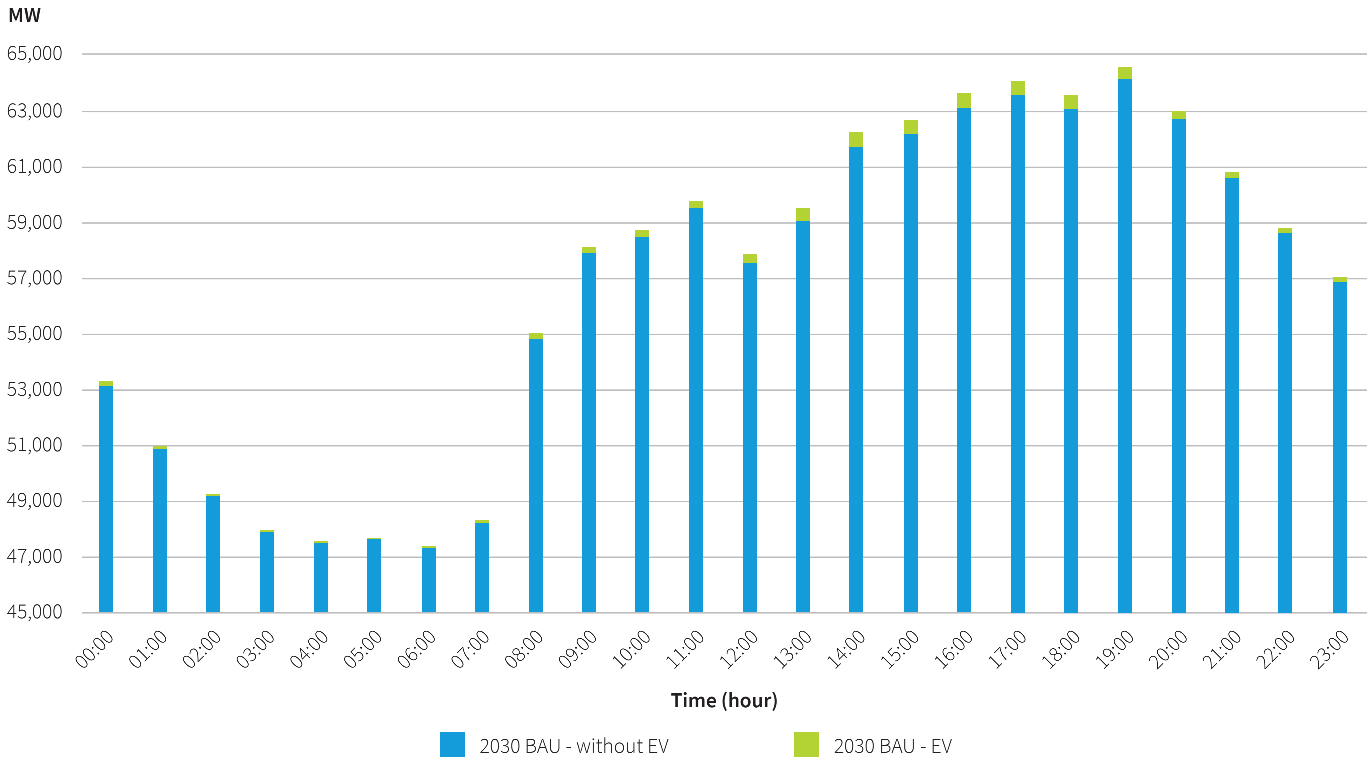
Table 2: *Total demand projection figures*

TEIAS's gross demand projections for 2030 (TWh)			Demand projections in the study for 2030 (TWh)			
Low	Normal	High	BAU Base	BAU (Low-demand sensitivities)	ARES (Base & sensitivities)	CPD (Base & sensitivities)
360	396	454	460 (Close to TEIAS high scenario)	360 (Same as TEIAS low scenario)	420 (More efficiency wrt. BAU Base	

Electrification includes charging loads from electric vehicles (EV). It is assumed that 1 million cars out of 19 million in total will be EV in the 2030 BAU Base scenario. This corresponds to almost 5% of the car fleet. Referring to the charging load profiles of EV cars in the recent Shura report,[21] the annual electricity demand of EV cars in 2030 is assumed to be 2 TWh according to the BAU Base. The aggregated charging profile of EVs in a typical day is illustrated in Figure 14 for the BAU Base scenario. Smart charging is assumed to some extent along with charging at home during night hours (alternating current-type slow-charging). However, it is assumed that the majority of the EV charging load will be incurred during the daytime (direct current-type fast-charging). The total number of EV cars is assumed to be 2.5 million in the ARES and CPD scenarios (i.e., 2.5*2=5 TWh). Assuming additional 5-TWh increase in load due to electrification in other sectors, the total electrification load in ARES and CPD is 3 (EV) + 5 (other sectors) = 8 TWh more than that of the BAU Base scenario. Despite this increase, total demand in ARES is 40 TWh less than that of BAU due to energy efficiency improvements.

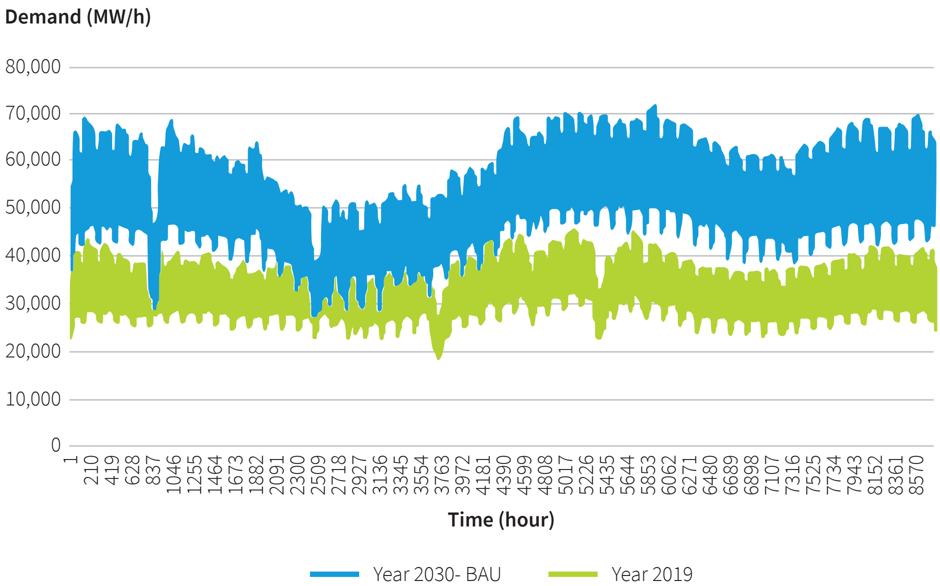
[18] TEIAS 10-year demand projection report (2021-2030) (https://webapi.teias.gov.tr/file/538d66ee-4d9e-4711-a29c-1e31dae54e8f?download)
[19] Shura Energy Transition Center. Optimum electricity generation capacity mix for Turkey towards 2030. July 2020 (https://www.shura.org.tr/wp-content/uploads/2020/09/ExecutiveSum.pdf)
[20] Shura Energy Transition Center. The Most Economic Solution for Turkey's Power System: Energy Efficiency and Business Models. Oct. 2020 (https://www.shura.org.tr/wp-content/uploads/2020/10/SHURA_Exum.pdf)
[21] Shura Transition Center, "Transport sector transformation: Integrating electric vehicles into Turkey's distribution grids," 2019 (https://www.shura.org.tr/transport_sector_transformationintegrating_electric_vehicles_into_ turkeys_distribution_ grids/)

Figure 14: *Aggregated charging profile of EVs in a typical day (2030-BAU)*



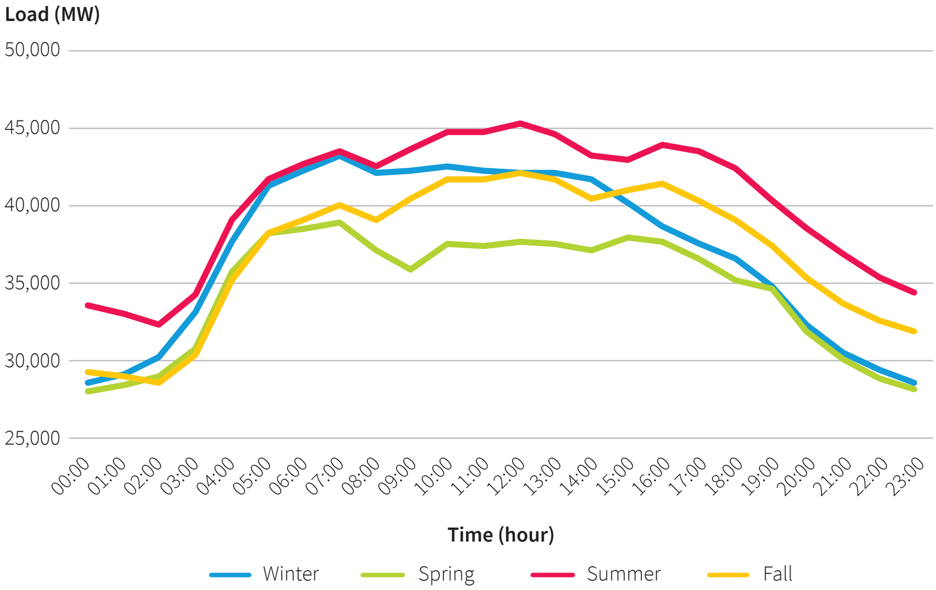
Total system demand in 2030 is profiled in hourly resolution to perform market and network simulations. For this, the hourly based annual demand profile in 2019[22] is scaled to 2030 considering the annual ten-day shift in religious holidays in Turkey as illustrated in Figure 15. Daily demand curves in typical seasonal days are presented in Figure 16 at a higher resolution. Daily load profiles show that there is a significant load ramp-up and down (more than 5 GW/hour) during both morning and night hours.

Figure 15: *Demand profiles in hourly resolution (2019 vs 2030-BAU Base)*



[22] Due to the Covid-19, the load profile in 2020 was not taken as a reference.

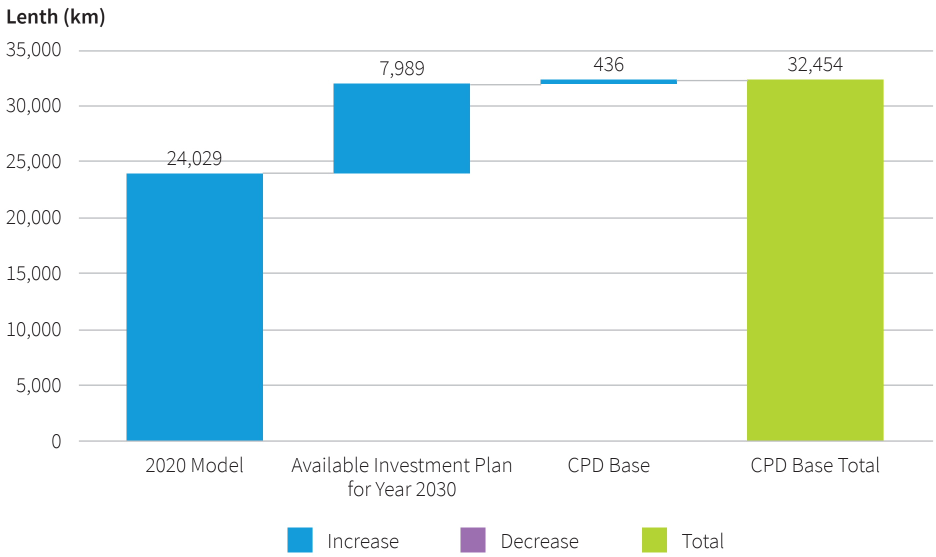
Figure 16: *Typical daily load curves in each season (2019)*



4.2. Transmission grid

Turkey's 400-kV grid investment plans, which are outlined in the recent grid map of Turkey, will add 7,989 km of new transmission lines in total and are assumed to be completed by 2030 (Figure 17). This corresponds to the addition of almost 800 km of new transmission lines per year on average between 2020 and 2030. In the previous SHURA study[23], the assumption in the base scenario was also around 800 km/year of new lines on average. Between 2017 and 2019 around 750 km of transmission lines were added annually.[24] While 800 km/year of new lines for a 400-kV grid is a significant target, it is comparable with TEIAS's recent implementations.

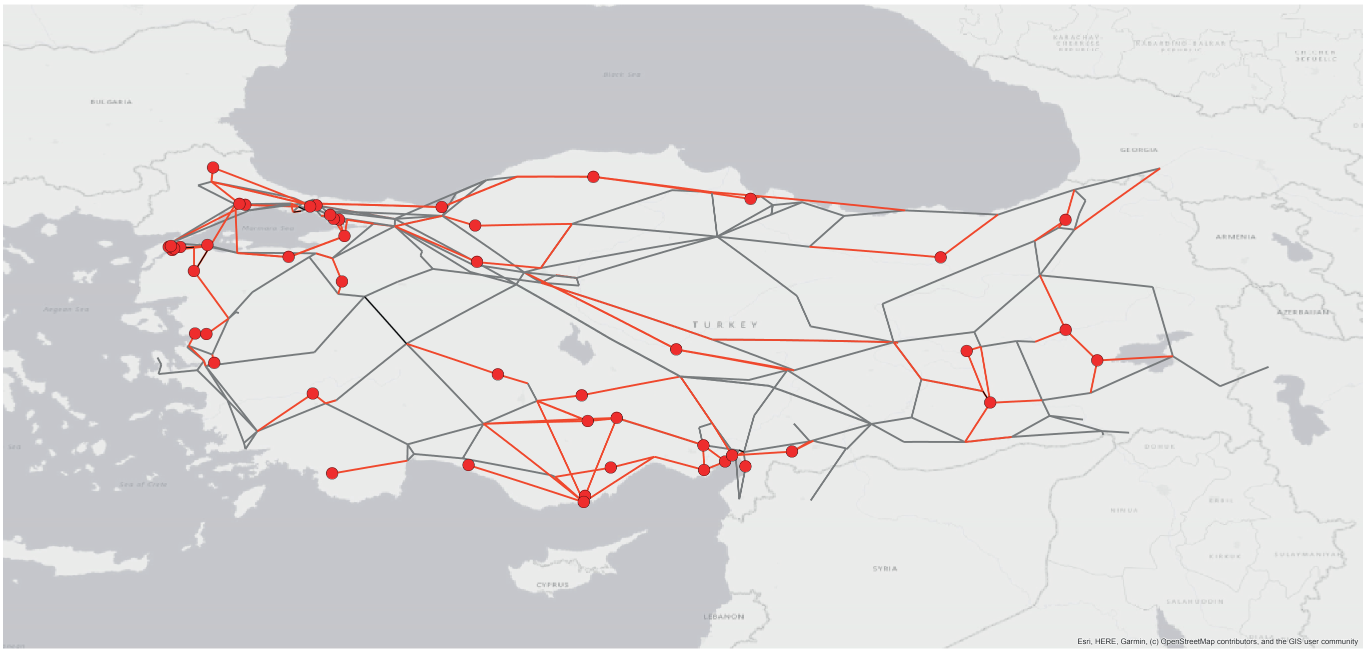
Figure 17: *400-kV transmission lines, the current investment plan*



[23] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)
[24] TEAS Activity Report 2020, 2019, and 2018 (https://www.teias.gov.tr/tr-TR/faaliyet-raporlari)

The 400-kV transmission grid model, which includes 7,989 km of transmission line investments along with 49 new 400-kV substations is considered as the “base grid model” in all scenarios and sensitivities (Figure 18). Additional transmission line reinforcements, which are quantified in network simulations as described in the Methodology Section above, complement the whole grid model in each scenario.

Figure 18: *Map of current (grey lines) and planned (red lines and dots) 400-kV transmission grid as per the updated ten year (2021-2030) prospective network development plan*



It is worth highlighting that there is a considerable investment in the 400-kV grid even for a lower base demand projection (360 TWh, Table 2). This facilitates the integration of new generation and demand as will be seen in the network simulation results, including the required redispatch and RES generation curtailment.

The current investment plans for the 154 kV grid have been made only for the next five years (in contrast to ten years for 400-kV grid projections) given the fact that grid investment requirements at the 154-kV level are mainly driven by demand. Therefore, There is no a 154-kV grid investment plan for 2030 like the 400-kV grid depicted in Figure 18. Hence, the 154-kV grid investment requirements are addressed using a different approach in the study. New 154-kV substations, which will be constructed between 2020 and 2030, are assumed to be connected to the current 154-kV grid based on N-1 contingency criteria. To address the investment requirements to reinforce the current 154-kV backbone grid as new substations and demand increase at the current substations, it is assumed that the load increase is scaled to the current 154-kV requirement in substations. Given such an approach, investments in the 154-kV grid identified in the study do not include new 154-kV transmission substations and their connections to the grid but rather reinforcement requirements for the current 154-kV backbone grid. Therefore, the amount of grid investment requirements identified in the study for the 154-kV grid (i.e., 84.7 km/year in average between 2020 and 2030 in BAU scenario) is less than TEIAS’s annual investment figures (i.e., 375 km in 2020).

4.3. Power generation technologies

This section presents the key assumptions made in the modelling of power generation technologies.

4.3.1. Locations of new power plants

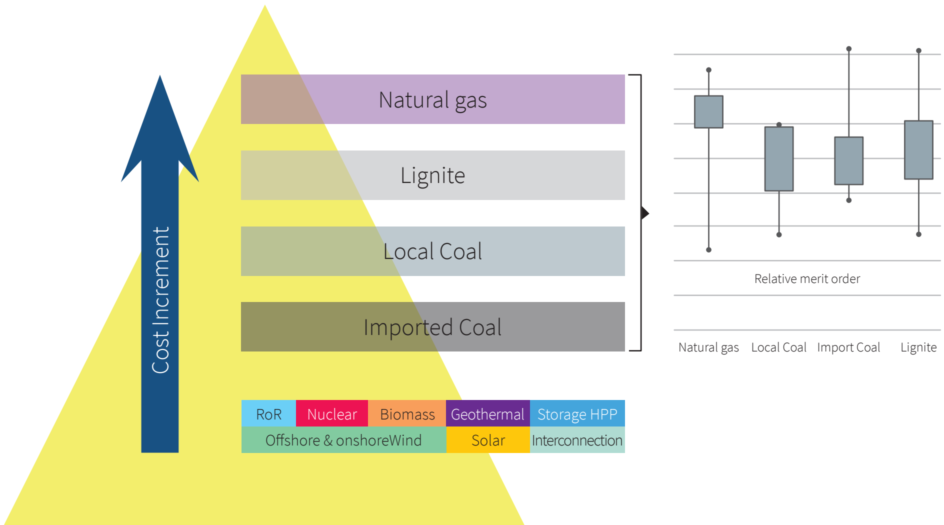
Like the approach in the previous SHURA study[25], system-driven approach was considered when identifying the locations of RES (solar, wind, and biomass) power plants. That is, priority was given to major load centers that have strong connections to the grid. Resource availability was taken into account when determining the locations of new geothermal and hydro power plants.

4.3.2. Merit order

The merit order assumption in the conducted study is depicted in Figure 19. In the assumed merit order, the near-zero short-run marginal cost (SRMC) of generation technologies—e.g., wind, solar, hydro, biomass, and geothermal—are placed at the bottom of the merit order. Here, a nuclear power plant is also considered at the bottom level due to long-term purchase guarantee contracts (70% and 30% generation of the first two and last two units, respectively). For conventional power plants—i.e., imported coal, local coal, lignite, and natural gas—the order from cheapest to most expensive is as follows: imported coal, local coal, lignite, and gas technologies. This order is assumed based on the average efficiencies and fuel costs. However, there is overlap among the merit blocs due to the variation in age and efficiency of different power plants. Such overlaps make it necessary to adjust the merits in order to better represent the Turkish electricity market. To do so, the annual generation breakdown realized in the years of 2019 and 2020 were used to verify the merit order identified in the modelling for different technologies. The results of the simulation are compared with actual generation in the years 2019 and 2020. Based on the difference between the calculated and realized generation values, the merit order assumptions are revised iteratively. Once the proper merit configuration—i.e., which satisfies the tolerable error between the calculated and realized dispatch values—is achieved, this merit order is used for the 2030 scenarios. The final relative merit order of conventional power plants that represents the Turkish electricity market is depicted on the right-hand side of Figure 19.

[25] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)

Figure 19: Merit order assumption in the study



4.3.3. Operational constraints

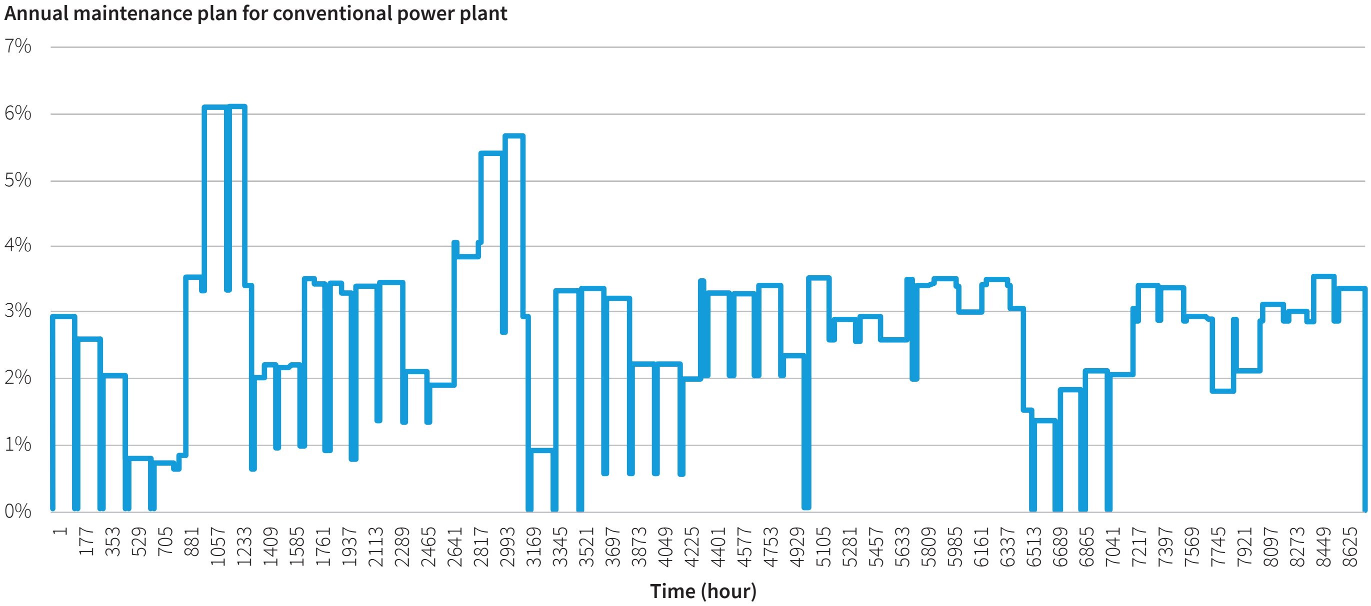
The approaches to modelling the operational constraints of power plants are described below:

- **Energy constraints of storage-type hydropower plants (HPP):** The generation of storage-type HPP is constrained by different factors other than the power system. These include operation constraints related to flood control; residential, agricultural, and industrial water supply needs; transport shipping; and environmental requirements. These are generally referred to as long-term energy constraints on storage-type HPPs. The purpose of long-term planning of cascaded hydro energy and water resource systems is to optimize water discharge and the storage and spillage of reservoirs at every stage. In this study, weekly energy constraints, which are modelled based on historical figures from power plants, are considered for storage-type HPPs. The details of modelling weekly energy constraints of HPPs can be found in the previous SHURA study.[26]
- **Run-of-River (RoR) type HPPs:** RoR HPPs are modelled as negative load and their associated generation profile is calculated based on historical data which is taken from EPIAS[27].
- **Ramping capability of nuclear power plant (NPP) units:** The installed capacity of each unit at Akkuyu NPP is 1,200 MW, with a minimum operational level of 600 MW. In the study, 100 MW/hour ramping capability is assumed for each unit.[28] That is, nuclear units can reduce their output power from their maximum level (1,200 MW) to their relative minimum level (600 MW) within six hours (and vice versa). Such flexibility from NPP is modelled in both market and network simulations.
- **Maintenance scheduling of power plants:** The maintenance plan depicted in Figure 20 is considered for conventional power plants. The main reason for having a maintenance plan is to simulate the real-world conditions of operating hours for conventional power plants. As can be seen from Figure 20, the maintenance of conventional power plants is distributed throughout the year. However, during two time periods, the number of conventional power plants that are out of service

[26] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)
[27] EPİAŞ report: https://seffaflik.epias.com.tr/transparency/
[28] Ramp up/down rate of nuclear units are taken from the Nuclear Regulatory Authority of Turkey.

is increased. These two one-week time periods represent the periods of religious holidays in Turkey, when a considerable number of conventional power plants, particularly NPP, can perform their scheduled maintenance plans, since demand (particularly from industrial and commercial activities) is at an annual minimum during these periods.

Figure 20: *Annual maintenance plan for conventional power plants*



- **Minimum on/off time and ramp up/down constraints of power plants:** Table 3 presents assumptions made for the minimum on/off time and ramp up/down constraints of conventional power plants. The constraints in the previous SHURA's study are considered in this study as well.

Table 3: *Assumptions for minimum on/off time and ramp up/down constraints*

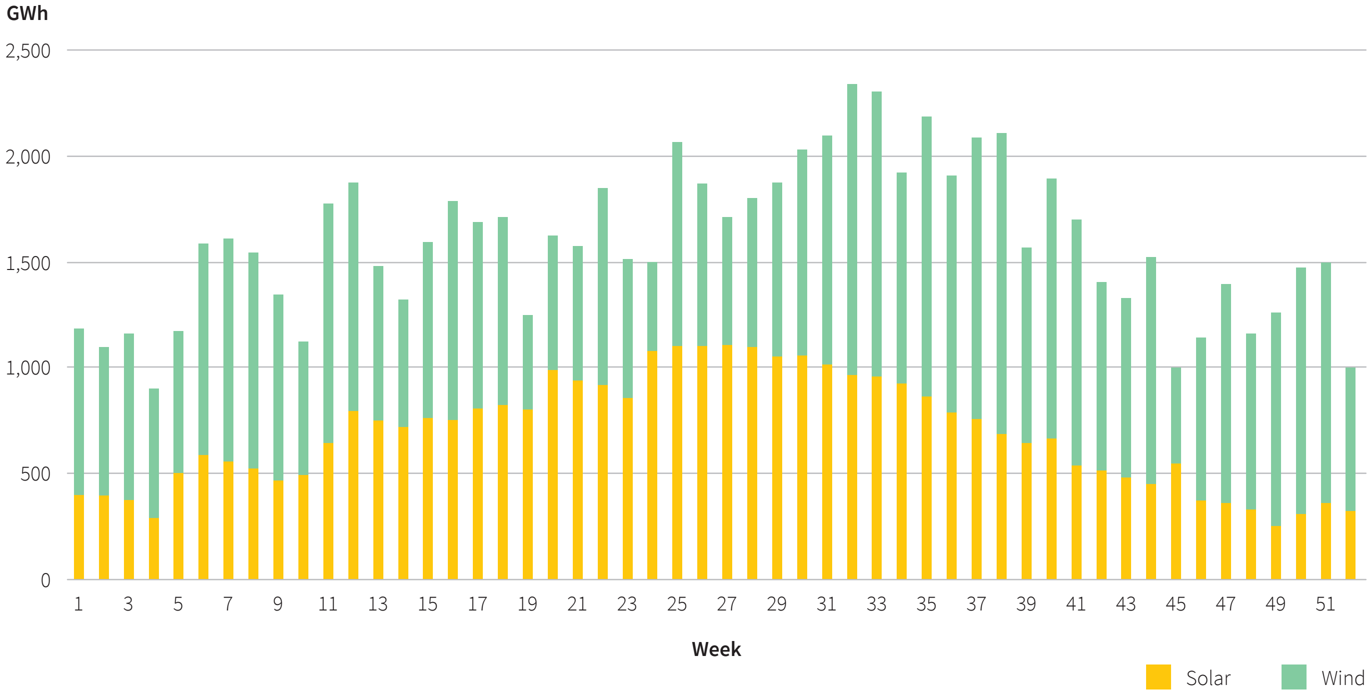
Generation Technology	Pmin ranges (%)	Minimum on/off time (hour)	In service ramp up/down (% per hour)
Gas	0%	1	100%
Coal	20%–40%	3	100%
Lignite	50%–70%	6	100%
Nuclear	50%	8	8.3%
Geothermal	0%–40%	1	100%
Biomass	0%–60%	1	100%
Hydro (Storage)	50%	1	100%

4.3.4. RES generation profiles

The RES generation profiles taken from the previous SHURA grid study (Section 3.5)[29] are considered in this study. Here, the system-driven approach for distributing RES is considered. As discussed previously, although the resource-driven distribution of RES generation results in a higher share of RES generation, it imposes extra stress on the grid. Therefore, a system-driven approach is more rational from a grid operation standpoint. The implementation of the YEKA mechanism in Turkey supports the system-driven approach.

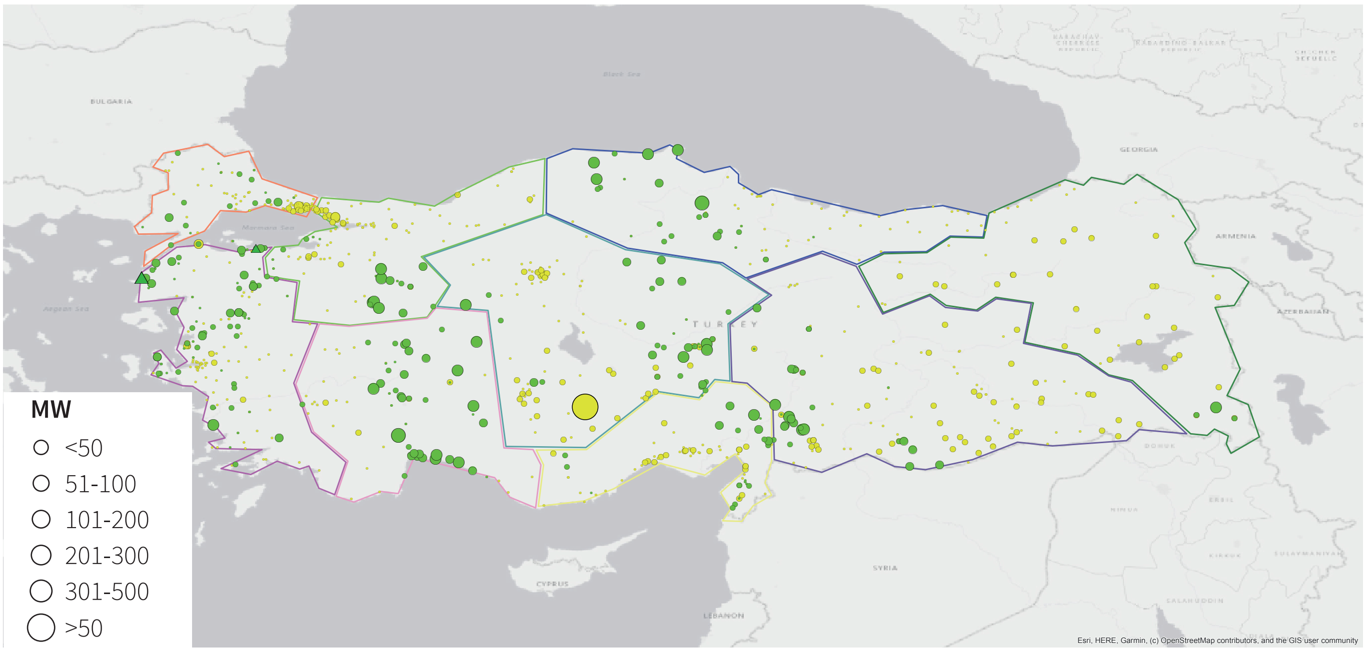
Offshore wind power plants are considered in the More RES and Less Gas PP sensitivities of the BAU scenario and in all bases and sensitivities of the ARES and CPD scenarios. Offshore wind power plants with a capacity of 1,152 GW are assumed to be placed in the Aegean Sea and have a higher capacity factor if compared to land-type wind power plants.[30] The aggregated energy generation profiles of wind and solar power plants are illustrated in Figure 21 (BAU Base scenario) in weekly resolution. The geographical distribution of solar and wind power plants are depicted in Figure 22 (ARES Base scenario).

Figure 21: *Aggregated generation profiles of wind & solar plants (weekly resolution) (BAU Base scenario)*



[29] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)
[30] Cali, Umit, Nuh Erdogan, Sadik Kucuksari, and Mehmet Argin. "Techno-economic analysis of high potential offshore wind farm locations in Turkey." Energy strategy reviews 22 (2018): 325-336.

Figure 22: *Geographical distribution of solar and wind power plants (yellow circle: solar; green circle: onshore wind; green triangle: offshore wind) (ARES Base)*

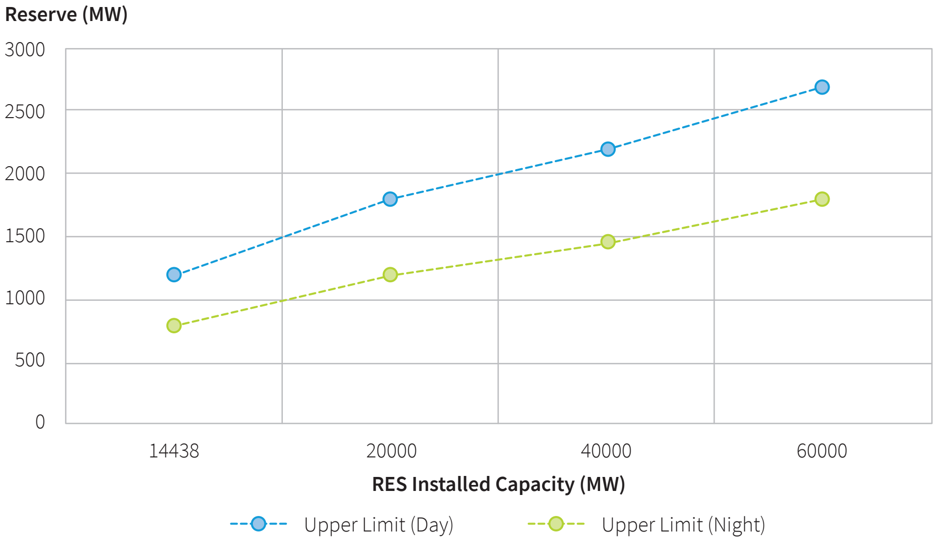


4.4. Spinning reserve requirement

By maintaining the spinning reserve capacity, the power system can maintain secure operations in case of deviation from day-ahead planning or in case of contingencies (e.g., power plant tripping). It is assumed that the spinning reserve requirement of the grid increases along with the amount of installed RES capacity. The spinning reserve requirement with respect to RES installed capacity is acquired from the previous SHURA grid study[31] as illustrated in Figure 23. The minimum and maximum amount of spinning reserve was 800 MW and 1,200 MW, respectively, in 2020. The minimum and maximum are assumed to increase to 1,800 MW and 2,700 MW, respectively, when the total installed capacity of wind and solar power plants is 60 GW in the 2030 ARES scenario.

[31] SHURA Energy Transition Center. Increasing the Share of Renewables in Turkey's Power System. May 2018 (https://www.shura.org.tr/increasing-the-share-of-renewables-in-turkeys-power-system/)

Figure 23: Spinning reserve requirement along with the installed RES capacity



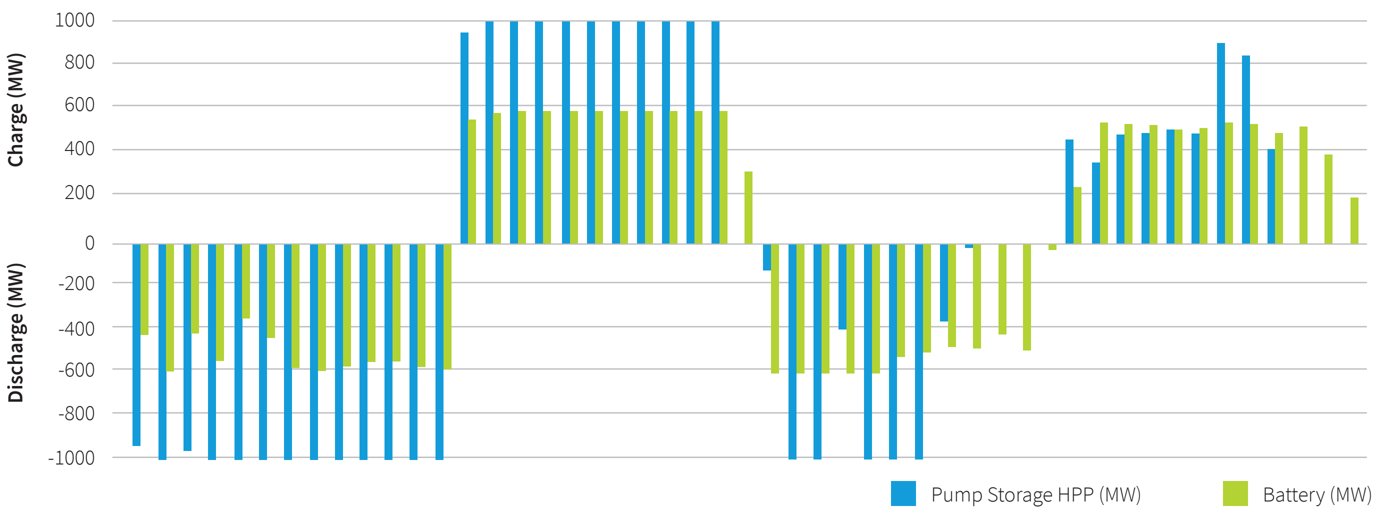
4.5. Flexibility options

The modelling of grid flexibility solutions is described in this section. The flexibility solutions addressed in this study are; energy storage systems (pumped-hydro and battery), wind and solar (1 GW Karapınar SPP) power plants providing a certain level of spinning reserves, peak shaving as a demand-side response, and grid flexibility gained through interconnections via market coupling.

4.5.1. Storage systems

The storage systems considered in the study are a 1-GW peak capacity pump-hydro power plant at Gokcekaya HPP and a total Li-ion battery capacity of 600-MW peak that is distributed to 154-kV substations (priority is given to substations that have relatively larger demand). The charging/discharging profiles of storage devices are determined by market and network simulations. An example of a typical 48-hour period is illustrated in Figure 24. In this example, storage systems charge (i.e., load) during nighttime while discharging (i.e., generation) occurs during the daytime in order to support the load generation balance under the high solar generation scenario.

Figure 24: *Charge/discharge pattern of storage units (1 GW pump storage & 600 MW battery)*[32]

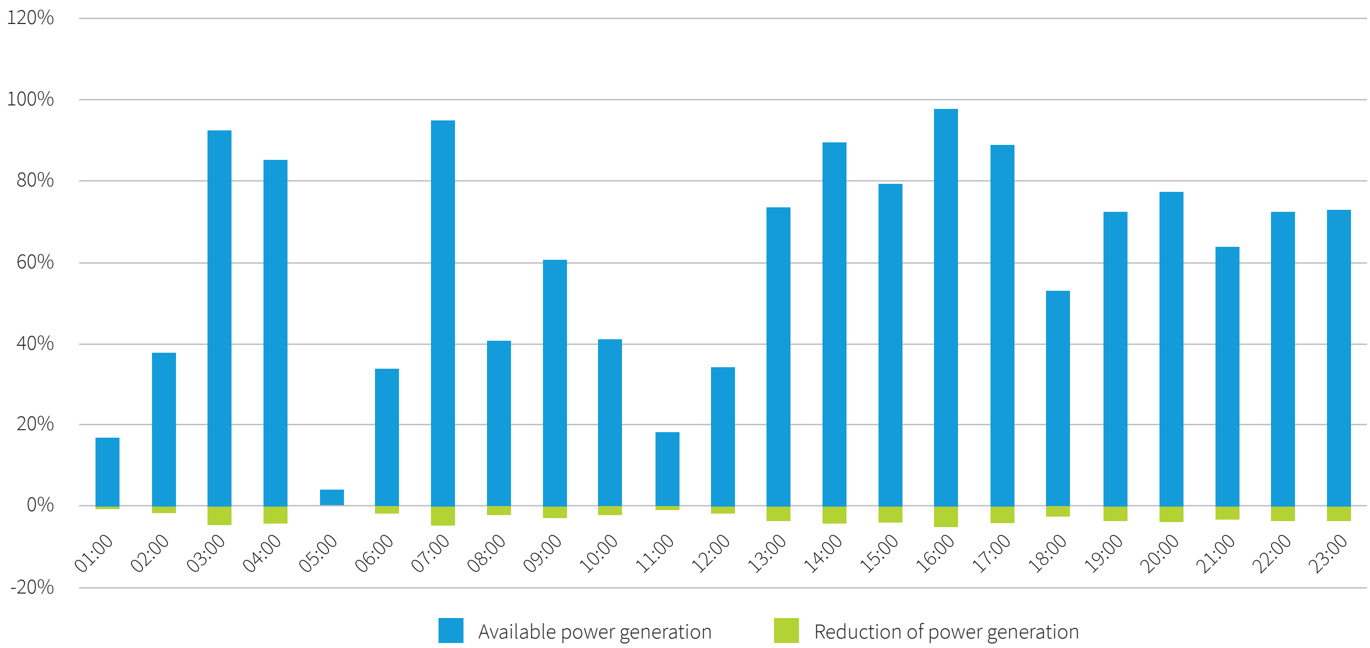


[32] This charging/discharging profile corresponds to ARES "More Flexibility," "Demand Response," and "More Flexibility on NTC" sensitivity and all CPD scenarios/sensitivities.

4.5.2. Spinning reserve provision from RES

In some sensitivity analyses (e.g., ARES – More Flexibility), it is assumed that wind power plants with a capacity of 50 MW or larger as well as the 1-GW capacity utility scale solar power plant in YEKA region provide spinning reserves. The amount of spinning reserves that can be provided at any hour is assumed to be 5% of available generation at that hour. This is modelled by assuming a 5% generation reduction at each hour as illustrated in Figure 25. The figure also shows the intermittency of wind generation, where the generation can fluctuate impressively within an hour (see 4:00, 5:00, and 6:00 in Figure 25).

Figure 25: *Modelling of spinning reserve provision from a typical wind plant (ARES More Flexibility)*



4.5.3. Peak shaving

Peak shaving, which is shifting the load from peak loading hours to off-peak loading hours, is one measure of flexibility in response to demand in the Demand Response and More Flexibility sensitivities of the ARES scenario (as well as in the CPD Base scenario and pathways). It is assumed that the peak load in any day can be reduced up to 5% at the peak loading hour[33]. This reduction can be made during the peak hour ± 2 hours. The total decrease in energy consumption during these hours is assumed to be shifted to off-peak hours at night. Modelling of peak shaving for a typical winter day is illustrated in Figure 26. Although peak load reduction is 5%, the total amount of shifted energy throughout the entire year is around 0.6% (i.e., 2.52 TWh of 420 TWh in ARES and CPD) if peak shaving occurs every day throughout the year.

[33] Shura Energy Transition Center, "Sector coupling for grid integration of wind and solar," May 2021 (https://www.shura.org.tr/sector_coupling_for_grid_integration_of_wind_and_solar/)

Figure 26: Demand shifting on a typical winter day (2030 ARES)

The main benefit from peak shaving is the reduction of generation from marginal power plants during peak loading hours, as shown in Figure 27. Note that the peak shaving policy for demand response reduces the peak and decreases the need for dispatching energy to power plants at the top of the merit order. However, this may not change (or even increase) the demand ramp at certain hours, which may lead to RES curtailment. Such an effect is observed in this study and is discussed in the Results Section.

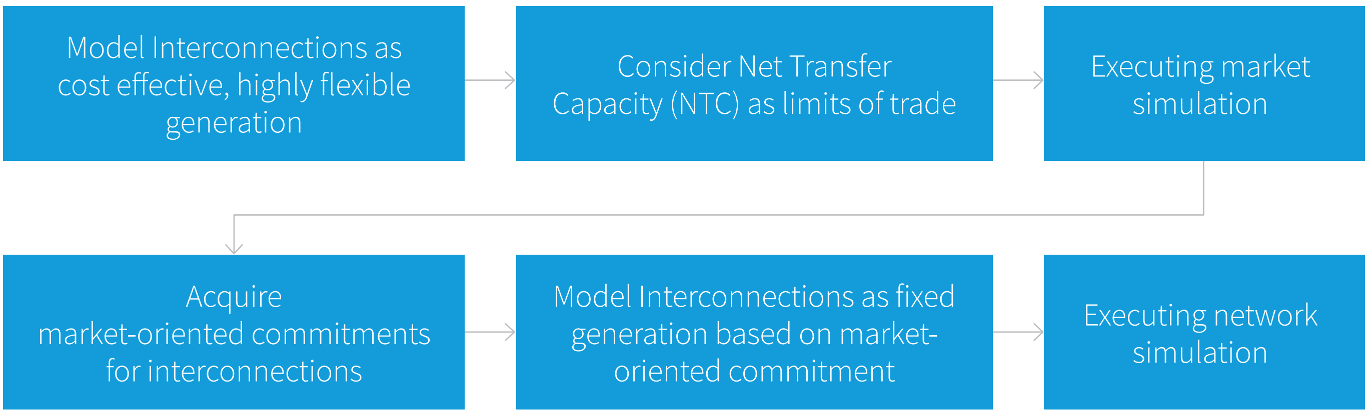
Figure 27: Effect of peak shaving on energy dispatch to gas power plants (typical winter day, ARES)

4.5.4. Flexibility from interconnections

The Turkish grid has a synchronous interconnection with the European Network of Transmission System Operators for Electricity (ENTSO-E) grid and High Voltage Direct Current Back-to-Back (HVDC B2B) interconnection with the Georgian grid. Its net transfer capacity (NTC) is 700 MW (max).[34] A HVDC B2B interconnection project with the Iranian grid is ongoing. Currently, trading on the interconnections is based on the allocation of NTCs to traders through a capacity auction mechanism.[35] Scheduled power transactions are controlled through TEIAS's automatic generation control (AGC) system. Since there is not any market coupling with spot markets in neighboring countries yet, the flexibility of interconnection lines is limited.

It is assumed in the study that the flexibility provided by interconnections will be maximized through the proper market mechanisms including market coupling and imbalance netting. The approach to modelling flexibility from interconnections is illustrated in Figure 28. At each point of interconnection, there is a near-zero SRMC and highly flexible generator with ratings of two times that of predefined NTC. In addition, a load equal to predefined NTC is considered at the interconnection point. Therefore, power transfer up to NTC can be acquired from the interconnection lines when the generation of the afore-mentioned power plant is at its maximum level. The amount and direction of the energy to be transferred has been determined by market and grid simulations. The trade amounts determined on an hourly basis in the market simulation are considered constant in the network simulation.

Figure 28: *Approach to modelling flexibility based on interconnections*

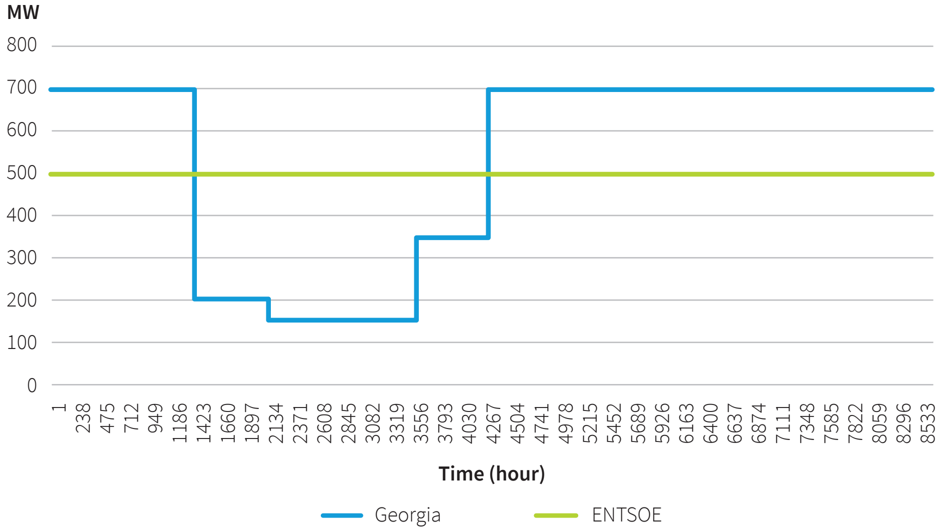


Once the limits for NTC are identified, a market simulation is executed in order to attain hourly dispatch. The cleared commitments in the market simulation are fixed in the network simulation. In other words, the generators at the interconnection points will have fixed generation amounts during the network simulations, which are previously determined by the market simulation.

[34] NTC of interconnection with Georgia depends on the season and the minimum in spring and the initial period of summer due to hydro-based generation in both countries in the region.
[35] TEIAS report: https://tcat.teias.gov.tr/

Seasonal variation of NTCs on interconnection lines with Georgia are considered to be consistent with TEIAS's current approach. Given transmission grid constraints, NTC in imported direction reduces in spring and early summer periods due to high generation from hydropower plants in the Northeast region of Turkey. The maximum available NTCs in the BAU scenario are presented in Figure 29. These figures correspond to current NTC levels in 2020.

Figure 29: *Maximum available NTCs in BAU scenario*



4.6. Cost-Benefit Analysis (CBA)

Cost-benefit analyses (CBA) are made to compare the value of flexibility solutions and the grid investment requirements addressed in the scenarios. The average costs (in terms of EUR/MWh) of the following items are calculated as follows:

- **Average MCP:** The annual average of the MCPs over the entire year of 2030 is one of the indicators used in the CBA. It should be noted that the hourly MCPs are determined considering a merit-order assumption (see Section 3 above for details).
- **Average fixed and variable operation & maintenance (O&M) and investment costs:**
    - Transmission grid investments
    - Battery storage investments
    - Pumped storage investments
    - Peak shaving mechanism (including required infrastructure to implement the mechanism)

Investment and O&M costs of the transmission grid, battery storage, and pumped storage are taken from the previous SHURA study[36] (Table 4). The cost of peak shaving includes infrastructure and O&M costs for implementation. The assumptions used in the cost calculations of peak shaving are summarized in Table 5.

[36] Shura Energy Transition Center, "Sector coupling for grid integration of wind and solar," May 2021 (https://www.shura.org.tr/sector_coupling_for_grid_integration_of_wind_and_solar/)

Table 4: *Investment and O&M cost figures*

Item	Cost Assumptions
400-kV transmission grid	260,000 EUR/km investment cost O&M cost: 33% of investment cost
154-kV transmission grid	173,000 EUR/km investment cost O&M cost: 33% of investment cost
400-kV substation with two power transformers	4 million EUR/substation including O&M cost
Pump storage (1 GW-peak capa-city)	83,000 EUR/MW per year including O&M cost (over lifetime)
Li-ion Battery (600 MW distributed to the grid)	104,000 EUR/MW including O&M cost (over lifetime)

Table 5: *Assumptions for calculating cost of infrastructure required for peak shaving mechanism*

Sector	Shaved GWh/year in 2030	%	Average Cost (EUR/MWh)
Commercial heating	842	33%	53.89
Residential heating	1,015	40%	70.53
Work EV	221	9%	72.46
Home EV	442	18%	79.40
Total	**2,520**	**100%**	**Average: 66.69**

- **Average redispatch and RES curtailment cost:** Redispatch costs are determined by multiplying hourly MCP values with the redispatch amount at the corresponding hour throughout the year. Similarly, the RES curtailment cost is calculated by multiplying the hourly MCP by the RES curtailment amount for the entire year. Both redispatch and RES curtailment are the system operator's operational solutions to mitigate technical constraints in the grid including overloads and N-1 contingency criteria.
- **Average capacity mechanism cost:** Cost of payments to power plants, which have a low capacity (utilization) factor but critical for the grid in terms of providing flexibility (ramp up/down capability), to ensure their availability in the grid under low-capacity factors. Capacity payment mechanisms address the challenge of power plants with a low utilization factor due to their relatively higher position in the merit order (e.g., some gas power plants). These power plants face the risk of not recovering their overhead costs, particularly in wholesale markets with ceiling prices that avoid price peaks that would allow for sufficient payback. The higher the RES generation capacity in the system, the lower the utilization factor of fossil fuel-fired power plants.

- **Average carbon cost:** The average cost of CO_2 emissions from fossil fuel-based power plants is calculated by dividing the total cost of carbon emissions by the total generation including renewables in each scenario. The conversion factors presented in Table 6 are considered to determine the amount of CO_2 emissions generated by fossil fuel-based power plants. The carbon cost is assumed to be 25 EUR/ton CO_2. This is a very conservative assumption as the current carbon price is above 60 EUR/ton CO_2 in European countries.[37] It is aimed in the study to see the savings from carbon prices even at minimum carbon cost levels.

Table 6: *Coefficients to convert Mt CO_2 to TWh*[38]

	Other	Hard Coal	Imported Coal	Lignite	Natural Gas
Mt CO_2 / TWh	0.50	1.03	0.96	1.19	0.40

Benefits are quantified in terms of the impacts of the solutions on the average MCP and relative changes in the average costs of the solutions among different scenarios. For this purpose, annualized costs are divided by the total amount of generation in each scenario. Average MCP and the average cost of investments solutions in the BAU Base scenario are taken as the point of reference.

[37] Shura energy Transition Center. The external cost of fossil fuel use in power generation, heating, and road transport in Turkey. December 2020 (https://www.shura.org.tr/the-external-cost-of-fossil-fuel-use-in-power-generation-heating-and-road-transport-in-turkey/)

[38] Bora Kat, "Renewable energy transition in the Turkish power sector: A techno-economic analysis with a high-resolution power expansion model, TR-Power," Feb. 2021. https://globalchange.mit.edu/sites/default/files/MITJPSPGC_Rpt346.pdf

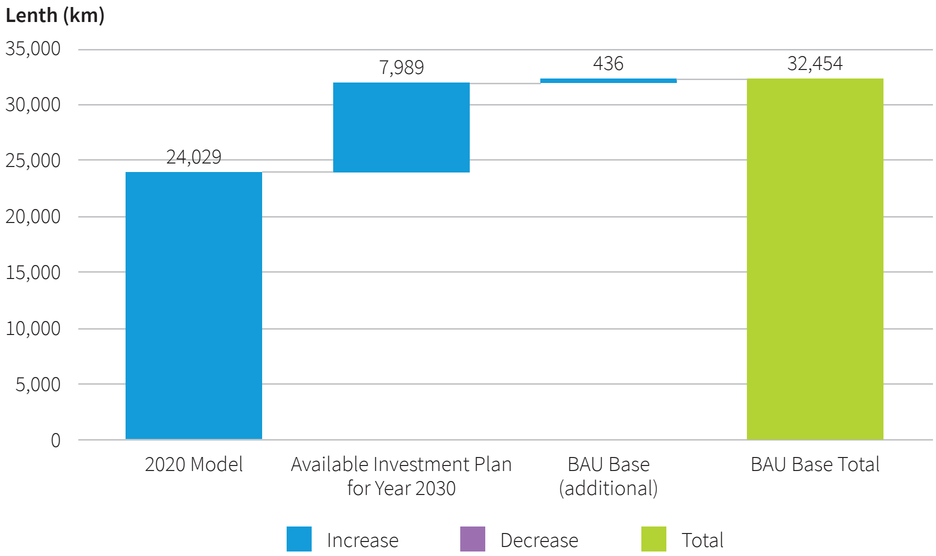
5. Results

The results of the study are presented in this section. The key parameters that are compared among the scenarios and sensitivities include transmission grid investments, annual generation breakdown by technology, power plant capacity factors, redispatch and RES curtailment amounts, and CBA results.

5.1. BAU scenario

The 400-kV grid investment requirements and the current investment plan are presented in Figure 30. One of the key observations is that Turkey has already made considerable investments toward the 400-kV grid, which has in turn resulted in a relatively small amount of additional investment requirements (e.g., 436 km in the BAU Base scenario).

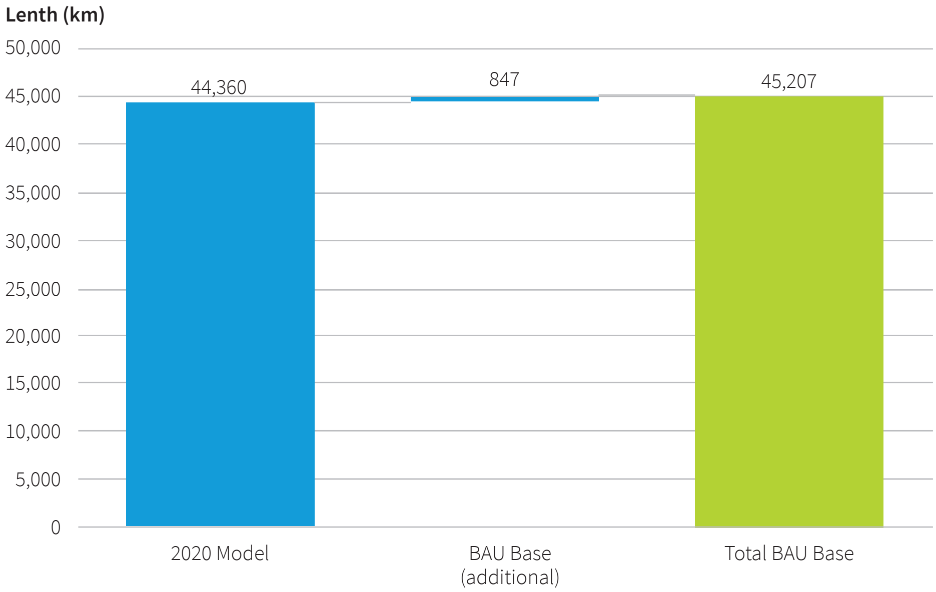
Figure 30: *400-kV grid investment figures (2020 vs BAU)*



The 154-kV grid investment requirements determined from the network simulations are presented in Figure 31. Note that the 154-kV grid investment requirements exclude connections from the new 154-kV substations, which will take place between 2020 and 2030, as their locations are unknown. However, those new 154-kV substations will essentially increase the burden on the current 154-kV backbone grid, which can be quantified by assuming that demand increase will occur at the current substations. Considering this approach, the 154-kV grid investment requirements in this study correspond to reinforcements on the current 154-kV backbone grid. Therefore, this amount may be less than TEIAS's annual investment figures for the 154-kV grid (375 km/year in 2020[39]).

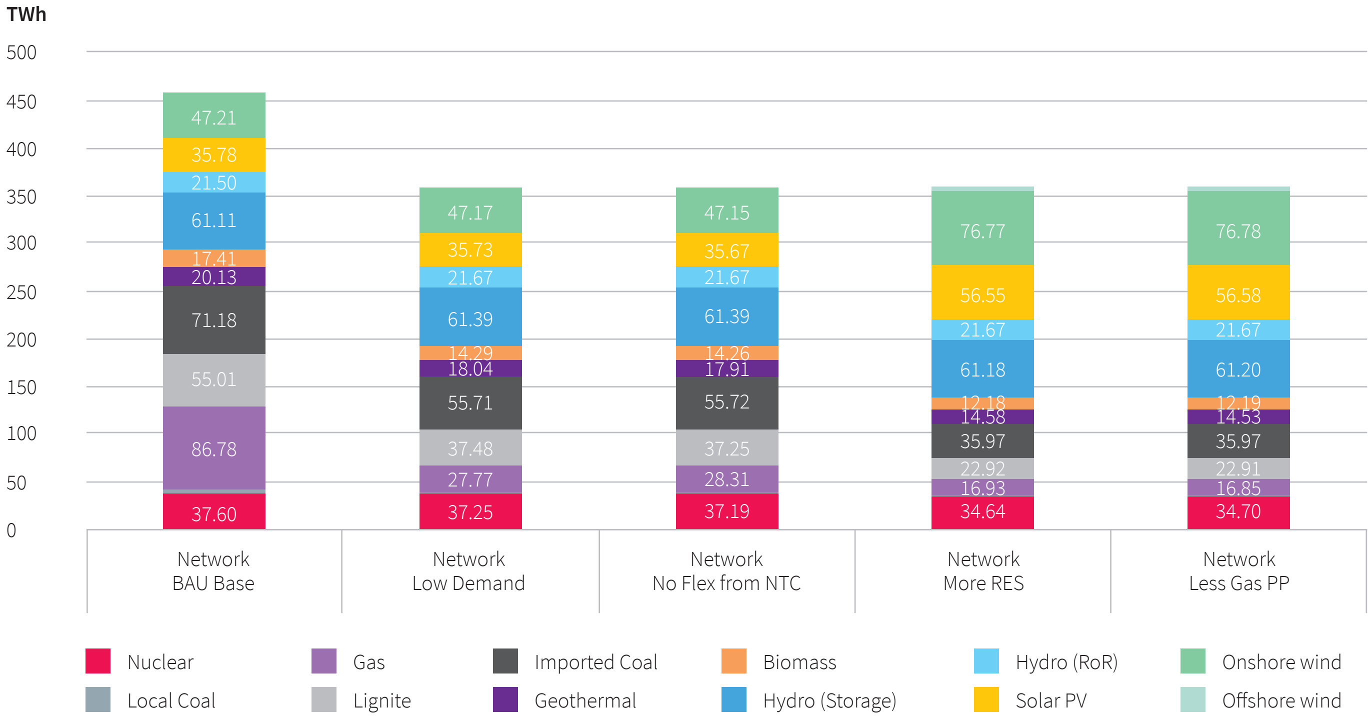
[39] TEİAS Activity Reports 2020, 2019, and 2018 (https://www.teias.gov.tr/tr-TR/faaliyet-raporlari)

Figure 31: *154-kV grid investment figures (2020 vs BAU Base)*[40]



The annual generation breakdown for the most critical sensitivities under the BAU scenario is presented in Figure 32. As depicted in the figure, from the BAU Base scenario to Low Demand sensitivity, a significant decrease is observed in gas, imported coal, and lignite technologies. The main reason is that demand is lower in BAU Low Demand sensitivity than that of the BAU Base scenario, where most of the demand is supplied by RES. Hence, the low share of generation is dedicated to conventional power plants in the Low Demand sensitivity. A major decrease is observed in the generation of gas power plants, which results in an average annual capacity factor reduction of 12% as depicted in Figure 33.

Figure 32: *Annual (2030) generation breakdown (BAU scenarios and sensitivities – Critical Changes)*



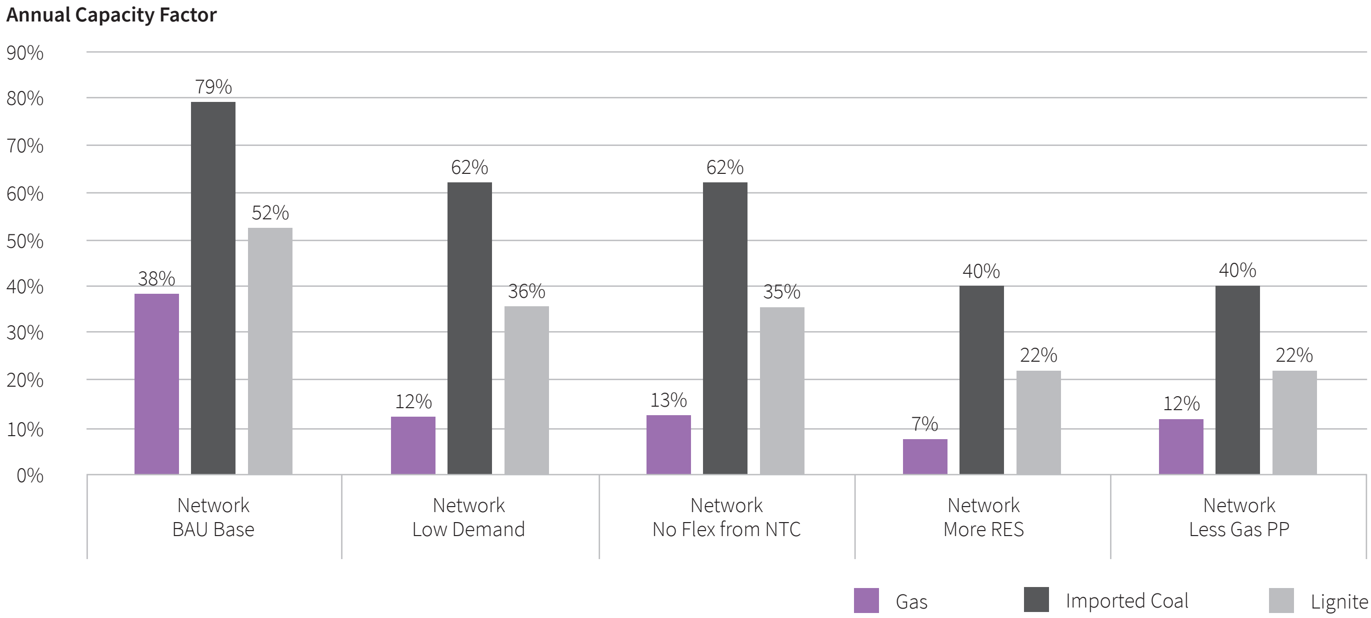
[40] The 154-kV grid investment requirements correspond to the reinforcement of the current 154-kV backbone grid and exclude connections of new 154-kV substations, which will take place between 2020 and 2030.

In the Low Demand sensitivity analysis, if there is no grid flexibility from interconnections (i.e., No Flex from NTC sensitivity), a slight increment in gas generation is observed (Figure 33), which is to compensate for the flexibility (i.e., grid aggregation, imbalance netting) need acquired via the interconnections in the Low Demand sensitivity.

Note that the annual average utilization factor of gas power plants was around 30% in the year 2020. The reason for the increment in the gas utilization factor in the year 2030 in the BAU scenario (38% as seen in Figure 33) is that the installed capacity of gas power plants is assumed to be slightly increasing (around 213 MW), while the demand is increasing considerably until 2030 (302 TWh in 2020 to 460 TWh in 2030).

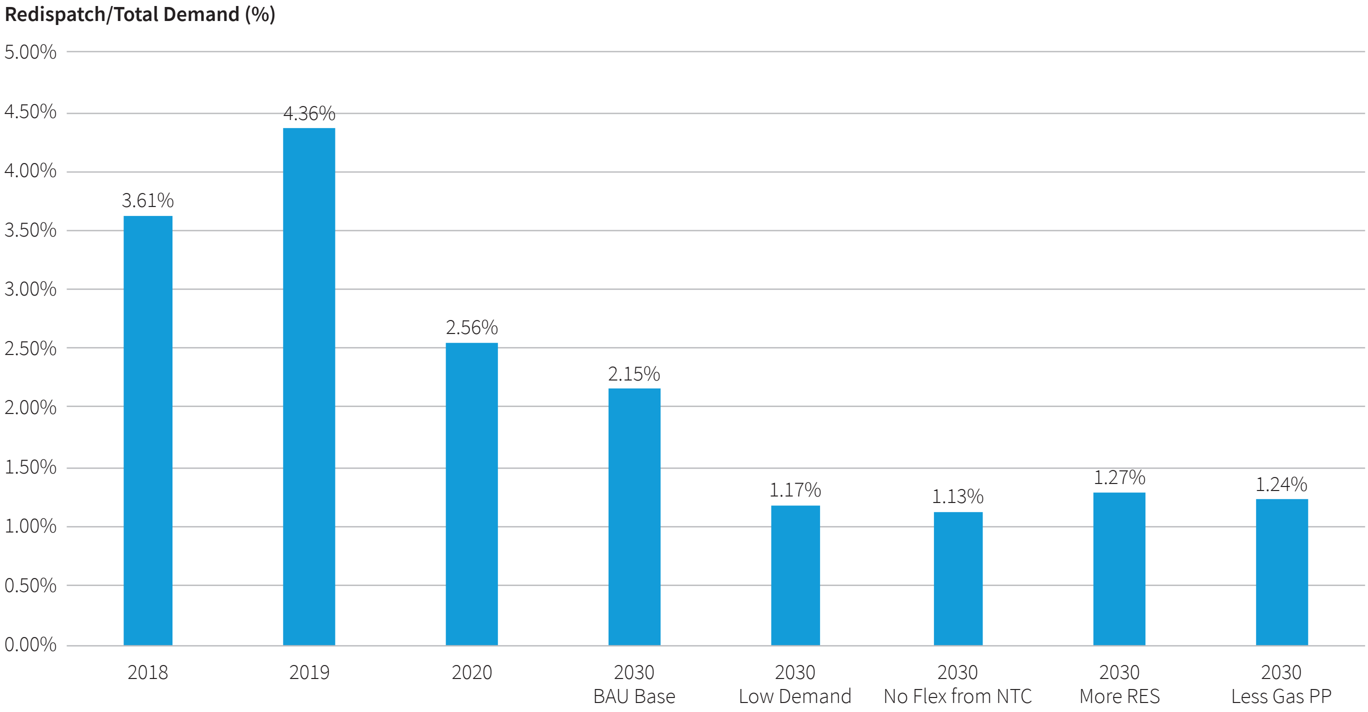
If the installed capacity of RES is increasing under low demand (i.e., More RES sensitivity), the generation and capacity factors of gas, imported coal, and lignite technologies are further reduced (Figure 33). In the More RES sensitivity, there are numerous gas power plants that are not committed either in the market or network simulations. Therefore, the installed capacity of gas technologies are reduced in the Less Gas PP sensitivity. Although generation breakdown has not changed as depicted in Figure 32, the average capacity factor of gas power plants increased from 7% to 12% (Figure 33). Nevertheless, the capacity factor of gas power plants decreases significantly in the Low Demand sensitivities.

Figure 33: *Annual (2030) capacity factors of conventional power plant technologies (BAU and sensitivities)*



The total amount of redispatch in the BAU Base scenario is around 10 TWh, which corresponds to 2.15% of total demand (460 TWh). This amount is reasonable if compared to TEIAS's recent redispatch order figures as depicted in Figure 34. This shows that the current grid investment plan provides significant benefit in terms of reducing redispatch amount in the BAU Base scenario and sensitivities.

Figure 34: *Annual redispatch figures*[41]



The RES curtailment amounts are presented in Figure 35. The RES curtailment amount in the Low Demand sensitivity is slightly larger compared to the BAU Base as depicted in the figure. The main reason for such a negligible increment even under low demand conditions is that RES generation is prioritized in load centers in this study (i.e., system-driven approach). However, if the installed capacity of RES is increased (i.e., More RES sensitivity), the RES curtailment amount is increased further under low demand conditions (More RES sensitivity in Figure 35). Despite the system-driven approach, in some hours there is no solution but curtailing the RES generation. Such an example is illustrated in Figure 36. As can be seen from the figure, the RES curtailment amount increases according to the decrease in the residual load (demand minus generation from RES). Here, residual load is the remaining part of the load that should be served by conventional power plants (gas, coal, lignite, storage-type HPP, and nuclear). RES curtailment in Figure 36 occurs on a typical spring day, i.e., off-peak period. The total amount of RES curtailment in the More RES sensitivity is 5.58 TWh (almost 4% of RES generation). Note that power transfer on the interconnection lines is in the export direction to minimize RES curtailment.

[41] EPIAS: https://seffaflik.epias.com.tr/transparency/

Figure 35: *Annual RES curtailment amounts (BAU Base and Sensitivities)*

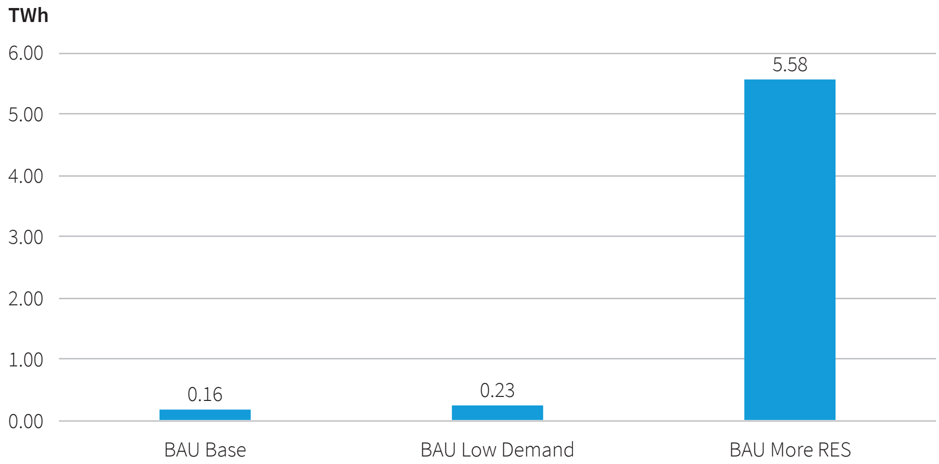
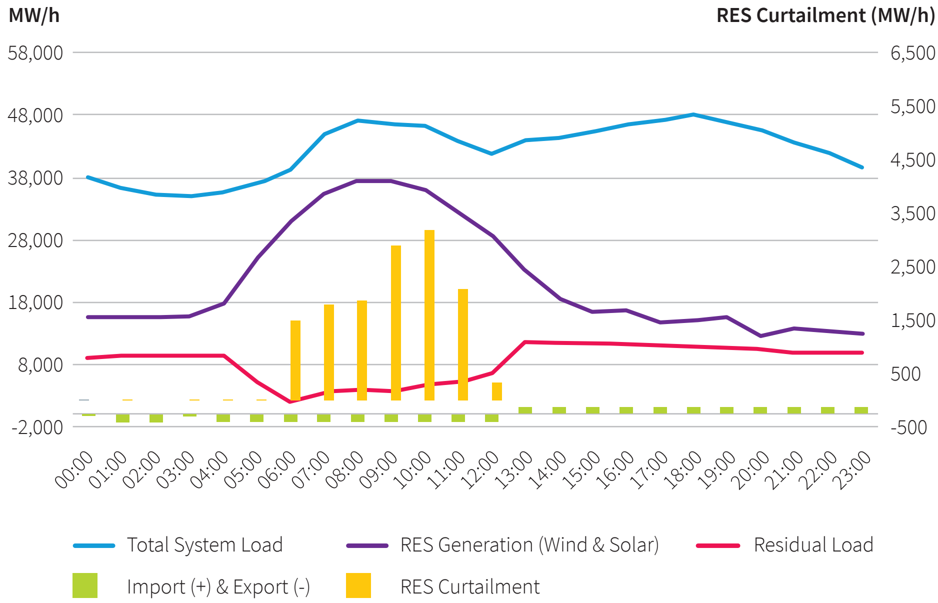
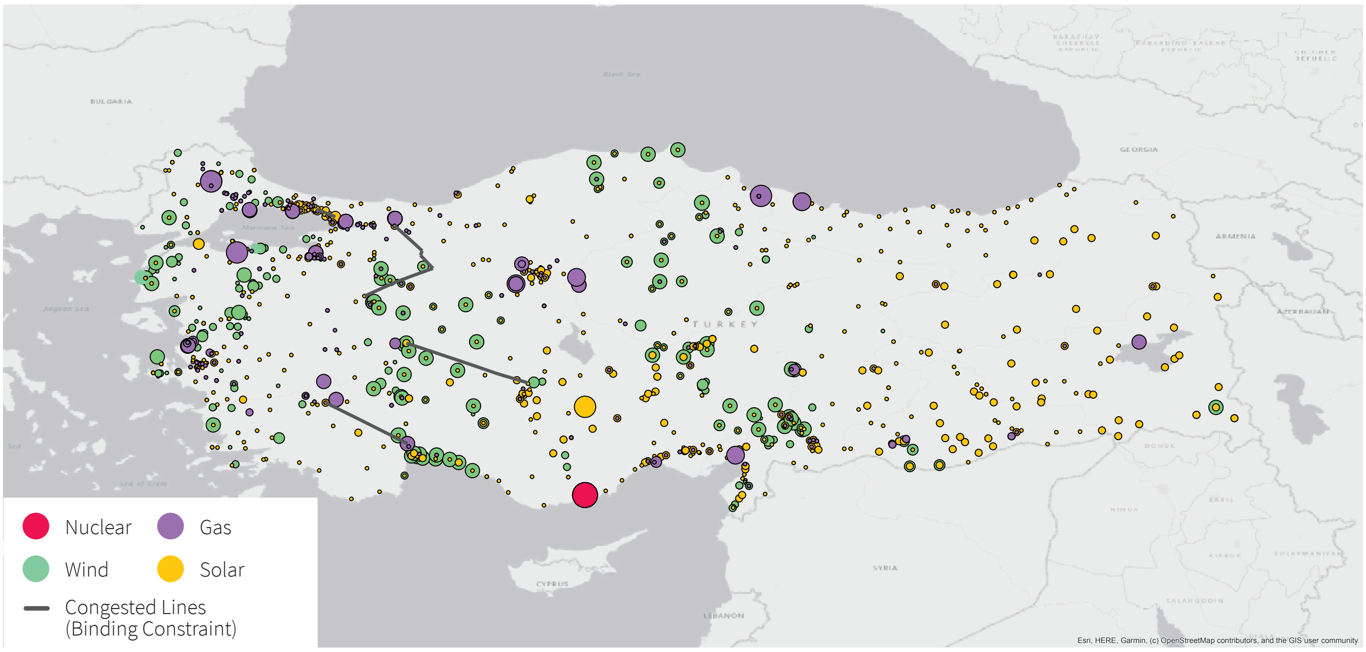


Figure 36: *Example of a day when RES curtailment is necessary (BAU – More RES sensitivity)*



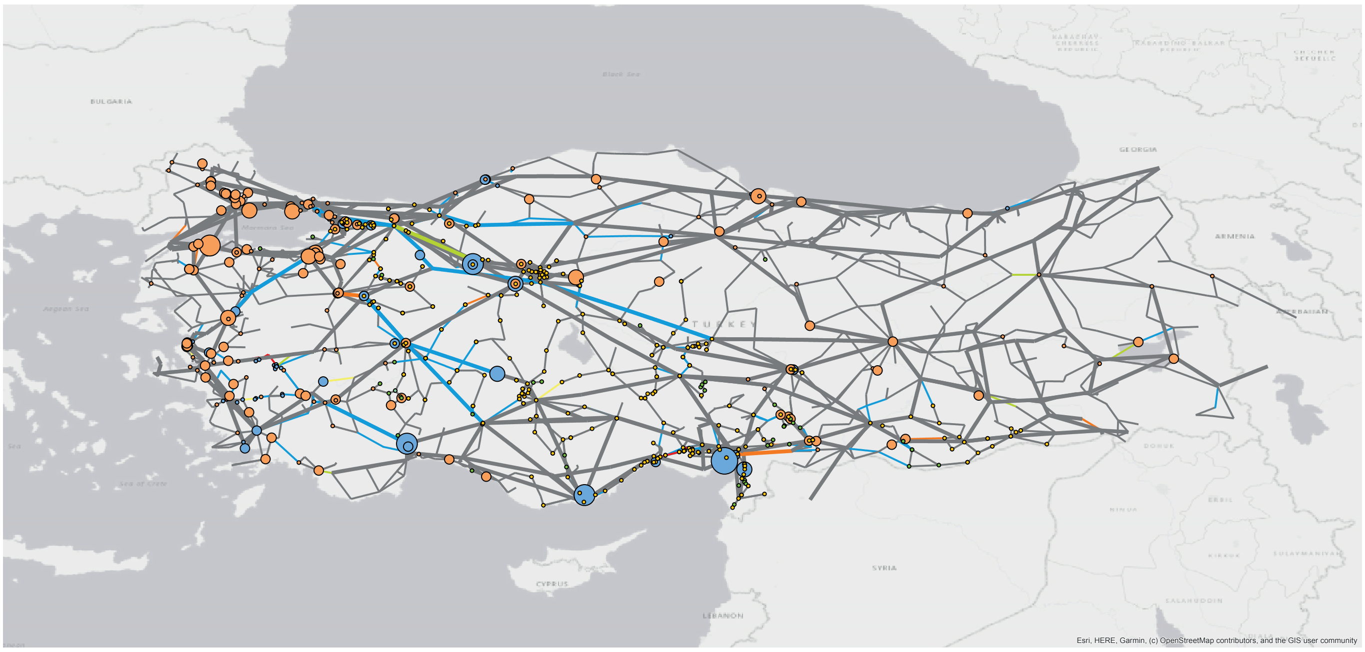
When the RES curtailment shown in Figure 36 is investigated in more detail, it is observed that there are 400-kV transmission lines that are subjected to congestion (Figure 37). The main reason for the congestion is the power flow from south to north and northeast. These congestions are relieved to some extent by redispatching nuclear power (downward direction). However, the nuclear power plant has a 100 MW/h ramping down constraint. Given that and other generator constraints, it is necessary to curtail some RES generation, particularly in the south region. This example shows the stress on the grid under minimum loading conditions when RES generation is high.

__Figure 37:__ Congested 400 kV lines 06:00 – 12:00 (see Figure 36)



The results of the BAU Base scenario and More RES sensitivity are depicted in the grid maps in Figure 38 and Figure 39, respectively. In both cases, redispatch orders due to congestion in transmission corridors from east to west are positive (generation increase) at demand centers, e.g. in the Marmara Region, as seen in the figures. Nuclear power plants are subjected to a significant volume of negative orders. This points to the importance of the ramp up/down capability of nuclear power plants, which is modelled as 100 MW/hour in this study. The difference between the BAU Base scenario and More RES sensitivity in terms of RES curtailment is apparent in the figures. RES curtailment is more observable at low demand centers (e.g., Central Anatolia for wind and Southern Turkey for solar). However, trivial amounts of RES curtailment are observable in Western and Northwestern Turkey, where major load centers are located. This supports the rationality of the system-driven approach for RES integration, particularly in the More RES sensitivity.

Figure 38: *BAU Base results (400-kV and 154-kV grid)*



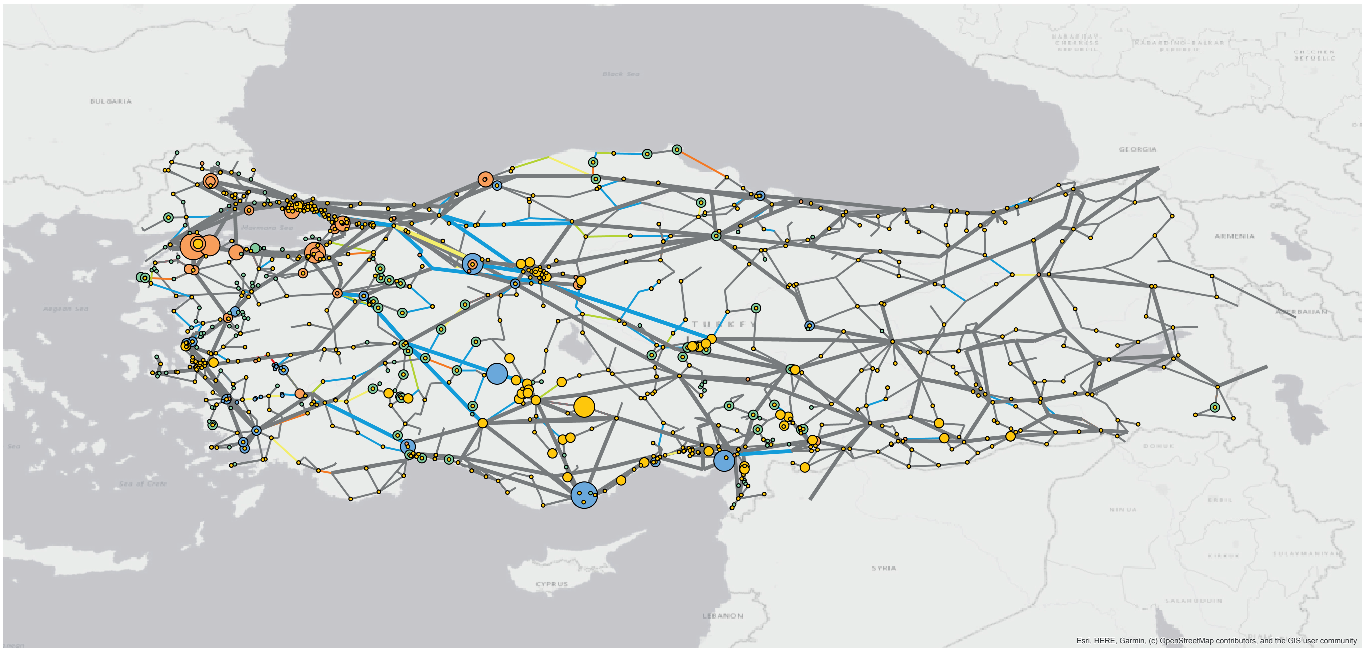
Redispatch Amount (MWh)
- <10000
- 10001-100000
- 100001-250000
- 250001-500000
- 500001<

- Negative Orders
- Positive Orders
- Wind Curtailment
- Solar Curtailment

Line Congestion Hours
- No Congestion
- < 250
- 251 - 500
- 501 - 1000
- 1001 - 2000
- 2001 <

- 154 kV Lines
- 400 kV Lines

Figure 39: *More RES sensitivity results (400-kV and 154-kV grid)*



Redispatch Amount (MWh)
- <10000
- 10001-100000
- 100001-250000
- 250001-500000
- 500001<

- Negative Orders
- Positive Orders
- Wind Curtailment
- Solar Curtailment

Line Congestion Hours
- No Congestion
- < 250
- 251 - 500
- 501 - 1000
- 1001 - 2000
- 2001 <

- 154 kV Lines
- 400 kV Lines

Annual net energy flows along with regional total generation and demand are presented in Figure 40 and Figure 41 for Low Demand sensitivity (with 36 GW wind + solar capacity under low demand) and More RES sensitivity (with 64 GW wind + solar capacity under low demand), respectively. The increase in RES capacity (i.e., More RES sensitivity) results in an increase in the net energy flows along the transmission corridors that connect Eastern and Central Anatolia with the West and Northwest regions. This result shows the importance of the current grid investment plan to reinforce these transmission corridors in order to comply with such challenging conditions (i.e., low demand under high-RES capacity).

Figure 40: *Annual net energy flows (BAU – Low Demand sensitivity)*

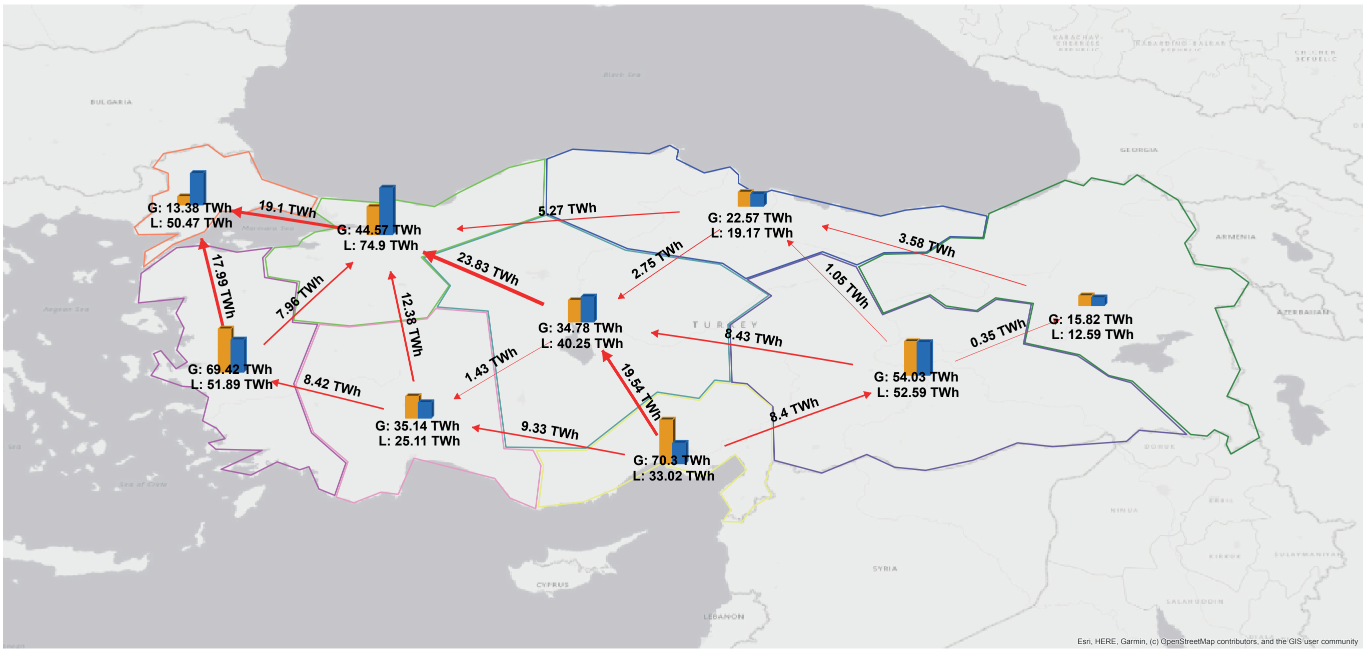
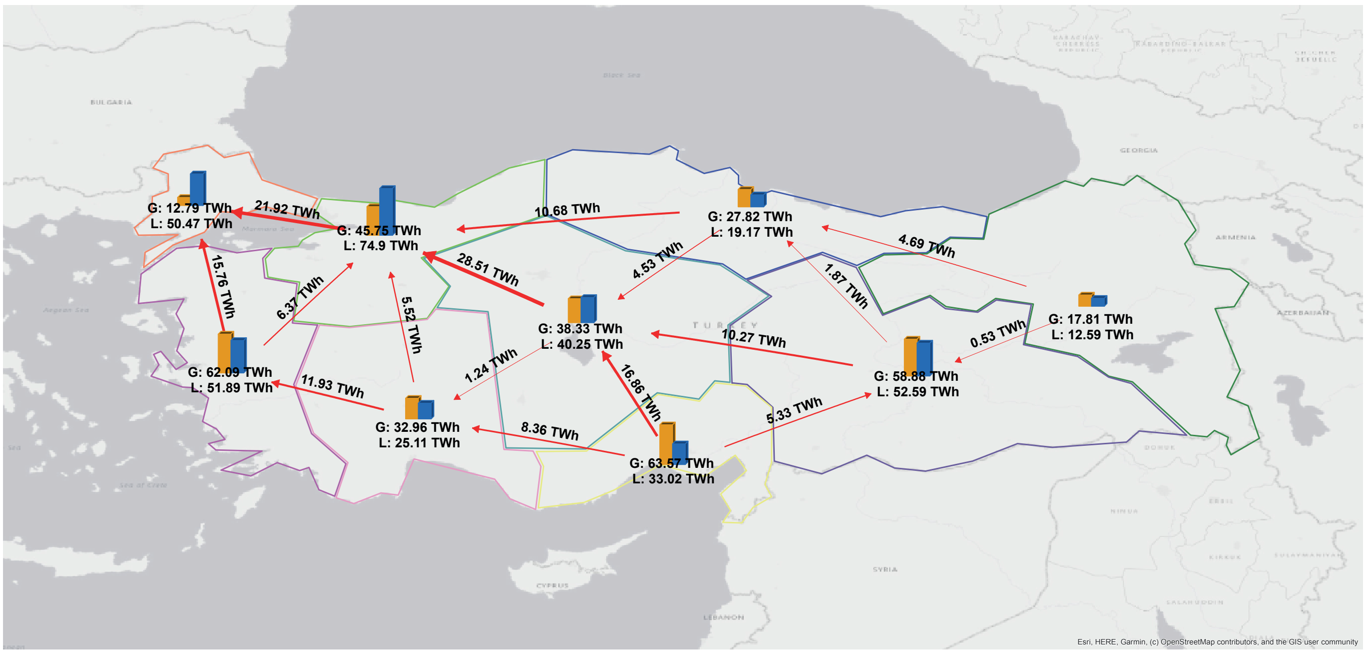
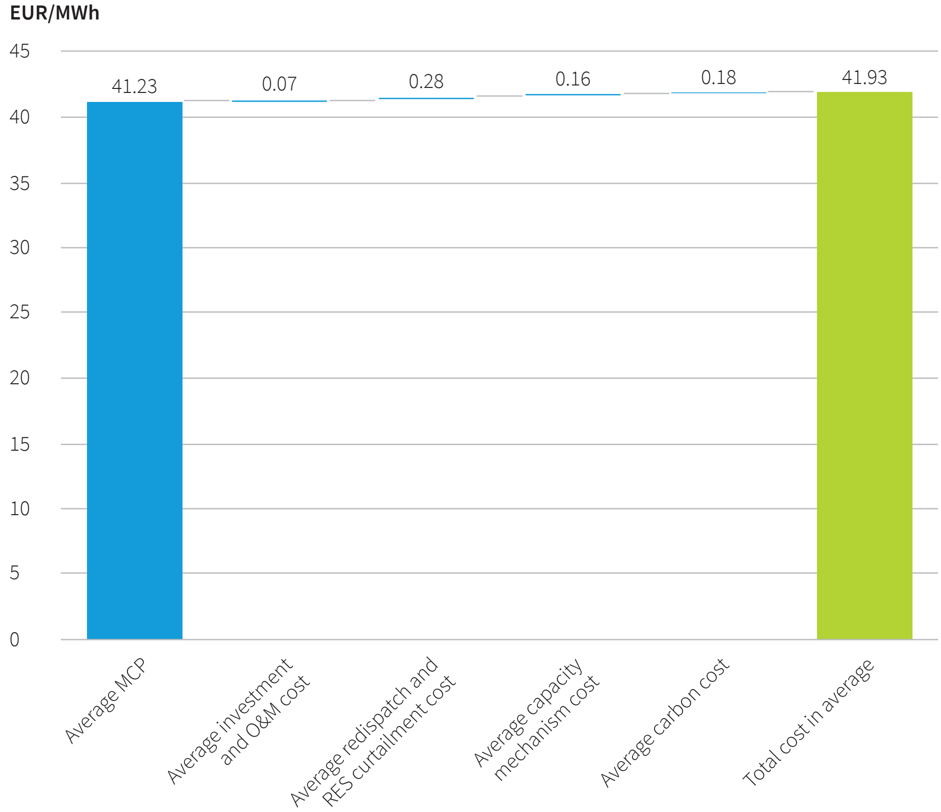


Figure 41: *Annual net energy flows (BAU – More RES sensitivity)*



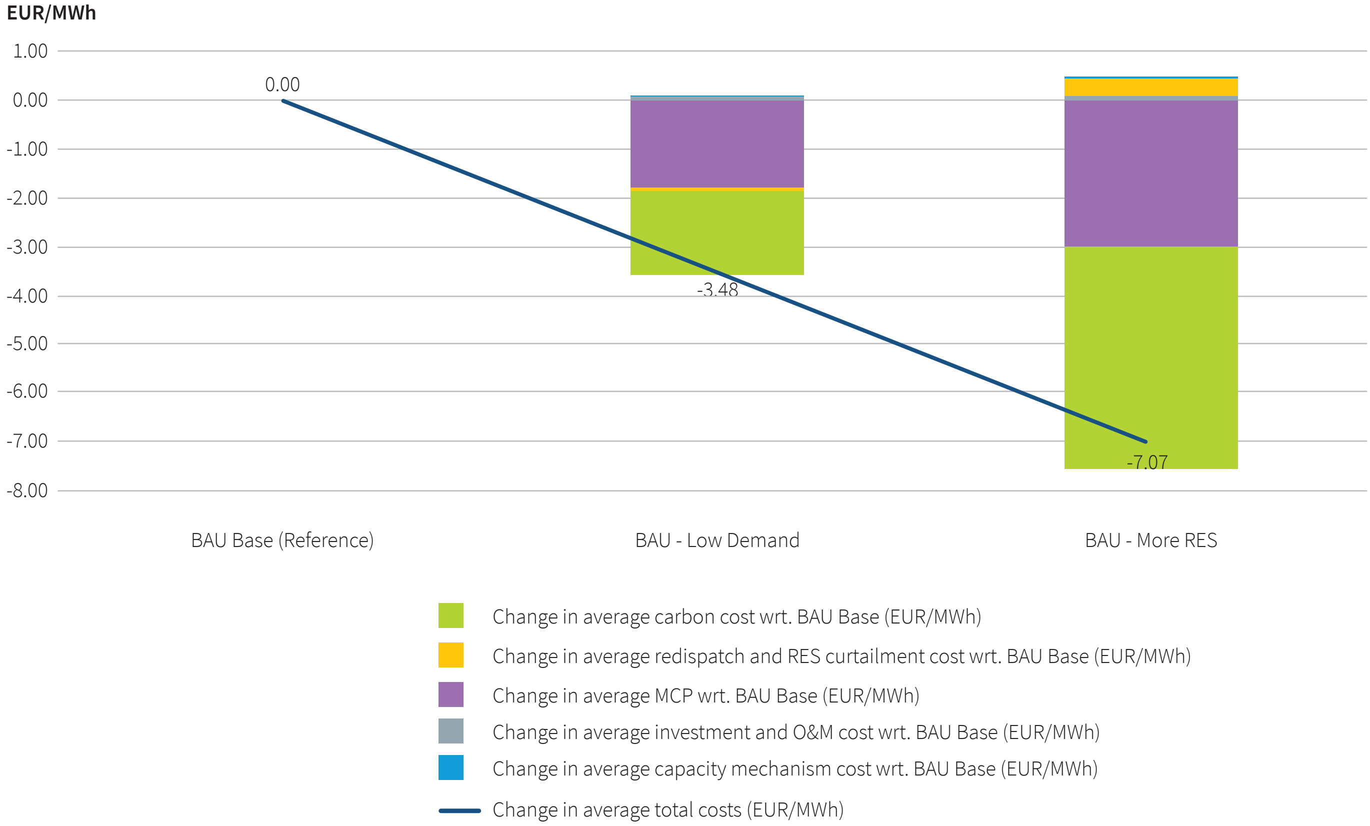
The average cost components in the BAU Base scenario are presented in Figure 42. Investment and O&M costs include the 400-kV and 154-kV grid. Redispatch costs comprise the majority of the total cost of redispatch and RES curtailment (almost 90%), which is consistent with the redispatch results in Figure 34 and RES curtailment results in Figure 35. The summation of the costs is 0.7 EUR/MWh excluding the average MCP.

Figure 42: *Average cost components in the reference scenario (BAU Base)*



The average costs of some sensitivities in the BAU scenario are compared in Figure 43 by taking the average costs in the BAU Base (Figure 42) as a reference. The main cost decrement in the Low Demand sensitivity with respect to the BAU Base scenario is driven by average MCP and carbon cost. Since total demand is low, the dispatch of fossil fuel-based power plants decreases significantly in the Low Demand sensitivity (see Figure 32), which in turn results in lower MCP and lower carbon emissions if compared to the BAU Base scenario. Further decrement is observed in the More RES sensitivity. The RES curtailment amount and, thereby, the cost of RES curtailment increases significantly in the More RES sensitivity. However, this increment is much smaller than the decrease in both MCP and the carbon cost, resulting in an almost 7 EUR/MWh reduction in total costs (including the MCP) if compared to the BAU Base scenario (Figure 43).

Figure 43: *Comparison of CBA results (BAU)*



5.2. ARES scenario

The 400-kV grid investment requirement (on top of the current plan) decreases in the ARES Base scenario (Figure 44) with respect to the BAU Base scenario. The main reason is that the grid investment requirement in the ARES Base scenario is more dominant at the 154-kV level given the high-RES capacity connected to the 154-kV substations (Figure 45). The grid investment requirement slightly increases in the More Flexibility sensitivity if compared to ARES Base, in order to utilize flexibility solutions within limited redispatch and RES curtailment (Figure 47 and Figure 48).

Figure 44: *400-kV grid investment figures (2020 vs ARES Base)*

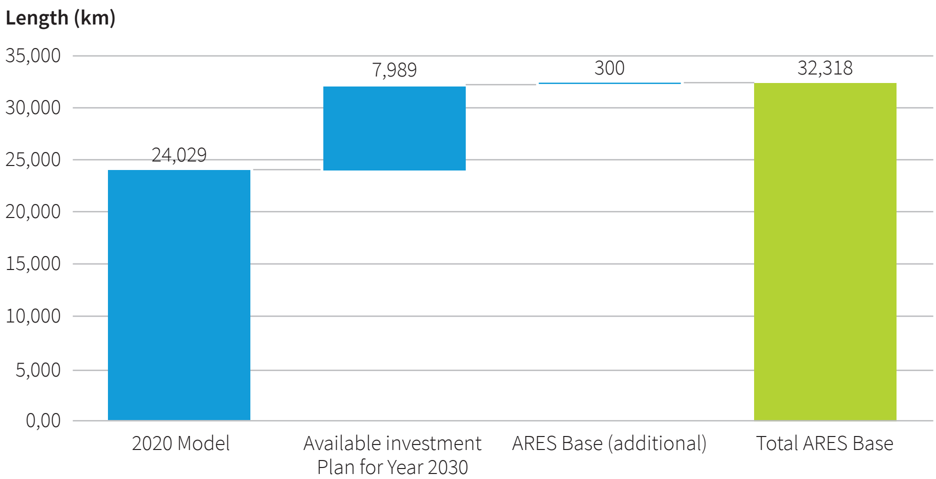
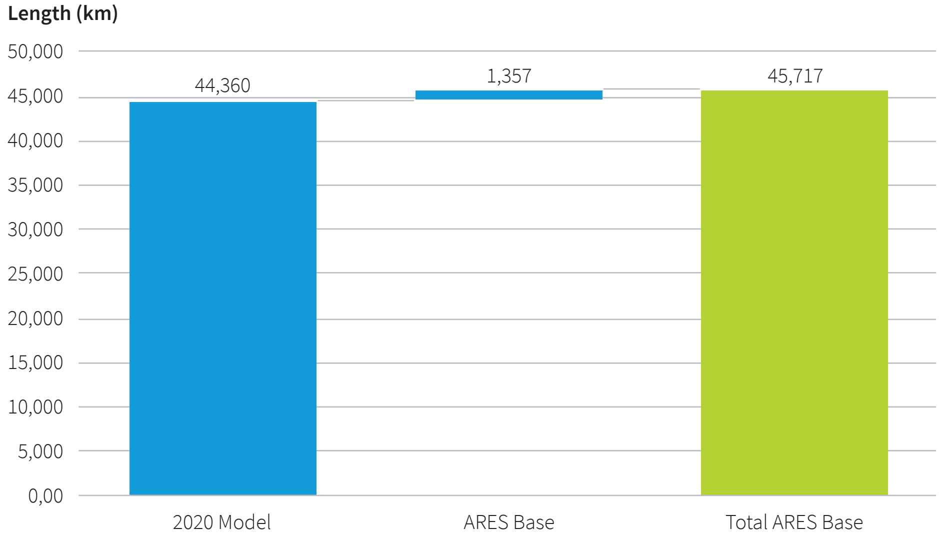


__Figure 45:__ 154-kV grid investment figures (2020 vs ARES Base)



The annual generation breakdown for the ARES Base scenario and 4 Nuclear Units sensitivity are compared in Figure 46. By increasing the number of nuclear units from two to four, the main change is observed in the amount of generation from gas power plants with almost 12 TWh decrement. This results in an increase in redispatch orders as depicted in Figure 47. This in turn results in higher amounts of RES curtailment if compared to the ARES Base scenario (Figure 48).

__Figure 46:__ Annual production amounts (ARES Base and ARES 4 Nuclear Unit Sensitivity)

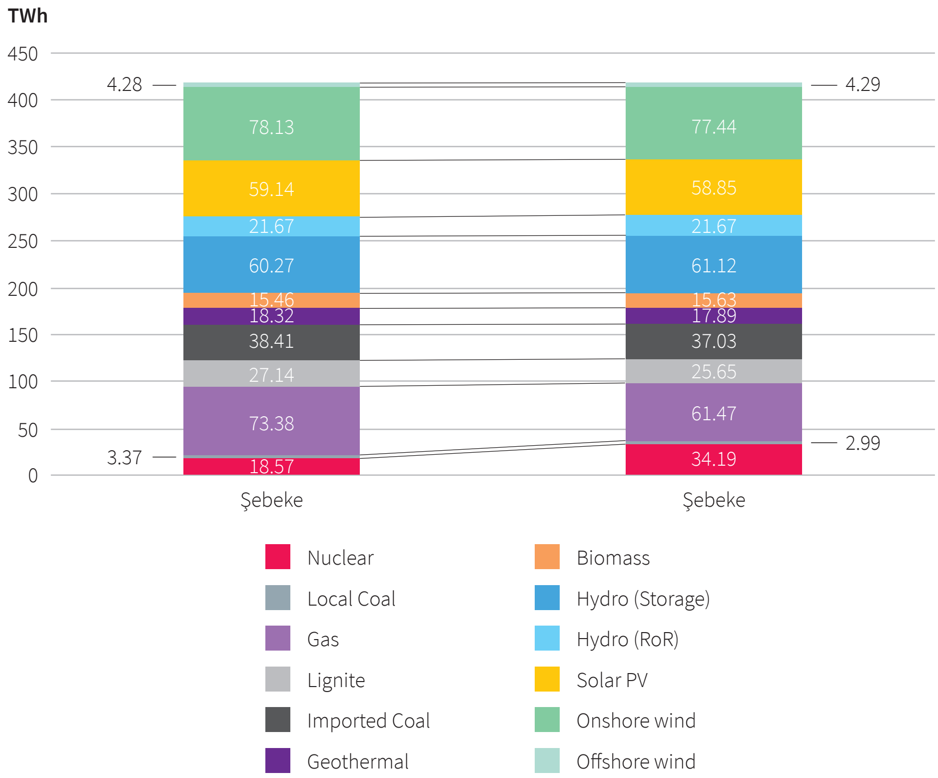
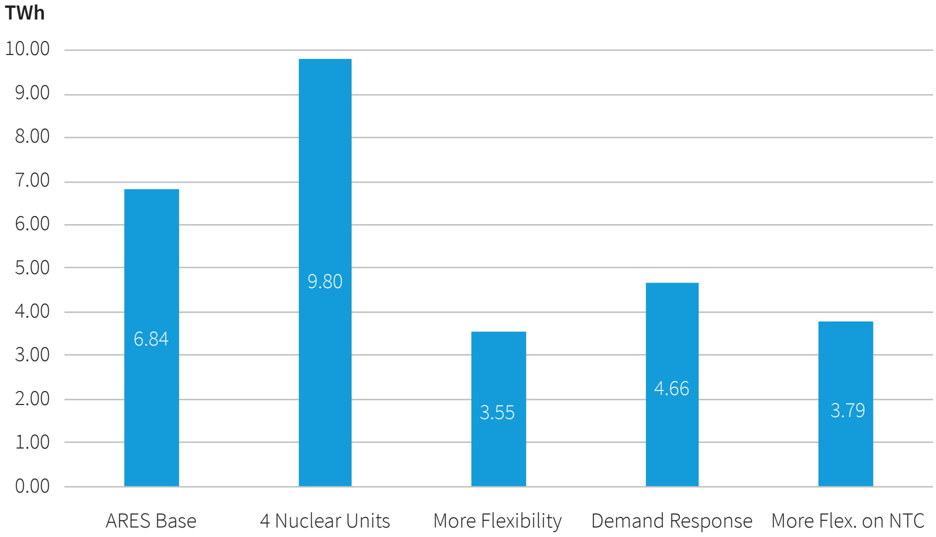


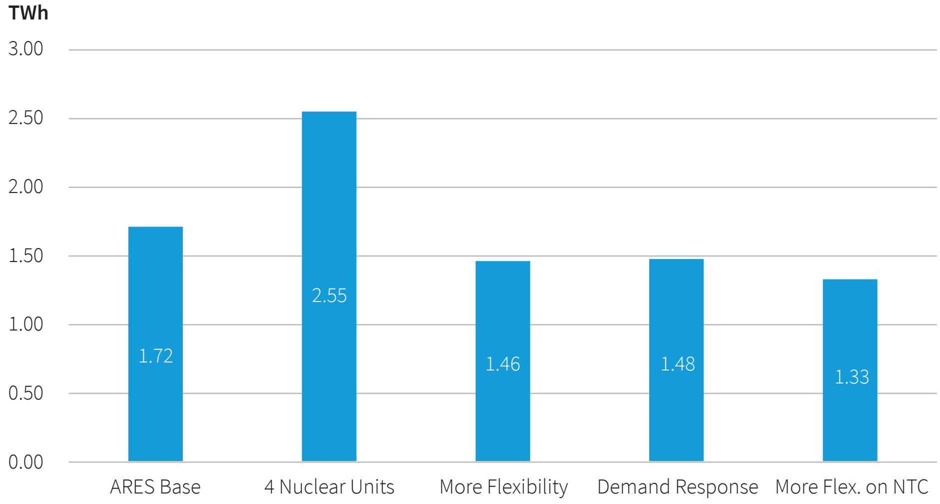
Figure 47: Annual redispatch figures (ARES and sensitivities)



The annual redispatch figures of the ARES Base and sensitivities are compared in Figure 47. The largest amount of redispatch is seen in the 4 Nuclear Units sensitivity, with around 10 TWh (as in the BAU scenario, which also assumes four nuclear units are in operation). If compared to the ARES Base scenario, there is more flexibility in the grid but less redispatch in the sensitivities, which also assumes two nuclear units are in operation.

Comparing the More Flexibility sensitivity with the ARES Base shows that by scaling up flexibility, we have less RES curtailment (More Flexibility vs. ARES Base in Figure 48). We see a slight increment in the RES curtailment if we add peak shaving as an additional flexibility solution to the More Flexibility sensitivity (i.e., Demand Response sensitivity). This originates from the obligatory demand response for peak shaving. Note that the peak shaving policy for demand response reduces the peak and decreases the need for dispatching the power plants at the top of the merit order as illustrated. However, it may not change (or even increase) the demand ramp at certain hours, which may lead to RES curtailment if no other flexibility solutions are available. For example, by increasing the NTC (i.e., More Flex on NTC sensitivity), the flexibility is increased, which contributes to the decrement in RES redispatch if compared to the Demand Response sensitivity.

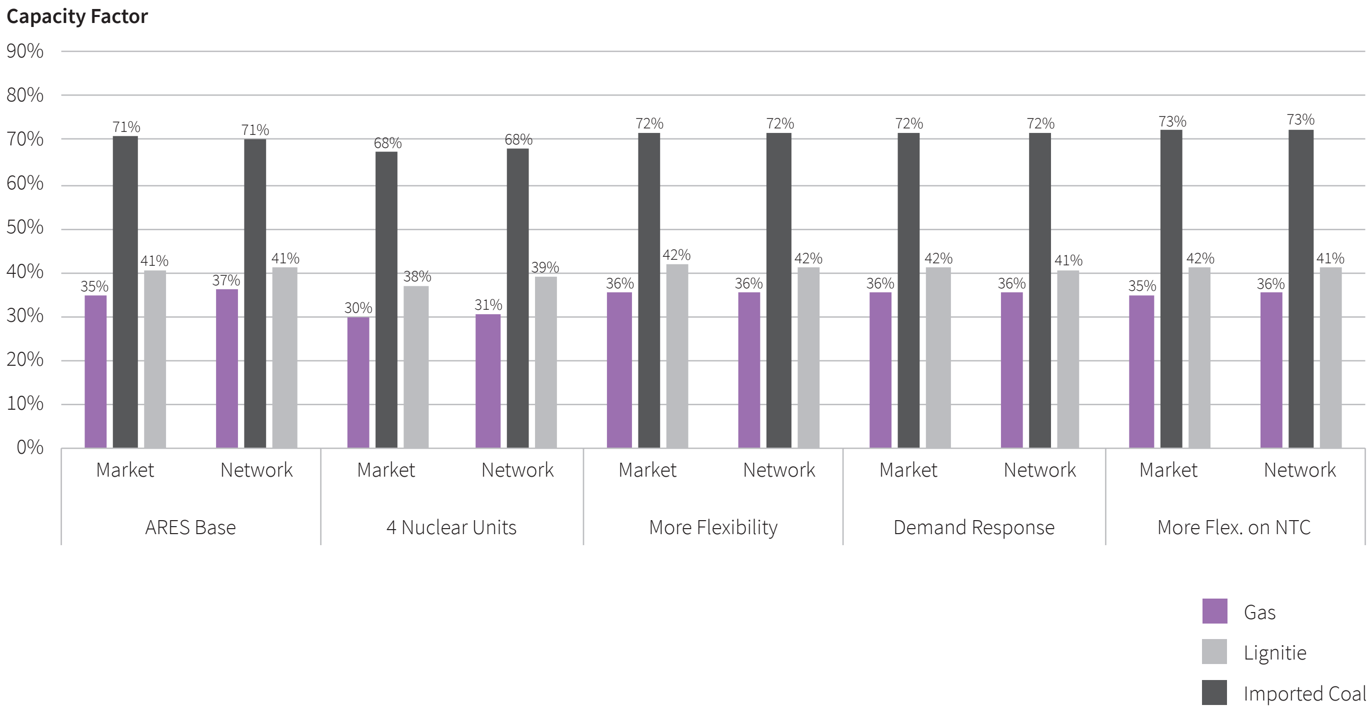
Figure 48: *Annual RES curtailment amounts (ARES and sensitivities)*



The utilization factor of gas power plants in the 4 Nuclear Units sensitivity drops to around 30% despite having almost 3 GW less in gas power plant capacity (in order not to have over-capacity) with respect to the BAU scenario (Figure 49). The main reason for this is the assumption that there is more RES installed capacity in ARES compared to BAU.

In the More Flexibility sensitivity, the capacity factor of gas power plants is slightly smaller compared to the ARES Base scenario (column 1 and 3 in Figure 49). However, the capacity factor is not further reduced after introducing peak-shaving oriented demand response (i.e., Demand Response sensitivity vs. More Flexibility). Although the effect of increasing flexibility on NTC (i.e., More Flex. on NTC sensitivity) is not observed in the capacity factor of conventional power plants (if compared to the Demand Response sensitivity), the associated effect is apparent in terms of redispatch orders and RES curtailment (Figure 47 and Figure 48, respectively).

Figure 49: *Annual capacity factors (ARES and sensitivities)*



The impact of flexibility measures on redispatch and RES curtailment figures is more apparent in Figure 50, which presents the dispatch amounts of power plants and utilization of flexibility measures including pumped storage, battery, and flexibility of interconnections. The figure also illustrates the utilization of ramp up/down capability in gas power plants and storage-HPPs as a flexibility solution.

Figure 50: *Network simulation results for typical days during spring (2030 ARES – More Flexibility)*

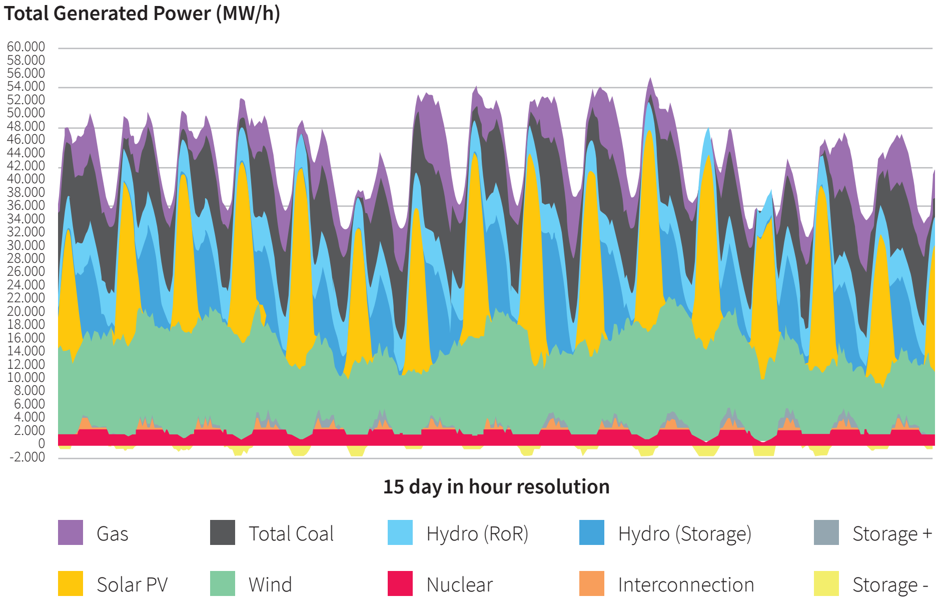
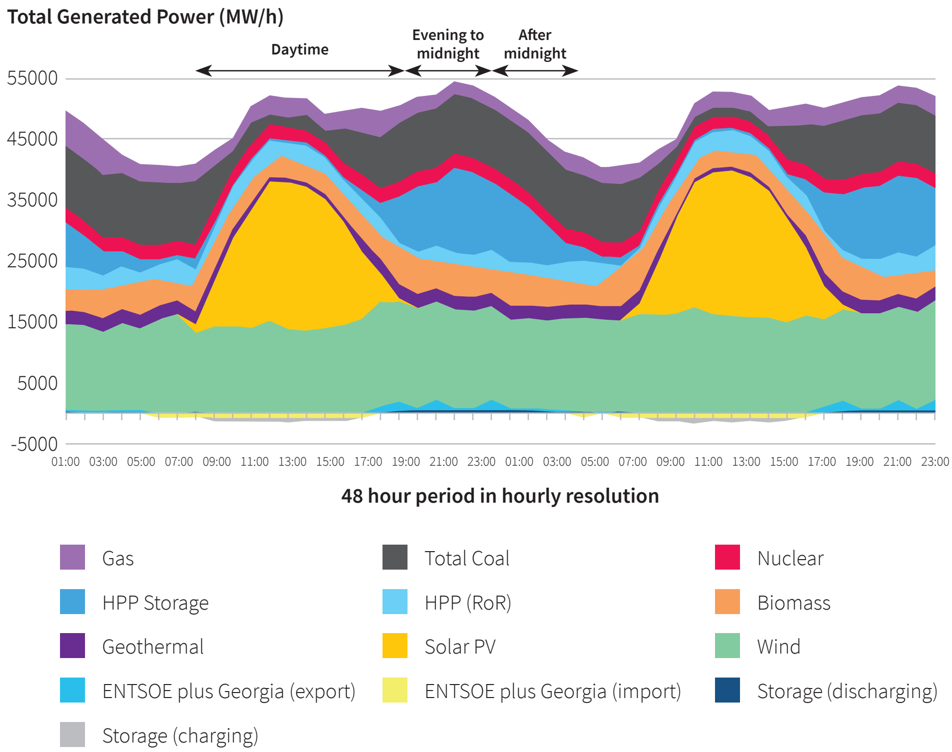


Figure 51 shows the data in Figure 50 at a higher resolution (48-hour resolution). Here, during daytime when a considerable amount of solar-based generation is available, coal- and hydro-based generation is reduced. However, the reduction in generation from gas power plants is slightly lower than that from coal and hydro in order to maintain spinning reserve requirements. The excess generation is exported or stored in storage devices (storage pumps and batteries). Between evening and midnight, coal, and hydro generation substitute for solar generation. In addition, stored energy is discharged to serve the load. The figure also illustrates that the load considerably drops after midnight, when hydro generation provides significant flexibility by ramping down in order to maintain the load generation balance.

Figure 51: *Network simulation results for a 48-hour period during spring (2030 ARES – More Flexibility)*



The annual net energy flows in the ARES Base sensitivity, which assumes there are two nuclear units in operation at Akkuyu, and 4 Nuclear Units sensitivity are presented in Figure 52 and Figure 53, respectively. Essentially, the loading levels of transmission corridors that connect to Southern Turkey, where nuclear power plants are located in the West and Northwest regions, increase in the 4 Nuclear Units sensitivity if compared to the ARES Base scenario.

Figure 52: *Annual net energy flows (ARES Base)*

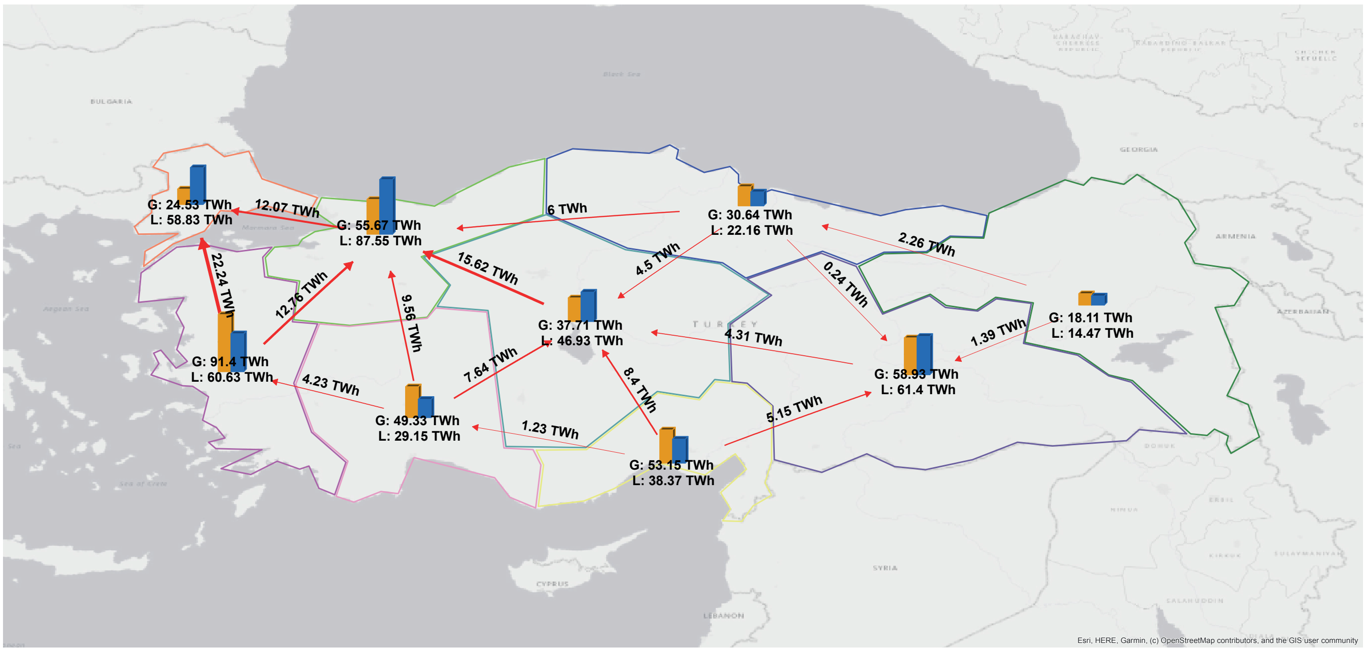
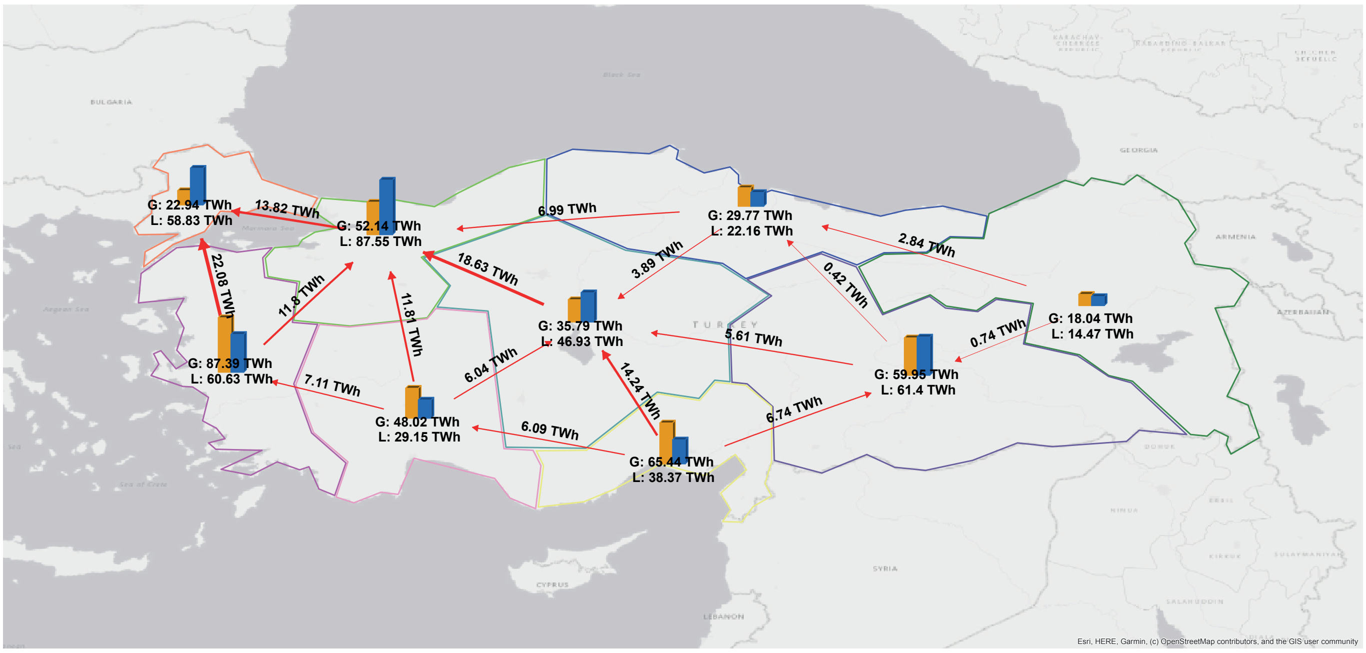
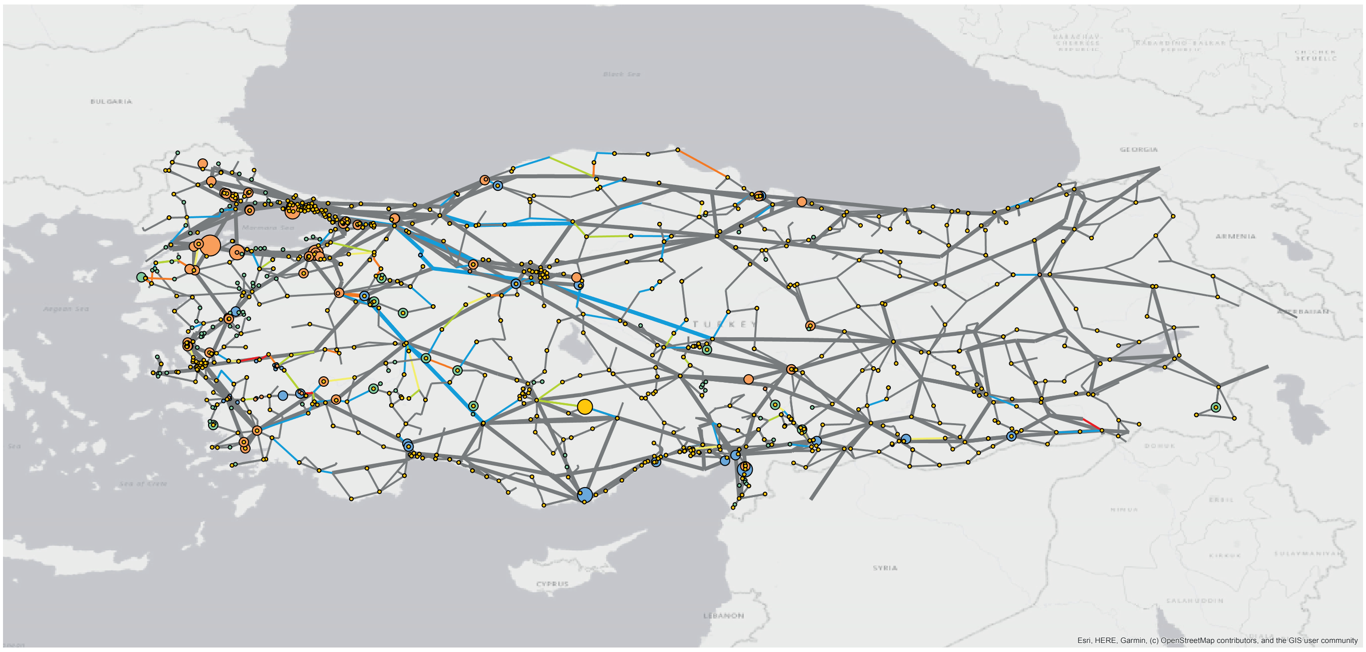


Figure 53: *Annual net energy flows (ARES - 4 Nuclear Units sensitivity)*



The results of the ARES Base scenario and More Flexibility sensitivity are presented in the grid map in Figure 54 and Figure 55, respectively. As depicted in the figures, the amount of redispatch orders and RES curtailment decreases along with an increase in flexibility at the expense of increment in congested lines (blue lines in the figures). It is worth mentioning that increments in congested lines are not a challenge that can be solved by minimizing redispatch orders as in the ARES Base scenario (Figure 47).

Figure 54: *ARES - Base results (400 kV and 154-kV)*



Redispatch Amount (MWh)

- <10000
- 10001-100000
- 100001-250000
- 250001-500000
- 500001<

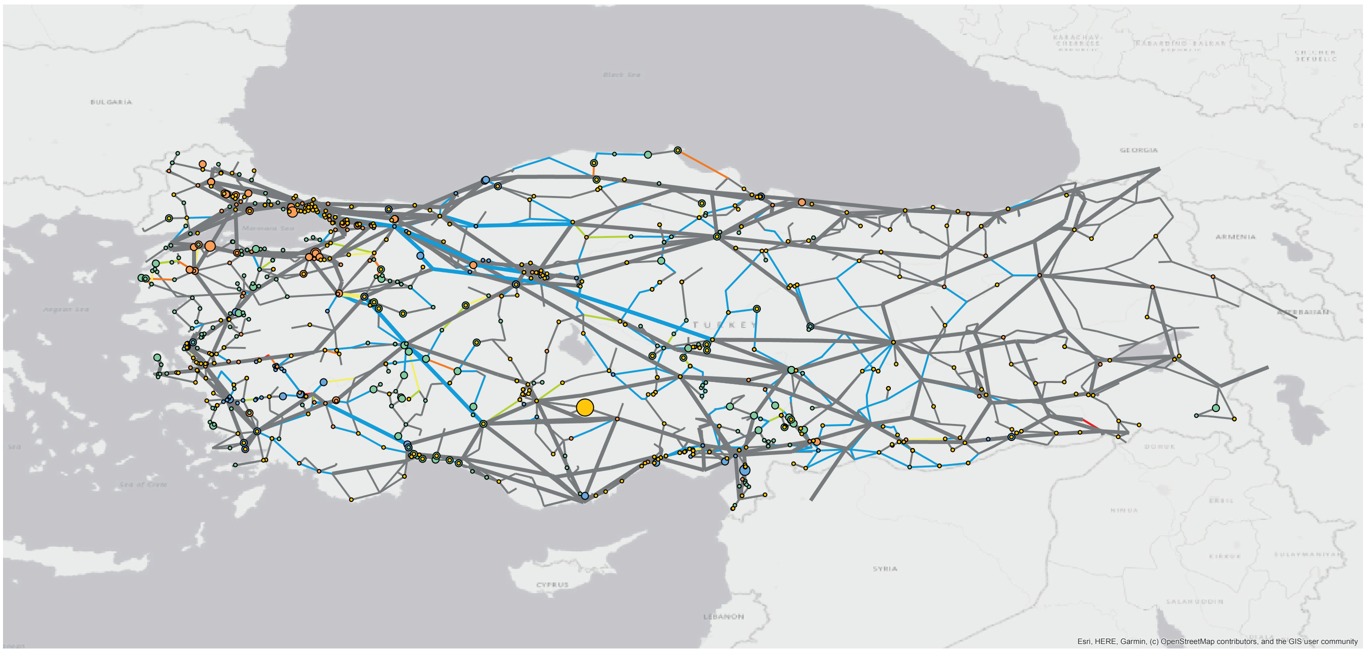
- Negative Orders
- Positive Orders
- Wind Curtailment
- Solar Curtailment

Line Congestion Hours

- No Congestion
- < 250
- 251 - 500
- 501 - 1000
- 1001 - 2000
- 2001 <

- 154 kV Lines
- 400 kV Lines

Figure 55: *ARES - More Flex results (400 kV and 154-kV)*



Redispatch Amount (MWh)

- <10000
- 10001-100000
- 100001-250000
- 250001-500000
- 500001<

- Negative Orders
- Positive Orders
- Wind Curtailment
- Solar Curtailment

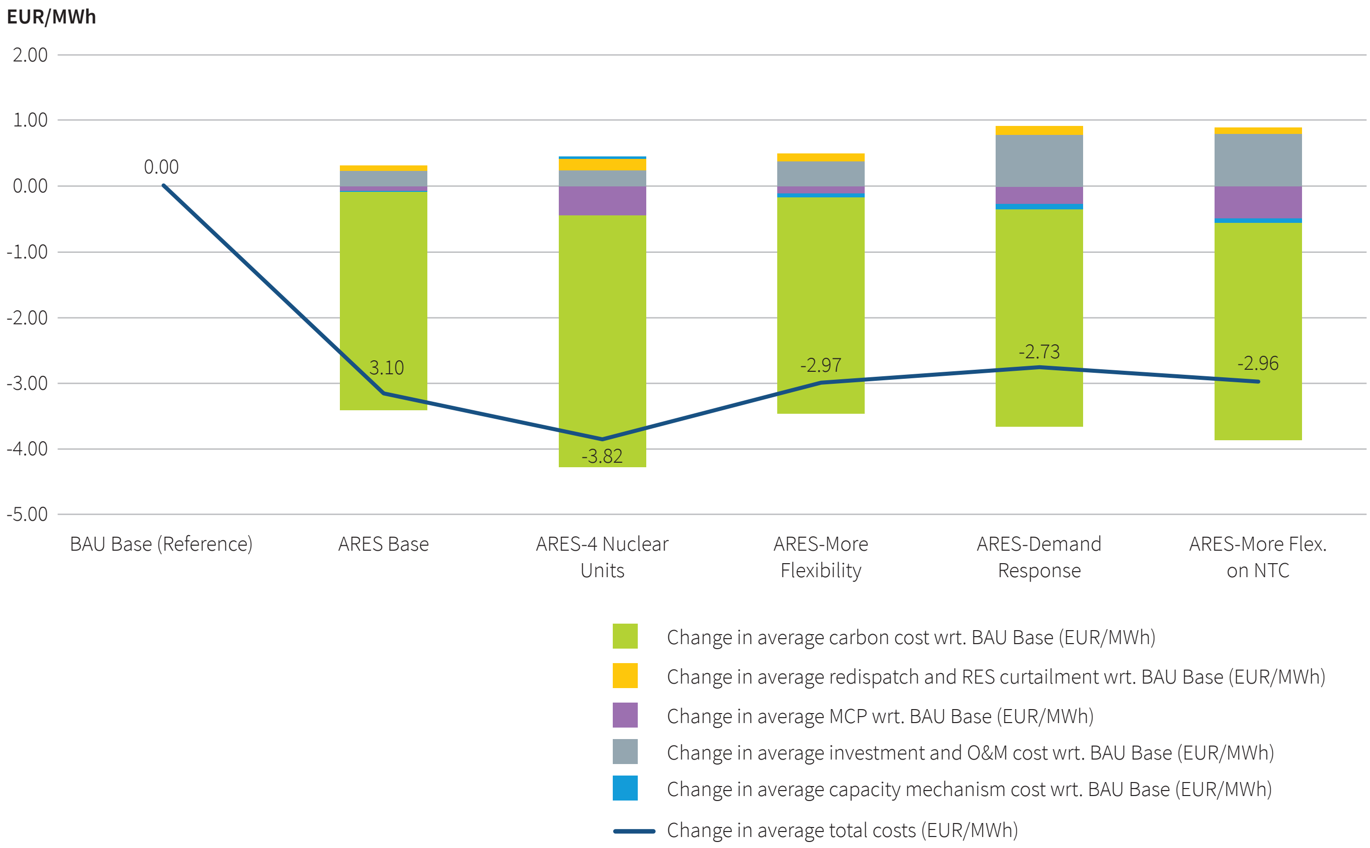
Line Congestion Hours

- No Congestion
- < 250
- 251 - 500
- 501 - 1000
- 1001 - 2000
- 2001 <

- 154 kV Lines
- 400 kV Lines

A comparison of CBA results is depicted in Figure 56 with reference to the BAU Base (i.e., reference scenario in terms of CBA results). The main observation here is the significant decrement in carbon costs with respect to the BAU Base scenario. This result is also valid for the 4 Nuclear Units sensitivity due to the assumption of zero carbon emissions from nuclear power units. The decrease in the average cost is also more apparent in the 4 Nuclear Units sensitivity due to the consideration of nuclear units at the bottom of the merit order given long-term purchase agreements. Therefore, the total decrement in carbon emission costs is greatest in the 4 Nuclear Units sensitivity. Another observation is that as the level of flexibility solutions increases, the average cost of investments and O&M costs increase. However, this increment in investment and O&M costs is still smaller than the decrement of carbon emissions costs, even in the More Flex on NTC sensitivity (i.e., sensitivity with the highest flexibility). The increase in flexibility also results in the decrement of the average MCP. The CBA results show that increasing RES capacity and the consideration of energy efficiency with respect to the BAU Base will provide significant savings for the Turkish power market as long as the integration of RES capacity continues to follow a system-driven approach and proper flexibility measures are taken into account. This result is valid under the assumptions of both two and four nuclear units in 2030.

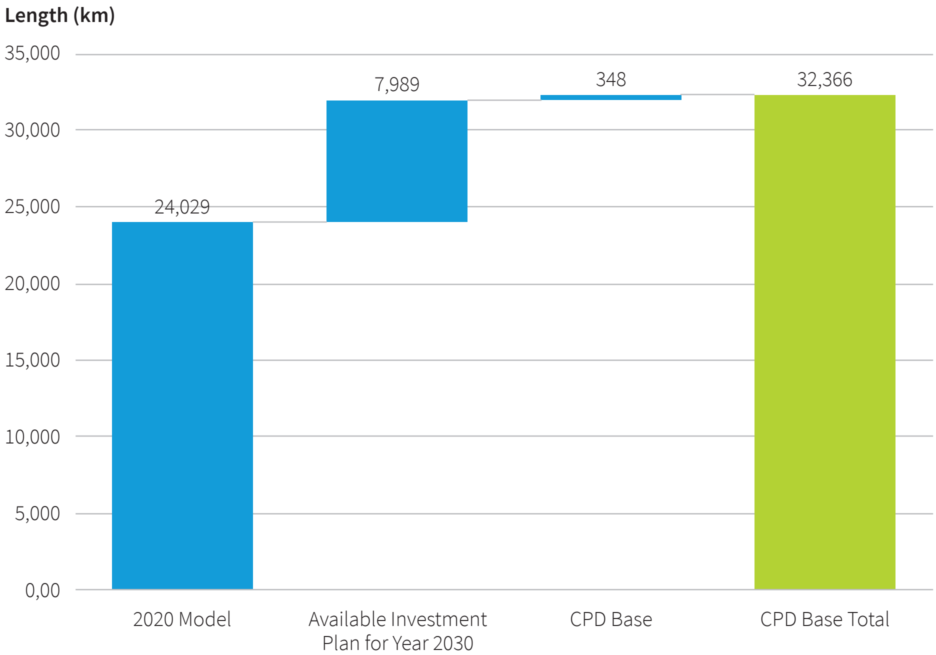
Figure 56: *Comparison of CBA results (ARES)*



5.3. Coal Phase Down (CPD) scenario

In the CPD Base scenario, all imported coal- and local coal-fired power plants are assumed to be shut down, only 5 GW of coal-fired power plants (3.2 GW imported coal and 1.8 GW lignite) will remain in service, and gas installed capacity is assumed to remain around 23 GW (with reference to the ARES Base). Total demand remains the same as in ARES. The 400-kV grid investment requirement on top of the current plan also decreases in CPD with respect to the BAU (Figure 57). Like ARES, the grid investment requirement in CPD is more dominant at the 154-kV level given the high-RES capacity, which is assumed to be connected at the 154-kV level.

Figure 57: *400-kV grid investment figures (2020 vs 2030 CPD)*



The annual generation breakdown in terms of network simulations is presented in Figure 58. As seen in the figure, gas power plants comprise the majority share of the generation mix with a considerable capacity factor (48% as seen in Figure 59).

Figure 58: *Annual generation breakdown (CPD Base, Path 1, and Path 2)*

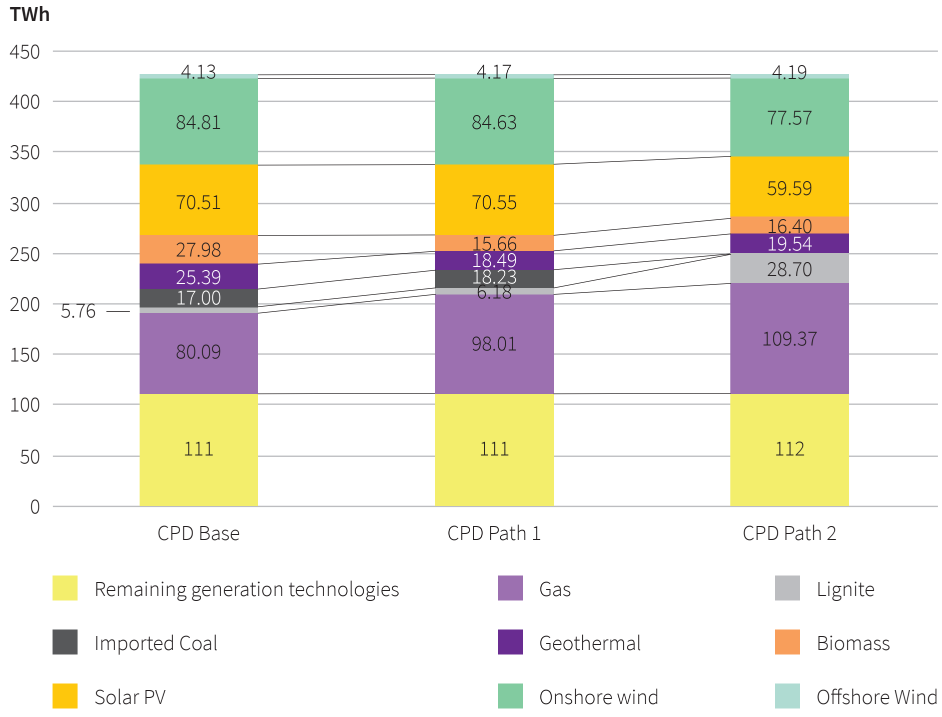


Figure 59: *Annual capacity factors (CPD Base, Path 1, and Path 2)*

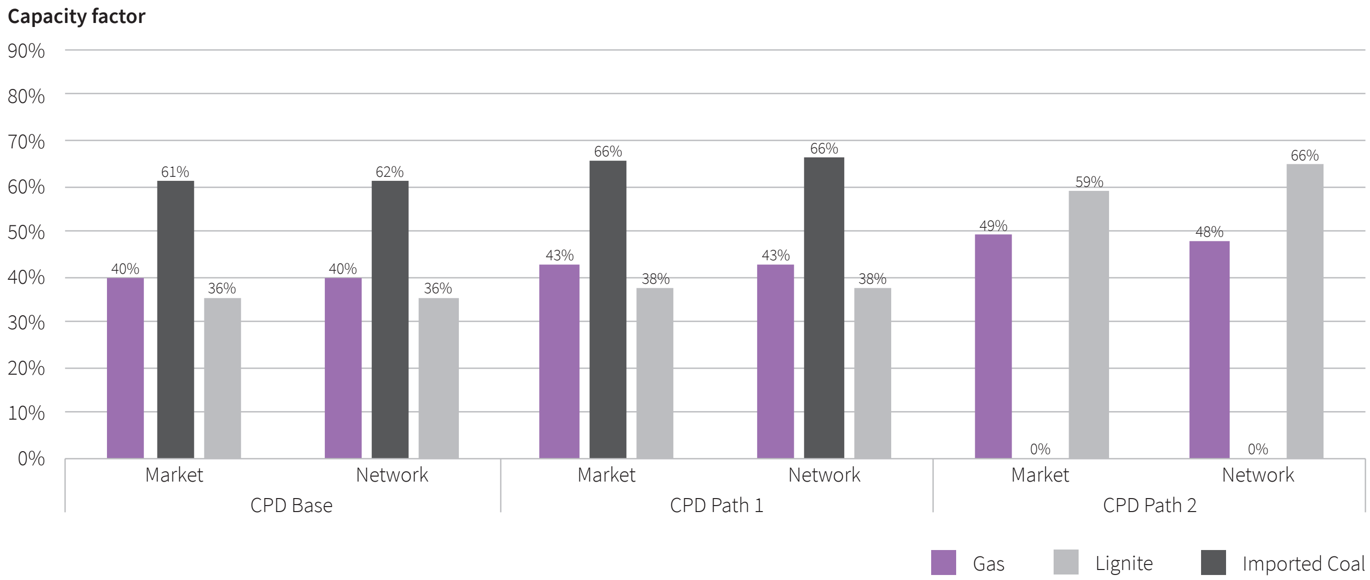
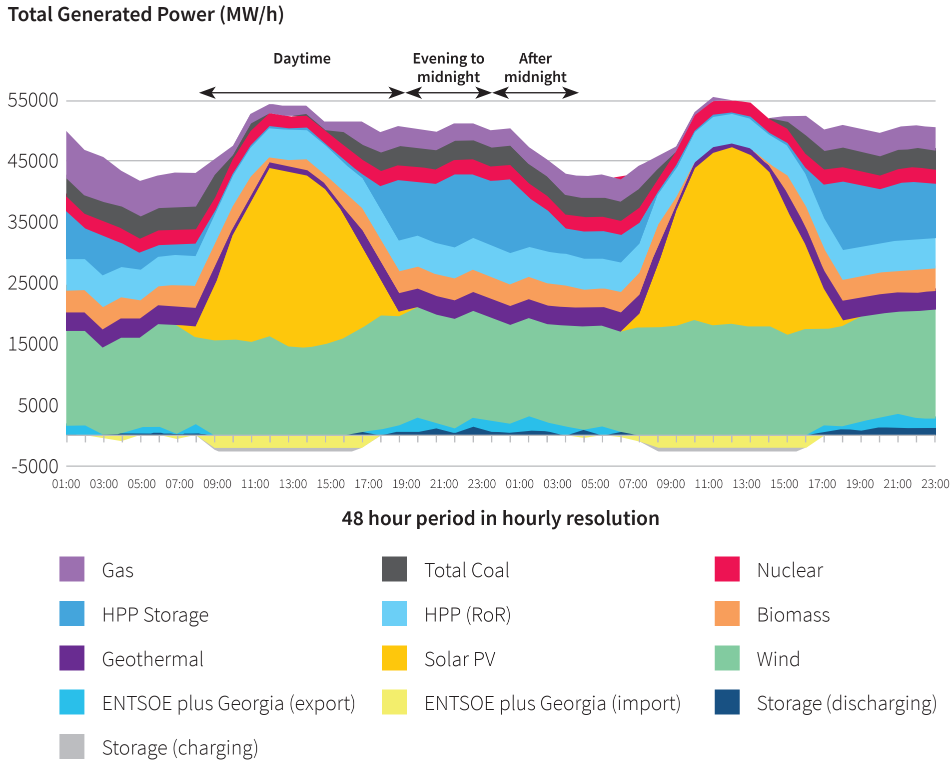


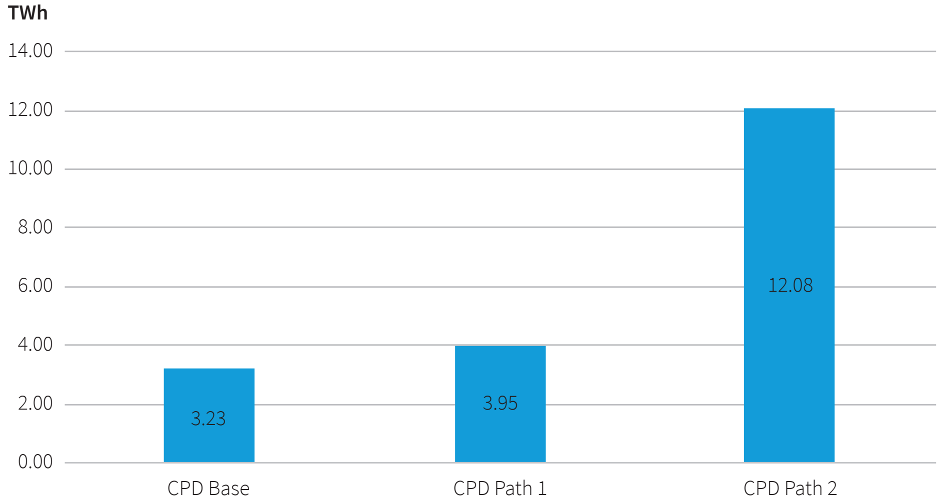
Figure 60 depicts the 48-hour network simulation results during spring. As can be seen from the figure, the coal-fired power plans take small share of generation mix as most of the coal-fired power plants are shut down in CPD base.

Figure 60: *Network simulation results for a 48-hour period during spring (2030 CPD Base)*



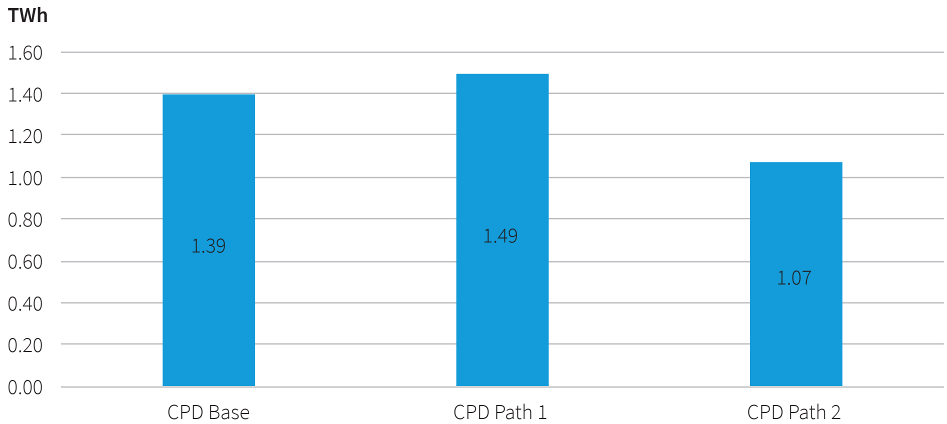
The coal phase-out in the CPD Base scenario results in 3.23 TWh of redispatch orders (Figure 61), which is considerably less than that of the BAU Base scenario. Here, the capacity factor of gas power plants is reduced to 40% even with 22 GW of gas installed capacity. In CPD path 1 and 2, the biomass and geothermal installed capacity is reduced to 3.3 GW and 2.8 GW, respectively, and instead, gas installed capacity is increased to 25.8 GW. Solar and wind installed capacity is also decreased by 10 GW (mostly solar) in the CPD Path 2 sensitivity if compared to the CPD Base scenario. Such increment contributes to the higher capacity factor in gas power plants in both CPD Path 1 and 2 if compared to the CPD Base scenario (Figure 59). In addition, the redispatch amount in the CPD Path 1 is slightly higher than in CPD Base due to the reducing installed capacity of more geothermal and biomass power plants that are close to major demand centers. This result shows that geothermal and biomass plants can effectively replace 3 GW of gas installed capacity in terms of flexibility. In CPD Path 2, the coal-fired generation mixture is changed to have only lignite-based power plants in service and shut all imported coal power plants down. Here, the amount of redispatch is considerably increased to 12 TWh (Figure 61). The main reason for such a considerable amount of redispatch orders is that imported coal-fired power plants that are close to major load points are shut down.

Figure 61: *Annual redispatch amounts in 2030 (CPD Base, Path 1, and Path 2)*



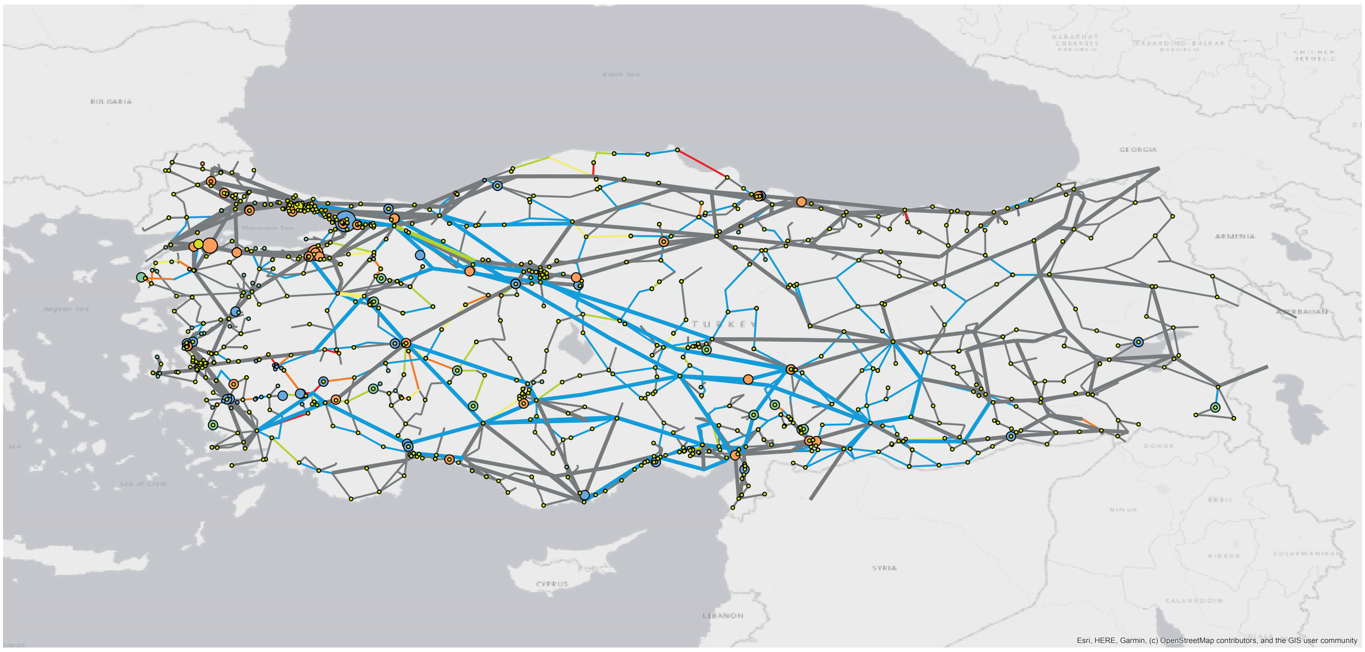
A comparison of RES curtailment amounts is depicted in Figure 62. RES curtailment is slightly greater in CPD Path 1 when compared to the CPD Base. The main reason for this is the increase in the capacity of wind and solar installed capacity (3 GW) in CPD Path 1 if compared to CPD Base. However, RES curtailment amount reduces in CPD Path 2 given the decrease of almost 10 GW RES capacity if compared to CPD Base.

Figure 62: *Annual RES curtailment amounts in 2030 (CPD Base, Path 1, and Path 2)*



The results of CPD Base and CPD Path 1 are presented in the grid map in Figure 63 and Figure 64, respectively. The total amount of RES curtailment is 1.39 TWh/year, which corresponds to almost 1% of RES generation in CPD Base. The removal of coal-fired power plants results in congestion on transmission lines that connect to regions dominated by coal-fired power plants. However, the total amount of redispatch is still tolerable, even under the CPD Path 2 scenario, given high flexibility solutions if compared to BAU. This result shows the importance of flexibility solutions in the replacement of coal-fired power plants with RES. The main difference between CPD Base and CPD Path 1 is observable by comparing Turkey's Southwest grid in Figure 63 and Figure 64. Congestion is more apparent in this region in CPD Base due to the concentration of geothermal power plants for which installed capacity is increased if compared to CPD Path 1.

Figure 63: *CPD – Base*



Redispatch Amount (MWh)

- <10000
- 10001-100000
- 100001-250000
- 250001-500000
- 500001<

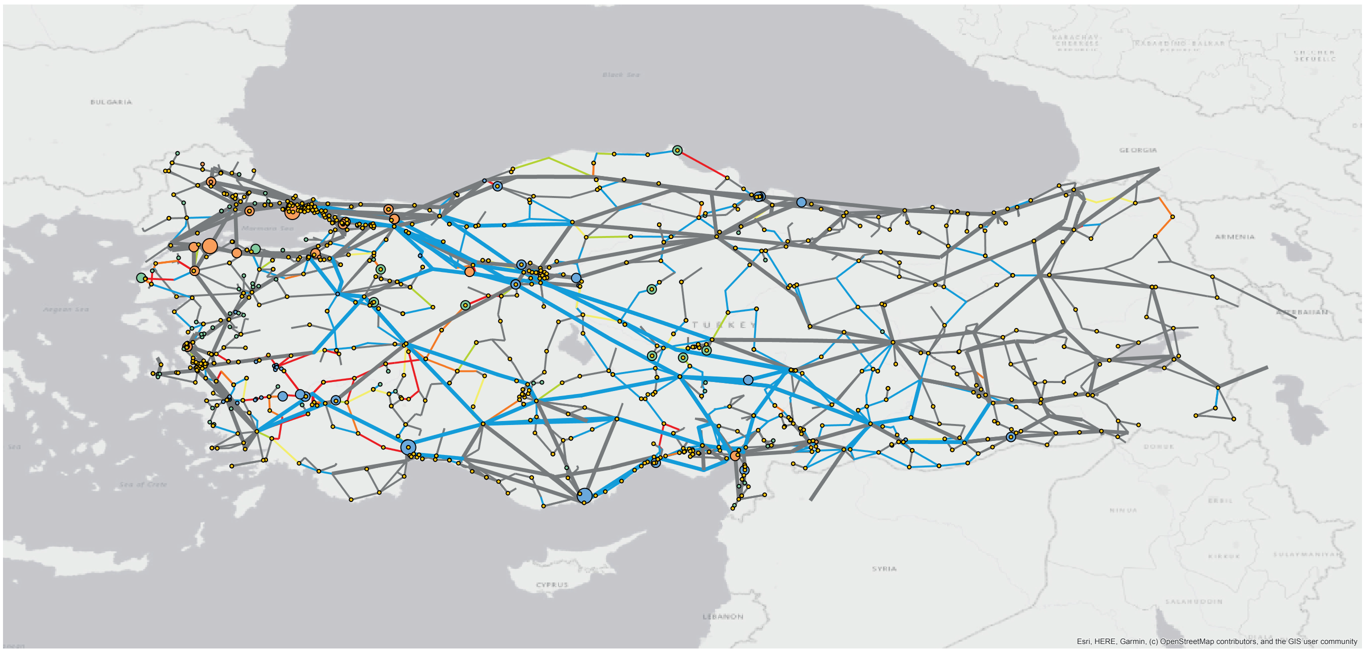
- Negative Orders
- Positive Orders
- Wind Curtailment
- Solar Curtailment

Line Congestion Hours

- No Congestion
- < 250
- 251 - 500
- 501 - 1000
- 1001 - 2000
- 2001 <

- 154 kV Lines
- 400 kV Lines

Figure 64: *CPD – Path 1*



Redispatch Amount (MWh)

- <10000
- 10001-100000
- 100001-250000
- 250001-500000
- 500001<

- Negative Orders
- Positive Orders
- Wind Curtailment
- Solar Curtailment

Line Congestion Hours

- No Congestion
- < 250
- 251 - 500
- 501 - 1000
- 1001 - 2000
- 2001 <

- 154 kV Lines
- 400 kV Lines

The annual net energy flows of the CPD Base scenario, CPD Path 1 sensitivity, and CPD Path 2 sensitivity are presented below, respectively. The main observation to note here is the west to east energy flows in South and Central Anatolia in the CPD base, which is unusual in the Turkish grid. The reason is that in CPD Base, the total installed capacity of coal-fired power plants (local coal, imported coal, and lignite) is reduced to 5 GW in 2030 from almost 23 GW in 2020, and this capacity reduction is compensated by RES (wind, solar, geothermal, and biomass) under the system-driven approach. This result supports the reasoning behind the minimum amount of redispatch in the CPD Base (Figure 61).

Figure 65: *Annual net energy flows (CPD Base)*

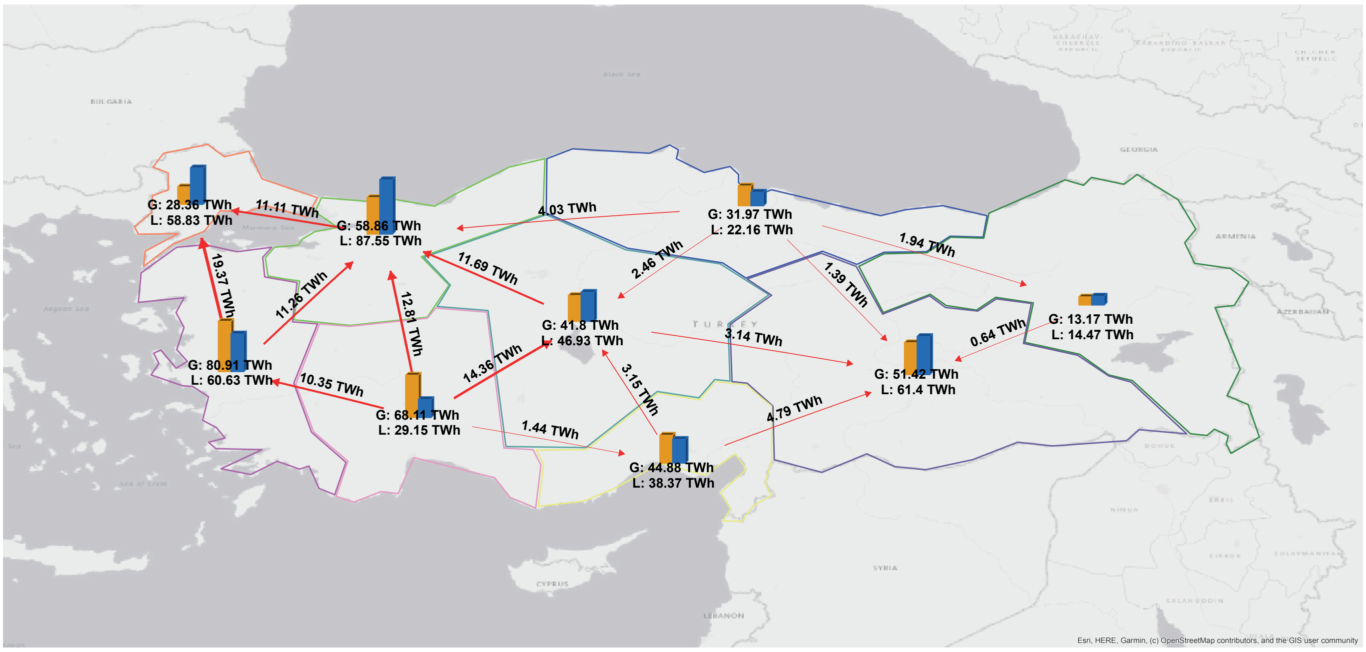


Figure 66: *Annual net energy flows (CPD Path 1)*

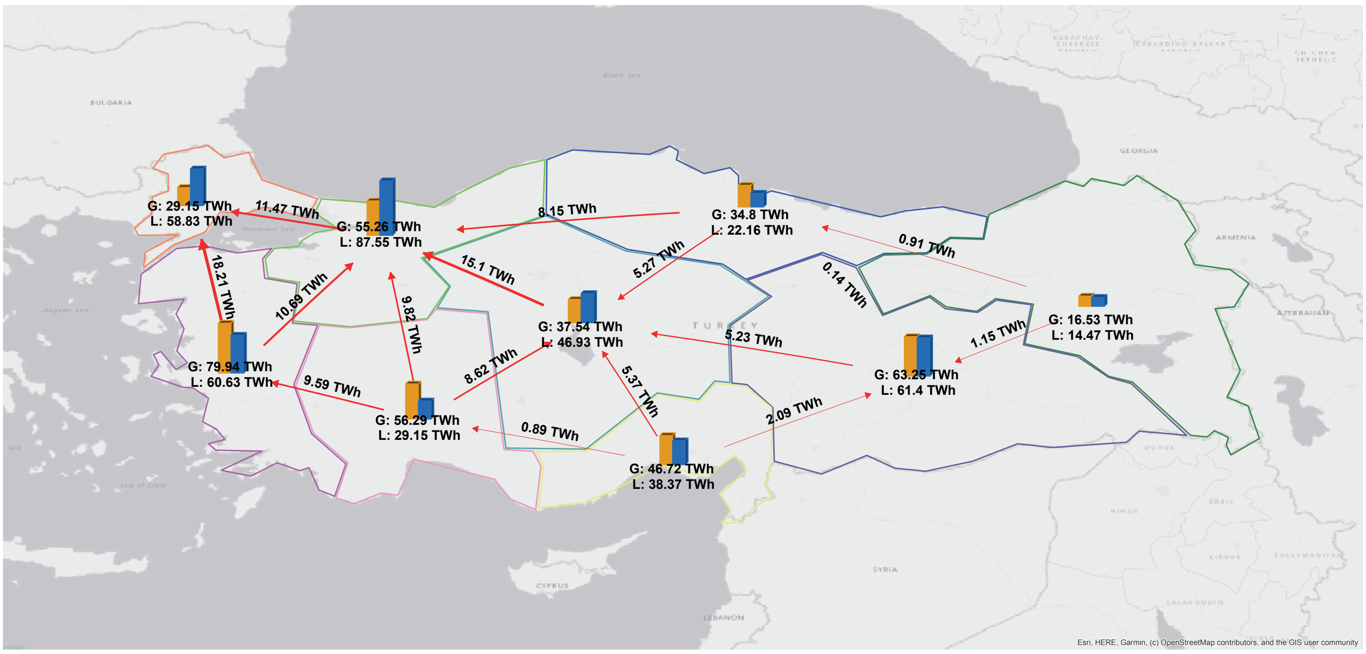


__Figure 67:__ Annual net energy flows (CPD Path 2)

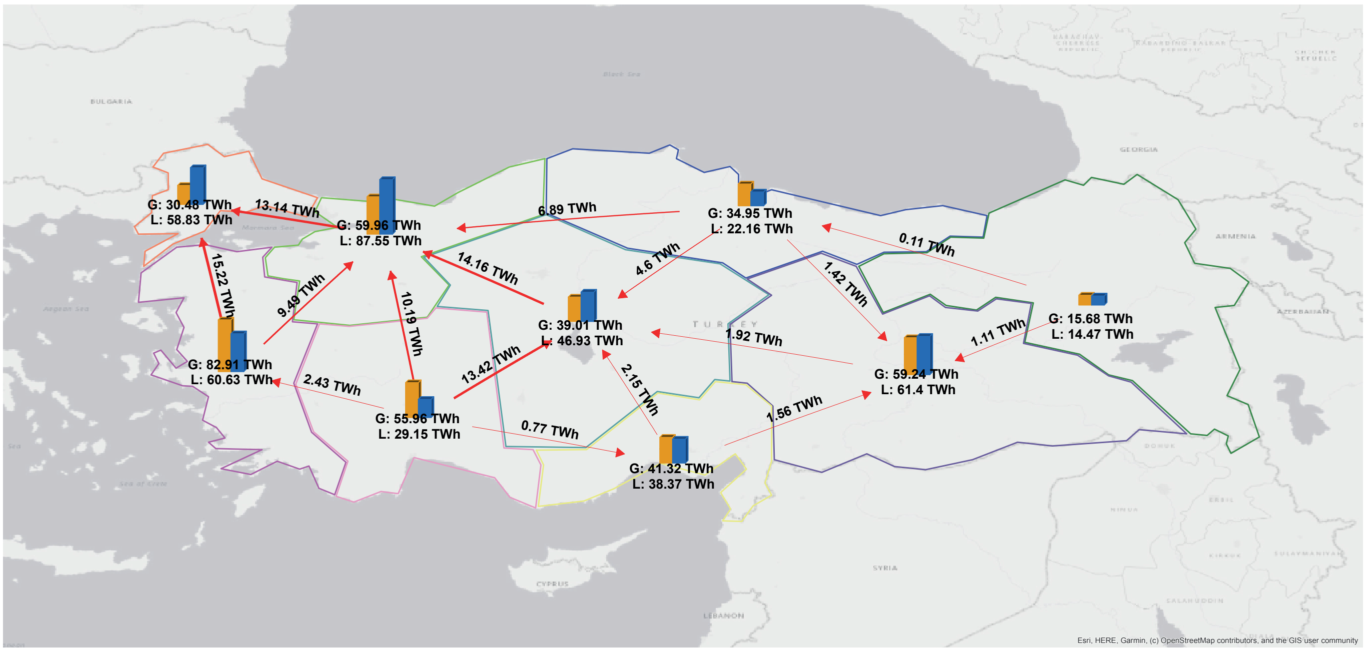


Figure 68 depicts a comparison of the CBA results with reference to the BAU Base (i.e., reference scenario) and ARES Base scenario. The main observation to note here is the expected reduction in the carbon cost component in the CPD Base and sensitivities. Further reduction of gas power plant installed capacity and compensating for this reduction with geothermal and biomass plants in CPD Base results in further decrement in carbon costs if compared to CPD Path 1. Although the average cost of investment and O&M is almost the same in the CPD Base and CPD sensitivities, the average MCP results in reduction of costs in the CPD Base if compared to reference (i.e., BAU Base). Therefore, the highest savings are observed in the CPD Base (5.48 EUR/MWh savings on average) with respect to the BAU Base. The CBA results show that consideration of the carbon phase-out as well as energy efficiency will provide additional savings in the Turkish power market if the integration of RES capacity continues under a system-driven approach and proper flexibility measures are taken into account.

Figure 68: *Comparison of CBA results (CPD and sensitivities)*

5.4. Comparison of the three main scenarios

A comparison of the three main scenarios (BAU Base, ARES Base, and CPD Base) is conducted in terms of grid investment requirements, annual redispatch amounts, RES curtailment amounts, and annual capacity factor of conventional power plants. The 400-kV transmission grid investment requirements on top of the current investment plan are presented in Figure 69. The 154-kV grid investment requirements are presented in Figure 70. As seen from the figures, the 400-kV grid investment requirement on top of the current plan decreases in the ARES Base scenario with respect to the BAU Base scenario. The main reason is that the grid investment requirement in the ARES Base scenario is more dominant at the 154-kV level given the high-RES capacity in this scenario, which is mainly connected to the implementation of 154-kV substations. This result is also valid for the CPD scenario.

Figure 69: *400-kV grid investment figures (BAU Base, ARES Base, CPD Base)*

Figure 70: *154-kV grid investment figures (BAU Base, ARES Base, CPD Base)*

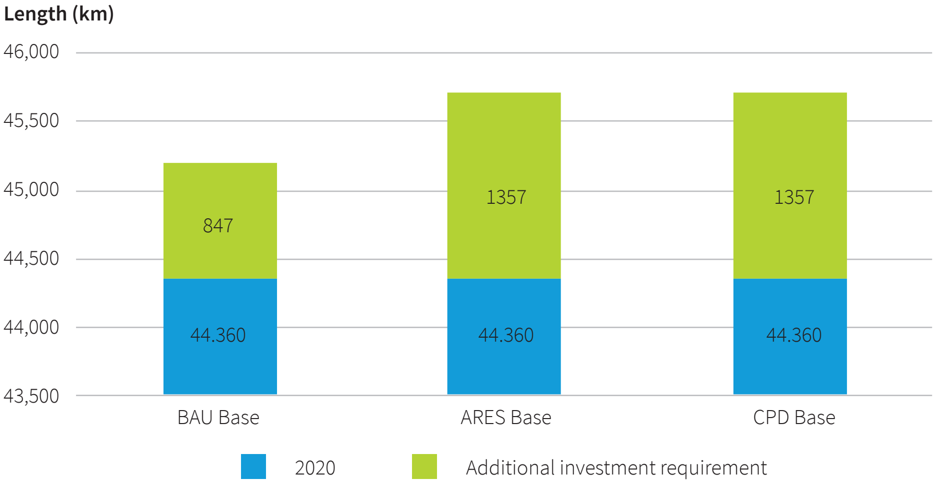


Figure 71 and Figure 72 summarise Turkey's energy generation mix in 2030 across each scenario. In the CPD Base scenario, only 5 GW coal fired power remaining in the system, comprising of a combination of imported (1.8 GW) and local lignite (3.2 GW). Although wind and solar installed capacity is some 10 GW greater than in ARES scenario, their generation remains relatively stable. While gas capacity remains the same in the CPD and ARES scenarios, gas fills the supply flexibility gap in the absence of coal, and its generation share increases from 73 TWh in the ARES to 80 TWh in CPD.

Figure 71: *Turkey's energy generation mix in 2030 according to each scenario*

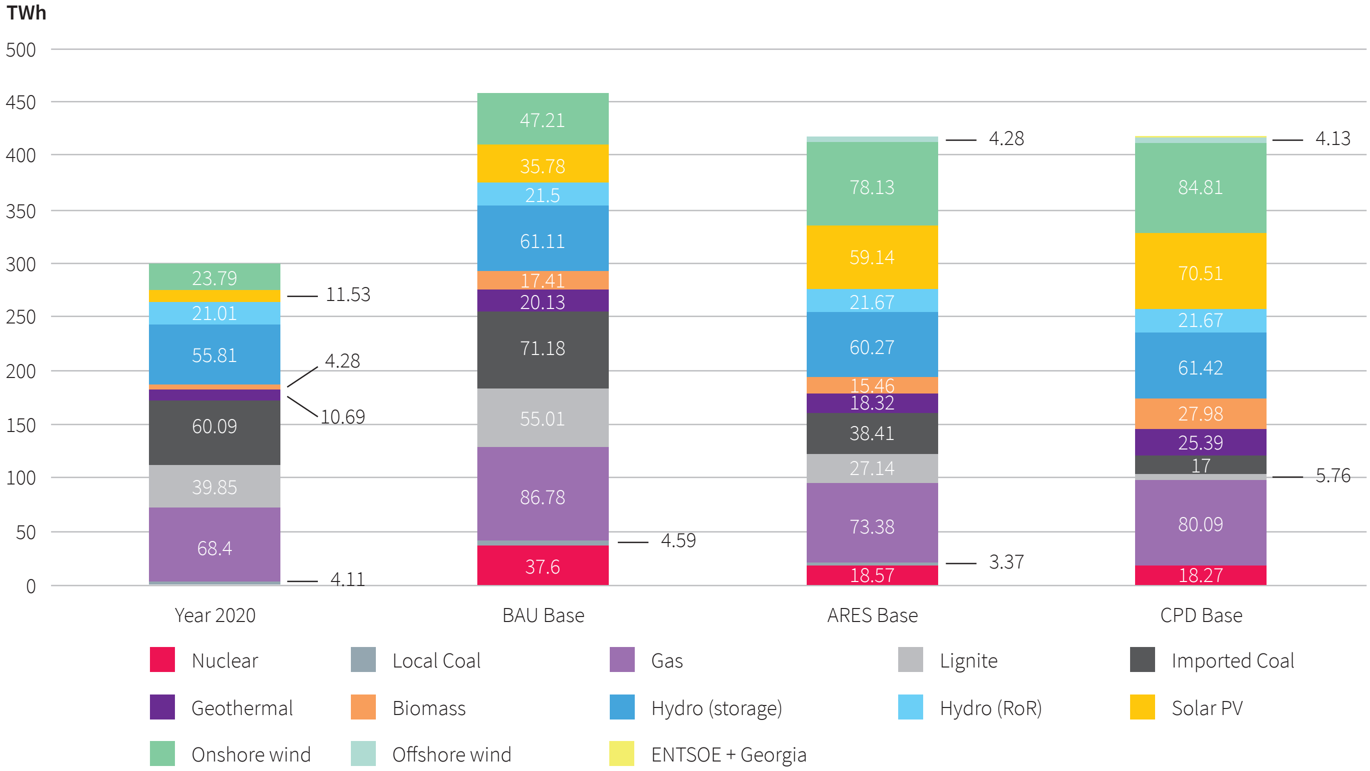


Figure 72: *Electricity generation by technology across each scenario*

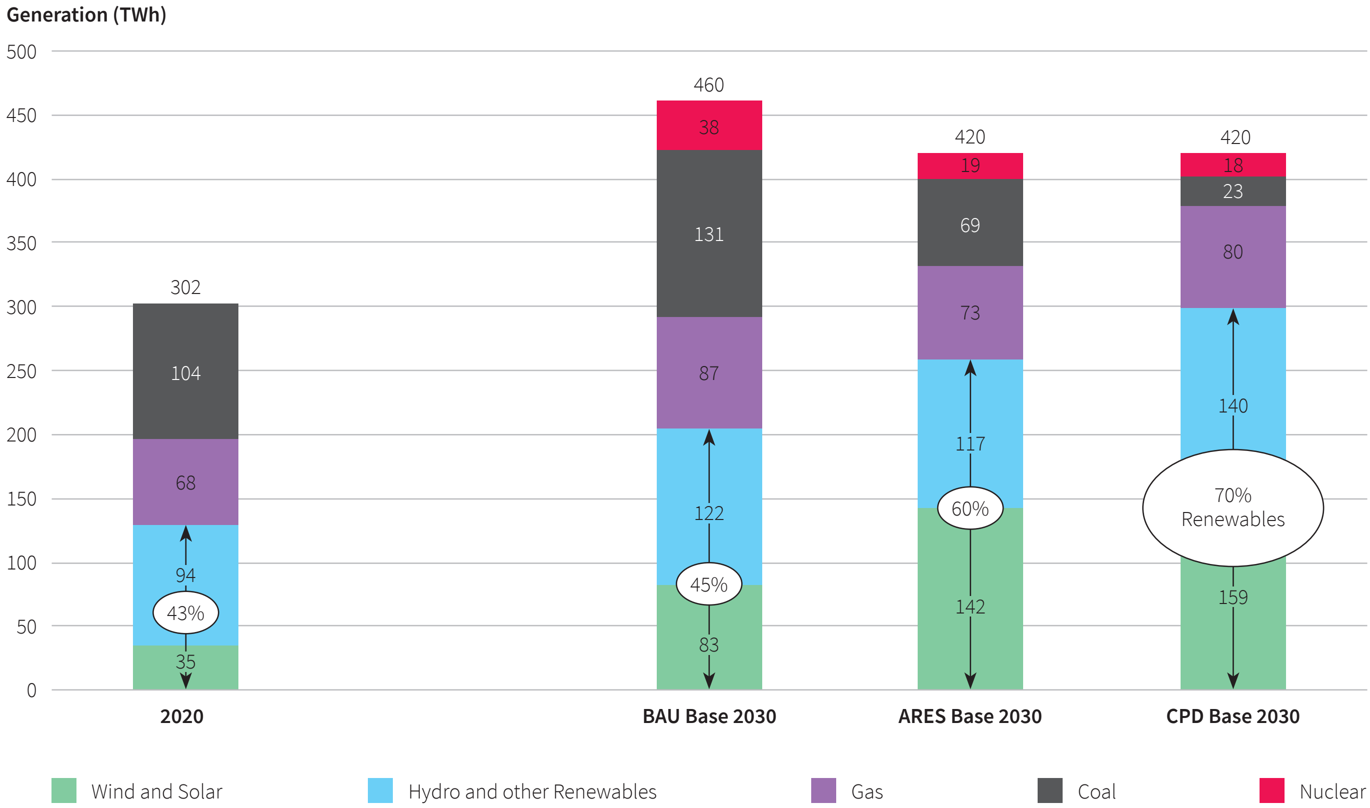
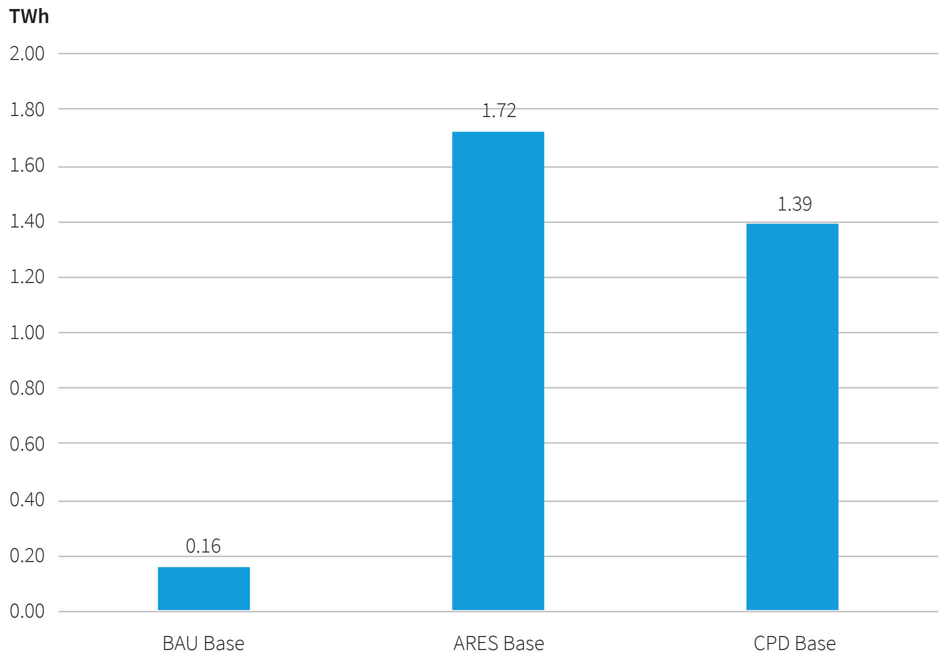


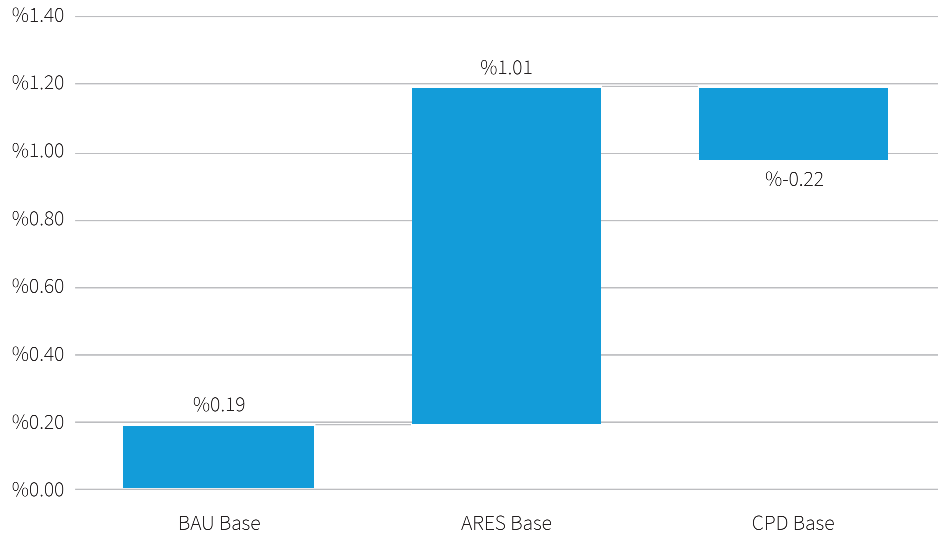
Figure 73 shows a comparison of the three main scenarios in terms of annual RES curtailment amounts. In both the ARES Base and CPD Base scenarios, RES installed capacity is significantly higher than that of the BAU Base scenario, which consequently results in higher RES curtailment amounts compared to the BAU Base scenario.

Figure 73: *a) Annual RES (solar + wind) curtailment amounts in 2030 (BAU Base, ARES Base, CPD Base) in TWh; b) Curtailment of renewable energy supply as a percentage of total renewable energy generation for three scenarios.*



(a)

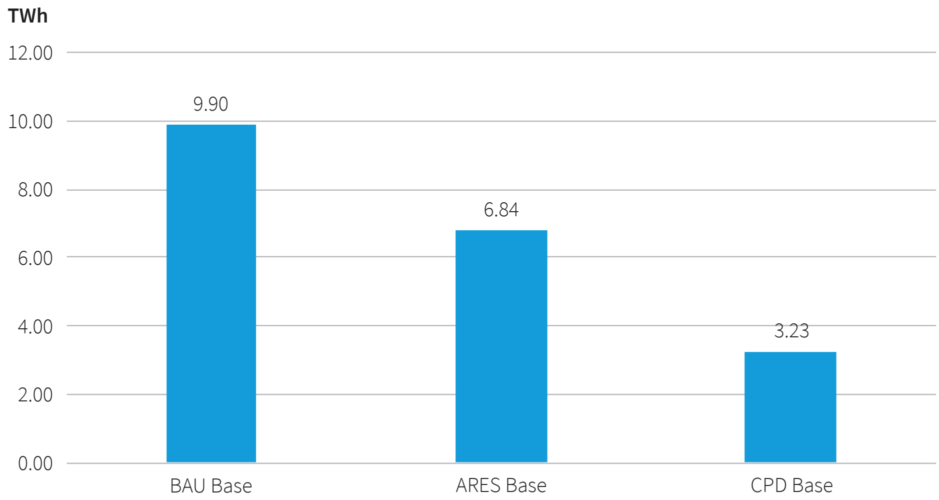
RES Curtailment with Respect to the Total Renewable Generation



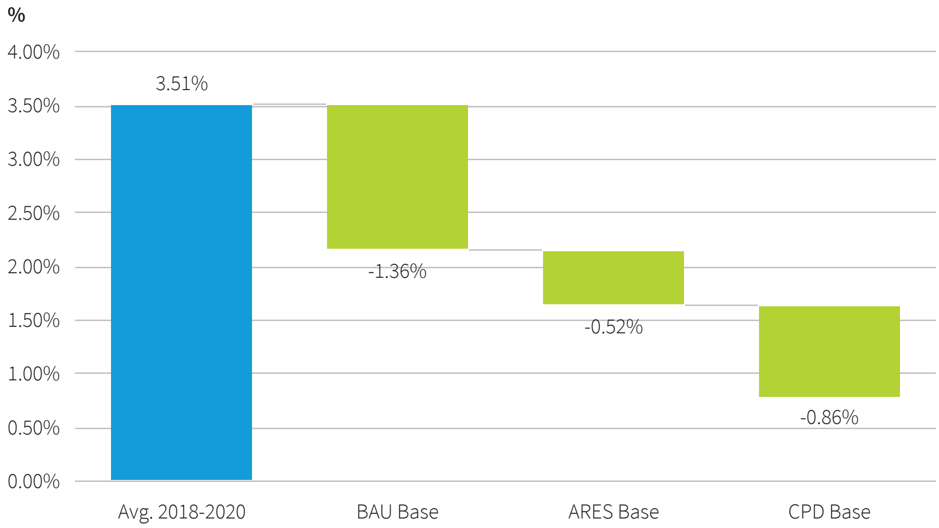
(b)

Figure 74 displays a comparison of the three main scenarios in terms of annual redispatch amounts. The redispatch amount in the ARES Base scenario is lower than that of the BAU Base scenario. The main reason is that the generation at the BAU Base is oriented towards more bulk generation, which injects more power to the 400-kV grid and imposes grid congestions. However, in the ARES Base scenario, the generation is localized at the major load centers through renewable sources at the 154-kV level. Therefore, the grid is subjected to less stress in the ARES Base scenario than that of the BAU Base scenario. This fact is reflected in the redispatch reduction in the ARES Base scenario compared to the BAU Base scenario. However, removing coal-fired generation reduces the need for redispatch. The main reason is coal-based power plants impost hard constraints to the system such as minimum up/down times and by removing them, the system is subject to less constraints which in turn, reduces the amount of redispatch.

Figure 74: *a) Annual redispatch amounts in 2030 (BAU Base, ARES Base, CPD Base); b) Percentage redispatch with respect to total generation, historical average (2018-2020) and across the three scenarios.*



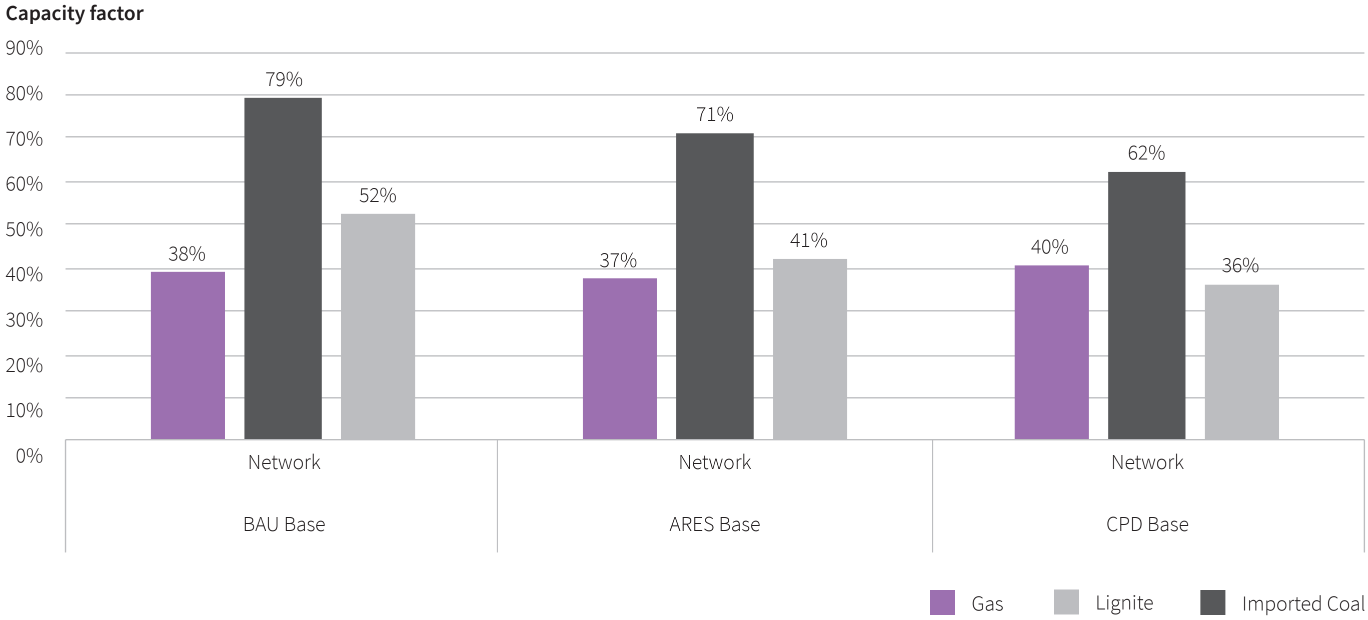
(a)



(b)

Finally, Figure 75 shows a comparison of the three main scenarios in terms of the annual capacity factors of conventional power plants (gas, lignite, and imported coal). The annual capacity factors of gas power plants are highest in the CPD Base scenario compared to the BAU Base and ARES Base scenarios. The main reason is the phase-out of imported coal-fired power plants in the CPD Base scenario. An increase in renewable capacity results in the reduction of the capacity factor of conventional power plants in the ARES Base and CPD Base scenarios if compared to the BAU Base scenario.

Figure 75: *Annual capacity factors of conventional power plants (BAU Base, ARES Base, CPD Base)*



6. Conclusions

This report presents the results and key outcomes of the updated market and network simulation study for the Turkish grid in 2030. Three scenarios are addressed: 1) Business as Usual (BAU); 2) Accelerated RES (ARES); and 3) Coal Phase Down (CPD). For each scenario, market and network simulations are performed for the target year 2030 in hourly resolution. In addition, demand increase, the number of nuclear units in 2030, different types and levels of flexibility options, and carbon phase-out pathways are considered in the sensitivity analyses.

Sensitivity analyses in the BAU scenario are designed as stress tests under low-demand conditions that correspond to challenging conditions as identified by TEIAS, particularly at minimum loading hours when RES generation is the highest and RES generation curtailment could be indispensable depending on the flexibility level of the grid. The logic behind the sensitivity analyses in the ARES scenario, which has more RES capacity compared to BAU, is to gradually increase the flexibility of the grid. These analyses aim to see how the increase in grid flexibility affects redispatch and RES curtailment requirements. Finally, sensitivity analyses in the CPD scenario represent two different pathways (i.e., the CPD Path 1 and CPD Path 2) for coal phase down under different levels of gas power plant and RES capacity.

The main conclusions of the study can be summarized as follows:

- There is a considerable investment plan for the 400-kV grid. Assuming that this plan is realized in 2030, this corresponds, on average, to almost 800 km/year of new transmission lines between 2020 and the 2030 horizon. While this is a significant target, it is comparable with TEIAS's recent implementations (750 km/year on average between 2017 and 2019).
- The current 400-kV investment plan includes new transmission corridors that connect Anatolia and the Thracian region of Turkey through the Bosporus and Dardanelles Straits. In addition, significant grid investments are foreseen that strengthen the connection between Northeastern Turkey and the grid at the center of the country. These investments will prove very valuable for constructing the backbone of a growing and transitioning power system. While planned under the assumption of growth and a modest shift to RES, the modelling analysis carried out shows that it will also enable much more ambitious energy transition scenarios with strong wind and solar growth and a coal phase-out pathway, reducing coal capacity to 5 GW by 2030 in the CPD scenario.
- Grid investment requirements, which are identified in the study on top of the current plan, are more on the 400-kV transmission grid in the BAU scenario, whereas the ARES scenario and CPD scenario require additional investments at the 154-kV level due to a higher level of RES capacity connected at the 154-kV level.
- Turkey, due to its geography and partially due to sensitive situations in neighbouring power systems (e.g., Iraq and Syria, in particular), has weak interconnections with its neighbours. Nevertheless, increasing NTC with the ENTSO-E system, Georgia, and its own Southeast region would enhance system flexibility and security if complemented by market coupling mechanisms. This will, however, also require associated internal grid investments, particularly at the 400-kV level, to maximize the utilization of flexibility on interconnection lines through market coupling and imbalance netting.

- Given the current investment plan and the flexibility solutions addressed in this study, 30 GW and 34 GW of system-driven wind and solar power plants, respectively, can be integrated into the Turkish grid in 2030 with acceptable redispatch and RES curtailment amounts (if compared to recent redispatch figures). The mentioned 64-GW of wind and solar investments as outlined in the ARES scenario correspond to 45% of total installed capacity and 34% of annual generation. Taking into account additional RES capacity, i.e., hydro, biomass, and geothermal, the total share of RES is around 60% in the ARES scenario. This ratio increases to around 70% in the CPD Base.
- The CPD scenario shows that it is technically feasible to reduce coal-fired installed capacity from almost 20 GW in 2020 to 5 GW in 2030 provided that installed gas power plant capacity in 2020 is preserved in 2030 (26 GW in CPD Path 1 and CPD Path 2) or 3 GW of gas power plants is replaced with geothermal and biomass plants (CPD Base). In CPD Path 2 scenario, this results in increment of the redispatch amount in the grid compared to the BAU and ARES scenarios. Shutting down the bulk of imported coal-fired power plants, most of which are close to demand centers, is the main reason for this. Nevertheless, the total amount of redispatch in the CPD scenario is still comparable to the BAU Base scenario (almost 10 TWh out of 460 TWh generation) and 2020 figures (7.75 TWh out of 302 TWh generation). A coal phase-out will result in a considerable increase in the gas utilization factor compared to the BAU scenario.
- According to the Paris Agreement, carbon emissions will have a significant cost in the near future. The cost of carbon emissions dominates even under the assumption of a 25 EUR/ton CO2 emission cost (the average in the EU is currently around 60 EUR/ton CO2). The cost of additional grid investments and the flexibility solutions required in the ARES and CPD scenarios will be covered—with even further savings—through a reduction in the carbon emissions cost and a decrease in the average MCP. System transformation to more RES will be a cheaper solution than sticking to a high carbon-based system despite the fact that grid investments and the cost of increasing the flexibility of the grid will slightly increase.
- The generation amount of gas power plants reduces significantly when four nuclear units are assumed to be in operation in the ARES - 4 Nuclear Units sensitivity. This results in decreased flexibility from gas power plants, which in turn results in higher redispatch and RES curtailment with respect to the ARES Base scenario.
- The demand of the Turkish power system continues to grow. However, there are uncertainties in the speed and magnitude of growth, which will depend not only on economic development but also the success of energy efficiency measures in end-use sectors as well as the impact of electrification in transport and building sectors. If demand increase is assumed to occur at a minimum level (360 TWh in 2030; i.e., 1.55% annual average increment), gas power plants will be most affected. Their utilization rate may be reduced to around 10% on average at low demand from around 40% at high demand, which under the current market regime may call into question whether many of these power plants would be able to earn back their investments. These include critical gas power plants that play an important role in providing ramping up/down capability to the system. In order to maintain system security, the market and regulations will need to provide sufficient signals to either invest in alternative flexibility options (like storage, more flexibility on interconnection lines, demand response, etc.) or keep gas power plants online, for example, through capacity payment mechanisms. The associated costs and benefits need to be carefully weighted. Current capacity payment mechanisms should be amended. Locations of power plants in terms of grid connection points

and annual capacity factors are among the most critical factors to be considered in amending the capacity payment mechanism.

- The model implemented in this study does not include reactive power and voltage-related concerns, because the DC load flow approach is considered in the network simulations. Reactive power support from RES that are connected to the 154-kV and 400-kV transmission grid is defined in the grid code. However, RES that contribute less than 30 MW and are connected to the distribution grid are not supposed to provide reactive power support under the current legislation. As recommended by international standards (IEEE 1547-2018[42] and BS EN 50549-2:2019[43]), getting reactive power support from those RES is becoming critical, along with the increase in installed RES capacity. Therefore, the Turkish grid code should include reactive power support rules and mechanisms for RES that are connected to the distribution system.
- Spinning reserves in the Turkish market have been procured symmetrically: that is, conventional power plants, particularly gas and storage-hydro that provide spinning reserves in the ancillary market, have to provide equal amounts of spinning reserves in an upward (positive) and downward (negative) direction. However, as the capacity of RES increases, non-symmetrical reserve capacity allocation should also be considered. During the minimum loading period when RES generation is high, biomass, geothermal, wind, and solar PV power plants can provide downward reserves to ensure the ramp-down flexibility requirement of the power grid. This capability is important in minimum loading and during high-RES generation periods.
- In addition to the downward direction, wind and solar power plants can also provide reserves in an upward direction. This study shows that getting upward reserves from wind and solar power plants reduces dependability on the power grid and gas and storage-hydro power plants used to satisfy spinning reserve constraints.
- Detailed CBAs should be made to compare the costs and benefits of different types of flexibility measures. Priority should be given to the most efficient measures such as market coupling through interconnections, which provides significant flexibility for the system. Furthermore, the current level of NTC along interconnection lines is limited (500 MW with ENTSO and 700 MW with Georgia). An increase in the total NTC will essentially contribute to the grid's RES hosting capacity as illustrated in the study. An increase in the NTC along interconnections as well as the implementation of market coupling mechanisms is the most prevailing measure to increase flexibility and thereby the RES hosting capacity of the power grid.

[42] IEEE Std. 1547-2018. IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

[43] BS EN 50549-2:2019. Requirements for generating plants to be connected in parallel with distribution networks Connection to a MV distribution network.

Appendix 1 - Comparison of the scenarios and sensitivities in terms of key assumptions

Scenario / Sensitivity	2020	Business as Usual (BAU)					Accelerated RES (ARES)					Coal Phaseout (CPD)		
		BAU Base	Low Demand	No Flexibility on NTC	More Wind & Solar	Less Gas PP	ARES Base	4 Nuclear Units	More Flexibility	Demand Response	More Flexibility on NTC	CPO Base	CPO Path 1	CPO Path 2
Total consumption (TWh - gross)	**303**	**460**	**360**	**360**	**360**	**360**	**420**	**420**	**420**	**420**	**420**	**420**	**420**	**420**
Base load (TWh)	303	458	358	358	358	358	458	458	458	458	458	458	458	458
Electrification & EV (TWh)		2	2	2	2	2	10	10	10	10	10	10	10	10
Efficiency (TWh)		-					-48	-48	-48	-48	-48	-48	-48	-48
Flexibility options														
Flexibility from interconnections	-	√	√	-	√	√	√	√	√	√	√	√	√	√
Pump storage*	-	-	-	-	-	-	√	√	√	√	√	√	√	√
Battery**	-	-	-	-	-	-	-	-	√	√	√	√	√	√
Spinning reserve from RES ***	-	-	-	-	-	-	-	-	√	√	√	√	√	√
Demand-side response ****	-	-	-	-	-	-	-	-	-	√	√	√	√	√
Installed generation capacity (MW)	**93,207**	**128,541**	**128,541**	**128,541**	**156,776**	**146,856**	**142,595**	**144,995**	**142,595**	**144,995**	**142,595**	**145,898**	**146,175**	**136,198**
Nuclear	-	4,800	4,800	4,800	4,800	4,800	2,400	4,800	2,400	4,800	2,400	2,400	2,400	2,400
Natural Gas	25,632	25,845	25,845	25,845	25,845	15,925	22,741	22,741	22,741	22,741	22,741	22,741	25,845	25,845
Imported Coal	8,967	10,267	10,267	10,267	10,267	10,267	6,188	6,188	6,188	6,188	6,188	3,135	3,135	-
Local Coal	811	918	918	918	918	918	811	811	811	811	811	-	-	-
Lignite	10,097	11,993	11,993	11,993	11,993	11,993	7,502	7,502	7,502	7,502	7,502	1,842	1,842	5,000
Total HPP	**29,790**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**	**31,700**
Hydro (Storage)	21,877	23,540	23,540	23,540	23,540	23,540	23,540	23,540	23,540	23,540	23,540	23,540	23,540	23,540
Hydro (RoR)	7,913	8,160	8,160	8,160	8,160	8,160	8,160	8,160	8,160	8,160	8,160	8,160	8,160	8,160
Total Wind	**8,077**	**16,679**	**16,679**	**16,679**	**30,376**	**30,376**	**30,376**	**30,376**	**30,376**	**30,376**	**30,376**	**33,376**	**33,376**	**30,376**
Onshore	8,077	16,679	16,679	16,679	29,224	29,224	29,224	29,224	29,224	29,224	29,224	32,224	32,224	29,224
Offshore	-	-	-	-	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152
Solar PV	6,361	19,796	19,796	19,796	34,334	34,334	34,334	34,334	34,334	34,334	34,334	41,334	41,334	34,334
Geothermal	1,515	2,884	2,884	2,884	2,884	4,000	2,884	2,884	2,884	2,884	2,884	4,000	2,884	2,884
Biomass	869	3,289	3,289	3,289	3,289	5,000	3,289	3,289	3,289	3,289	3,289	5,000	3,289	3,289
Other	1,088	370	370	370	370	370	370	370	370	370	370	370	370	370
NTC (MW)														
ENTSO-E	500	500	500	500	500	500	500	500	500	500	1000	1000	1000	1000
Georgia	700	700	700	700	700	700	700	700	700	700	1000	1000	1000	1000
Southeast	-	-	-	-	-	-	-	-	-	-	750	750	750	750

* 1000 MW pump storage at Gokcekaya HPP;
** 600 MW Li-Ion;
*** 5% of RES generation from RES >50 MW capacity;
**** Demand shifting from peak hour to off-peak hour

NOTES

NOTES

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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