Türk-Alman Enerji Forumu
Deutsch-Türkisches Energieforum

Supported by:
Federal Ministry for Economic Affairs and Energy
on the basis of a decision by the German Bundestag

German–Turkish Energy Partnership

Flexibility for the Turkish and German Electricity Grids

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Date: 11/2021

Please quote as: German Energy Agency (Publisher) (dena, 2021): Flexibility for the Turkish and German Electricity Grids

Executive Summary

Climate change is a game changer of our time. International efforts to minimise emissions that cause climate change have increased in the past decade. Most countries have drawn up national climate goals, which are often also reflected in their NDCs as part of the Paris Agreement. The deployment of electricity from renewable energies (RE) is one of the means to achieve the climate goals. Since RE also happen to be a cheap source of energy, they are on the rise worldwide. However, their integration into grids that have been designed to mainly accommodate fossil fuel plants presents unprecedented challenges.

A fundamental aspect for their successful grid integration is power system flexibilisation. In order to accommodate volatile renewable energies, the flexibility potential of all other sources of energy, as well as grid management and market operations, needs to be increased.

The German Energy Agency (dena), within the **framework of the German-Turkish Energy Partnership**, has conducted a comparative analysis of flexibility measures for Turkish and German power grids as both countries would like to deepen their exchange on possible flexibility measures. Guiding questions in this context were: Are certain flexibility measures easier to implement in one country than in another? What regulatory starting points may be the cause of those differences? What pitfalls have the countries experienced so far? Can they learn from each other so that mistakes are not repeated?

The document at hand looks into various flexibility measures (operational, regulatory and technological) and assesses the impact and opportunities for flexibilising the grids in the two countries. The several sources of (additional) flexibility are clusted into six chapters:

- Flexibility measures for Conventional Power Plants
- Demand Side Management
- Large-scale Batteries
- Small-scale Batteries
- Power-to-Gas
- Further Operational and Market Design Flexibility Options

For each flexibility option, the status quo in each country is described including the most relevant regulations as well as the potential of these options.

The comparative study is divided into three parts.

- **Part A** is for readers who want an **overview** over the **most important findings** in each country as well as a comparison.
- **Part B and C** are **in-depth analyses** for each country respectively.

Part A - draws on the two separate case studies in Part B and Part C on Germany, prepared by Team Consult, and on Turkey, prepared by Aplus Enerji. Written by dena, this part sets the scene by contrasting the different market structures and actors as well as the decarbonisation targets of both countries. Finally, **three lessons learned for each country** are identified and essential elements of Part B and Part C highlighted.

For Germany, the following three aspects are important lessons learned regarding the introduction of more flexibility to the grid:

- Increasing the granularity - e.g. lead time, product duration, price increments and spatial resolution - in the market.
- Modernizing and increasing the flexibility of coal plants through innovative approaches.
- Regular adaptations of support schemes, as evidenced by the example of the Renewable Energy Sources Act (EEG).

The Turkish experience also provides valuable examples of successful applications of flexibility measures:

- Inclusion of a battery scheme in the technical specifications of an auction – as was the case with the YEKA solar capacity auction.
- Controlling investments in small solar power plants, which have the sole aim of selling to the grid, through provisions that regulate the reduced tariffs and net metering of consumption.
- Developing early on a sound market design is crucial for the later introduction and implementation of various flexibility measures.

Part A highlights **five recommendations for each country**.

Recommendations for Germany:

- Reducing the overall must-run time of conventional power plants through new technologies and appropriate obligations and financial incentives.
- Fully exploiting the DSM potential with various incentives (e.g. flexibility markets and quotas, dynamic grid fees).
- Addressing all legal provisions of battery applications.
- Incentivising the optimal allocation and operation of electrolysers, while clarifying the corresponding legal framework on hydrogen production.
- Developing an all-encompassing coordination mechanism between TSOs and DSOs as well as a transparent data exchange.

Recommendations for Turkey:

- Disseminating the utilization of DSM, through appropriate incentives and opening the market to additional players.
- Developing a coherent regulatory framework, a hydrogen strategy and financial mechanisms aimed at facilitating hydrogen production.
- Adjusting the participation of generating units in the ancillary services market and moving auctions closer to real-time.
- Abolishing of lignite purchase guarantees and allowing negative prices in order to encourage the flexibilisation of conventional power plants.
- Incentivising the installation of small-scale batteries at existing and new RES facilities through incentive mechanisms and subsidies.

Part B provides an in-depth analysis of flexibility in the German electricity grid. Germany has already achieved significant gains in terms of power system flexibility in the last years. The most challenging steps were the introduction of competition and the unbundling of the electricity grids as well as substantial growth in renewable power generation:

Though **conventional power plants** have a certain degree of flexibility from the outset, they are able to provide increasingly volatile residual load. Thereby they form the basis for the further integration of renewable energy into the existing electricity system. The degree of flexibility of existing plants can be increased, e.g. by reducing the minimum load or by increasing the maximum load gradient of a plant. The future phase-out of conventional power plants with less inherent flexibility, i.e. nuclear, lignite and hard coal power plants, will change the overall composition of the German power plant fleet. The new power plants will predominantly be gas-fired and thus feature a high level of built-in flexibility.

Demand-Side Management (DSM) is a principle by which the demand of electricity consumer is adjusted according to the requirements of the electricity system. Germany has longstanding experience in the application of DSM. A variety of incentives exists in the energy system, which aim to increase the number of electricity customers engaging in DSM. An important instrument directed at industry customers are interruptible loads. At the residential level, which is managed by the distribution system operators (DSOs), DSM is conducted under so-called load control agreements. The increasing use of battery-electric vehicles and smart devices "behind the meter" provide another large potential for DSM to DSOs.

Large-scale batteries (LSBs) have seen an unprecedented growth in Germany over the last years, particularly from 2016, resulting in LSB installations of more than 400 MW in total. This happened under a regulatory system that paid no particular regard to LSBs specifically and electricity storage technologies in general. Nonetheless, a multi-use approach in LSB business cases has become the norm today, meaning that LSBs are used in parallel to provide not only control energy but also to serve other purposes, like optimization in the spot market and the reduction of grid connection fees (by means of peak shaving).

Small-scale batteries in residential homes are usually installed in combination with a PV rooftop system. The most common application is the maximization of self-consumption of PV electricity instead of the (more expensive) electricity withdrawn from the power grid. In such a set-up, no regard is usually paid to the (flexibility) requirements of the connected electricity grid. Nevertheless, small-scale batteries in some cases do provide services to the public grid, e.g. through energy companies that aggregate a large number of small-scale batteries into a larger virtual unit which the company (the aggregator) then uses for trading purposes in the intra-day spot market or to provide services in the markets for ancillary services. The rollout of smart metering and smart grid technologies will expand opportunities for prosumers to use their batteries to the benefit of the connected grid and to benefit from that economically.

The Power-to-Gas (PtG) technology and the provision of green fuels such as hydrogen and synthetic methane represents an important option in the transformation towards a more sustainable energy system, especially for sectors that cannot be easily electrified. This option will also be the main driver of PtG capacity expansion, which in turn will further drive the need for more (intermittent) renewable generation capacity to run PtG plants. This means the electricity system will have to cope with additional intermittent electricity generation, and the PtG plants will have to contribute the lion's share of the additional flexibility required. In essence, the load profile of PtG plants will have to mirror the load profile of "their" renewable power generation. How this can be coordinated – e.g. through the intra-day spot market, control energy markets, interruptible loads etc. – remains to be seen. Compared to expectations for the future, current PtG capacity is still very limited in Germany. The upscaling of electrolyser production and the size of electrolysers will reduce the investment costs and improve the competitiveness of green hydrogen and hydrogen-based fuels.

Operational and market design flexibility measures are of a different nature than the measures discussed above. The above-mentioned means of providing flexibility to the electricity systems in most cases require the expansion of some kind of capacity (storage, electricity generation, transmission, PtG, …) and, thus, investments. In order to avoid unnecessary investments, it is crucial (i) to prevent a lack of supply-demand coordination that leads to an ostensible need for flexibility that in reality does not exist and (ii) to mobilise and use all existing flexibility potential already imbedded in the system. This means that all capacities – generation, transmission, distribution and (load-controlled) demand – should be operated providently and in a manner that takes into consideration the electricity system's requirements. For that, all operators of capacity need to be informed of the system's requirements and to be incentivized to accommodate them.

Part C provides an in-depth analysis of flexibility in the Turkish electricity grid. Turkey is at a crossroads regarding its energy transition, having achieved a substantial amount of renewable energy penetration over the last decade. The further integration of variable renewable energies requires an even more flexible power system.

Conventional power plants: a significant portion of the current thermal and coal power plant fleet in Turkey is old and inflexible. Several incentives such as purchase guarantees and a capacity mechanism are acting as barriers for flexibility investments. On the other hand, there are also some mechanisms and regulations like the ancillary services market and the hybrid power plant regulation that are beneficial to the flexibility of conventional power plants. The re-evaluation of the current local coal purchase guarantee and capacity mechanism schemes would be a positive step to promote flexibility investments for the domestic power plant fleet.

Demand-side management (DSM): the utilization of DSM applications is one of the top policy targets for the Turkish energy market in several official strategy documents. Moreover, recent changes in the ancillary services regulation are also a positive step in terms of the promotion of DSM applications. Several steps have also been taken regarding smart metering, grids and cities. Despite the importance given to DSM utilization already, there is still a vast remaining potential in Turkey. This potential can be accessed through changes in the market architecture of the ancillary services, balancing power and the day-ahead market. The currently low maximum price limit applied in electricity markets is a barrier for increased demand-side involvement in the market.

Battery storage: The utilization of electricity storage systems is one of the main policy goals and significant steps have been made to establish a regulatory framework for battery storage in the market. Further steps to expedite their utilization are:

- Abolishing or re-designing of the price cap formulation in the day-ahead market can increase the attractiveness of battery installations aimed at energy arbitrage.
- Establishing subsidies such as tax cuts, credits or grants to invest in battery technologies would help introduce battery applications to the market and increase the flexibility of the energy system.

Since **power-to-gas systems** are a technology under development, there is a lack of regulation in this field in Turkey. Hydrogen has recently become one of the areas that policy makers see as a priority and R&D studies have gained momentum. These studies should be continued and a regulation for the use of power-to-gas systems should be prepared.

In addition to the aforementioned technical solutions regarding system flexibility, there are also several **operational and market design measures** that can be implemented. Such measures are options that bring benefits at the lowest cost since they do not require major CAPEX investments in the system. New regulations and schemes that support flexibility should be defined, the temporal and spatial granularity of the Turkish energy market should be increased, and digital systems should be utilized in order to improve predictions of renewable energy generation.

Outlook: the authors hope that the insights given will contribute to accelerating the deployment of RE with a view to the climate goals of both countries, while ensuring safe operations of the electricity system. By highlighting areas where action is needed, we hope this report will trigger and further support the ongoing dialogue between both countries on the energy transition. Further, we hope that experts from Germany and Turkey will contribute to this knowledge transfer in the months to come and address important issues constructively.

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Flexibility measures for the Turkish and German electricity grids (Part A)

Lessons learned in both countries and recommendations for actions

1 Bilateral exchange on power grid flexibilisation

In order to appreciate and better grasp the analyses to come, this introduction shall start by providing a deeper understanding of why flexibility measures are such an important part of the energy transition. This will be followed by a presentation of key figures of the German and Turkish energy markets. Lastly, the climate goals and key emission figures of each country will be presented and contrasted. The numbers shall provide an understanding of the urgency to speed up the deployment of renewable energies and thus the adoption of flexibility measures at all levels.

The importance of system flexibilisation for an integrated energy transition

As power systems transform, flexibility has become a priority. Making an energy system more flexible also means modernising it and thereby facilitating cleaner and more reliable, more resilient and more affordable energy. The range of instruments to increase flexibility includes operational, policy and investment-based interventions.

It is important to recognise that all power system assets, including variable renewable energy, can provide flexible services if enabled by the right policy, market and regulatory frameworks. These assets include power plants, electricity networks, energy storage and distributed energy resources. When talking about the role of grids, distribution grids in particular play a central part in handling past and future changes because almost all generation from renewables stems from the distribution grids. Moreover, almost all power consumers are connected to lower voltage levels where new loads are increasing, e.g. electric mobility and heat pumps.

Another important aspect is that adaptations are not only necessary to the overall market design but also specifically to the ancillary services market. This is the case as not only energy supply and demand but also grid stability needs to be achieved.

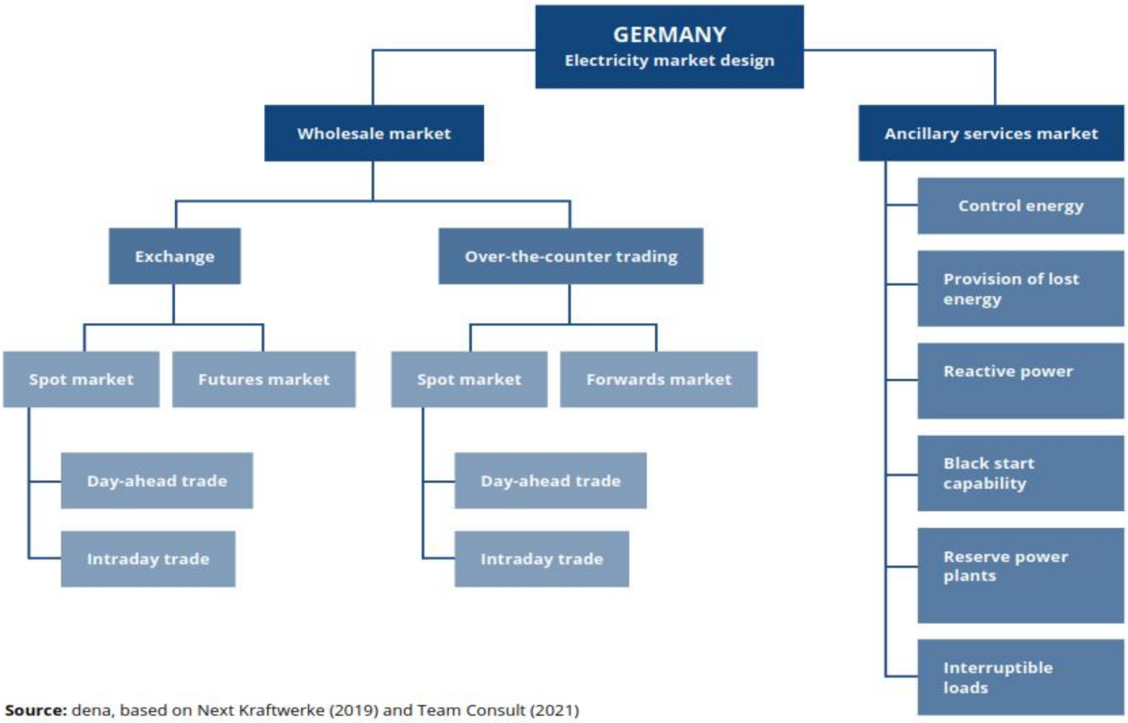
This report takes all of the above into consideration to list the flexibility options in each country and provide insights into the regulatory framework for each option as well as possible ongoing modification efforts, before finally identifying challenges and opportunities to unlock even more flexibility and thus accelerate the transformation of the power system.

The German and Turkish electricity markets at a glance

Both countries started early on with liberalisation reforms in their electricity sectors, which subsequently enabled an enhanced deployment of RE. However, it was the introduction of a feed-in tariff scheme that catapulted the deployment of RE in both markets. This scheme has been in place since 2011 in Turkey. Meanwhile, it was introduced in 2000 in Germany and has evolved into a feed-in premium scheme ever since. Another milestone in these reforms has been the liberalisation of both markets. This process was launched in the late 90s in Germany and in 2001 in Turkey, where it is still ongoing, considering the various new actors assuming new roles in the power systems. The liberalisation of the electricity markets gave rise to a diverse set of participants in the different market segments and enabled the effective operation of liquid wholesale markets. Thanks to these two factors, it is now possible to react flexibly and efficiently to the volatile electricity generation from renewable energy sources. An overview of the main actors is provided in Figures 1 and 2 below.

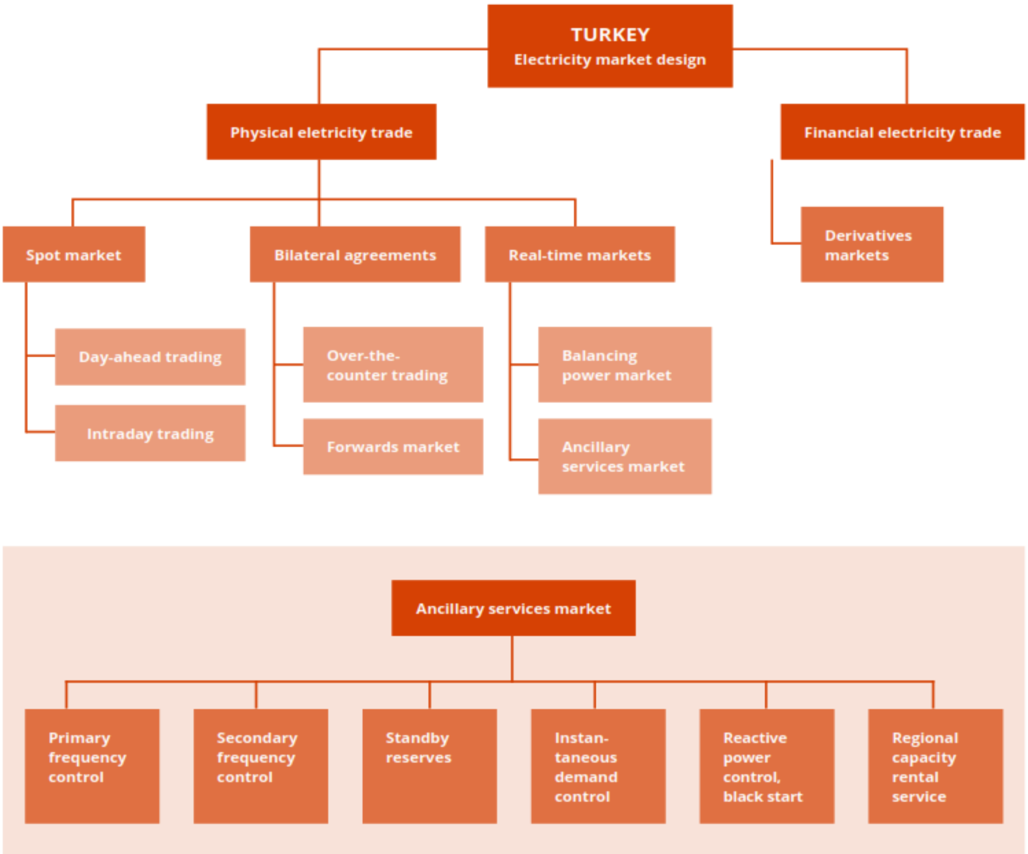
The respective regulatory authorities, namely the Turkish Energy Market Regulatory Authority (EMRA) and the German Federal Network Agency (BNetzA), are tasked with regulating and supervising the electricity and natural gas markets. Further information on the various market actors and their roles can be found in the Turkish part of the flexibility study (pp. 110), as well as in the "German experiences with large-scale batteries" study (pp. 11–13, to be found in the Annex).

The central marketplaces for commercial trade and physical balancing are set up as follows:



Source: dena, based on Next Kraftwerke (2019) and Team Consult (2021)

Figure 1: German electricity markets



Source: dena based on Aplus (2021)

Figure 2: Turkish electricity markets

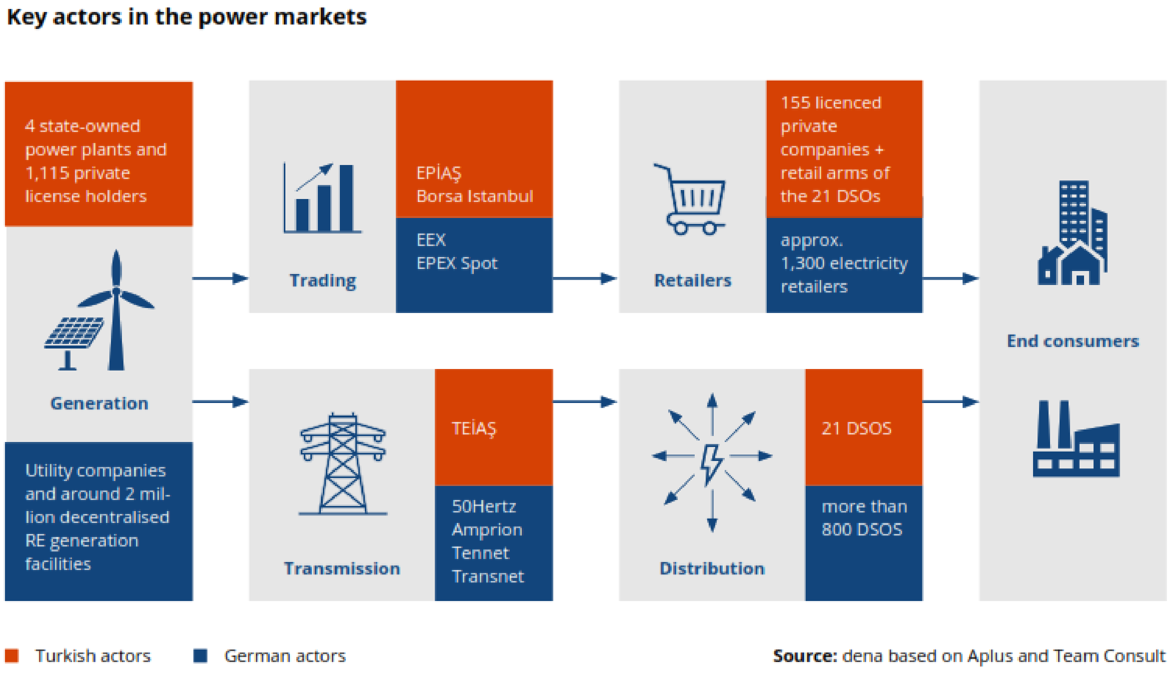


Figure 3: Key actors in the power markets

For more detailed descriptions, please refer to pp. 109–110 of the Turkish flexibility study as well as pp. 13–14 of the "German experiences with large-scale batteries" study.

As already mentioned, Turkish and German legislation have put relevant support schemes in place over the past several years to increase the share of RE in the system. A feed-in tariff mechanism (YEKDEM) was first introduced in the Turkish market in 2011 and is set to expire after the first half of 2021. A new feed-in tariff will replace the former after 1st of July 2021 and will essentially be developed as a support mechanism based on an auction system; further details are provided on page 112. The German example has a similar starting point since individual guaranteed feed-in tariffs for RE were first introduced in 2000 with the Renewable Energy Sources Act (hereafter: EEG). The EEG and the respective support schemes were amended and revised regularly throughout the years, evolving into the current support scheme based on auctions. Further information on these support schemes can be found on pp. 111–112 of the Turkish flexibility study and pp. 97–98 in the German section.

Further indicative aspects that were considered when assessing the need for each power system to be flexible are the existing interconnection capacities and the SAIDI index. Looking into the SAIDI index of both countries provides great insight into the reliability of the electricity system and the corresponding need for flexibility in the power system:

- The average interruption time in Germany's electricity supply for 2019 was 12.20 minutes/year.
- The corresponding figure for Turkey in 2019 was 45 hours/year, according to World Bank estimates.

A poor SAIDI score is not necessarily correlated with a high share of renewable energies; factors such as economic or political developments or the expansion of the energy infrastructure are much more decisive in that regard.[1]

Concerning the interconnection capacities of both systems, there are some considerable differences. An observer membership agreement, signed between ENTSO-E and TEİAŞ, allowed for synchronous connections

[1] Next Kraftwerke (n.d.)

between the Turkish power system and the European grid; as a result, the monthly capacity of the existing interconnection lines in Turkey was also made available to the European market.[2] Through its interconnections with Bulgaria and Greece, Turkey imports 600 MW and exports 500 MW of electricity to Europe on average.[3] On the other hand, Germany, in part due to its geographical location, is interconnected with many neighbouring countries, namely Austria, Switzerland, the Netherlands, France and some Nordic countries. Germany has progressively become a large net exporter of electricity with an export balance of 25.19 TWh in 2019.[4] The largest share of Germany's net exports went to the Netherlands, Austria and Poland; imports came mostly from France.[5]

Decarbonisation targets in both economies

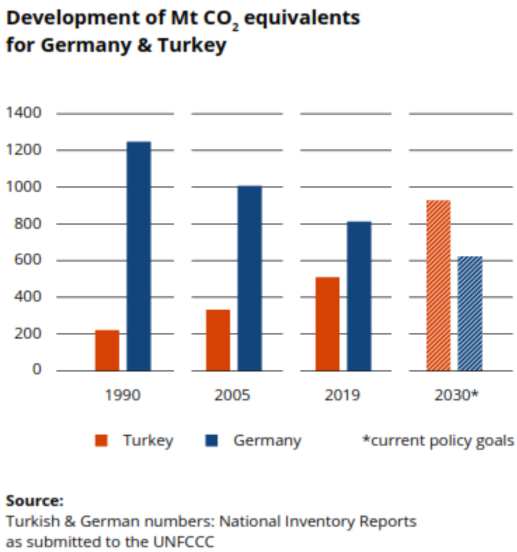


Figure 4: Development of Mt CO_2 equivalents for Germany and Turkey

The above goals are the national goals of each country. Concerning international commitments, Turkey ratified the Paris Agreement in October 2021. In its National Inventory Report to the UNFC, which dates back to 2015, Turkey suggests an intended Nationally Determined Contribution (NDC) of -21% compared to a business-as-usual scenario. However, following the ratification of the Paris Agreement, Turkey still needs to submit an updated NDC.[6] Germany has ratified the Paris Agreement; however, as it belongs to the EU, Germany did not submit its own NDC to the Paris Agreement. Therefore, the above stated national targets serve as the best indicator.

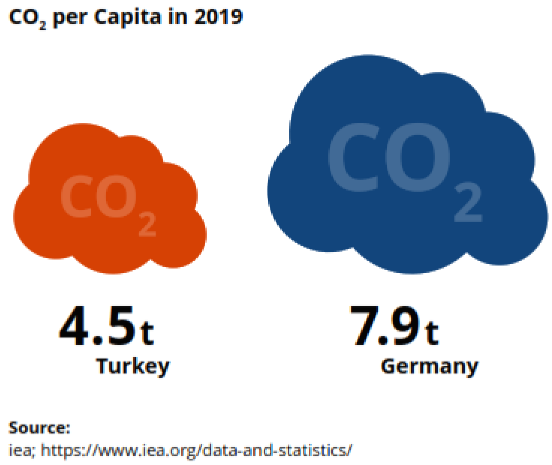


Figure 5: CO_2 per capita in 2019

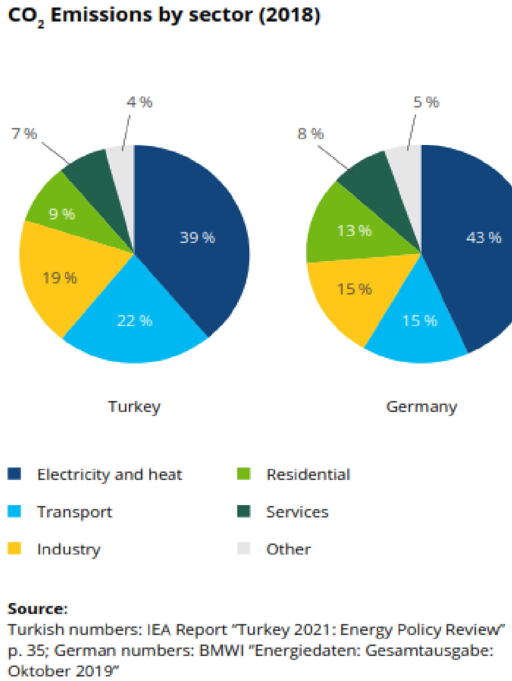


Figure 6: CO_2 Emmissions by sector (2018)

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[2] IEA, Turkey Energy Policy Review (2021)
[3] Ibid.
[4] Federal Network Agency (BNetzA), 2020
[5] IEA, Germany Energy Policy Review (2020)
[6] Climate Action Tracker, Turkey (2021)

2 Regulatory recommendations with a view to 2030

It is expected that regulations set clear goals to optimise the power system and maintain affordable electricity prices. The regulation of the energy system is deeply embedded in the national context, its stakeholders and their interest as well as incentive regimes. Most often, such incentive regimes have been set to achieve certain goals in time and are usually still prevailing. As they are amended and complemented by different regulations, they leave behind a mixed carpet of varying incentive regimes. Regulations aiming at enhancing flexibility can be quite different from country to country. Nowadays, especially in Germany, progress in the energy transition is often hampered, more due to long public debates than a lack of technical knowledge.

With a view to flexibility options, it should also be noted that the system can be viewed as a whole or from the grid operators' perspective as well as from the producers' or consumers' standpoint. The regulatory recommendations presented below are based on the results of the German and Turkish flexibility studies, which can be found following this comparative analysis. The top five measures below shall be examined in the context of these studies, which do not necessarily mirror all the aspects of current national discussions on flexibility. The reason for that is that the studies cater to the need for knowledge transfer and thus need to look beyond the national context as well as take into account certain topics agreed upon by the two partnership countries.

Top five measures identified for Germany

1. Must-run times of conventional power plants

Even though conventional plants offer substantial flexibility and can be retrofitted to increase flexibility, the study emphasises that this is – although substantial – not without its limits, especially when it comes to reducing electricity output for short periods. The study cites the regulator, who has analysed that up to 28 GW of conventional capacity will remain in production even when electricity wholesale prices are negative. This baseload is called must-run capacity. There are different ways of addressing and reducing must-run capacity:

Technical restrictions: Some power plants are not in a position to reduce feed-in, even if it were economically feasible, due to, in particular, technical limitations (minimum load, ramping rates, start-up and shut-down times) of the plants or the obligation to generate heat. These technical restrictions vary between the different generation technologies. Nuclear power plants and lignite power plants, for instance, are particularly inflexible. Therefore, with the German coal and nuclear phase-out, the increase of renewable energy sources and the increase of more flexible (H2-ready) gas-fired plants, the must-run capacity is expected to decrease accordingly.

Ancillary Services: Various ancillary services, such as control reserve, reactive power, inertia and redispatch, must be provided for reliable grid operation. Today these services are mainly provided by conventional power plants. However, since Germany plans to become climate-neutral by 2045, these plants will gradually feed less and less electricity into the grid. For the success of the energy transition and the reduction of conventional generation capacity, it is therefore required that renewable energies, batteries, flexible consumers and additional compensation plants take over the stability tasks of conventional power plants.

Missing incentives: Hard coal power plants or even lignite power plants can be retrofitted or redesigned to become more flexible. These technical measures can be costly and require economic incentives. The market signal should therefore not be distorted, and negative prices are very important. Furthermore, there need to be new incentives or even obligations for the provision of ancillary services. RES and new technologies like batteries will only take responsibility for system stability if they are compensated for their service or obligated to provide this kind of service.

In summary, reducing the must-run capacity has various factors and reducing the fleet of conventional power plants should reduce the overall must-run time. However, in the future, new technologies must then contribute to system stability, which requires the right obligations and financial incentives.

2. Accurate demand-side management

Demand-side management (DSM) has been widely used for a long time in Germany. The study points out that system operators have many instruments and incentives at their disposal to engage industry and consumers in DSM. While TSOs use the DSM potential of industry customers, DSOs utilise the potential in the residential sector. Driven by an expansion of e-mobility, heat pumps and new local consumption patterns, DSOs face complex tasks and need increasingly sophisticated control and metering technologies.

There is a need for more differentiated incentives, such as time-of-use tariffs and variable network tariffs, to make effective use of those technologies. In that context, discussions currently focus on flexibility markets and quotas as possible incentives. The path is definitely laid out for dynamic grid fees, making rigid rules like the 7,000-hour incentive questionable.[7] This specific incentive allows grid operators to offer customers who have more than 7,000 annual full load hours personally reduced grid fees or even not charge them at all. The idea is that their load profiles make them system relevant. However, this might send the wrong market signals.

DSM potential is set to grow in Germany, but it will be more challenging than ever to deploy additional flexibilities. According to the study, one area of growth is the car market. There are around 47 million passenger cars registered in Germany. Different scenarios opt for 22%–50% of electric vehicles by 2050, which would create a combined (simultaneous) peak load of 16 GW and electricity consumption of 59 TWh/yr. If only a fraction of that electricity can be shifted time-wise to accommodate the needs of DSOs with regard to grid stabilisation, DSM potential from BEVs in the long-term will be significantly higher than the flexibility derived from any other electricity storage technology today. The consequence will be a significant contribution to load management. However, this alone will not serve the flexibility needs. Accompanying measures, such as full-fledged flexibility markets, may still be required.

An amendment of §14a of the Energy Industry Act (Energiewirtschaftsgesetz – EnWG), had the intention to introduce an instrument for peak load smoothing. However, it did not pass the parliament before the elections in fall 2021. The proposed changes were to make grid connection for electric cars or heat pumps more flexible for grid operators and to deactivate them by remote control and thereby reduce the need for grid expansion at the lower levels.

However, even if peak load smoothing as instrument will pass, it may not solve all issues. Further development of the grid tariff system and flexibility markets will also be an essential part of this process.

3. Proper legal framework and incentives for large- and small-scale batteries

Even though large scale batteries (LSB) and small scale batteries (SSB) have a valuable place in the range of flexibility options and are currently much discussed in Germany, they are not necessarily the best fit nor the cheapest flexibility option. The integration of almost 50% RES in the German electricity system was achieved with a relatively low number of batteries. Furthermore, a large proportion of batteries are used for self-consumption rather than grid stabilisation. Other means of load management, such as grid operator measures, are often a more suitable solution for most energy markets with lower RE shares.

This being said, various legal provisions and definitions target batteries, at least in parts. The amendment to the Energy Industry Act (EnWG) of June 2021 tackles the issue as it encourages a more proactive use of energy storage systems by reducing most double burdens by taxes, surcharges and levies. Moreover, it allows their use as system-relevant sources by the grid operators in addition to normal market activities. Hence, a multi-use of energy storage systems opens up to e.g. residential and commerical photovoltaic storage systems and enables large-scale storage systems to offer several services in the future.

Currently, neither TSOs nor DSOs are acting as operators of electricity storage in the regulatory framework due to unbundling reasons. However, the issue is being considered and is developing. New regulatory changes allow for exceptions and the Federal Network Agency seems to recognise that TSOs and DSOs should operate LSBs for certain purposes. Hence, the operation of grid boosters were explicitly allowed in the latest Grid Development Plan.

Finally, the proper framework must also address ongoing problems regarding levies or taxes on electricity stored in LSBs. This issue has led to much discussion. The latest

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[7] According to the 7,000-hour rule – see the Regulation on Charges for Access to Electricity Supply Networks – a large end consumer may have an individual network charge, which may not be less than 20 percent of the published network charge. This applies when the consumption exceeds 10 GWh/yr and if the number of load hours per year is at least 7,000. The discount can be further increased according to the increase in the number of full load hours.

amendment to EEG 2021 and EU Directive 2019/944 has improved the situation for LSBs. The double charging of levies was abolished. The puzzle of exemptions affects the operation of LSBs; therefore, it is currently carefully considered in any business case for LSBs. Ideally, the regulatory landscape should be simplified.

Moving on to small-scale battery systems (SSBS), in some cases, such systems can provide services to the grid, especially when combined with PV rooftop systems. Current incentives aim to maximise self-consumption: small-scale batteries can usually power a household for about two to three hours at maximum power. However, the provision of services to the public grid is not targeted or incentivised. Such services could include electricity provision via a virtual large-scale battery or virtual power plant (VPP) or time-shifted consumption, which would decrease the load from the public power grid in times of high electricity feed-in. Lastly, these services could also facilitate the limitation of feed-in power from the PV system. The study mentions possible incentives, such as time-of-use tariffs. In addition, a digital infrastructure and automation technologies could enhance the integration of small-scale batteries into the public grid.

While public incentives are lacking, the market provides some benefits. The declining costs of small-scale batteries and PV systems as well as the increasing power prices continue to work as incentives for the widespread use of these technologies. However, it should be noted that large numbers of private households with a great degree of energy autonomy can also be problematic because even though such households are connected to the public grid, they nevertheless pay reduced grid fees, which creates a free-rider effect on the common infrastructure.

Another view, which is shared by many and should also be considered in this discussion, is that the installation of SSBS may adversely affect the predictability of energy fed into the grid. As feed-in energy from private storage units is hard to predict, it is not easy for the grid operator to integrate them. However, as long as prosumers react to price signals or are integrated into a virtual power plant (VPP), the potential negative effects of SSBS could be alleviated.

The Federal Network Agency recently presented ideas on further developing the role and regulatory treatment of prosumers, including remuneration schemes and balancing rules. The study mentions that the regulator proposed three models from which the prosumer would be able to choose. The models vary in how actively prosumers would have to manage their own electricity production, consumption and flexibility.

4. Green hydrogen production as load management

Although hydrogen is not a new energy carrier, it never played a very large role in the German energy mix. That changed with the Hydrogen Strategy released by the German government in June 2020. The electrolyser capacity is set to increase to 5 GW by 2030 and again by 5 GW by 2040 at the latest. Based on 70% efficiency and 4,000 full load hours per year, hydrogen production would be 14 TWh/yr in 2030 and 28 TWh/yr in 2040.

To limit electricity grid expansion, electrolysers should be built close to locations with a significant potential to generate renewable energy. A location close to the large offshore wind farms in northern Germany would reduce curtailment and guarantee that the hydrogen is actually green. Furthermore, future regulations must ensure that the operation of electrolysers is “grid-oriented” and that the electrolysers adapt their generation to the current grid situation. Today there is no comprehensive legal framework in place. Current subsidies, such as the EEG exemption, stimulate production regardless of location. However, in light of the lack of acceptance for grid expansion measures in Germany, incentives for the optimal allocation and operation of electrolysers are becoming more and more crucial.

Moreover, pressing challenges to the legal framework include the actual definition of green hydrogen and a sound guarantees of origin regime to prevent fraud or false declarations. Whether Germany will find its own definition or the EU takes the lead remains to been seen.

5. TSO and DSO cooperation

The study rightly outlines that Germany’s electricity system is transitioning from a unidirectional to a bidirectional electricity flow, which complicates system operations while reshaping the role of DSOs. Not only do DSOs have to distribute the electricity, but they also increasingly act as intermediaries, managing flows and flexibility, much like TSOs. Effective coordination between DSOs and TSOs is key to utilising the flexibility solutions offered to the grid. Developing an all-encompassing coordination mechanism and increasing the exchange and transparency of relevant data are key steps for a more flexible power system.

To meet the increasing need for information, it became important to initiate a regulatory reform of redispatch rules. The so-called Redispatch 2.0 reform addresses all electricity generation units (down to 100 kW) and includes them in the redispatch regime. Smaller units in the regime are typically connected to distribution grids, requiring the DSOs to monitor and – if necessary – control their electricity output. Until recently, redispatch measures only applied to conventional power plants (with a min. installed power of 10 MW) that implemented these measures based on the requirements set by the TSOs. Now, RE and CHP power plants (with a min. installed power of 100 kW) also participate in redispatch measures, and distribution system operators are also given a role in redispatching.

Since there are four TSOs and hundreds of DSOs as well as other participants, such as balancing group managers, the communication task is immense and will likely continue to expand. For that reason, sound data management and automated processes must be coordinated.

Germany is implementing the EU Directive “System Operation Guideline” 2017/1485 in a step-by-step process. This directive sets up a harmonised framework for exchanging information and data between TSOs, DSOs and other significant grid users.

Top five measures identified for Turkey

1. Utilisation of demand-side flexibility

A key aspect that could greatly enhance the system’s flexibility is the utilisation of demand-side flexibility potentials. According to the study, several changes regarding DSM are expected to be introduced into the regulation for ancillary services in Turkey.

The initial step in incentivising the application of DSM for larger and industrial consumers should be identifying energy-intensive regions since the peak and total load figures of these regions are more critical for a successful application of DSM. As stated in the study, this step would prove valuable in designing suitable policies. Considering the lack of digitalisation and data infrastructures, the study also suggests starting from safer operations, such as emergency generators or secondary services, while simultaneously eliminating any deficiencies within the system.

Furthermore, heating and cooling processes are ideal for the wider utilisation of DSM. Thus, the installation of heat pumps (ground, water or air source) would help to increase the flexibility of the electricity market.

However, the study also highlights the importance of small and less energy-intensive consumers participating in the market. In this regard, DSOs have to take on a more complex task than in the past, considering the more decentralised nature of the residential sector. Several measures are proposed in the study. For instance, smart pricing, such as time-of-use tariffs and dynamic network tariffs, which reflect the actual wholesale price, may incentivise consumers to shift their consumption patterns to cheaper and less constrained periods. In doing so, consumers would be actively participating in the real-time balancing of the grid and help flatten peak demands.

An essential prerequisite for these services is, of course, the availability of enabling digital infrastructure, both on the DSO side (smart grids) and the consumer side (smart meters). The concurrent introduction of appropriate equipment would make it possible to widely apply the aforementioned dynamic pricing schemes. The foundations of such a practice have already been laid: a time-of-use regulated tariff dividing the day into three time zones based on the level of consumption is already in place in the current electricity tariff regulation. However, since switching to this tariff is optional, it is currently not a common practice.

In general, all customer groups (industry, commercial and household customers) should have access to the electricity markets to trade their flexibility. In this sense, introducing rules on small and distributed aggregation could be another key step. Opening up the market to aggregators/VPPs could add an intermediary step between customer groups and the market.

Some additional recommendations reiterating the above can be derived from dena’s projects on DSM. Conducting an information campaign on DSM for industrial companies and introducing DSM into exchanges within energy efficiency networks were among the key measures. Additionally, an obligatory examination of DSM potential should be a prerequisite on the list of requirements for exemptions from market levies. In the long run, this should be implemented as a standard in energy audits according to DIN EN ISO 50001 and DIN EN 16247-1.

2. Upscaling of power-to-gas

The study concludes that there is an opportunity to effectively design relevant regulations from the beginning, as there is currently no legal framework regulating power-to-gas and hydrogen applications in the country. Power-to-gas technology is key to linking the electricity and gas sectors; hydrogen – especially green hydrogen – and synthetic methane carry a high potential for storing energy in high volumes, thus providing the system with the necessary flexibility.

A harmonised definition of green hydrogen forms the foundation for establishing a comprehensive framework. The standards regarding the blending of hydrogen into the natural gas grid vary between countries. Based on ongoing R&D projects in Turkey, clear standards for hydrogen that apply to the gas grid should be developed in the future. According to the study, the use of smart meters, for instance, is an aspect that should be considered alongside these standards when developing the country's hydrogen strategy.

The study sees the establishment of a coherent regulatory framework and a long-term strategy equally as important as support measures incentivising hydrogen production. For instance, applying a feed-in tariff scheme within the framework of the YEKDEM mechanism could provide a corresponding level of incentive for domestic hydrogen production.

Further policy options aiming at a larger scale utilisation of hydrogen are also considered. These mainly include financial mechanisms, such as loan guarantees or tax breaks, or the application of renewable or low-carbon obligation standards. Employing an ETS scheme is also believed to be a very important factor facilitating the development of hydrogen energy as a low-carbon energy source.

All in all, the fact that the regulation of power-to-gas and further hydrogen applications is still in its nascent stages in Turkey should be seen as an advantage. This provides an opportunity to develop a coherent regulatory framework, a hydrogen strategy and proper support measures from the very beginning, streamlining the deployment of these technologies. As mentioned in the respective section on Germany above, it would be advisable to subsidise PtG plants that produce hydrogen using renewable electricity. Doing so would have a considerable influence on the decision concerning the location of the plant. Allocating electrolysers close to RE power plants would potentially offer more benefits for the existing transmission grid.

3. Improvements to the ancillary services market

The study mentions that the recent introduction of an ancillary services market in Turkey (launched in 2017) and the experiences acquired thus far already point to needed improvements. Restructuring and optimising the ancillary services market in Turkey will make a substantial contribution to the system's flexibility. Its design needs to encourage innovation and act as an incentivising tool. Apart from that, the transparent and efficient operation of the ancillary services market is a precondition for the implementation of projects improving the system's flexibility, such as the construction of flexible generation, demand response systems and energy storage.

The study points out several ways in which the market can be optimised and have an overall positive effect on different levels across the value chain. One option would be to decrease the limit for the participation of generating units in the ASM. According to the current Ancillary Services Regulation, only generation units with over 100 MW capacity can participate in the market. Decreasing this limit could have an impact on:

The flexibilisation of conventional power plants: Enabling the participation of smaller generation units in the market would subsequently support flexibility investments in smaller power plants, such as gas engines, which are also better suited for providing frequency control services.

Battery storage systems: Decreasing this limit would enable large- and smaller-scale battery units to participate and eventually provide their services in the market. An additional optimisation would be the classification of demand response as an ancillary service in order to enable the participation of small consumers connected through the distribution grid in the new market.

Another crucial element the study highlights and which could substantially improve the ASM is moving the auctions for the secondary and primary frequency control reserves closer to real-time. Market participants currently enter the auctions two days in advance of their reserve obligation and rely on forecasted prices for calculating their bids. By moving the auctions closer to real-time, the participants' bids during the auction would reflect more accurate and up-to-date information, which in turn would contribute to a generally smoother operation of the ASM.

4. Flexibility in conventional power plants

The existence of inflexible conventional power plants in the system often proves to be a challenge for the TSO when trying to balance fluctuating electricity generation due to intermittent renewable energy sources. Various retrofitting options – which are also highlighted in the study – can increase the operational flexibility of power plants. The benefits derived from the flexibilisation of conventional power plants are significant and should be in the interest of the TSO, considering the extent to which the system is made more flexible. Having regulatory incentives in place aimed at encouraging the plants' flexible behaviour and corresponding flexibility investments is, of course, critical. The study suggests the following changes to further enhance this process:

The existence of lignite purchase guarantees as well as of a capacity mechanism mainly favouring inflexible power plants (lignite, coal) should be reevaluated. Both these mechanisms encourage old and inflexible power plants to remain in the fleet and operate as baseload. It is strongly advised that they be abolished to incentivise flexibility investments.

Concerning the design of the day-ahead market, allowing for negative prices could provide an incentive for conventional power plants to invest in additional flexibility, which may have a particularly positive effect on inflexible coal power plants. When high shares of RES are fed into the market, the wholesale price drops to the marginal price of the cheaper plants. If conventional power plants are not sufficiently flexible to react to this price drop, negative prices are formed. Therefore, flexibility investments in conventional power plants are crucial for them to avoid negative prices.

The study evaluates the recently introduced hybrid plant regulation as a positive step in the right direction since allowing for hybrid power plant installations can significantly contribute to the flexibility of conventional power plants. Along these lines, introducing amendments to the regulation to enable more geothermal power plants to install additional solar or wind power plants in their vicinities is deemed necessary in the future.

5. Promotion of small-scale battery installations

The discourse on flexibility should focus in equal measure on incentivising battery development across the value chain. Energy storage systems can provide ancillary services to power networks and ensure their reliability. Under such circumstances, targeted incentives can be promoted to ease the switch from net metering to battery storage installations.

Several steps can be taken to strengthen the role of small-scale battery installations in the energy system. The study puts forward several key recommendations. Since there is little incentive to install battery storage systems, establishing necessary incentive mechanisms and subsidies encouraging the installation of battery storage systems at existing and new RES facilities would enhance the deployment of battery applications to the market, thus contributing to the system's flexibility. Targeted incentives can facilitate the installation of battery storage. Various policy options, such as tax cuts, credits or grants, are among the recommendations for promoting small-scale off-grid battery installations.

Another opportunity for promoting the installation of SSBS lies in the unlicensed generation facilities, which were built under the older unlicensed regulation. Allowing these power plants to operate in the wholesale electricity markets after their feed-in tariff periods would prevent a significant amount of available generation capacity from being wasted. Additionally, establishing subsidies for these facilities to invest in battery technologies would help introduce widescale battery applications to the market and increase the flexibility of the energy system.

Small-scale batteries are one of many flexibility options available to the Turkish power grid. The general recommendation would be to first deploy other flexibility options before moving onto this specific one.

3 Comparison of lessons learned in both countries

The idea of this report is above all to see if the two countries can learn from each other and thus benefit from the steps that have already been taken as well as avoid certain pitfalls. That is why we have listed the top lessons learned from each country in the following. We invite the reader to take a closer look at the country reports to find further interesting facts and maybe even pick up other points that may serve as best practice examples. The information is structured so that lessons one country learned are translated into recommendations from that country to their partner. For instance, the lessons learned from Germany should be read as recommendations or warnings from Germany to Turkey as to what did not work well, and vice versa.

Key lessons learned from Germany

1. Increase granularity in the markets

There is a trade-off between product granularity and market liquidity. High liquidity in the market leads to cost-efficient prices and competition between different market players since different options are available for trade. High product granularity allows market participants to balance supply and demand more accurately in terms of time and space.

In the early stages of developing a trading market, liquidity is naturally low since there are only a few market participants. These circumstances limit the granularity of the products that can be traded. However, as liquidity increases over time, this creates the chance to increase product granularity as well.

The granularity of the products in the electricity market can be measured by the lead time, the product duration, price increments and spatial resolution. The lead time, which is the time span during which the product is open for trading before delivery, was reduced in Germany's intraday market from 45 minutes to 30 minutes in 2015 and again to 5 minutes in 2017. The reduction of the lead time represents an important step towards a precise resolution of imbalances in the power grid using intraday power exchange products.

In addition to the lead time, the duration of the products is an important factor for their usefulness regarding short-term flexibility. The products in the intraday market are available in periods of 30 minutes, 1 hour and blocks of several hours. In 2014, a product with a delivery period of only 15 minutes was introduced. These products can be used to offset any account imbalance arising from errors in renewable energy forecasts or technical incidents in power plants, for instance.

Another significant parameter regarding the granularity of products in the electricity market is the price increment in EUR/MWh. It is set at 0.1 EUR/MWh. That means offers and bids in the trading market can be made in increments of 0.1 EUR/MWh. The prices in the intraday market are technically limited to ± 3,000 EUR/MWh, which is considerably lower than the technical price cap in the control energy market, which currently is set to a limit of ± 99,999.99 EUR/MWh. Both caps will automatically be raised when clearing prices approach them.

Another dimension of granularity is the spatial resolution of the electricity product. It can help to introduce a local price signal, allowing the market to more precisely indicate possible needs for additional capacity if network bottlenecks occur often.

The development of the intraday trading volume in Germany (which includes Luxembourg) tripled from 19 TWh in 2013 to almost 60 TWh in 2019, which corresponds to about 10% of the annual electricity consumption in Germany in 2019. Out of the 60 TWh in 2019, about 10% are based on trades with 15-minute products. At the same time, the tender volumes for control energy decreased for tertiary (manual frequency restoration reserve, mFRR) and secondary (automatic frequency restoration reserve, aFRR) control energy products by more than 50% and 20%, respectively, in comparison to 2013. Only the primary (frequency containment reserve, FCR) control energy product increased by 10% during the same period. For secondary and tertiary control energy, the values represent the yearly average of the positive and negative control energy product.

The steady increase of the intraday trading volume in combination with the decrease of the control energy tender volumes indicates that short-term flexibility is increasingly managed by market participants. This development was enabled by an increase in the product granularity in the intra-day spot market.

2. With special relevance for the Turkish market: increase the flexibility of coal plants

As Turkey has a large share of coal plants, an energy technology that Germany is phasing out, there are nevertheless some measures that helped Germany during the transition phase, where coal plants were modernised to adapt to changing network and operation conditions.

The hard coal-fired Moorburg plant is an example of how conventional power plants can be made more flexible and adapt to the challenges posed by the energy transition. The plant is relatively new and has been in operation for almost six years. It consists of two blocks with a generation capacity of slightly more than 800 MW each.

Building a conventional power plant is a large and complex project that takes a long time to complete from start to finish, sometimes as much as ten years. When the Moorburg project begun in 2006, the circumstances in the German electricity market were quite different from today. When the plant became operational in 2015, the flexibility requirements were much higher than what developers had had in mind.

That is why around the time when the plant first went into operation, additional projects were implemented to increase the flexibility of the plant. The following flexibility improvements were achieved:

- Reduction of the minimum load from 40% to 26% of capacity, reducing the frequency of necessary shutdowns
- Increase of the maximum load gradient to +/- 500 MW in ten minutes
- Prolongation of the cooling process after shutdown, allowing for a "warm start" (rather than a costly and wearing "cold start") within a period of 48 hours after shutdown, which is especially useful when a block is idle on weekends and has to be restarted at the beginning of the following week

According to Vattenfall, the operator of the Moorborg plant, the flexibilisation was an economic success. The operation of both blocks can now react more quickly to the electricity system requirements and changes in electricity prices.

3. Regularly adapt support schemes to incentivise flexibility

The support scheme for renewable energies in Germany is defined in the EEG. It was first introduced in 2000 and aims to enable the sustainable development of energy supplies and significantly increase the share of renewable energies in overall power generation in Germany. EEG 2000 introduced separate guaranteed feed-in tariffs for renewable energies. These feed-in tariffs are guaranteed for a period of 20 years. Nine years later, EEG 2009 introduced a direct marketing scheme whereby operators of renewable capacities can choose each month to market electricity on their own in the spot market or under the regular compensation system. This system was intended to prevent producers from optimising their profits while placing the market risks on grid operators.

The 2012 revision to the EEG introduced the possibility (on a voluntary basis) to market the electricity directly. Along with the direct marketing option, a market premium model (or feed-in premium) was introduced. Producers of renewable energy that choose to market their electricity directly can request a market premium from their grid operator. The market premium serves as an essential instrument for the integration and demand-oriented generation of renewable energy. It covers the difference between the EEG tariff and a reference price based on the achievable market price minus the technology-specific marketing costs (management premium). At the same time, if grid operators have to intervene because of incorrect RE forecasting, those producers can be held responsible.

With the revision of the EEG in 2014, an auctioning system was introduced to determine feed-in premiums. The auctions were introduced progressively and started with ground-mounted solar installations in 2015. All renewable generation units had to market their electricity directly under the market premium model as of 2014.

EEG 2017 introduced further changes to the system and completed the general shift towards auctions to determine the feed-in tariffs for almost all renewable energy sources, including:

- Onshore wind (> 750 kW)
- Solar (> 750 kW)
- Biomass (> 150 kW)
- Offshore wind

The 2021 revision of the EEG focuses on aligning further market integration of renewable energies into the power grid and expanding transmission grid capacities. It defines the auction volumes for renewable energies up to 2028 and lowers the maximum bid amount to further reduce renewable generation costs. New tender segments were also introduced in order to increasingly promote innovations such as agri-photovoltaics, floating photovoltaics or solar carports.

The EEG levy will be partially financed by the federal budget to assist in reducing the EEG levy for all consumers. Small-scale units, which have stopped receiving the guaranteed feed-in tariff after 20 years (see reference in the first EEG from 2000), will be able to sell electricity directly to the TSO, which will remunerate the electricity at market price minus a marketing fee.

It is evident that the worldwide recognised and replicated success of the EEG is a story of many changes and adaptions. As a market matures and its granularity increases, regulators should not be afraid to adapt to new circumstances. However, the EEG was often adapted to new market realities, it was always done in a way to protect investments and hence support planning security of businesses. That means that there were never retroactive changes undertaken and major changes were often introduced via transitional arrangements in order to give investors time to adapt to the new regime.

Generally, it should be noted that there is a broad public debate on nearly all issues regarding the path of the German energy transition. The discussions are very often heated and cumbersome, as consequences range from licenses to operate to substantial financial losses and gains to climate effects. Nevertheless, the discussions are necessary because the public needs to know, understand and support the policy decisions, especially as they often involve long-term and costly infrastructure changes.

Key lessons learned from Turkey

1. Regulate energy storage

The study highlights that one of the main targets of Turkish legislation is to introduce an all-encompassing electricity storage regulation by 2022. Alongside R&D studies, this is part of the effort to increase the utilisation of battery storage. Despite the current lack of regulations regarding electricity storage applications in the market, efforts have already been made to stimulate the installation of such applications.

The installation of a battery system was considered one of the technical requirements of the YEKA project, a large-scale solar capacity auction. Specifically, the winner from the Niğde-Bor region of 300 MW of solar capacity was required to establish a Li-on battery storage facility with a capacity of 30 MW/90 MWh (AC). Although this tender was eventually cancelled due to economic conditions, the inclusion of a battery scheme in the technical specifications of the auction indicates the government's willingness to prioritise battery applications. In this context, the study mentions that future auctions are also expected to include similar provisions to incentivise the utilisation of battery storage in Turkey.

Germany could also eventually adopt such a provision, as doing so could positively impact the business case for installing battery systems, especially for large-scale batteries.

2. Encouraging self-consumption of electricity

Small consumers can contribute significantly to system flexibility by using energy more flexibly, i.e. through load shifting or by responding to price signals via dynamic tariffs. Encouraging the self-consumption of electricity is key to unlocking the flexibility small consumers can provide to the grid. The study offers some particularly interesting insights into incentivising solar power plant owners to self-consume rather than sell electricity to the grid. As of now, the majority of the installed solar energy capacity in Turkey consists of unlicensed power plants since, according to prior regulation, micro-cogeneration and renewable power plants with a maximum capacity of 1 MW for on-grid applications were exempt from obtaining a generation license. These power plants were eligible for the YEKDEM tariff (133 USD/MWh for solar) for a period of ten years. As a result, they were mainly built for selling to the grid instead of self-consumption, an issue many European countries are also faced with.

A new Presidential Decree (2019) increased the limit for the maximum capacity of unlicensed electricity generation to 5 MW, while no limit applies to off-grid installations. These new unlicensed generation facilities can benefit from a purchase guarantee based on the "active energy cost", i.e. the overall cost of energy generation for a certain period taking into consideration aspects such as the day-ahead market price and the YEKDEM unit cost. The purchase guarantee is applicable for a period of ten years. The active energy cost of 67.7 USD/MWh is significantly lower than the aforementioned feed-in tariff applied to unlicensed power plants.

Nevertheless, the new regulation also allows for monthly net metering, i.e. the monthly calculation of the difference between consumption and generation that the generator sells to the grid. If the total monthly generation exceeds the total consumption, the generators can sell the excess generation based on the active energy cost. If the opposite is true, the consumer can buy additional electricity from the national tariff. There are two main benefits to this:

- It offsets any potential negative effects caused by the intermittent nature of solar energy.
- Considering the combined effect of net metering and the reduced tariff, it is apparent that the focus is shifted to the regulation of new unlicensed power plants, especially rooftop and facade applications aimed at self-consumption. The aforementioned combined effect is particularly suitable for large industrial consumers, as it can reduce their costs significantly via self-consumption. In that context, most of the future additional solar energy capacity is expected to come from such installations. On the other hand, the new regulation effectively halts any unlicensed investments aimed at selling to the grid – a desired outcome for many countries.

Overall, the provisions introduced regarding the reduced tariff and the net metering of consumption and generation of the installed facilities managed to control investments in power plants solely for the aim of selling to the grid while simultaneously promoting and safeguarding the self-consumption of electricity.

3. Reform & liberalise market structures: a success story

Part of Turkey's success regarding the deployment of RE lies in the incremental introduction of electricity market reforms, starting in the 1980s with the adoption of the Electricity Market Law. Even in the face of adversity, in the form of economic crises and political turmoil over the last several decades, Turkey successfully managed to develop a sound market design and integrate large RE shares in its system.

In response to the rapid growth in electricity demand – the corresponding installed capacity of Turkey increased from 27.3 GW in 2000 to 94.9 GW in 2020 – and the market reformation process, Turkey now has a complex electricity market with a diverse set of participants in the different market segments, such as generation, transmission, wholesale trade, retail trade and distribution.

This fundamental electricity market design is a prerequisite for the streamlined introduction and implementation of various flexibility measures, addressing some of the flexibility necessities described in the studies. The Turkish example can serve as a successful case study for introducing the required reforms in the market structure early on. This example could also be applied to countries in their early stages of transitioning to a system with higher RE shares.

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Flexibility Options for the German Electricity Grid (Part B)

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1 Introduction

The German electricity system is currently undergoing a transformation away from predictable load patterns with substantial base load towards more volatility caused by renewable generation. To ensure the stability of the grid, components that offer flexibility are increasingly required, as are incentives for market participants to provide flexibility.

Transitions in the German Energy System

The central features of the "Energiewende" are the decarbonisation of energy supply and the switch to renewable energies, which are so far mainly taking place in the electricity system. The first step towards the "Energiewende" of the German energy system was set in 1991, when the Stromeinspeisungsgesetz (Power feed-in law, StromEinspG) became effective. The StromEinspG obligated the system network operators to accept and remunerate electricity produced by renewable energies. The StromEinspG was afterwards replaced by the Erneuerbare Energien Gesetz (Renewable Energy Law, EEG) in 2000, which provided feed-in priority for renewable electricity and guaranteed feed-in tariffs to operators of renewable power plants that were independent of electricity prices paid by customers. The main challenge posed by renewable energies is their fluctuating generation of electricity, which impedes a stable and demand-actuated provision of energy, which is why amendments were made to the EEG over time to place more responsibility on operators of renewable plants and incentivize them to operate their plants in a more market-oriented way.

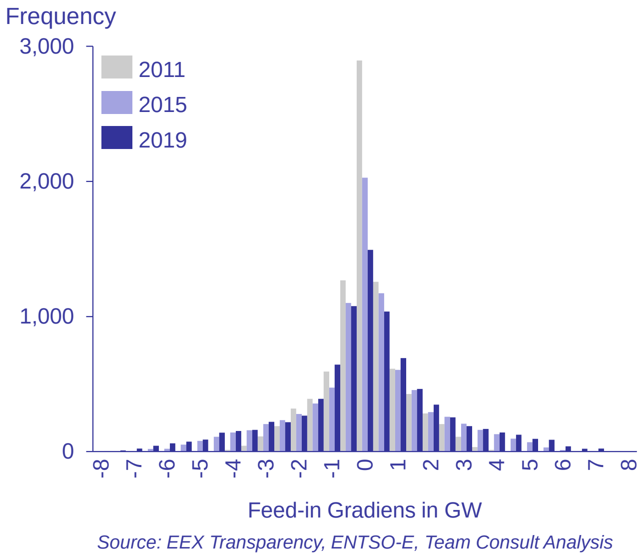


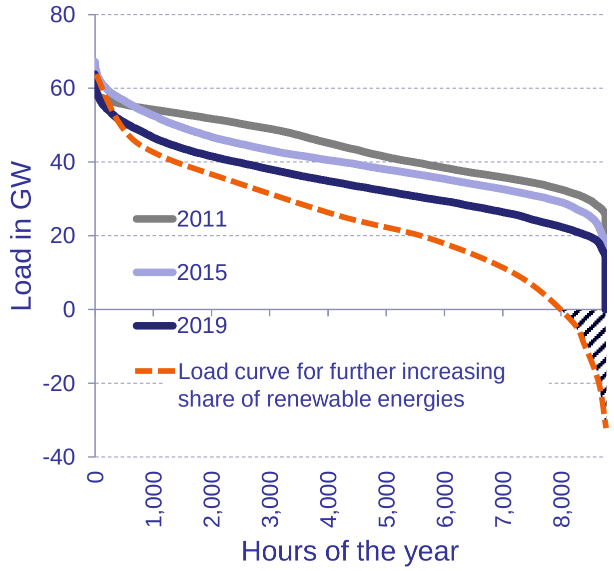
Figure 6: Frequency of hourly feed-in gradients in the German energy system

Over the years, the increasing share of renewable energies has led to higher load changes (feed-in gradients) in the power grid, as can be seen in Figure 6. The feed-in gradients from renewable energies comprise solar and wind electricity production. While in 2011, the renewable energies contributed about 21% to the overall electricity production in Germany, their share increased to 31% in 2015 and about 45% in 2019[8]. The feed-in gradients moved mainly in a range from +1 to -1 GW in 2011. However, with the increasing share of renewable energies, the distributions of the feed-in gradients widened to higher amounts of larger feed-in gradients and lower amounts of smaller feed-in gradients. The increasing amount of larger feed-in gradients stress the public power grid and forces the transmission network operators (TSO) to adapt the loads in the power grid. These feed-in gradients are a problem for the stability of the grid and put the stability of the public power grid at risk, which the TSOs need to ensure at all times.

The effect of the increasing share of the renewable energies in the overall energy systems is likewise evident in the yearly sorted curves of the residual loads (see Figure 7). The residual loads represent the share of non-renewable energy production in the system. The increasing electricity production from renewable energies pushes conventional power plants more and more out of the system. This becomes obvious from the decline in residual load over time. For the TSOs, this means that

[8] Values for 2011 and 2015: Federal Network Agency – Monitoringbericht, values for 2019 based on Team Consult Analysis and ENTSO-E data

other components and solutions within the grid are needed to accommodate these changes, such as back-up reserve, energy storage and flexibility measures.



Source: ENTSO-E, Team Consult Analysis

Data for 2011 estimated from overall load

Figure 7: Sorted annual load curves of the German energy system

The share of the renewable energies in the electricity system will continue to increase over the next decades. The German government set a target of 65% share of renewable energies in the overall electricity consumption for 2030[9]. The additional electricity produced by renewable energies will push the residual load curve further down and likely into negative residual loads. These negative residual loads represent electricity produced by renewable energies, which is not consumed immediately, since the production exceeds the consumption. The amount of negative residual load can be made available for later usage by flexibility measures in the energy system, either by storage and energy transformation technologies or by the flexible adaption of loads from consumers and producers. The current system copes with these difficulties by wasting valuable renewable energies and generating increasing costs for consumers. Other measures are needed to integrate as much of the already existing renewable energies and lower the costs for the grid operation.

Current Status in Germany

TSOs are the link between power generation and consumption in the electricity system. In order to ensure the stability of the frequency and the balance between demand and supply, the TSOs have a number of different instruments at their disposal. These are referred to as ancillary services, which the TSOs procure from other market participants, and stabilization measures they can take unilaterally. Ancillary services and stabilization measures are discussed in more detail in the section "7 Further operational and market design flexibility options".

In this context, we take the costs incurred by the TSOs for such services and measures as an indicator of whether it has become more challenging to balance and stabilize the grid. According to the German regulator, The Federal Network Agency, the costs have grown from 1,211 million Euros in 2014 to 1,811 million Euros in 2018, representing an increase of 55% in four years. Obviously, it has become substantially more complex and demanding for the TSOs to ensure the system's stability. The figure below shows how the costs developed over time and how they are distributed between different ancillary services and stabilization measures.

[9] Bundesregierung (2019) – Klimaschutzprogramm 2030 der Bundesregierung zur Umsetzung des Klimaschutzplans 2050, p. 36

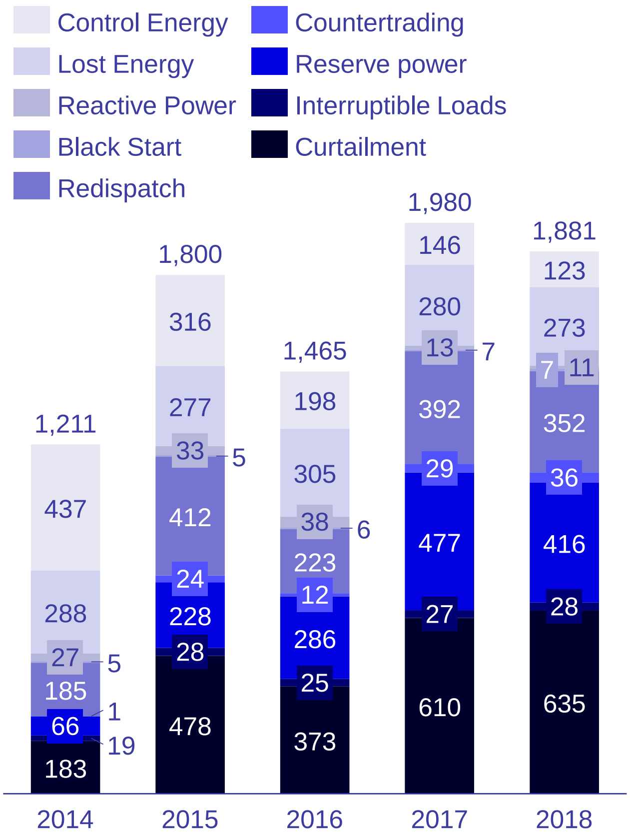


Figure 8: Cost development for the ancillary services of the TSOs in Germany in Mio. EUR

This study highlights the current state of flexibility measures and integration of renewable energies in the German electricity system and discusses the way forward and the challenges ahead.

2 Flexibility Measures for Conventional Power Plants

Today, most electrical flexibility in Germany is provided by conventional power plants. The shift in the German power plant fleet caused by the phase-out of nuclear and coal-fired power plants will move gas-fired power plants – the most flexible conventional plants by design – more into focus. Additionally, cogeneration plants can be equipped with heat storages and power-to-heat modules to increase their more limited ability to provide flexibility.

Definitions

Flexibility

The term "flexibility" in the context of power generation refers to the ability of a power generation facility to adapt power production, i.e. to increase or decrease it. Flexibility is needed in power generation because it is technically difficult and costly to store electricity, which is why production has to be synchronized with consumption, i.e. it has to follow consumption as the latter increases or decreases.

Conventional power plants

In the context of this study, the term "conventional power plants" should be understood to mean facilities which produce electricity from fossil fuels (mostly lignite, hard coal and natural gas) or uranium by means of thermal engines (mostly gas turbines or steam turbines). That means, in conventional power plants the fossil fuel is burnt to produce heat which is then converted via a turbine and a generator to electricity. In the conversion from heat to electricity, a certain share of the energy is lost ("heat loss"), resulting in a thermal efficiency factor of less than 100%. Thermal efficiency typically ranges from around 30%-35% for older plants (coal, nuclear, open-cycle gas turbine) to above 60% for state-of-the-art combined-cycle gas turbines.

Cogeneration

"Cogeneration" denotes the combined production of electricity and heat at the same time. It addresses the above-mentioned problem of heat loss during power generation by capturing the heat and making it available where it can be used instead of emitting it through a chimney or cooling tower into the atmosphere. Cogeneration saves fuel by increasing fuel utilization to up to 90%, from the thermal efficiency of mere power generation of between ~30% and 60% mentioned above. Fuel is saved at the location where the heat is used, which is now supplied with heat from the cogeneration plant and thus does not have to burn fuel to produce its own heat.

Cogeneration is used to supply public electricity and heat grids as well as for the purpose of own consumption, mostly in the industry. Data availability differs between public supply cogeneration and own consumption cogeneration. Unless stated otherwise, quantitative information given in this study refers to cogeneration in general, i.e. including cogeneration for public supply as well as for own consumption.

Flexibilisation of conventional power plants

Any measure which expands the capability of a conventional power plant to adapt power production to the system's requirements can be referred to as "flexibilisation of conventional power plants". This includes amongst others measures that enable the plant to run in a wider load range (e.g. a lower minimum load) and investments that enable faster load changes or make it possible for load changes to occur more often.

It is worth noting that flexibility in regard to conventional power generation plants (potentially) covers a wide spectrum, from intra-day load changes on the short-term end to the provision of seasonal profiles or even strategic reserve on the long-term end.

When flexibility of conventional power plants (or lack thereof) is discussed in Germany, this often refers to the challenges posed by a system that accommodates increasing shares of volatile renewable power generation and leaves only the *residual load* to be served by conventional power plants. Over time, the residual load becomes more volatile and smaller in total annual volume. In other words, the *additional* flexibility needed in conventional plants is the ability to cope with faster and more frequently occurring load changes as well as the ability to cope with fewer load hours and longer downtimes.

Flexibilisation of cogeneration plants

The ability of cogeneration plants to adapt power generation to market requirements is limited by the necessity to provide heat, which in cogeneration plants is coupled to power generation. That means, at any given moment the unit produces both power and heat or neither. However, in many plants, it is possible to produce power but no heat (except for the heat loss) by condensing the steam; the reverse – heat generation without power generation – is harder to achieve.

Thus, there is an extra layer of inflexibility in cogeneration plants compared to other conventional power plants. During the winter, the heat and power generation in most cogeneration plants is "heat-driven", i.e. the level of production is determined by the heat required. During the summer, this may also be the case if the heat is needed for industry processes ("process heat"). If, however, the heat is used to provide space heating in residential households (which is not needed in the summer), the respective cogeneration plant is operated in an "electricity-driven" mode in the summer.

The term "flexibilisation of cogeneration plants" in this study refers to any measure that increases the plant's ability to modulate power production without impairing its ability to provide the required heat. Such measures may include:

- The installation of a (generally smaller) extra unit that can be used to produce heat but not electricity (i.e., a boiler)
- A heat storage that allows the cogeneration unit to produce more heat than is required (and store the excess heat) for a certain period and, afterwards, to produce less heat than is required (and take the residual heat needed from the storage) for a certain period
- A power-to-heat unit that can be used to produce heat from electricity (i.e., an electric boiler)

The above measures are not exhaustive, but they are among the most important measures in terms of flexibilisation potential. It is worth noting that flexibilisation measures are not mutually exclusive but may be combined in rather complex ways in optimizing cogeneration plants to the requirements and possibilities of the given situation.

Current Status in Germany

Conventional power plants

Conventional power plants have a certain minimum degree of flexibility by design. All conventional plants can either run and produce electricity or be shut down. Of course, the degree of flexibility that a plant features by design differs between the plants, depending i.a. on the fuel, the technology and the age of the respective plant.

Basically all thermal plants can run in partial load, i.e. in the range between a plant-specific minimum load and full load. In case thermal plants are shut down, it takes a certain time before they can be restarted. The table below shows these flexibility parameters for different categories of thermal plants.

	Min. load (%)	Min. offtime (h)
Nuclear	50	10
Lignite	40	8
Hard coal	38	8
Gas CCGT	45	2
Gas turbine	20	0

Source: DIW

Figure 9: Flexibility parameters of conventional power plants

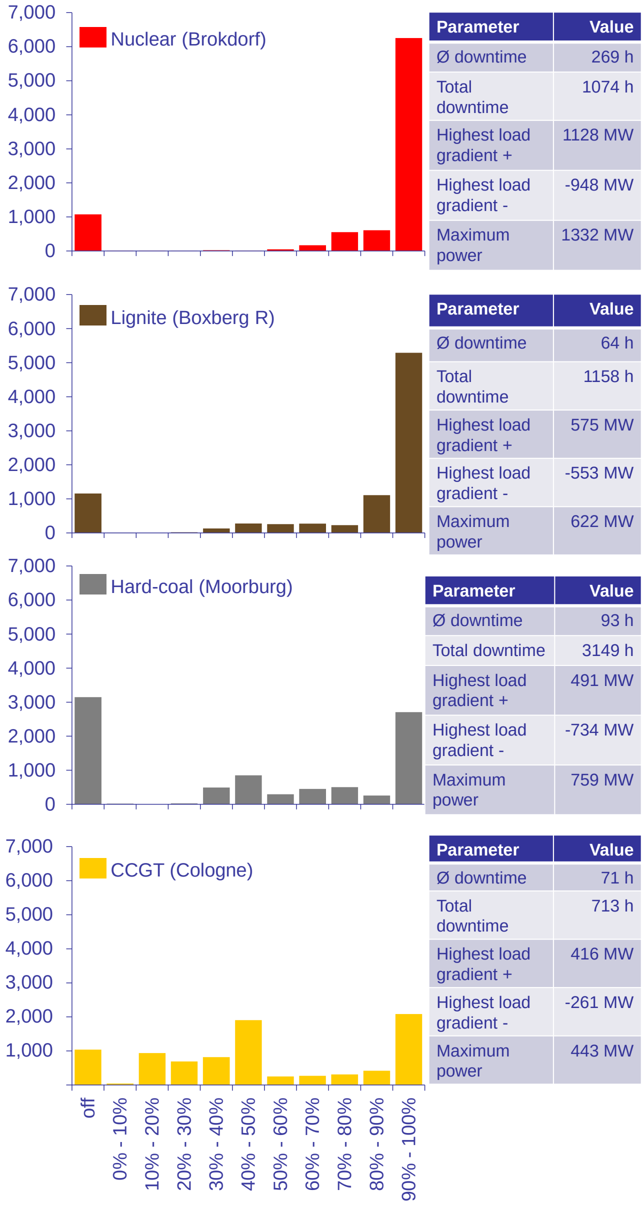
From these numbers it is obvious that even nuclear and lignite power plants, which are known as base-load plants, are technically more flexible than they are sometimes given credit for. Of course, technical flexibility is a much more complex issue, and there are numerous other parameters which play a crucial role, including i.a. ramp-up time, maximum load gradients and the total number of load cycles. Also, the above parameters are not identical for all plants of the same category. In fact, it is possible to take measures and make investments that change parameters towards a higher degree of flexibility of existing power plants. For instance, there were projects in Germany to reduce the minimum load of hard coal plants, as we will discuss in more detail further below (cf. the section "Example Case" in this chapter).

However, as a general matter it is clear from the parameters above that gas turbines are by far the most flexible conventional power plants while nuclear, lignite and hard coal plants are the least flexible. This assumption is reinforced by their economics.

The question to what extent the flexibility that a plant offers technically is made use of is an economic one. Plants with very low marginal costs of electricity production can earn a positive margin when wholesale electricity prices are in the usual range. This is particularly the case for nuclear and lignite plants. As a consequence, they are being operated rather continuously.

On the other hand, plants with high marginal costs of electricity production require higher wholesale prices to be profitable; they are only in production mode when wholesale electricity prices are high.

In essence, for technological and economic reasons, nuclear and lignite plants are run primarily as base load providers while hard coal and gas-fired plants cover the medium and peak loads. This can be seen from the distribution of production loads of some individual power plants shown in the figure below.



Source: SMARD.de, Team Consult Analysis

Figure 10: Load distribution of individual power plants (2019)

Figure 10 shows that the nuclear plant was operated generally at high loads, close to or at 100%, and that the few times it was shut down (four times) it remained down for more than ten days. The lignite and hard coal plants were run in a range between 40% and 100%, most often at full load. The lignite plant was down 18 times, on average for a bit less than three days, while the hard coal plant had many downtimes (34), on average for approx. four days, and in total for about 130 days. The gas-fired CCGT was operated in a wide range from 20% to 100%. It was down ten times for about three days each. Obviously, the minimum load of this particular CCGT is lower than the value stated for CCGTs in general in the table in Figure 9.

Conventional plants (together with hydroelectric power plants) provide basically all dispatchable generation capacity in Germany. As of 2019, conventional power plants – nuclear, lignite, hard coal and natural gas combined – had an installed capacity of approx. 83 GW. In total, they produced 315 TWh in 2019 (more than half of total German net electricity production of 575 TWh). The table below shows how capacity, electricity production and load factor of conventional plants in Germany developed on average for the different energies over the last 20 years.

	Generation capacity (GW)				
	2000	2005	2010	2015	2019
Nuclear	22.4	20.3	20.5	10.8	9.6
Lignite	20.1	20.2	20.4	21.0	20.9
Hard Coal	30.1	27.6	27.9	28.2	23.1
Natural Gas	20.5	21.3	25.7	28.4	29.7

	Net electricity production (TWh)				
	2000	2005	2010	2015	2019
Nuclear	170	163	141	92	71
Lignite	148	154	146	155	105
Hard Coal	143	134	117	118	52
Natural Gas	49	73	89	62	88

	Load hours (h/a)				
	2000	2005	2010	2015	2019
Nuclear	7,573	8,013	6,866	8,501	7,421
Lignite	7,397	7,612	7,160	7,346	5,020
Hard Coal	4,751	4,868	4,195	4,172	2,236
Natural Gas	2,406	3,420	3,472	2,186	2,962

Source: bdew, Team Consult Analysis

Figure 11: Capacity, production and load hours of conventional power plants in Germany by energies from 2000 to 2019

The table above shows the traditional distribution of roles between the fuels at the beginning of the time period (2000) – nuclear and lignite as base load providers at load factors of approx. 80% (7,000 h/a) or more, hard coal for medium load and natural gas as provider of peak load (load factor below 40% or 3,500 h/a).

This distribution of roles held at least until 2015. This is no surprise as the fleet of conventional power plants in Germany – as probably anywhere else – was basically built for this distribution of roles. Nuclear and lignite plants have high capital expenditures but low operating costs; for base load production, they generate electricity at the lowest average costs per kilowatt-hour. They have limited built-in flexibility from the outset. Gas-fired plants (especially open-cycle gas turbines) have lower fixed costs and higher variable costs; for peak production, they generate electricity at the lowest average costs per kilowatt-hour. That is why they are built to be flexible from the outset.

At some point between 2015 and 2019 things in the German electricity market began to shift more substantially than before. This can be seen from the unusually low load factor of hard coal plants in 2019. Even the average load factor of lignite plants dipped. The load factor of gas-fired power plants, on the other hand, had increased significantly compared to 2015 and had surpassed that of hard-coal plants.

Two main developments are behind those changes. First, the price situation in the commodity markets for coal and natural gas, in combination with prices of EUAs (European Union Allowances for greenhouse gas emissions under the EU's Emission Trading Scheme), had driven the marginal costs of gas-fired plants below those of hard-coal plants, i.e. natural gas and hard-coal plants had switched places in the merit order. Secondly, and more fundamentally, renewable electricity generation had increased to such an extent that, at times, there was hardly any additional generation from conventional power plants needed to satisfy demand. In some instances, renewables had not just driven natural gas and hard coal out of the market but also lignite.

The key takeaway here is that, at least regarding the expansion of renewable electricity generation and shrinking load factors of conventional power plants, this development will continue. There is no going back to the pre-2015 electricity market; on the contrary, the load factors of conventional plants will decrease further in the future. The price situation in the commodity and EUA markets will decide which fuels will have to retreat more than others.

What all this means is that the flexibility *needed* in conventional plants is now much higher than what developers had in mind when the plants were built; moreover, it is set to further increase in the future.

Cogeneration

Cogeneration plants – at least those running on lignite, hard coal or gas – are a subset of all conventional power plants, and cogeneration electricity production is a partial quantity of overall electricity production. That is why when discussing the flexibility and flexibilisation of conventional power plants, it is also necessary to discuss the role of cogeneration plants which, as discussed above, have an additional layer of inflexibility. The figure below shows the development of the two for the period between 2005 and 2018.

	Net heat production (TWh)			
	2005	2010	2015	2018
Lignite	16.4	17.4	18.0	15.5
Hard Coal	40.3	37.4	32.2	31.7
Gas	94.1	98.2	93.2	105.6
Other	39.7	59.9	71.9	75.1
Total	**190.5**	**212.9**	**215.3**	**227.9**

	Net electricity production (TWh)			
	2005	2010	2015	2018
Lignite	5.1	5.4	5.3	4.7
Hard Coal	15.7	15.3	11.9	11.3
Gas	49.6	55.3	54.6	61.3
Other	13.4	24.7	36.9	38.1
Total	**83.8**	**100.7**	**108.7**	**115.4**

Source: Umweltbundesamt

Figure 12: Net heat and net power production from cogeneration plants by energies, 2005 to 2018

There are several points worth noting with regard to these numbers:

- Cogeneration has been on a moderate but steady rise since 2005; most recently, it contributed approx. 20% of overall net electricity production
- Gas has a much higher share in net electricity production from cogeneration plants (around 50%) than in net electricity production overall (around 15% in 2019); besides “other” fuels, it is the only fuel that shows a steady increase in cogeneration
- The growth in heat and electricity production from other fuels is driven primarily by biomass
- Net heat production and net electricity production from cogeneration plants are highly correlated

The latter is no surprise as this is the idea of cogeneration. On the other hand, it would be desirable if cogeneration plants contributed to the requirements of the electricity system. However, a comparison of net electricity generation from cogeneration (Figure 12, lower table) with overall net electricity generation (Figure 11, center table), shows that:

- While net electricity production from cogeneration increased by more than 35% since 2005, production from conventional plants overall fell by 40% since 2005
- For natural gas, cogeneration plants seem to set a lower bound for overall net electricity production. For example, in 2015 – a time when the commodity price situation for gas-fired power plants was very unfavorable – production from cogeneration was around 55 TWh while overall production was only slightly higher, at 62 TWh.
- The annual net electricity production from cogeneration and from overall conventional plants is not correlated (e.g. for natural gas the correlation from 2010 on is very low, and for hard coal it is non-existent)

In the past, electricity production from cogeneration was obviously not able to accommodate the requirements of the electricity system. Since flexibility requirements have been growing and will continue to grow, cogeneration plants in the future will have to adapt more to the needs of the electricity system and be operated in a more “electricity-driven” mode. However, as security of heat supply has to be ensured at all times, it is not an option to just halt cogeneration altogether and interrupt heat supply whenever the electricity system cannot absorb the plant’s electricity production.

Therefore, from a flexibility point of view, it would be desirable to remove this extra layer of inflexibility, i.e. to decouple heat and electricity production in cogeneration plants. Heat production should be able to follow the time profile of heat demand of the connected heat customers, and at the same time electricity production should be able to adapt to the requirements of the electricity system. There are two measures, which can contribute significantly to achieve this, namely the installation of heat storages and the installation of power-to-heat modules.

Heat storages allow the operator of a cogeneration plant to *temporarily* run the plant in an electricity-driven mode. Depending on the charge-/discharge-capacity of the storage in relation to the cogeneration unit, this is the case at least within a certain load range. The principle is:

- At times when the economically optimum level of power generation is above what the heat demand allows, the cogeneration unit runs at a level serving the optimum power generation, and the excess heat is stored. This is possible until the storage is full. Beyond that point, production of the cogeneration unit is again restricted by the level of heat demand
- When the economically optimum level of power generation is below what the heat demand requires, the cogeneration unit runs at a level serving the optimum power generation, and the missing heat is withdrawn from the heat storage. This is possible until the storage is empty. Beyond that point, production of the cogeneration unit has to be increased to the level required by heat demand

Over the last years, operators of cogeneration plants have increasingly invested into heat storages. The figure below shows the development of the total storage capacity of heat storages since 2011 deployed mostly by municipal utilities in public supply heat grids for the purpose of flexibilisation of cogeneration plants.

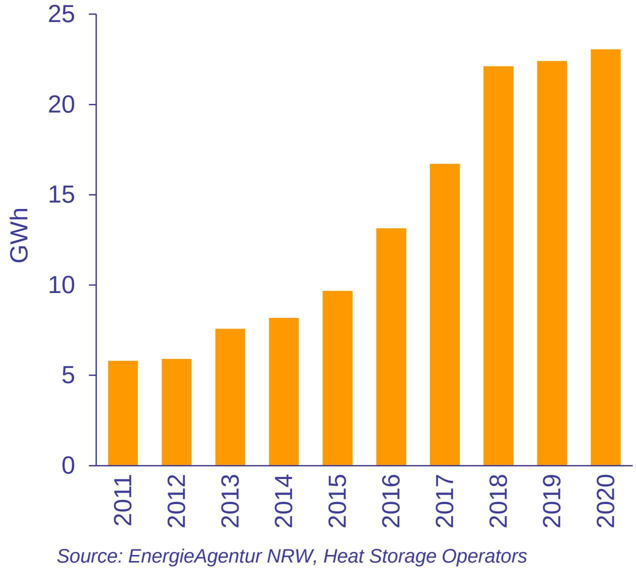


Figure 13: Cumulative capacity of heat storages deployed in public supply heat grids, 2011-2020

The total capacity in 2020 reached around 23 GWh was almost five times higher than in 2011. It was distributed across 36 heat storages, ranging in capacity from 0.1 to 2 GWh; the average capacity is 0.64 GWh.

In relative terms, the growth over the past decade is impressive. The numbers indicate, first, that flexibility of cogeneration was not much of an issue until a few years ago and, secondly, that operators of public supply cogeneration plants and heat grids have been increasingly striving to make their plants more flexible by means of heat storage.

In absolute terms, total capacity of heat storages in public heat supply grids can be regarded as high or low, depending on what it is compared to. It is more than 50 times higher than the total capacity of large-scale batteries connected to the electricity supply grids (approx. 0.42 GWh). It is in the same order of magnitude as pumped-storage hydroelectricity plants in Germany, which have a total capacity of around 37 GWh. However, it is only a tiny fraction (0.02%) of the total amount of heat that is supplied via public heat grids which by order of magnitude is 100 TWh per year.[10]

The latter comparison shows that heat storages in public supply heat grids today can only store heat on a scale of hours rather than days or even weeks. For flexibility of electricity production, this means that heat storages of today's volume and technology can provide mostly intra-day flexibility for cogeneration plants. For longer periods, other means are required.

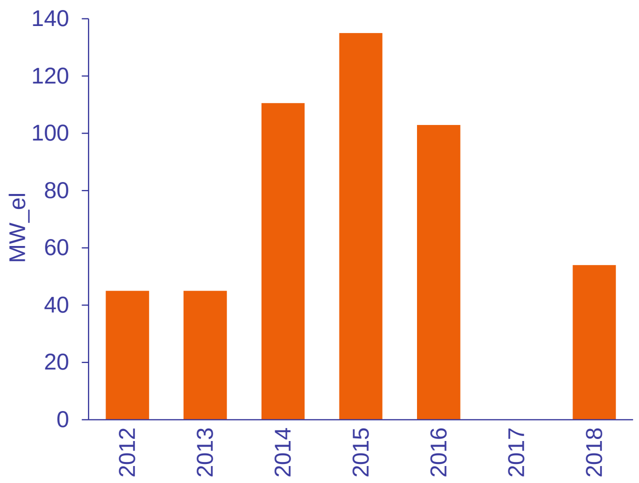
Power-to-heat (PtH) modules allow the operator of a cogeneration plant to *permanently* run the plant in an electricity-driven mode. The relation of the capacity of the PtH module to the required heat production capacity determines by how much the production from the cogeneration unit can be decreased. The principle is:

- At times when the production and sale of electricity is economically attractive, the cogeneration unit is used to produce both power and heat
- When the sale of power is not economically attractive, production from the cogeneration unit is reduced, and the missing heat is produced from power by the PtH module

Over the last years, there have been substantial investments into PtH modules. The total PtH capacity in Germany was estimated to be 640 MW_{el} in 2018. The main investors into PtH capacity are those operators of cogeneration plants that produce heat for public supply grids (district heat), i.e. municipal utilities. Around two thirds of total PtH capacity is connected to heat supply grids, approx. a quarter of the capacity is operated in the industry.[11] The annual growth of PtH capacity in Germany between 2012 and 2018 is shown in the figure below.

[10] EnergieAgentur NRW states a value of 110 TWh/a for district heat. The association for energy efficiency in heating, cooling and cogeneration (AGFW) states a value of 83 TWh/a. Contribution to the latter statistic is voluntary.

[11] Prognos, Fraunhofer IFAM, Öko-Institut, BHKW-Consult, Stiftung Umweltenergierecht, "Evaluation of combined head and power production", 2019 (A study commissioned by the Federal Ministry for Economic Affair and Energy of Germany)



Source: Fraunhofer IFAM et al.

Figure 14: Electric capacity of new PtH facilities in Germany by year of start-up, 2012-2018

The chart shows that the lion's share of estimated total PtH capacity in Germany was put into service from 2012 on (490 MW_{el} in the period from 2012 to 2018). Newly installed capacity reached a peak in 2015 and then declined considerably.

To put this in perspective, the total installed PtH capacity of 640 MW_{el} is by a factor of approx. 200 smaller than the combined peak power generation capacity of all renewable energies in Germany (~124 GW_{el})[12]; in comparison with the generation capacity of all conventional power plants (~94 GW_{el})[13], the factor is about 150. Thus, the ability of PtH modules to absorb excess electricity from the electricity grids is rather limited.

Compared to the heat generation capacity connected to heating grids of approx. 38 GW[14] (which stems mostly from cogeneration plants), the capacity of PtH modules connected to heating grids (approx. 430 MW) is smaller by a factor of about 90. That means, the ability of PtH modules to make a meaningful contribution to the supply of heating grids is still very limited as well.

The findings for heat storages and PtH modules are similar – as the flexibility requirements from the electricity system increased, these flexibility-providing elements have seen a boom in the last ten years. However, in comparison with the volumes of supplied energy and total installed cogeneration capacity, their role is still small.

Regulatory Aspects

Conventional power plants

As a general matter, the operation of conventional power plants is market-driven. This is true for investment decisions as well as the day-to-day decisions on whether the plant produces electricity and, if so, how much and at what times.

The electricity market design of Germany entails competition for most actors, depending on the role they play. Only the network operators – transmission system as well as distribution system operators – are regulated entities. This means they operate as a monopoly in their respective areas, their tariffs are regulated and their investments have to be approved by the regulator, the Federal Network Agency of Germany (Bundesnetzagentur, BNetzA). All other actors, including electricity generation (except from renewable energies), wholesale trading and retail operate in a competitive environment. For a more detailed description of the German market design, reference is made to the study "German experiences with large-scale batteries".[15]

This means that companies active in conventional electricity generation in Germany are free in their decisions on whether or not to invest into power plants, how to utilize their plants and whether or not to decommission them. This also applies to all decisions regarding the flexibility and the flexibilisation of conventional power plants. All of these decisions are based on commercial considerations by the operators. However, there are exceptions to this rule.

First, Germany has taken the decision to **phase out** electricity generation from several fuels, all affecting conventional power plants, namely:

- By December 31st, 2022, all nuclear power plants in Germany will have to cease operation, i.e. within the next two years 9.6 GW (representing around 10% of dispatchable generation capacity in Germany) will be shut down.
- By the end of 2038, all lignite and hard coal-fired power plants in Germany will have to cease operation, i.e. within the next 18 years 44 GW

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[12] BDEW, Installed capacity and generation 2019.
[13] ibid.
[14] Association for energy efficiency in heating, cooling and cogeneration (AGFW), Main Report, 2018.

[15] Team Consult, dena (publisher): German experiences with large-scale batteries – regulatory framework and business models, 2020 (A study supported by the Federal Ministry for Economic Affair and Energy of Germany)

(representing around 45% of dispatchable generation capacity in German) will be shut down.

Secondly, given the crucial role of security of electricity supply, the German lawmaker has authorized transmission system operators (TSOs) and the regulator to override the operators' commercial decision under certain, clearly defined circumstances. The most important legislation in this regard is found in the Energy Industry Act (Energiewirtschaftsgesetz, EnWG), in particular:

- §13a EnWG: Redispatch of conventional electricity generation by TSOs
- §13b EnWG: Obligation of power plant operators to announce the decommissioning of plants; designation of "system-relevant" plants by TSOs; ban of decommissionings of system-relevant plants

The **redispatch** regulation is basically an obligation for conventional power plants to utilize their flexibility to the benefit of the connected transmission network if necessary. The respective TSO may order an adjustment (upward or downward) of a plant's electricity generation, under the condition that other measures to ensure the grid's stability have been exploited and were not sufficient. The operator of the affected power plant gets a reimbursement of the costs incurred due to the redispatch. The calculation of the reimbursement has been a topic of controversial discussions and even litigation as it was deemed too low by several power plant operators.

The **system-relevant plants** regulation requires operators of conventional power plants above a capacity threshold of 10 MW to announce plans to temporarily or permanently decommission capacity (even if only partially) at least 12 months ahead of time. The TSO operating the grid connected to the plant may then designate the plant as system-relevant, if without the plant there is sufficient probability that the stability and reliability of the electricity system is in danger.

Preliminary decommissionings are then forbidden for the next 24 months. After this period expires, the designation as system-relevant may be renewed, in which case the ban of decommissioning is extended. Permanent decomissionings of system-relevant plants above a capacity of 50 MW are forbidden for as long as the TSO declares the plant system-relevant and the regulator (Federal Network Agency, BNetzA) approves that designation. The operators of affected plants get a reimbursement of the related costs.

In essence, operators of conventional power plants have to place the plants' flexibility at the disposal of the operator of the transmission network to which the plants is connected, to the extent necessary (redispatch). They have to keep the plants operational, even if shutdown is commercially the best option, to the extent necessary (system-relevant plants).

It is worth noting, however, that these measures are "last resort" measures. Usually, participation in the wholesale electricity market and the market for control energy procured by the TSOs should provide sufficient incentives to operators to keep system-relevant plants operational and to utilize their flexibility in a manner that is beneficial to the system's stability (cf. section "Functions and Applications" below).

The reality is, however, that products in the wholesale markets and control energy markets are standardized.[16] This means that as long as a plant can deliver what the standard product requires, it is treated equally to all other plants that can deliver the same. The result is that sometimes a plant's special, high-value characteristics – such as its location in a particularly congested zone of the market area – cannot be rewarded by the market under standard products. That is where the regulations described above come into play.

Cogeneration

There is a support scheme in place in Germany for cogeneration plants as such. Its legal basis is the law Combined Heat and Power Production Act (Kraft-Wärme-Kopplungsgesetz, KWKG). Under this law, cogeneration plants may receive remunerations for the electricity they generate significantly above or on top of electricity wholesale market prices.

The reason why the lawmaker put a support scheme in place for cogeneration plants is the superior fuel efficiency of cogeneration compared to uncoupled generation of heat and power and, thus, their lower CO_2 footprint.

The latest amendment of the law entails:

- Instruments to increase plants' responsiveness to market signals

[16] A certain degree of standardization is necessary to keep the markets liquid and functional.

- Augmented incentives to transition existing coal-fired cogeneration plants to other fuels
- An expanded auction segment to determine remunerations of electricity from cogeneration plants
- A bonus to increase the share of renewables in heating grids
- A maximum annual volume of support of 1.8 billion Euros

As can be seen from the table in Figure 12 above, net electricity production from cogeneration plants in 2018 was very close to the target for 2025. This basically means that cogeneration plants get to keep their current role while other conventional power plants will have to retreat further as renewable electricity generation continues to increase.

From a flexibility standpoint, a support scheme for cogeneration as such is rather counter-productive, because cogeneration is inherently less flexible than electricity generation from other conventional power plants. The lawmaker recognized the value of flexibility by inserting two flexibility-related provisions into the law.

First, there is now a provision that requires operators of cogeneration plants with a capacity of above 100 kW to directly market the electricity generated in the electricity wholesale market (or delegate this task to a company specialized in direct marketing). This is in contrast to just giving the electricity to the TSO and letting the TSO worry about what to do with it, as it was done before that provision came into effect. Thus, the incentives provided by the market to run plants flexibly and to invest into flexibilisation are passed through to operators of cogeneration plants.

Secondly, under the KWKG the installation of heat storages or cold storages is supported as well. In §§ 22ff. KWKG it is stipulated that:

- Heat Storages receive 250,- Euros per cubic meter of storage volume in subsidies (§23 KWKG); subsidies are capped at 10 million Euros or 30% of relevant investment costs (whichever is lower)
- A heat storage unit qualifies for the subsidy if it becomes operational before 2030, the heat it stores comes primarily from cogeneration plants and goes into public supply heat grids, and the heat loss is less than 15 Watt per square meter of surface area. These conditions apply cumulatively (§22 KWKG)
- The provisions for heat storages are to be applied to cold storages analogously (§25 KWKG)

Thus, the German lawmaker not only recognizes the superior fuel efficiency of cogeneration as such, but also the value of flexibility that heat and cold storages provide. As discussed further above, heat (or cold) storages in general do not primarily serve the flexibilisation of heat (or cold) supply[17], they serve the flexibilisation of electricity production in cogeneration.

Furthermore, with the most recent amendment of the Renewable Energy Act (EEG 2021), a provision was included that requires cogeneration plant operators to equip plants with a capapcity of more than 25 kilowatts with intelligent metering systems ("smart meters"). The TSO or another third party is authorized to monitor electricity output from the cogeneration plant and also to adjust it. It shows that the German lawmaker has identified cogeneration as a part of the electricity system that should become more flexible.

Functions and Applications

From a system point of view, conventional power plants have different functions to fulfill. Most importantly, they have to supply the **residual demand load** at all times. Since renewable generation has feed-in priority, conventional plants supply the exact share of electricity demand that cannot be covered by renewable electricity generation. As discussed in the introduction to this study, that residual load

- Becomes smaller in annual volume over time; this is because renewable generation grows faster than electricity demand
- Is continuously getting more volatile, due to the growing share of intermittent renewable generation and
- In the future is set to become negative at times

This means for conventional plants, that their annual production will shrink, they will see more frequent load changes, and they will be idle more often. However, the decline in electricity output from conventional plants does not necessarily imply a decline in their capacity. This is because conventional plants have to provide the required **dispatchable capacity**, i.e. generation capacity that is available on demand, regardless of weather conditions. Moreover, a **minimum level of conventional generation** is required even when renewable generation is more than sufficient to cover demand. This is because

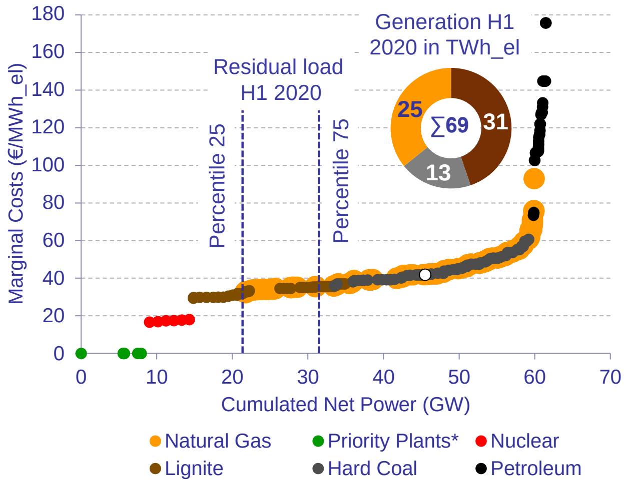
[17] This is because most cogeneration plants are run in a "heat-driven" mode from the outset.

some ancillary services provided by conventional plants require the respective plants to run at a minimum load.[18]

From an operator's commercial point of view, conventional plants have to earn money from the electricity they produce and, possibly, the flexibility services they provide. They can do this by participating in the **electricity wholesale market** or in the **control energy market**.[19]

The vast majority of conventional plants participate in the electricity wholesale market. The German electricity wholesale market is designed as a so-called "energy only market", meaning that the prices paid are for the actual delivery of energy (electricity), as opposed to a "capacity market" in which operators are paid for holding available generation capacities. While capacity charges do play a role in ancillary service markets (e.g. in interruptible loads or in control energy), the general market design of the electricity wholesale market in Germany is that of an "energy only" market. Ideas of introducing a "capacity market" on a large scale were brought forward and discussed 5-10 years ago, driven by worries that the energy only market would in the long run not provide sufficient incentives to invest into dispatchable generation capacity. However, those ideas were discarded for the time being, due to abundant dispatchable capacity at the time and the obvious capability of the energy only market to incentivize flexibilisation of the existing fleet of power plants.

For conventional power plants, the energy only market means that they produce electricity when the price in the electricity wholesale market exceeds their marginal cost of production (i.e. there is a positive margin), and they are idle when the price is below the marginal cost of production (i.e. the margin would be negative). When the conventional plants are sorted by their marginal costs of electricity production in ascending order, it becomes obvious which plants run most often and which run least often. The current merit order of plants in Germany is depicted in the figure below, in which each dot represents a conventional power plant.



Source: Team Consult Analysis

Figure 15: The German merit order of power plants in 2020

The residual load is represented by the vertical lines in the above graph. The 25-percentile line shows that 25% of the time, the residual load in the first half of 2020 was at 22 GW or less. This means that the first 22 GW of the merit order were only idle in 25% of the time (at most), i.e. they were running at least 75% of the time. The 75-percentile line shows that 75% of the time, the residual load was at 32 GW or less. This means that plants behind the first 32 GW of the merit order (to the right of the 75-percentile line) were idle at least 75% of the time, i.e. they were running at best 25% of the time.

As a general matter, the residual load can be envisioned as a vertical line in the above graph moving in the left-and-right direction as the residual load changes over time. In general, all plants to the left of such vertical line are in production while all plants to the right of that line are idle.

It is worth noting that the merit order is not a constant. Depending on the commodity price situation in the fuel markets (especially natural gas and hard coal) and on the EUA price (for CO_2 emission allowances), a plant's marginal costs of production can change significantly and so can its position in the merit order.

Interestingly, this chart shows that while nuclear and lignite plants have the lowest marginal costs and thus provide the base load, natural gas plants have moved up in the merit order and are now in many cases placed in front of hard coal plants. This is in contrast to the old world of electricity production in which hard coal

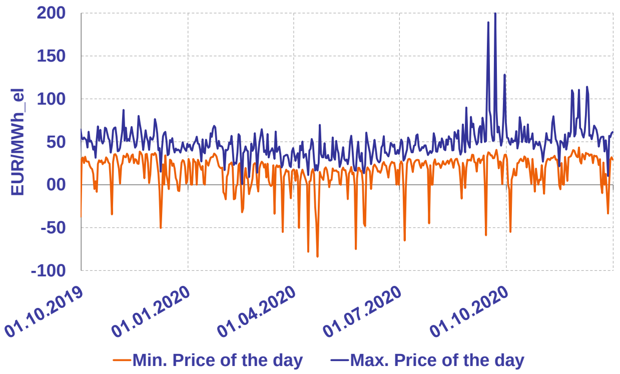
[18] Cf. dena, Ergebniszusammenfassung des dena-Symposiums Must-Run und gesicherte Leistung, 2019, p. 2.

[19] It is possible to participate in the electricity wholesale market and in the control energy market at the same time.

provided medium load and natural gas provided peak load, but the new picture is corroborated by the load distribution discussed above and shown in Figure 10.

What this says about flexibility in conventional plants is that nowadays flexibility is required across almost the entire fleet of conventional power plants, as the residual load moves in a very broad range. And this movement of the residual load causes prices fluctuations in the electricity wholesale market. To adapt to the price situation, plants have to be able to quickly adjust their production across a wide load range and to quickly change between operational and idle.

The figure below shows short-term price fluctuations in the German electricity wholesale market. It depicts two time series, one representing the maximum of hourly prices by day (blue line), and the other representing the minimum of hourly prices by day (orange line).



Source: EPEX SPOT, Team Consult Analysis

Figure 16: Development of minimum hourly price by day and maximum hourly price by day in Germany,

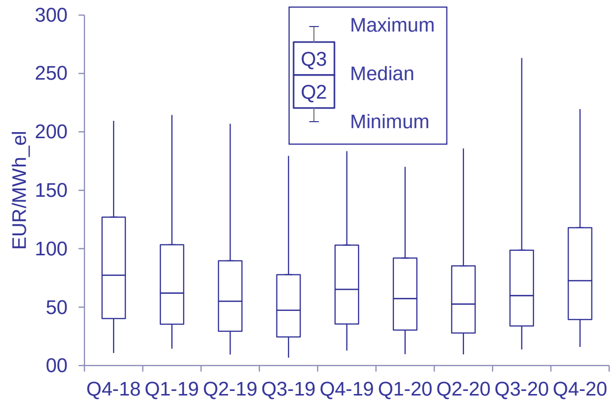
This graph shows that

- On many days, the maximum price reached a level of 50 EUR/MWh or higher
- On many days, the minimum price was at 30 EUR/MWh or below, and on several days it was negative
- On most days, there was a considerable spread between the minimum and the maximum price of the day
- On some days, the minimum price was negative

This means that on many days, most **conventional power plants** at least for a few hours were "out of the money" since marginal costs of production for most plants are above 30 EUR/MWh. Also, on many days, most conventional power plants were "in the money" since marginal costs for most plants are below 50 EUR/MWh (cf. Figure 15) above. The intra-day spot market thus provided rewards to plants that quickly adjusted electricity output across a wide load range. The possibility of negative prices was introduced in September of 2008 in Germany for intra-day and day-ahead trades. They have a particular role in mobilizing flexibility of conventional power plants, as they incentivize operators of near-zero marginal cost power plants (e.g. nuclear plants) to reduce power output to the minimum load.

PtH modules in cogeneration plants were able to profit from the very low (and, at times, even negative) minimum prices. When the electricity price falls below the marginal cost of heat production by other means, it becomes beneficial to switch from the "regular" means of heat production to heat production by the PtH module. When the electricity price is negative, it becomes rational to produce heat by PtH even when the heat is not needed, as long as there is an outlet for the heat (e.g. a storage).

To discuss what the intra-day spot price development means for the short-term flexibility of conventional plants, especially heat storages in cogeneration, it is worth to take a closer look at how the minimum vs. maximum spreads (i.e., the difference between the highest and the lowest price during a day) have developed over time. This is shown in the figure below.



Source: EPEX SPOT, Team Consult Analysis

Figure 17: Distribution of intra-day price spreads in the German wholesale electricity market, Q4-2018 to

The above chart shows that intra-day price spreads have been substantial over the entire period since Q4-2018, and there is no pronounced downward or upward trend. The median intra-day price spread in many quarters is above the typical level of electricity prices.

That means, there is a lot to gain for **cogeneration plants with heat storages** by focusing production on times during the day when electricity prices are high. The electricity can then be sold with a good margin, and the excess heat can be stored in the heat storage. At times with low electricity prices, production is reduced and any missing heat taken from the storage.

So the intra-day spot market for electricity currently does provide a profitable application of flexibility in electricity generation. In the control energy market, which by definition exists to reward flexibility, things have not been so stable. In the study "German experiences with large-scale batteries",[20] we have shown how with the boom of large-scale batteries in Germany, the prices of primary control energy have deteriorated over the last years. The same trend can be observed in the market for secondary control energy, as the figure below shows.

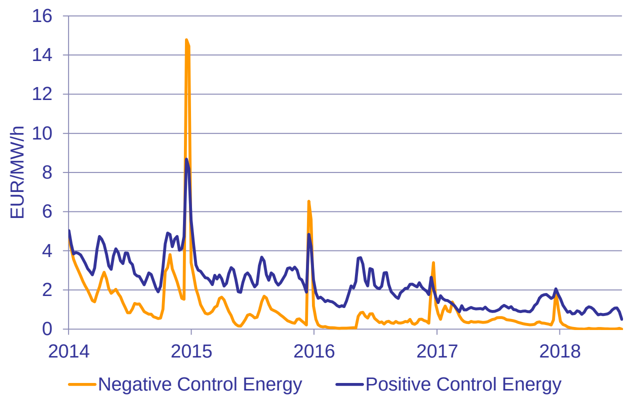


Figure 18: Price development in the market for secondary control energy, 2010-2018

Prices have substantially gone down, and in the case of negative control energy have even gone to basically zero. This means that in regard to short-term electrical flexibility, the control energy market does not provide much opportunity, and a business case for investment, if any, may be built on the intra-day spot market.

Example cases

Conventional power plants

An example of how conventional power plants can be made more flexible and adapt to the challenges posed by the energy transition is the hard coal-fired plant **Moorburg**. The plant is relatively new and has been in operation now for almost six years. It consists of two blocks with a generation capacity of slightly above 800 MW each.

Building a conventional power plant is a large and complex project that from start to finish takes a long time, sometimes as much as ten years, to complete. When the Moorburg project was started in 2006, the situation in the German electricity market was quite different from today. When the plant became operational in 2015, the flexibility requirements were much higher than what developers had had in mind.

- That is why around the time when the plant first went into operation, projects were started to make the plant more flexible. The following flexibility improvements were achieved:
- Reduction of the minimum load from 40% to 26% of capacity. This reduces the frequency of necessary shutdowns
- Increase of the maximum load gradient to +/-500 MW in ten minutes
- Prolongation of the cooling process after shutdown, allowing for "warm start" (rather than a costly and wearing "cold start") within a period of 48 hours after shutdown. This is especially useful when on weekends a block is idle and has to be restarted at the beginning of the subsequent week

According to Vattenfall, the operator of the Moorborg plant, the flexibilisation was an economic success. The operation of both blocks can now react more quickly to the requirements of the electricity system and changes in electricity prices.

The policy decision to phase out electricity generation from coal by 2038 will affect the plant in Moorburg very soon. An auction system was set up in Germany that allows operators of hard coal plants to place bids in regard to the compensation for which they are willing to close down a plant permanently. The first auction was started on September 1st, 2020 for 4,000 MW to be shut down. Vattenfall has announced its participation in that auction, and in December 2020 the regulator accepted Vattenfall's bid to shut down the Moorburg plant as early as 2021.

Cogeneration

An example of the flexibilisation of cogeneration plants is the "coastal power plant" ("Küstenkraftwerk") by **Stadtwerke Kiel**, a municipal utility. In the plant, 20 gas-fired motors generate electricity and heat. The key parameters are:

[20] Team Consult, dena (publisher): German experiences with large-scale batteries – regulatory framework and business models, 2020 (A study supported by the Federal Ministry for Economic Affair and Energy of Germany)

- Electric generation capacity: 190 MWel
- Heat generation capacity: 192 MWth
- Maximum load gradient: +190 MWel in 5 minutes
- Fuel efficiency: 90% (electricity and heat combined)
- To be able to decouple electricity and heat generation, at heat storage and a PtH module are installed. The parameters of the heat storage are:
- Heat capacity: 1,500 MWhth
- Maximum charge: 200 MWth
- Maximum discharge: 200 MWth
- Storage medium: water, in unpressurized steel cylinder (30 m diameter, 60 m height)

Based on these parameters, it is possible to run the cogeneration plant at full load for up to eight hours by filling the storage from empty to full, even when no heat is required to be fed into the heat supply grid. Also, it is possible to put the cogeneration unit into idle mode for up to eight hours, even when the maximum heat supply is required, by emptying the storage. That means that for a given amount of heat that has to be generated during a day, the operator can rather freely chose at what times during the day the plant should produce, and this decision can be based on price signals from the electricity intra-day spot market.

The PtH module has a power of 35 MW. Thus, it is not designed to cover the maximum heat capacity, but it is able to contribute to heat supply, and it can help stabilize the electricity grid by absorbing excess electricity and making use of it by converting it to heat.

Potential

Conventional power plants

There are basically two key takeaways from the sections above in regard to conventional power plants. First, conventional plants do offer substantial flexibility and can be retrofitted to increase flexibility, as the example of the Moorburg hard-coal plant shows. Secondly, flexibility requirements have been increasing and will continue to increase.

In 2019 and 2020, an exceptional high level of flexibility was required of hard coal plants. That is because the price situation in the commodity markets for hard coal and natural gas as well as the EUA prices (for CO_2 emission allowances) drove them to the back of the merit order, partly behind gas-fired plants. Thus, they were going back and forth between between “in the money” and “out of the money” and thus switched between idle and production quite frequently.

However, this does not necessarily mean that more investments into the flexibilisation of coal plants are imminent, for at least two reasons. One reason is that the commodity price situation recently was rather unusual and can always change back and put hard coal plants further up in the merit order (and ahead of gas-fired plants), where flexibility is less needed. The other reason is the upcoming phase-out of coal plants. By the end of 2022, the combined generation capacity of hard-coal and lignite plants by law is required to be reduced to 30 GW (from above 40 GW today). That means that the amortization period for investments into flexibility may be quite limited. It is also worth noting that flexible operation reduces the lifetime of conventional plants due to thermal stress on components.[21] This is particularly the case for coal-fired plants that are operated in a much more flexible manner than they were originally built for. However, given the policy decision to phase out coal-fired generation in Germany altogether, this may be less of a concern if the residual lifetime of a plant is deemed to be beyond the phase-out date.

Furthermore, flexibility of conventional plants – although substantial – is not without limits. This is true especially when it comes to their ability (or propensity) to reduce electricity output for short periods. An analysis by the regulator has shown that up to 28 GW of conventional capacity will remain in production even when electricity wholesale prices are negative. This **must-run** capacity is due to technical restrictions of plants, coupled heat generation, self-provision of electricity by operators or the requirement to keep the plant running in order to be able to provide ancillary services.[22]

The increase in flexibility required from the entirety of conventional power plants combined will not primarily be catered for by the flexibilisation of individual existing plants, but by changes in the composition of the *fleet* of plants. By the end of 2022, around 18 GW of generation capacity will be permanently closed down due to the phase-out of nuclear and (partly) of coal-fired power plants. Those plants are on the least flexible end of the spectrum (almost 10 GW nuclear, 2.8 GW lignite and at least 5.5 GW hard coal). At the same time, the German regulator BNetzA expects only 2.3 GW of new conventional generation capacity to come on stream by 2022.

[21] Cf. cf. Prognos, Fichtner, Agora Energiewende (2019): Flexibility in thermal power plants, p. 15.

[22] Cf. dena, Ergebniszusammenfassung des dena-Symposiums Must-Run und gesicherte Leistung, 2019, p. 2.

For those conventional power plants remaining after 2022, this means that they will improve their position in the merit order by 10 to 15 GW (depending on where they are positioned now). The likely outcome is

- The remaining plants that will then be those with the lowest marginal costs, i.e. at the top of the merit order, and find themselves in a cozier place of providing base or at least medium load; as they will be "in the money" at most times, there is not much incentive to invest into a higher level of flexibility of these plants
- As the entire merit order curve moves to the left (cf. Figure 15 above), plants with higher marginal costs of production which currently hardly ever run will become price setters more often, which helps stabilizing the level of electricity wholesale prices
- The net effect on the price signals for flexibility is harder to estimate; on the one hand, those plants leaving the market did provide some flexibility; as that is taken away, flexibility gets more scarce, and price signals for flexibility could improve. On the other hand, these plants also had certain inflexibilities to them[23], which will be removed from the market as well

In essence, coal-fired plants will not have much incentive to increase flexibility. Gas-fired plants are already the most flexible, albeit restrained in many cases by coupled heat production. It can be expected that in the near to mid-term, some new dispatchable generation capacity will be required to replace the plants that are leaving the market. In any case, new capacity will be planned to be highly flexible from the outset.

Cogeneration

In cogeneration, there is still a lot of potential for flexibilisation of existing plants by means of heat storages or PtH modules. According to the association for energy efficiency in heating, cooling and cogeneration (AGFW), the total heat production capacity connected to public supply heat grids is about 38 GW. This means:

- If the entire heat production capacity in public supply heating grids was equipped with heat storages for eight full load hours (as was done in the "coastal power plant" in Kiel), there would be around 300 GWh of storage instead of the 23 GWh in place today
- If the entire heat production capacity in public supply heating grids was equipped with an additional PtH capacity of 15% (a bit less than the 18% realized in the "coastal power plant"), there would be a combined PtH capacity of 5 GW instead of the 0.64 GW in place today

It is worth noting that these numbers are order-of-magnitude estimations, not an assessment of an actual (or even economic) potential. Nevertheless, they show that there could be substantial potential as compared to what is in place today. A more important conclusion is that the flexibilisation of cogeneration will not on its own solve the flexibility problem posed by an ever more volatile residual load to the electricity system. In the future, there will be occasions on which renewable generation will exceed aggregated consumption by tens of GW. In such cases, the ability to halt production of cogeneration units for a few hours and to absorb a couple of GW via PtH modules would certainly help. However, substantial amounts of flexibility will have to be provided by other means.

Conclusion

Conventional power plants in Germany have demonstrated their ability to provide the evermore-volatile residual load, thereby enabling the electricity system to accommodate increasing shares of renewable generation. Although they have inherent flexibility from the outset, some plants have been retrofitted to improve their flexibility features.

A further increase of flexibility from conventional power plants will be required in the future. This increase, however, will largely be provided by changes in the *fleet* of power plants, i.e. by a replacement of less flexible power plants such as nuclear and lignite plants by more flexible units such as gas-fired plants.

For heat-driven cogeneration plants, it is particularly challenging to provide for increasing flexibility needs in the electricity system. Operators of cogeneration plants have been upgrading their facilities to make them more flexible, e.g. by investing into heat storages and into power-to-heat modules – a development that is likely to continue.

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[23] For example, there were instances when some conventional plants (e.g. nuclear plants) remaind in production mode even though wholesale electricity prices were negative for a short time. This is because the revenue benefit from shutting down for as long as the prices were negative was smaller than the cost of shutting down and restarting.

3 Demand Side Management

Demand-Side Management (DSM) has been successfully employed by TSOs as well as DSOs for a long time in Germany. The TSOs are focused on industrial consumers, while DSOs handle the residential sector. Especially the task for the DSOs will become more and more complex with the implementation of heat pumps for space heating and the expansion of e-mobility.

Definitions

Demand side management

The term "demand side management" refers to the time-wise adaptation of the consumers' electricity demand according to the system's requirements. Thus, the term describes a reversal of the typical roles in the system of electricity supply, in which usually generation follows consumption.

The "regular" mode of operation of the electricity system is that consumers decide, based merely on their own needs, if, when and how much electricity they withdraw from the grid. Power generation units, in turn, adapt electricity production according to demand load (or, more precisely in a system with feed-in priority for renewable energies, they adapt to *residual* demand load).

While this principle – generation follows consumption – is taken for granted nowadays, it is worth remembering why the system was designed around this principle in the first place. The reason is simply that it is much more efficient to adapt the generation of conventional power plants to a given demand pattern than it would be to organize electricity consumption such that it follows a given pattern of electricity production.

As discussed in the previous chapter, conventional power plants inherently offer flexibility, as electricity output can easily be modulated within a certain load range, and some plants (especially open-cycle gas turbines) can quickly switch between operational and idle. On the other hand, it would be hard to impossible to coordinate millions of devices and appliances of residential household consumers to create a certain demand pattern, and it would be extremely costly to permanently adapt the industry's electricity consumption to the electricity system requirements. Therefore, in the past, the "generation-follows-consumption"-principle was basically the only way.

The question arises, why then has demand side management become a hot topic of energy policy discussions? The reason is twofold; one is related to flexibility demand and one related to flexibility supply:

- **Flexibility demand**: as volatile renewable power generation increases and so does volatility in residual load, an ever-higher level of flexibility is required in the electricity system, in particular from the fleet of conventional power plants. As the need for flexibility increases, so does the cost of providing that flexibility. This makes it necessary to mobilize all flexibility potentials, including those on the side of electricity demand, i.e. consumers.
- **Flexibility supply**: on the consumers' side, the increasing electrification of space heating (heat pumps) and transport (battery electric vehicles) introduces new elements of flexibility, while digital technologies (smart home and smart grid) enable the coordination and management of such elements of flexibility; i.e. potential flexibility on the consumers' side (the demand side) increases.

Moreover, as electrolysers will increasingly enter the system in order to produce green hydrogen from renewable electricity in the future, they will also offer flexibility potential. Although such facilities are not consumers from an overall energy system perspective (as they merely convert energy into a different form) they can be classified as consumers from an electricity system standpoint. Using their flexibility in electricity usage could therefore also qualify as demand side management.

However, despite these new developments, the idea of demand side management is not a new one. To a certain extent, demand response has been practiced for a long time in Germany.

Interruptible loads

Transmission system operators conclude contracts with large electricity consumers, usually from the industry segment, on so-called interruptible loads. The contractor is remunerated for the provision of interruptible load and/or for actual interruptions.

Under a contract for interruptible load, the TSO may interrupt electricity supply to the contractor at certain terms and conditions. These include the time interval, in which interruptions may occur, the maximum number and duration of interruptions, the time for notice and the contractor's remuneration.

It is necessary for TSOs to contract such interruptible loads as a precaution for instances in which the stability of the grid can otherwise not be maintained. Although this measure is usually more costly than e.g. control energy and used as a "last resort", it is less costly than running the risk of uncontrolled outages (blackouts) and supply interruptions for which consumers are not prepared.

Load shifting

The term "load shifting" describes the postponing (or preponing) of electricity withdrawals from the grid by a consumer such that the load occurs at a time when the grid is better prepared to accommodate it, i.e. usually during times of low aggregate demand. As a result of load shifting, the time profile of electricity consumption changes, while the total amount of electricity taken from the grid over a longer time span does not.

Load shifting generally requires some kind of energy storage for buffering. This is because the consumers in most cases do not want to change the time profile of their actual use of energy (e.g. the industry does not want to change production schedules, and the residential consumer does not want to change the schedule of when to have a room heated to a certain temperature). Therefore, in order to do load shifting with regard to electricity withdrawals from the grid, it is necessary to decouple the time profile of actual energy use from the time profile of electricity withdrawals from the grid by means of storage.

In Germany, this practice goes back to at least the 1950s and 1960s when storage heaters were installed in many households in Western Germany. Storage heaters are electric heating devices that convert electricity to heat directly and store it in a thermal storage (mostly at night times) for later use during the day. Although the primary motivation of the electricity companies behind the promotion of storage heaters was to sell more electricity, the interesting part in this context is the load shifting – electricity withdrawals during the grid's off-peak times at night to heat up the storage and the use of heat during the day by emptying the storage. This load shifting behavior was incentivized by time-of-use tariffs with lower electricity prices at night and higher prices during the day. In this way it was possible for electricity companies to achieve a more even and higher average utilization of base load power plants and electricity grids.

As electricity prices over time were burdened with higher taxes and levies and, thus, rose disproportionately compared to the prices of other forms of energy, storage heaters became uncompetitive. In addition, they are also very inefficient with regard to the primary energy they require per kilowatthour of heat supplied. As a result, their share in installed heating systems has gone down drastically over time. According to a 2019 study published by the German Association of Energy and Water Industries (BDEW, Bundesverband der Energie- und Wasserwirtschaft), only 2.6% of the approx. 40.6 million housing or apartment units in Germany were heated by a storage heater.[24]

Although this particular form of load shifting has been declining, the principle itself will remain relevant as electric heat pumps and battery-electric vehicles are on the rise. Both are rather new kinds of electricity consumers with substantial load shifting potential.

Current Status in Germany

Interruptible loads

Demand side management in Germany today primarily occurs in the form of interruptible loads which are contracted by the TSOs from large electricity consumers, mostly from the industry segment. Interruptible loads are among a wider range of ancillary services used by the TSOs to keep the electricity grids stable, which also include the different levels of control energy (primary, secondary, tertiary), reserve power plants, redispatch and others. The legal basis is the Energy Industry Act (Energiewirtschaftsgesetz), and the relevant regulation is the Regulation on Interruptible Loads (Verordnung zu abschaltbaren Lasten). The relevant provisions are laid out in detail further below.[25]

Regarding the magnitude in which interruptible load is used by the TSOs, there are at least three parameters to look at:

[24] BDEW (2019): Wie heizt Deutschland 2019? – BDEW-Studie zum Heizungsmarkt, p. 12.

[25] Reference is made to section "Regulatory Aspects" further down in this chapter.

- Pre-qualified and tendered interruptible load
- Contracted interruptible load
- Usage of interruptible load

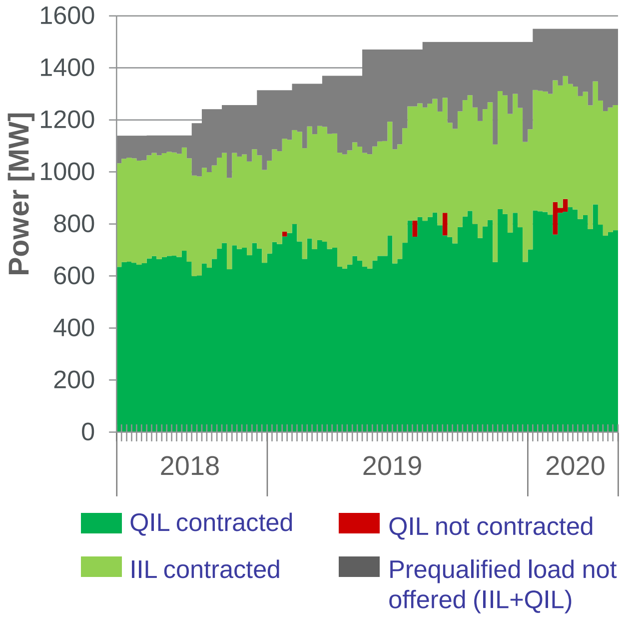
In order be admitted by the TSOs' as a provider of interruptible load, a potential provider has to go through a pre-qualification process. The reason is mainly that the electricity-consuming facility, which is used for interruption, has to meet certain technical specifications.

The TSOs have to pre-qualify at least the amount of interruptible load, which they anticipate they want to tender and contract in the relevant period. When in June 2020 the German TSOs published their latest report on interruptible loads, the pre-qualfied load was 1,532 MW, and a total of 1,500 MW of interruptible load was tendered every week, leaving a margin of only 32 MW (2%) of pre-qualified load over the tendered volume.[26]

The interruptible loads are contracted via tenders that the TSOs conduct once a week. The purpose of tendering procedure is to ensure that interruptible loads are contracted at prices which are not higher than necessary – the order in which bids are accepted is determined by the offered price, with the lowest-priced bid accepted first. However, to protect the TSOs (and the electricity consumers, who ultimately bear the costs of all procured services) from a potential lack of competition, the relevant regulation stipulates price limits which may not be exceeded by the providers in their bids. There are two price components, which the TSOs pay to the providers of interruptible loads:

- **A capacity charge**: this price component is paid by the TSO to the provider of contracted capacity merely for holding the interruptible load available, regardless of whether or not the interruptible load is actually used (i.e. interrupted) by the TSO during the contract period. The regulatory price limit is 500 EUR/MW per week.
- **A commodity charge**: this price component is paid by the TSO to the provider of interruptible load only in case the load is actually interrupted for the electricity shortfall, i.e. the amount of electricity that was not delivered due to the interruption. The regulatory price limit for this component is 400 EUR/MWh.

The figure below shows the development of the pre-qualified and the contracted interruptible load for the period from mid-2018 to April 2020.



Source: Bericht der ÜNB zu abschaltbaren Lasten 2020, p. 6
Note: QIL – Quickly Interruptible Load, IIL – Immediately Interruptible Load

Figure 19: Pre-qualified and contracted interruptible loads

It is obvious from this chart that both the pre-qualified and the contracted interruptible load have shown a trend of increase in the period displayed. While the pre-qualified interruptible load grew incrementally from approx. 1,100 MW in mid-2018 to slightly above 1,500 MW in early 2020 (+36% in less than two years), the contracted interruptible load fluctuated a bit more, but also grew from slightly above 1,000 MW to around 1,200 MW (+20%) over the same time period. The load pre-qualified and tendered but not offered has grown over time.

This compares to a tendered volume of of 620 MW of primary control energy, 1,876 MW of (positive) secondary control energy, and 1,166 MW of tertiary control energy in 2018, resulting in a total of 3,662 MW of control energy.[27]

The different shades of green in the figure above represent two different products of interruptible load. These are:

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[26] 50hertz, amprion, tennet, transnet BW (2020): Bericht der Übertragungsnetzbetreiber zu abschaltbaren Lasten gem. §8, Abs. 3 AbLaV.

[27] Bundesnetzagentur (2019): Monitoringbericht 2019, p. 207ff.

- **Quickly interruptible load**
  (QIL, dark green at the bottom of the stacked bars) The interruption of the load is ordered remotely by the TSO and has to take effect within 15 minutes. The tender volume is 750 MW every week (as of June 2020)
- **Immediately interruptible load**
  (IIL, light green in the middle of the stacked bars) The interruption of the load is either triggered automatically based on the grid frequency an takes effect within 350 milliseconds or is ordered remotely by the TSO in which case it has to take effect within one second. The tender volume is 750 MW every week as well (as of June 2020).

It appears that the “market” for interruptible loads is a sellers’ market, as the tendered volume (i.e. the volume the TSOs want to contract) grows faster than the contracted volume. This is further supported by the low number of pre-qualified providers (eight in total, primarily from the aluminum, chemistry and paper industries) as well as by the tender results displayed in the table below.

		Auction Results (Nov. 2, 2020)	
		IIL	QIL
Capacity charge (avg.)	EUR/MW	500	496
Commodity Charge (avg.)	EUR/MWh	400	398
Tender volume	MW	750	750
Offered volume	MW	480	804
Subscription rate		64%	107%
Contracted volume	MW	480	804
Success rate		100%	100%

Source: regelleistung.net, Team Consult Analysis

Figure 20: Results of interruptible load tenders, Nov. 2020

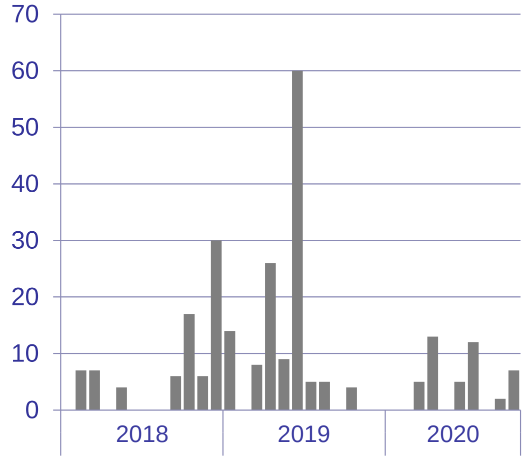
The tender results clearly indicate an absence of competition on the side of the providers of interruptible loads. For the more demanding, higher-value product of immediately interruptible loads, both the capacity charge and the commodity charge reached the regulatory price limit on average – meaning that all accepted bids were placed at the price limits. Of the tender volume of 750 MW, only 480 MW were even offered, resulting in a subscription rate of 64%, i.e. the tender was undersubscribed. That is why all bids were successful.

The picture is very similar for the quickly interruptible load. Averages of the awarded prices were only marginally below the regulatory price caps. The tender volume of 750 MW was slightly oversubscribed at 804 MW. Despite this, the TSOs obviously decided to accept all bids for this product as well, possibly to make up for the lack of contracted volume of immediately interruptible load.

The lack of competition revealed by the tender data is not surprising. Unforeseen events in industry processes – such as the interruption of (part of) the electricity supply at short notice – can affect the flow of production and cause substantial costs which may easily exceed the remuneration offered under interruptible load contracts. One must assume that the companies pre-qualified as providers of interruptible loads have taken precautions to the effect that an interruption under interruptible load contracts has a very limited (if any) effect on production and limits the costs to a magnitude in line with the remuneration. Still, some costs which may be related, for instance, to sudden stops and restarts of machinery can hardly be avoided.

Regarding the occurrence of actual interruptions, there is no clear pattern. Interruptions happen erratically – there are time intervals of several months, in which not a single interruption occurs. Then again, there are days when many (up to 30) interruption events occur on the same day. In 2018, a total of 77 interruption events occurred on 20 different days, meaning that on 345 days, not a single interruption occurred. In 2019, there were 131 interruption events which took place on 22 different days. The number of interruption events dropped considerably in the first ten months of 2020, namely to 44 event that happened on 13 different days.

The figure below shows the number of interruption events called by the German TSOs under interruptible load contracts by months from the beginning of 2018 until October 2020.



Source: regelleistung.net, Team Consult Analysis

Figure 21: Number of interruption events by months, from 2018

Further analysis reveals that

- The average load per interruption event slightly decreased from 78 MW in 2018 to 60 MW in 2020,
- Different interruption events can occur at the same time; the maximum load that was interrupted at the same time was 744 MW in 2018 (15 parallel events), 736 MW in 2019 (14 parallel events) and 480 MW in 2020 (5 parallel events),
- The electricity shortfall (i.e. the amount of electricity that was not delivered due to interruptions) was 4,508 MWh in 2018, 8,345 MWh in 2019 and 2,304 MWh in the first ten months of 2020,
- In 2018 only one third of interruption events happened under the immediately interruptible load product; this share increased to 75% of events in 2020,
- The interruptions range in duration from 15 minutes to several hours (in rare cases); the average duration of interruption events decreased from 74 minutes in 2018 to 68 minutes in 2019 and to 52 minutes in 2020.

The German regulator states in its monitoring report that in 2018 interruptible loads caused costs of around 28 million Euros, only one million of which was paid as commodity charge by the TSOs to the providers of interruptible loads while approx. 27 million were paid as capacity charge.[28] The costs are passed on to all final consumers via a levy. The levy is recalculated once a year based on cost forecasts and usually ranges between 0.005 ct/kWh and 0.01 ct/kWh, i.e. it is very low compared to other electricity price elements.

To put this into perspective, the costs for interruptible loads represent only a tiny fraction (around 1.5%) of the total costs incurred by the TSOs for ancillary services and stabilization measures, which the regulator reports to be 1.9 billion Euros for 2018. The large chunks of these costs are caused by curtailment, redispatch, reserve power plants and energy losses, each of which is in the three-digit million Euro magnitude. The costs for primary, secondary and tertiary control energy combined were slightly above 110 million Euros.[29]

Load shifting – Load control agreements

While the instrument of interruptible loads is used by the TSOs, i.e. the operators of the (higher-voltage) transmission networks, there is another DSM instrument used by the operators of lower-voltage distribution grids (DSOs), which is referred to as load control agreement.

Under this instrument, a DSO and a small electricity customer agree that the DSO has the right to manage the electricity consumption of one of the customer's electrical devices. In turn, the electricity customer benefits from a discount on the network tariff charged by the DSO. Load control agreements are primarily directed at electric heating devices with a storage unit, i.e. mostly heat pumps and storage heaters. While there is a legal basis for load control agreements in the Energy Industry Act (§14a), more specific regulation does not exist.[30]

The purpose of load control agreements is to enable a DSO to prevent local grid congestions from occurring. Such congestions may happen when too many heating devices withdraw electricity from the distribution grid at the same time. In such a case, the DSO uses its rights under load control agreements and directs some of the devices to stop withdrawing electricity for a limited period of time. The effect is that the peak in aggregate demand load is capped and electricity withdrawals are distributed across a longer time interval. In other words, the DSO practices *load shifting*.

Of the 844 DSOs active in Germany, 677 made use of load control agreements in 2018, according to the regulator's monitoring report.[31] A total of 1.45 million load control agreements were in effect in 2018.

Two thirds of the 1.45 million devices were storage heaters, as shown in the figure below. This amounts to one million storage heaters which are managed under load control agreements. Heat pumps had a share of 24% in 2018 (a plus of 2 percentage points compare to 2017). Other devices with a share of 9% also mostly include electrical heating devices.

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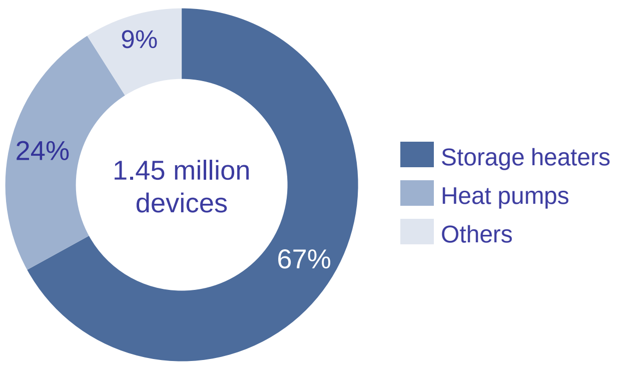
[28] Bundesnetzagentur (2019): Monitoringbericht 2019, p. 222.
[29] Ibidem, p. 202.
[30] For a more elaborate description, reference is made to section "Regulatory Aspects" further down in this chapter
[31] Bundesnetzagentur (2019): Monitoringbericht 2019, p. 198.



Source: Bundesnetzagenur, Monitoring report 2019, p. 199

Figure 22: Devices operated under load control agreements 2018

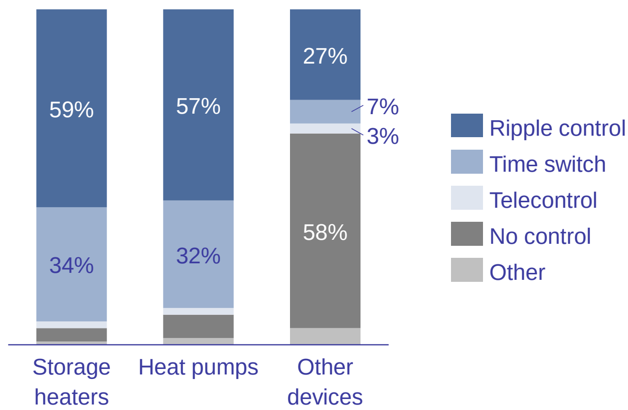
The discount the DSOs offer in return for load control agreements is not specified by regulation and thus varies significantly between the different TSOs. On average, it is 3.44 ct/kWh, or 55% of the network tariff charged by the DSO. The discount also amounts to a substantial share of the electricity price which for final consumers in the residential segment in Germany is around 30 ct/kWh. The total amount of discounts granted under load control agreements by all DSOs combined is not reported by the regulator, and neither is the total load controlled by the DSOs nor the electricity volume affected.

However, these parameters can be estimated through an order-of-magnitude calculation. According to data published by the German Association of Energy and Water Industries, one storage heater consumes around 8,200 kWh of electricity per year on average,[32] resulting in a total consumption of storage heaters managed under load control agreements (one million) of 8.2 TWh per year. The combined storage volume is, of course, much smaller. Assuming that 80% of the total consumption goes through the storage and assuming further 150 storage cycles per year,[33] the resulting storage volume is 45 GWh, or 45 kWh per device. The latter is in line with technical data of storage heaters which are commercially marketed today. If the average storage heater has an electrical capacity of five kilowatts[34], the total capacity of storage heaters managed under load control agreements in Germany is 5 GW.

This means the German DSOs command electric capacity of approx. 5 GW and a storage volume of approx. 45 GWh[35] under load control agreements, and this considers only the storage heaters. Additional capacity and storage volume from heat pumps and other devices come on top. However, the flexibility provided by a single heat pump to the electricity system is much lower than the flexibility provided by a comparable[36] storage heater. This is for two reasons; first, because the heat pump by its very nature requires a lot less electricity to produce the same amount of heat and, second, because the buffer storage connected to a heat pump is usually of smaller scale and covers shorter time ranges than that of a storage heater.

The capacity and storage volume available to DSOs under load control agreements are changing, as storage heaters are being increasingly replaced by other heat generators and the number of heat pumps is increasing considerably.

As the principle of load control has been used for decades, the technology of control devices is rather simple when compared with the potential offered by the technologies available today. The figure below shows the share of different load control technologies in use, stated separately for storage heaters, heat pumps and other devices.



Source: Bundesnetzagenur, Monitoring report 2019, p. 200

Figure 23: Technologies used for load control

[32] BDEW (2019): Entwicklung des Wärmeverbrauchs in Deutschland – Basisdaten und Einflussfaktoren, p. 29.
[33] This corresponds to one load cycle per day and a heating season of 150 days per year.
[34] Again, this would be in line with commercially marketed devices. Also, it would result in 1,650 full load hours per year which for heating devices of residential customers is a reasonable assumption.
[35] It is worth noting that when the storage is emptied, the energy can only be withdrawn as heat, not as electricity. Therefore, the storage – although it enables the prvision of flexibility to the electricity system – cannot be regarded as "electricity storage".
[36] Comparable here means "of the same heating capacity", i.e. the storage heater and heat pump are assumed to cover the same heating demand.

Three different technologies are used for load control:

- Time Switch
- Ripple Control
- Telecontrol

The best-known technology used for load control is probably the **time switch**. The period in which the load-controlled device may withdraw electricity from the grid is determined once and programmed into the time switch. The time switch repeats the same pattern every day. Thus, it does not allow the DSO to exert remote control. This means electricity withdrawals from the grid by the load-controlled device cannot be adapted in a flexible manner according to the changing demand and supply situation of the grid.

The most commonly used technology for load control is referred to as "**ripple control**". It is a rather basic information technology that allows sending control signals (impulses) via the electricity grid. The signals only go one-way, i.e. bidirectional communication is not possible. This technology requires the installation of a receiver at the location of the load-controlled device. The advantage of ripple control is that the DSO can remotely activate pre-defined load profiles, and the electricity grid can be used for signal transmission; a connection with other systems (such as e.g. modern-day mobile communication networks) is not required.

Telecontrol is the most sophisticated technology used for load control, but also the least common. It allows for bidirectional communication. Thus, in addition to exerting remote control, the DSO can also monitor the status of the respective device and check whether the control signals have been properly executed. Telecontrol devices are connected to telecommunication networks, i.e. the signals are not transmitted via the electricity grid. This results in much higher bandwidth compared to ripple control, and allows for more complex control signals. It is not just possible to remotely activate pre-defined profiles, but also to re-program time profiles remotely. As time patters of the supply and demand balance of grids have been increasingly changing in the wake of the energy transition, this is a major advantage.

The bottom line is that the load control technologies in use are not state-of-the-art. This indicates a very substantial potential for improvement. In the future, all devices involved with load control agreements will be required by regulation to have a smart metering system installed, which will essentially render the time switch and ripple control technologies obsolete for this purpose. It is a separate question, however, if it is worthwhile to upgrade many of the storage heaters with smart technologies as they are on their way out of the market anyway.[37]

The vast majority of heat pumps, on the other hand, will certainly be upgraded as the inventory of heat pumps in German buildings is still rather new and, when replaced, will be replaced by another heat pump. Considering that most of the heat pumps were installed in the last ten years, it is a bit suprising that they do not tilt to more advanced load control technologies than storage heaters. The exact reasons are unclear[38], but this certainly shows the perseverance of established and functioning technologies even in the face of better solutions. However, considering that regulation has become more demanding in this regard, the growing number of new installations of heat pumps – as well as other forms of DSM potential, such as e.g. electric vehicles – will increasingly be equipped with smart technologies from the outset.

Load shifting – Other means

The DSM instruments described above – interruptible loads and load control agreements – were designed exclusively for the purpose of demand side management. DSM activities under these instruments are well documented, as they have a transactional character, both in terms of contracts (the TSO or DSO procures DSM services from the electricity customers) and in terms of operations (the TSO or DSO triggers the DSM activity remotely). Due to transparency obligations and extensive reporting done by the regulator, extensive data is available.

For these reasons, interruptible loads and load control agreements are the most "visible" part of demand side management; however, they are far from being the only

[37] According to data published by the German Association of Energy and Water Industries, the inventory of storage heaters in German buildings has been decreasing by 3.9% p.a., cf. BDEW (2019): Entwicklung des Wärmeverbrauchs in Deutschland – Basisdaten und Einflussfaktoren, p. 29.
In 2009, legislation and regulation were introduced that would have banned storage heaters, starting in 2020. That ban, however, never came into effect, as the relevant provision was removed from legislation in 2013.

[38] Potential reasons may include a lack of standarization and specification of requirements with regard to smart technologies in the past. It is also possible that when storage heaters were increasingly decommissioned and more and more heat pumps were installed, DSOs re-used the existing ripple control devices for heat pumps.

instruments, and – in terms of costs – they are not even the most important instruments.

Since 2018, the German regulator *Bundesnetzagentur* in cooperation with the Federal Ministry for Economic Affairs and Energy conducts a survey once a year in which electricity customers from the industry segment are polled about their load management (i.e. demand side management) activities. The survey includes all customers that at least in one of the past two years had an electricity consumption of at least 50 GWh/a. From these companies, all sites above 10 GWh/a are included in the survey. Overall, the survey in 2018 included 486 companies with 1,112 sites and a combined electricity consumption of 153 TWh/a, representing around two thirds of overall industrial electricity consumption. In 2018, 577 out of 1,112 industry sites (52%) were reported to have a load management system in operation. The figure below depicts the load-managed electricity consumption vs. the unmanaged electricity consumption by industry branches.

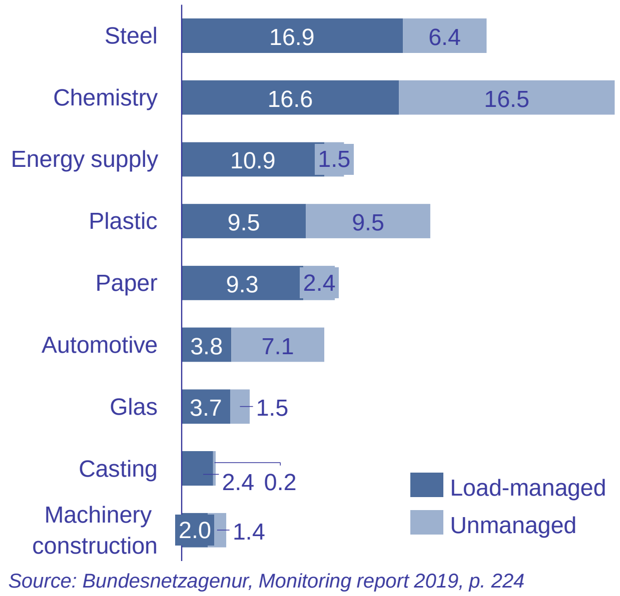


Figure 24: Load-managed vs. unmanaged consumption by industry branches in TWh, 2018

The branches in the chart above are in order of load-managed electricity consumption, with steel production and chemistry at the top. Overall, load-managed consumption significantly exceeds unmanaged consumption. The sum of load-managed consumption across all of the branches in the chart amounts to 75 TWh. This amount of load-managed electricity is much higher than the electricity consumption managed by the DSOs under load control agreements (approx. 8.2 TWh for storage heaters), and it is also higher than the electricity consumption controlled by TSOs under interruptible load contracts. The latter is not reported but can be estimated from the pre-qualified load of 1.5 GW to be in the magnitude of 10.5 TWh/a.[39]

The difference between the load management activities reported in the survey on the one side and interruptible loads and load control agreements on the other side is that the latter are managed by the grid operators (TSOs and DSOs) while the former are mostly[40] carried out by the industry itself (or, in case the load management was outsourced, on behalf of the industry).

The survey conducted by Bundesnetzagentur and the Federal Ministry also asks the participants about their reasons for doing load management. At the top of the list are optimization of the electricity procurement price and optimization in regard to the network tariffs charged by the grid operators. The latter is the most important. It is split into three different elements[41]:

- Limitation of the peak load in order to reduce the annual capacity payment to the grid operator (§17 II StromNEV)
- Meeting the requirements regarding load hours and minimum consumption for network tariff discounts under the "7,000 hours rule"42 (§19 II 2 StromNEV)
- Meeting the requirements for network tariff discounts under the "atypical grid usage rule" (§19 II 1 StromNEV)

The figure below shows the number of times a reason for load management was mentioned in the survey.

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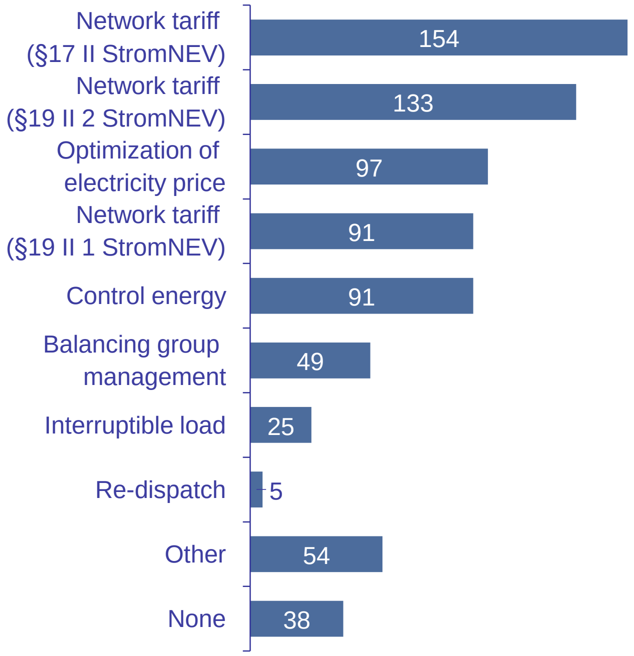
[39] This number is approximated from the pre-qualified load of 1.5 GW and an estimated number of full load hours of 7,000 per year.

[40] The survey comprises all load management activities concerning the industry segment and thus also includes those involving the TSOs (such as interruptible loads, but also control energy and redispatch). However, the vast majority is carried out by the industry companies (or their agents) in their own responsibility.

[41] The relevant regulatory provisions and their purpose are discussed in more detail in section "Regulatory Aspects" further down in this chapter.

[42] Based on the „7,000 hours rule", a large electricity consumer can reduce the grid capacity tariffs down to 20% of regular prices. For the discount to apply the consumption has to exceed 10 GWh per year and the number of load hours per year (annual consumption in MWh divided by the maximum use grid connection capacity in MW) has to be at least 7,000 hours.



Source: Bundesnetzagenur, Monitoring report 2019, p. 225

Figure 25: Reasons for load management in the industry, 2018

Obviously, considerations concerning network tariffs are the prime motivation for large customers to practice load management. The reason becomes clear by looking at the costs to TSOs (and, conversely, the financial benefits to customers) from these tariff-related provisions. These are much higher than the costs for any of the ancillary service procured by the TSOs, as will be discussed in more detail below. The effect of these tariff-based incentives to have a "grid-friendly" load profile goes beyond active load management in day-to-day operations (although this is an important factor). They also play a role in the cost calculations of industry customers more generally, e.g. in the design of a new production process. The effect is that a more levelled electrical load is built into the production process from the outset.

Beside financial considerations in regard to the network tariff, the optimization of the electricity procurement price, the provision of control energy and balancing group management stand out as main resons for load management. Optimization of the procurement price mostly takes place in the intra-day wholesale electricity market. As discussed above in the chapter on flexibility measures for conventional power plants, intra-day price spreads are quite significant, with the median often reaching 50 EUR/MWh or more. Just as electricity producers take advantage of these spreads by generating electricity at times when the price peaks during the day, (large) electricity consumers take advantage by taking electricity from the grid at times when the price plummets.

Providing control energy is often thought of as a task for electricity producers. However, electricity consumers can also participate in the markets for control energy. If they meet the pre-qualification criteria, they can take part in tenders and contribute positive or negative control energy at the different levels of that market (primary, secondary, tertiary) by reducing or increasing their load on the electricity grid.

The main incentive for load management under balancing group management is the balancing energy price. It is a price the entity responsible for the balancing group pays (if the imbalance is a deficit) or receives (if the imbalance is a surplus) for imbalances. The balancing energy price is designed to be unattractive – i.e. the price for positive balancing energy is high, and the price for negative balancing energy is low –, so that it provides sufficient incentives to the balancing group managers to avoid imbalances. Balancing group managers can avoid imbalances either by making adjustments on the procurement/supply side (e.g. by making purchases or sales in the intra-day spot market) or by adjusting their load, i.e. by load management.

It is impossible to know the exact financial benefit industry customers generate for themselves by practicing load management. This is because in some cases there is no data collected; for instance, even though the TSOs know the imbalances of individual balancing groups, they don't know the extent to which load management helped to limit or reduce the imbalance (i.e. what the imbalance would have been without load management). Similarly, it is not known what financial benefit industry customers generated by optimizing the electricity procurement price in the spot market on the basis of load management.

However, in some areas a significant amount of such DSM-related data is reported by the regulator. Regarding discounts on network tariffs under the 7,000-hours-rule and the atypical-grid-usage rule, the regulator publishes the number of affected network tariff contracts, the amount of affected electricity delivered and the aggregated reduction in network tariff payments, i.e. the overall financial benefit to customers. The numbers for 2019 are displayed in the table below. It also contains the numbers for 2015 for the sake of comparison.

7,000 hours rule (§ 19 II 2 StromNEV)		2015	2019*	Difference
No. of individually billed network tariff contracts		275	552	+101%
Amount of electricity	TWh/a	43	90	+111%
Aggregate tariff reduction	Million EUR/a	325	999	+208%

Atypical grid usage (§ 19 II 1 StromNEV)		2015	2019*	Difference
No. of individually billed network tariff contracts		2,987	6,059	+103%
Amount of electricity	TWh/a	25	41	+61%
Aggregate tariff reduction	Million EUR/a	292	425	+45%

Source: Bundesnetzagentur, Monitoringreport 2019, p. 189ff.

* preliminary

Figure 26: Network tariff discounts granted, 2019 vs. 2015

Obviously, discounts on network tariffs under the two respective provisions have substantially increased since 2015 and in total reached an amount of more than 1.4 billion Euros in 2019. In a four-year period, total discounts more than doubled, and discounts granted under the 7,000-hours-rule even tripled. This indicates that load management directed at meeting the requirements of the two discount provisions has substantially increased.

By comparison, the costs incurred by the TSOs for DSM-related ancillary services are much lower: in 2018, capacity payments for interruptible loads were 28 million Euros. These payments are fully DSM-related, i.e. from the industry customers perspective they represent revenues generated on the basis of load management. The sum of these payments has been rather constant over the last few years.

By contrast, in the control energy market, capacity payments reached 65 million Euros for primary control energy, 53 million Euros for secondary control energy and 6 million Euros for tertiary control energy in 2018. However, these payments are not exclusively DSM-related. A substantial share of revenues in the control energy market is generated by power plants, i.e. by flexible elements on the power *production* side. Nevertheless, industry customers may be pre-qualified for control energy and compete in tenders for control energy. Thus, a part of the revenues in the control energy market is generated on the basis of load management.

The costs incurred by TSOs for control energy and, thus, the revenues generated by providers of control energy have been in substantial decline over the past few years. This decrease was driven by a reduction in control energy prices while the extent to which TSOs used control energy services has remained remarkably constant (with the exception of tertiary control energy). This indicates an increase in competition among the providers of control energy. To some extent, this can be explained by new technologies with decreasing costs (such as large-scale batteries) which are used for the provision of control energy. However, it is very likely that additional load management capabilities mobilized by industry customers have also contributed to this development.

Regulatory Aspects

As indicated above, demand side management activities are not all based on explicit regulations for DSM – some, if not most of them are based on incentives provided by the market or by the general market design. These incentives include price spreads in the intra-day electricity wholesale market, prices for control energy, the balancing energy price paid or received for account imbalances, and the mere fact that network fees include a capacity payment, i.e. the costs for the network connection increase proportionally to the capacity of the grid connection.

Nevertheless, there are regulations that are specifically directed at demand side management in Germany. These are distributed across a number of different laws and ordinances.

Interruptible loads

The legal basis for interruptible loads is the Energy Industry Act (Energiewirtschaftsgesetz, EnWG), a federal law of Germany. It specifies:

- TSOs have the responsibility to guarantee the stability of the electricity system, i.a. by using market-related measures, including among others interruptible loads (§13 I 2, EnWG)
- In procuring interruptible loads, TSOs will hold transparent and non-discriminatory tenders (§13 VI, EnWG)
- The Federal Government may regulate interruptible loads in further detail in additional regulations (§13i VI, EnWG)
- Minimum technical requirements, including a minimum lot size of 5 MW and a maximum lead time of 15 minutes (§13i II 4 EnWG)

More detailed provisions on interruptible loads are laid down in the Regulation on Interruptible Loads (Verordnung zu abschaltbaren Lasten, AbLaV). It stipulates among others:

- Definitions (§2 AbLaV):
  Most importantly, this paragraph specifies that interruptible loads have to be connected via no more than two levels of transformation with the extra-high-

voltage-grid and must be located in the effective range of an extra-high-voltage-grid node. Moreover, this paragraph specifies the two products (immediately interruptible loads, quickly interruptible loads)
- Remuneration (§4 AbLaV):
  Providers of interruptible loads receive a capacity payment for holding available the interruptible load and a commodity payment for actual interruptions. The remuneration is determined in a tender and is capped at 500 Euros per MW per week (capacity payment) and 400 Euros per MWh (commodity payment).
- Technical requirements regarding in particular the required availability of interruptible loads and permitted durations of interruptions (§5 AbLaV)

The regulation further stipulates that tenders take place once a week and that in total 1,500 Megawatt have to be tendered (split equally between immediately and quickly interruptible loads). Those providers awarded in the tenders have to hold available the capacity contracted as interruptible loads; however, they are allowed to market the contracted capacities additionally in the day-ahead spot market and in the markets for positive control energy or for primary control energy. At times when the interruptible loads are marketed in the day-ahead or control energy market, they do not have to be available as interruptible loads.

Load control agreements

Load control agreements are governed by §14a of the Energy Industry Act (EnWG). It stipulates that DSOs have to grant discounts on network tariffs to those final consumers with whom they conclude a load control agreement. The requirement is that the controlled devices have to be suited to be load-controlled and that they have a separate measuring point. Although the law authorizes the Federal Government to enact further regulation, such further regulation does not exist.

Regulatory standards concerning load control agreements are meager, as there is no specification in regulation of e.g. the tariff discount that has to be granted or of technical requirements of load-controlled devices. Accordingly, implementation may vary between the different DSOs. For example, the average discount granted on network tariffs on average amounted to 3.44 ct/kWh in 2018, which was a 55% reduction of the average regular tariff. However, the highest discount observed by the regulator was 91%, the lowest 6% on the regular tariff.[43]

It is expected that the German lawmaker will revise the regulatory provisions on load management in distribution grids in 2021. This is deemed necessary as the circumstances are changing in regard to smart metering and smart grid technologies as well as new types of devices suited for load control such as battery electric vehicles. It remains to be seen whether the revised regulation will be more specific and thus take a step towards a higher degree of standardization of load control agreements.

Further regulations

Further regulations in regard to load management can be found in the Regulation on Electricity Network Tariffs (Stromnetzentgeltverordnung, StromNEV). The relevant provisions are mentioned here for the sake of completeness and are only described briefly, as they are elaborated in more detail in our sudy on large-scale batteries.[44] The provisions are:

- §17 II StromNEV – annual capacity payment
- §19 II 1 StromNEV – discount for atypical grid usage
- §19 II 2 StromNEV – discount under the 7,000 hour rule

The annual capacity payment ensures that the annual payment the customer makes to the grid operator is proportional to the peak load in the relevant year, i.e. a reduction in peak load translates linearly into a reduction of the capacity payment for network access. The two provisions on discounts ensure that "grid-friendly" load profiles are rewarded; this is the case if the customer's peak load occurs during the grid's off-peak times (atypical grid usage, §19 II 1) or if the number of full load hours is at least 7,000 (7,000-hours-rule, §19 II 2). The discounts may be up to 80% off the regular tariff (atypical grid usage) or at least 80% off the regular tariff (7,000-hours-rule). The two discounts are either or, i.e. they cannot be applied cumulatively.

All three provisions are meant to incentivize large electricity customers to manage their withdrawals from the electricity grid such that the peak load is not higher

[43] Bundesnetzagentur (2019): Monitoringbericht 2019, p. 199.
[44] Team Consult, dena (publisher): German experiences with large-scale batteries – regulatory framework and business models, 2020 (A study supported by the Federal Ministry for Economic Affair and Energy of Germany), p. 19.

than necessary, the time profile of the load is rather levelled and fluctuations are low.

However, given the substantial and increasing use of these provisions and the related costs incurred by grid operators, these discounts have come under scrutiny. The regulator in 2015 evaluated these regulations, including by polling the grid operators and inquiring their views. The bottom line of the report published by the regulator was that positive effects for the grid were found to be quite limited.[45]

One reason for that finding is that it is unclear whether the discounted customer's reduction in maximum load contributes to a reduction of load at times when the grid actually needs a reduction (i.e. during the grid's peak time). Further, particularly the 7,000 hours rule may hinder the customers' willingness to offer additional flexibility if the provision of extra flexibility leads to a reduction in annual volume that pushes the number of load hours below 7,000. This is because the latter would result in a loss of the network tariff discount.

Functions and Applications

Functions – customer perspective

From the perspective of an individual electricity customer that practices demand side management (or allows the grid operator to exert load control) the objective is financial optimization. The instruments which may be used in the optimization are displayed in Figure 21. above and include most importantly network tariff optimization, provision of control energy or interruptible loads, optimization of electricity procurement costs in the spot market and balancing group management.

Functions – system perspective

The functions served by DSM from a macro (system) perspective become evident by looking at the time ranges in which the application of the above instruments take effect[46]:

- Interruptible loads: immediately to 8 hours[47]
- Control energy: 30 seconds to one hour
- Procurement price optimization (spot market): from 5 minutes upwards[48]
- Balancing group management: 15 minutes (the balance is assessed once every 15 minutes)
- Network tariff optimization: one year

Obviously, demand side management fulfils at least two functions at the system level – first, contributing to short-term stability of the electricity system and, secondly, ensuring a levelled load profile during the day as well as over the year and, thus, a more steady utilization of electricity grids and power plants.

The important contribution of DSM to short-term system stability is not surprising, as a reduction in demand load in many cases may be achieved more quickly than a ramp-up of electricity production. For example, if demand exceeds supply in an electricity grid and the grid frequency drops, load-managed electricity consuming devices in many cases can reduce their load in a matter of seconds while an increase in electricity output of a conventional power plant takes from several minutes to several hours[49].

Ensuring a levelled load profile by means of DSM is efficient if the cost of practicing DSM is lower than the cost of additional capacities for electricity generation and transport that would be needed without DSM and, thus, a less levelled withdrawal profile with higher peak load.

Applications

There are several applications in the final demand segments – industry, commercial and residential customers – which are suited for demand side

[45] Bundesnetzagentur (2015): Evaluierungsbericht zu den Auswirkungen des §19 Abs.2 StromNEV auf den Betrieb von Elektrizitätsversorgungsnetzen.
[46] The time ranges are based i.a. on the following sources: Bundesnetzagentur (2019), Monitoringreport 2019, p. 204, Fig. 79;
Energy Industry Act (EnWG), §13i II 4;
transnetBW: Bilanzkreisabrechung und Bilanzkreistreue (Website, 2020);
Amprion: Ausgleichsenergieabrechnung gegenüber Bilanzkreisverantwortlichen (Website, 2020);
EPEX SPOT: Trading on EPEX SPOT 2020, p. 6.;
Regulation on Electricity Network Tariffs (StromNEV), §§ 17 II, 19 II 2.
[47] The lead time of the immediately interruptible load product is zero by regulation ("instantaneous"), which in practice is below one second, while for the quickly interruptible product it is 15 minutes. The duration of interruptions under both products is multiples of 15 minutes, but not more than eight hours.
[48] The lead time (i.e. the time between the end of the trading session and the beginning of the delivery period) at the EPEX SPOT exchange in Germany is 5 minutes, and the minimum product delivery time is 15 minutes.
[49] For flexibility parameters of conventional plants such as start-up time and ramp rate cf. Prognos, Fichtner, Agora Energiewende (2019): Flexibility in thermal power plants, p. 48.

management. Criteria for the suitability of an application for DSM are[50]:

- High electricity consumption: the amount of total electricity consumption by a single application represents an upper bound for its DSM potential. If the consumption per customer is high, substantial DSM potential may be mobilized by engaging a limited number of customers in DSM
- Flexibility of electricity consumption: the level of flexibility (measured e.g. by load gradients, access time, deferral time, max. number of activations per day etc.) determines what share of total electricity consumption actually represents DSM potential
- No impairment of the application's value by DSM: practicing DSM should not adversely affect the primary purpose of the application such as e.g. the production of goods in the industry or the supply of room heating in households (i.e. there should be no or very limited opportunity costs to the customer); this is mostly achieved by means of buffer storages
- Technical access: a solution must exist that enables the adaptation of the application's load to the grid's requirements either automatically or manually

The **industry segment** stands for almost half of total electricity consumption in Germany. Both the residential customer segment and the commercial customer segment have about a quarter, while the share of the transport sector is minimal[51]. In addition, the average consumption per customer is much higher in the industry segment than in the other segments. This makes the industry segment an interesting candidate for DSM.

On the other hand, interruptions of production are very expensive. Therefore, the production process has to be designed from the start to offer flexibility *without* interrupting production itself. Otherwise, the costs would be prohibitive.

Another area in which DSM will play a major role in the future is hydrogen production, or **power-to-gas**. It is mentioned here for the sake of completeness and analyzed in more detail in the power-to-gas section further below.

In the **residential segment**, the demand-side management application that was dominant in the past – storage heaters – will be increasingly replaced by two new applications. These are:

- Heat pumps, which are usually installed in combination with a small storage of warm water.
- Battery-electric vehicles, which require substantial charging capacity, and the timing of the charging process provides room to maneuver.

Example cases

TRIMET aluminum smelter as a "virtual battery"

TRIMET is a producer of aluminum with smelters in Germany and abroad. In Germany, the most important production sites are Essen, Hamburg and Voerde.

The production of aluminum is an energy-intensive process that requires large volumes of electricity of a very constant load profile. The load factor is usually 99.7% or 8,740 of 8,760 hours per year[52].

The combination of high electricity consumption and high load factors make aluminum production attractive as a potential flexibility provider. In order to unlock the flexibility potential of its production facilities, TRIMET has repurposed 120 furnaces in an electrolysis hall at its production site in Essen. Several measures had to be taken, including[53]:

1. Cladding the electrolysis cells in newly developed heat exchangers
2. Measures for compensating disruptive magnetic field influences resulting from fluctuating power consumption
3. A completely new process control concept using innovative measuring and control technology

This creates flexibility in withdrawals from the electricity grid that is equivalent to a storage capacity of 1,120 MWh with 95% efficiency. With a storage performance of +/- 22

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[50] cf. Ladwig, T., Technische Universität Dresden (ed.) (2018): Demand Side Management in Deutschland zur Systemintegration erneuerbarer Energien, Dissertation, 2018, p. 16.

[51] According to data from the German Association of Energy and Water Industries (BDEW), total electricity consumption in 2019 was 512 TWh, and the exact shares were 45.7% (Industry), 24.6% (Residential), 27.4% (Commercial) and 2.3% (Transport). source: BDEW (2020): Stromverbrauch in Deutschland nach Verbrauchergruppen 2019.

[52] Trimet 2020a: "Virtual Battery" – DSM in the Aluminium Elektrolysis, presentation held in a dena workshop in the context of the German-Turkish Energy Partnership, September 22nd, 2020.

[53] Trimtet 2020b: The aluminium smelter as "virtual battery" (Website), Download on December 22nd, 2020.

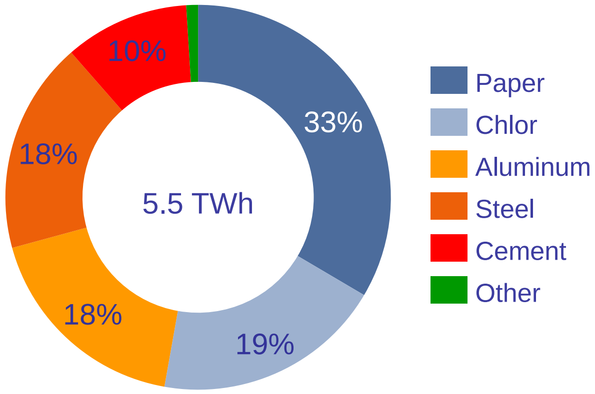
MW, this creates a range of up to 48 hours. This range is considerably higher than what usual (electrochemical) batteries typically offer, which is in the lower one-digit hour range. As a future option, TRIMET is considering to expand this solution from one to three halls in Essen, which would result in a capacity of 3,360 MWh and a storage performance of +/- 70 MW.[54]

Potential

Industry

The highest potential for demand side management in the industry is widely considered to be in the most energy-intensive sectors and processes, including in particular steel production, the aluminum electrolysis, cement production, paper, and the chemical industry (especially the chlor-alkali process). In a meta-analysis of several studies on the topic, the DSM potential in the German industry was found to amount to between 3 and 5 GW.[55] Across the analyzed studies, potential in the industry was consistently found to be lower than in the residential household segment, where the potential is seen in all but one of six studies to be 10 GW or more. While a potential of 3 to 5 GW in the industry may not be a game-changer in terms of volume, industry processes are already making and will continue to make a meaningful contribution to grid stability especially where they are connected to higher-voltage grids, located in proximity to grid nodes or if they feature very fast reactivity.

With regard to future growth of DSM potential in the industry, expectations are limited. A study conducted by leading German energy research institutes in 2018 evaluated the DSM potential in Germany at 6.6 GW in 2050, of which 76% (5 GW) are expected to be utilized, resulting in a total shifted load of 5.5 TWh.[56] The distribution of the shifted load across different sectors is shown in the figure below.



Source: K. Görner und D. Lindenberger (ed.) (2018): Virtuelles Institut Strom zu Gas und Wärme, p. 36

Figure 27: DSM potential in the German industry in 2050

E-mobility

The future DSM potential from battery electric vehicles (BEV) depends most importantly on the number of BEVs. Today, there are around 47 million passenger cars registered in Germany, only a small fraction of which are BEVs. Estimations of the future market share of BEVs vary, but at some point between 2030 and 2050, the number of 10 million BEVs will be surpassed. In one scenario analyzed in the professional literature, 22 million BEVs are assumed to exist in Germany in 2050.

These would create a combined (simultaneous) peak load of 16 GW and an electricity consumption of 59 TWh/a[57]. If only a fraction of that electricity can be shifted time-wise to accommodate the needs of DSOs with regard to grid stabilization, DSM potential from BEVs in the long-term will be significantly higher than the flexibility derived from any other electricity storage technology today. In any case, it will be crucial to manage the load from BEV charging such that BEVs in a given grid are not all being charged at the same time. This will be required to avoid overloads of distribution grids in the future.

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[54] Trimet 2020a: "Virtual Battery" – DSM in the Aluminium Elektrolysis, presentation held in a dena workshop in the context of the German-Turkish Energy Partnership, September 22nd, 2020.
[55] cf. Ladwig, T., Technische Universität Dresden (ed.) (2018): Demand Side Management in Deutschland zur Systemintegration erneuerbarer Energien, Dissertation, 2018, p. 42.
[56] K. Görner und D. Lindenberger (ed.) (2018): Virtuelles Institut Strom zu Gas und Wärme – Flexibilisierungsoptionen im Strom-Gas-Wärme-System, p. 35f.
[57] cf. Ladwig, T., Technische Universität Dresden (ed.) (2018): Demand Side Management in Deutschland zur Systemintegration erneuerbarer Energien, Dissertation, 2018, p. 204.

Heat pumps

Unlike storage heaters, heat pumps are not designed from the outset to withdraw electricity from the grid during the grid's off-peak times (at night), put it into a storage unit and release the stored energy as heat during the day. Heat pumps in general are designed to produce heat efficiently when it is needed, i.e. electricity demand from heat pumps coincides with the users' heat demand. Their electricity load profile is much more leveled than that of storage heaters. However, heat pumps are usually equipped with a water tank serving as buffer storage, so that electricity and heat demand can be de-coupled at least to some extent. This serves two purposes:

- Holding available warm water at all times, to avoid wait times
- Providing heat during electricity "off-times" specified by the DSO[58]

The future number of heat pumps installed in buildings in Germany is unknown. Today, there are around 19 million residential buildings in Germany, of which around one million are heated by heat pumps. However, the number of heat pumps is growing quickly. This is because a substantial share of new buildings (between 40% and 45% in recent years) is equipped with heat pumps. In addition, existing buildings are in some cases switched from fossil-based heating (e.g. gasoil) to heat pumps. In one scenario analyzed in the professional literature, 5 million heat pumps are assumed for 2050 with a combined electricity consumption of 42 TWh/a.[59] As discussed above, only a small fraction of that electricity demand could be time-shifted, since the electricity demand of heat pumps generally coincides with heat demand. However, buffer storages and "off-times" will help relieve DSOs in avoiding congestions in distribution grids.

Conclusion

DSM is and has been for a long time widely used in Germany. There is a multitude of instruments and incentives the system operators have to engage customers in DSM. While TSOs make use of the DSM potential of industry customers, DSOs utilize the potential in the residential sector. The DSOs task will become more complex, driven by an expansion of e-mobility, heat pumps and increasingly sophisticated control and metering technologies. Those technologies will also facilitate more differentiated incentives such as time-of-use tariffs and variable network tariffs, while rather rigid and costly provisions with unclear benefits, such as the 7,000 hours rule may be revised. DSM potential is set to grow in Germany, and it will be more challenging than ever to realize that potential.

[58] Off-times of e.g. six hours per day can be specified under load control agreements between DSOs and residential customers for electricity supply of heat pumps.

[59] cf. Ladwig, T., Technische Universität Dresden (ed.) (2018): Demand Side Management in Deutschland zur Systemintegration erneuerbarer Energien, Dissertation, 2018, p. 203.

4 Large-scale batteries

Flexibility is nowadays required anywhere in the electricity value chain from generation to consumption. Consumption is volatile, as is renewable generation from wind and solar. This requires elements in the electricity system that can adapt quickly to changes in demand or (residual) supply load. LSBs can therefore be placed anywhere in the system, i.e. close to power generation facilities, in proximity to the grid or near locations where power is consumed.

Definitions

Batteries are energy storage devices, which store the energy in chemical form. During an electrochemical reaction the stored chemical energy is transformed into usable electrical energy. There are two different types of batteries, based on their reusability. Primary batteries are only capable of transforming chemical into electrical energy and can only be used once. Secondary batteries are capable of reversing the electrochemical reaction and transform electrical energy into chemically stored energy, they can be recharged and used multiple times. In the following sections, only secondary, rechargeable batteries are considered.

Next to primary and secondary batteries, a classification by the power and storage size can be made. A clear definition of large and small scale does not exist. The power or storage capacities are usually employed to classify into large and small scale, and for the purpose of this study we consider batteries with at least 50 kW or kWh as large-scale. Batteries below this threshold are classified as small-scale and usually found in private households. Large-scale batteries (LSB) are used for various purposes in the electricity system, as will be shown below.

Caution is required in evaluating the stated power and capacity of batteries. The nominal or rated power and capacity are defined by the manufacturing size of the battery. The actually usable power and capacity are often limited to smaller values by the operator or the manufacturer. The purpose of such restrictions is to increase the lifespan of the battery. For example, the usable capacity of Li-ion batteries is usually limited to 85 % of their total capacity to minimize damages, while for flywheel energy storage system 100 % of the nominal capacity can be used.

LSB batteries consist of different technical components. Next to the battery pack itself, the LSB includes a battery-management-system (BMS), a cooling system and an inverter, which are installed within an enclosure. The enclosure protects the internal components from the surrounding. The BMS is the electronic and software control unit of the battery packs and supervises parameters like temperature and state of charge to keep the battery cells in their desired temperature interval and to avoid over- or undercharging. The cooling system controls the temperature within the enclosure and keeps it at a constant level, to ensure constant performance of the LSB. The inverter transforms the direct current of the LSB into the alternating current needed for the grid. The additional technical components are becoming increasingly complex due to newly developed capabilities, which results in higher investment costs for LSB projects[60].

A variety of different battery technologies exist ranging from commercially available such as Li-ion or alkaline batteries to new upcoming technologies, which are expected to reach market readiness within the next years and decades, such as lithium-air and lithium-sulphur. The German LSB market is dominated by four major technologies, namely Li-ion, lead-acid, sodium-sulphur and redox-flow. The focus of this section is therefore on these technologies.

Sodium-sulphur belongs to the class of high-temperature batteries, due to its working temperature of around 300 °C. The energy is stored in liquid electrolytes (sodium and sulphur), but inside the electrochemical cell. For optimal operation, the cells are thermally isolated to minimize heat losses or cycled at least once a day to produce

[60] IRENA - Battery Storage for Renewables: Market Status and Technology Outlook (2015)

enough heat from internal electrical resistance to maintain in the working temperature range. The technology exhibits a high market maturity due to long-term experience, a complete technical readiness and low maintenance costs. High cycle life and energy density are additional advantages. The cells are usually small cylindrical units, which offer good scalability. The low power density and the higher temperature needed for the operation are the main drawbacks of the sodium-sulphur technology.

Lead-acid and Li-ion batteries are operated at room temperature. Lead-acid batteries build on long-term experience in the manufacturing process and require lower investments due to low costs of the necessary materials and low maintenance costs. The limited cycle life is a drawback of lead-acid batteries. Nevertheless, they still offer potential for further improvements regarding cost reduction and increasing energy density. Scaling of power and capacity is performed by combining smaller lead-acid battery packs.

Li-ion batteries offer a wide variety of properties due to different materials that can be used. High cycle stability and energy and power density combined with continuously declining cell costs explain the common use in different applications. Safety concerns and uncertainty of the availability of resources are the major drawbacks of Li-ion batteries. Scaling of LSB using Li-ion cells is performed in the same way as for lead-acid batteries without any technical limit.

In the redox-flow technology, the energy is stored in liquid electrolytes and the reaction for the generation of electrical current occurs inside electrochemical reaction cells. The capacity of redox-flow battery is determined by the available size of the tanks for the electrolyte and is therefore easily scalable. The storage tanks can be spatially separated from the energy transformation (reaction cell). Redox-flow batteries offer high capacities and cycle life, but the power capability regarding discharge speed is usually lower compared to other battery technologies. The capacity and power are independent parameters in the set-up of the cell and can therefore be scaled separately, which is a major advantage compared to other technologies. Other drawbacks are the low energy density, maintenance costs and efforts, which are higher compared to other battery technologies.

Current Status in Germany

As can be seen from the total amount of large-scale batteries (i.e. batteries with a discharge capacity of at least 50 kW) that has been installed in Germany in the time period between 2013 and 2019, there is clearly a role to play for LSBs in the German electricity system. The figure below shows the discharge capacity of the new LSBs installed per calendar year as well as the total discharge capacity that was reached at the end of the respective calendar year in Germany.

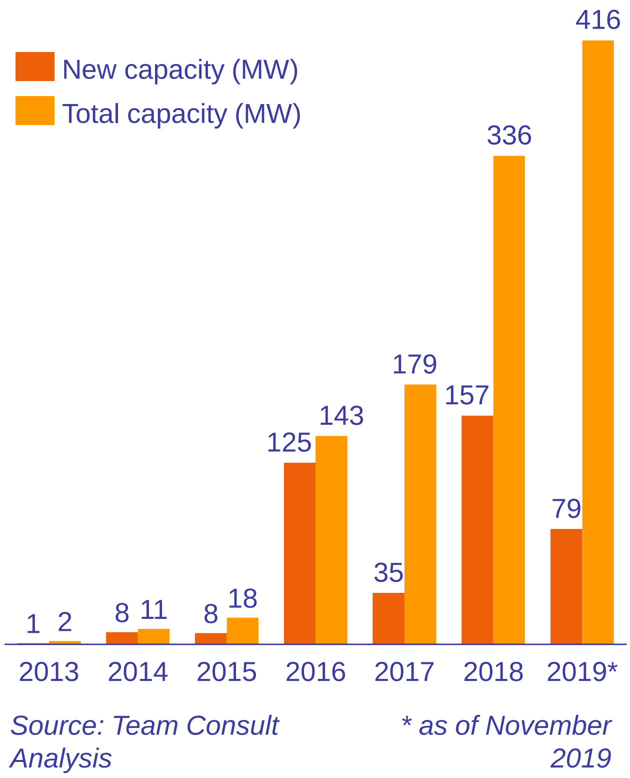

Figure 28: Discharge capacity of large-scale battery installations in Germany

The chart above shows that between 2013 and 2019, total installed LSB capacity has grown from virtually zero to above 400 MW. Especially from 2016 on, newly built installations reached an unprecedented magnitude. The reasons behind the changes in capacity growth are primarily a decrease in investment costs and changes in the price of primary control energy, which LSBs are particularly suited to provide.

Policy and regulation

Neither the German electricity market design nor the regulatory framework define the role of the electricity storage operator. Contrary to the electricity market, gas storage operators or storage system operators (SSO) are clearly defined in the gas market, since they have been important actors in the gas system for a long time. Due to the missing definitions of the electricity storage operators, a variety of requirements and specifications are partially affecting LSB, which are not systematically collected within a certain framework but are instead scattered over different regulations and ordinances.

The challenges regarding the creation of a proper regulatory framework result from the increasing importance of electricity storage. This is due to the increasing share of fluctuating and renewable energy in the overall electricity generation on the one hand and the existence of a multitude of different electricity storage technologies with diverging system properties and varying market entries over time on the other hand. These challenges make the creation of a comprehensive regulation quite complex and lead to the gradual modification and adaption of existing regulations with the attempt to include the current and upcoming technologies as good as possible.

The most precise definition of a stationary battery is given in the Stromsteuergesetz (StromStG) (Electricity Taxation Act) of 2018 in §2 section 9 as "A rechargeable energy storage device for electricity based on electrochemistry, which is located during its operation at a geographical fix point, connected permanently with the grid and not installed inside a vehicle."

The regulations affecting the market cases for LSB are mostly found in the StromStG, the EEG 2021 and the EnWG[61]. Not all of these regulations explicitly refer to LSBs as electrochemical energy storage devices, but are more generally directed at energy related facilities, which also comprises LSB. In particular:

- The exemptions of LSB from taxation and levies are regulated in the EnWG, the EEG62 and the StromStG (see chapter 4.5).
- Issues concerning grid connection of LSB are regulated under the EEG 2017 and the EnWG.

TSOs and DSOs as operators of LSB?

In a competitive market, such as parts of the electricity market, all participants are in principle able to invest into and operate any available asset. Nevertheless, in the current regulatory framework, neither TSOs nor DSOs are explicitly considered to act as operator of electricity storages. The TSOs and DSOs are orderly not allowed to operate electricity storages, but can do so under specific terms and when considering the unbundling conditions of the network operator and the supply of energy[63]. The application process for an exception directed to the BNetzA has many hurdels and even if the exception is granted, a review will take place after some years.

As already mentioned, TSOs are acting within a regulated monopoly, which limits their scope, since their investments into the grid need to be granted by the BNetzA[64]. The BNetzA seems to recognize that TSOs and DSOs should operate LSB for certain purposes. This is at least indicated by the BNetzA's decision to approve so-called grid boosters under the Network Development Plan.

Functions and Applications

As discussed above, all (rechargeable) batteries are at their core providers of short-term electrical flexibility. This means that they can switch from not charging or discharging at all (zero power) to maximum charge or discharge power in a matter of seconds or less; however, they can maintain charging or discharging at peak capacity for a limited time only, usually in the magnitude of one hour or at most a few hours.

This kind of flexibility is nowadays required anywhere in the electricity value chain from generation to consumption. Consumption is volatile, as is renewable generation from wind and solar. This requires elements in the electricity systems, which can adapt quickly to changes in demand or renewable supply load. LSBs can therefore be placed anywhere in the system, i.e. close to power generation facilities, in proximity to the grid or near locations where power is consumed.

The function of the LSB is determined by the context in which it is used and by the purpose it serves. We distinguish between user-related functions and market-related functions, as shown in the figure below.

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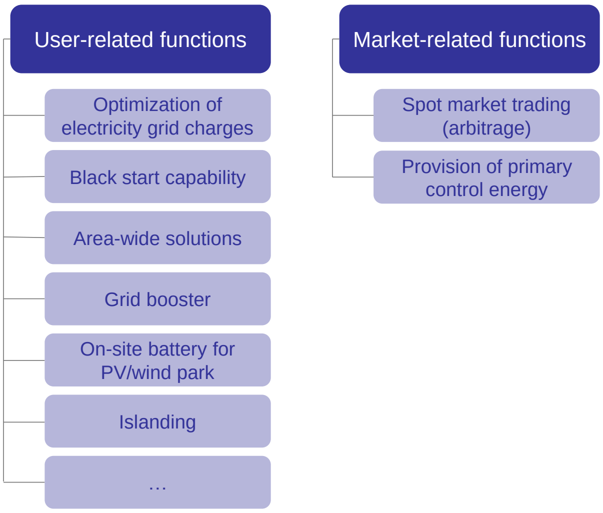
[61] EnWG: Energiewirtschaftsgesetzt (Energy Industry Act)
[62] EEG: Erneuerbare Energien Gesetz (Renewable Energy law)
[63] EU directive 2019/944 Art. 32 as well as EnWG §14c
[64] BNetzA: Bundesnetzagentur (Federal Network Agency)



Source: Team Consult Illustration

Figure 29: User-related and market-related functions of LSBs in the electricity system

The term "user-related" means that a participant in the electricity market installs a battery for its own use, i.e. as a means to create a more complex or higher-value product. The term "market-related" means that a participant in the electricity market installs and operates the battery for the purpose of marketing the capabilities of the battery in the electricity market.

It could be argued that a third category of functions exists which may be called "grid-related". This term would encompass all functions which contribute to the operation and stability of the electricity grid. However, in case the TSOs own and operate the LSBs for such functions, the respective function may be regarded as user-related with the TSO being the user. Conversely, if the TSOs outsource the function and buy the respective service from other market participants that then own and operate the battery, the function may be allocated to the market-related category. For the purpose of this report we distinguish between user-related and market-related only.

For the market-related functions, we present quantitative business cases below. This is possible as these functions are more standardized, and the relevant market data – such as prices from the trading market or the control energy market – is available. The user-related functions are much more individual, i.e. the context and parameters under which the battery is operated vary substantially from user to user. They cannot be listed exhaustively, and those we identify are discussed qualitatively.

It is worth noting that, usually, LSBs are deployed in multi-use scenarios, as the economics of using the LSB for just one function are not favorable in most cases. Nevertheless, we describe the different functions separately in the sections below. Later, we discuss the general possibility and the constraints of using a LSB for spot market trading (arbitrage) as well as for provision of primary control energy.

Optimization of electricity grid charges

Large electricity consumers with high-capacity connections to the electricity grid (i.e. industry facilities) use LSBs mostly to reduce the charges they have to pay for the grid connection. The reduction may result from different effects or provisions relating to tariff discounts, namely:

- Peak shaving – reduction of required grid capacity
- "7000 hours rule" – discount on grid tariffs
- "Atypical grid usage" – discount on grid tariffs
- "Avoided grid charges" – pay-out of savings realized by the grid operator

To the extent the use of a LSB **reduces the required capacity** of the grid connection (by supplying peak loads from the LSB instead of from the grid), the charges for the grid connection a reduced proportionally. For example, if a LSB with a discharge capacity of 10 MW (10,000 kW) and a required investment of 7.5 Mio. € reduces the required grid connection capacity by the same amount (i.e., 10 MW), this would save up to 1.1 Mio. € p.a. The financial benefit is usually considerably lower as this assumes a regular tariff, while in most real-world scenarios considerable discounts are applied to the regular grid tariff, as described below.

Under the "**7,000 hours rule**", a large electricity consumer may only pay as much as 20% of the regular grid capacity tariffs. The discount applies under two conditions, (i) the annual consumption exceeds 10 GWh and (ii) the number of load hours per year (i.e., the annual consumption in MWh divided by the grid capacity in MW) is at least 7,000. The discount increases if the number of load hours is above 7,500 load hours per year (15% of regular tariff is paid), and again if the number of load hours exceeds 8,000 hours per year (with only 10% of the regular tariff remaining).

The rule is laid down in §19 StromNEV (subsection 2, sentence 2). By reducing the required grid connection capacity, a LSB helps to drive up the number of load hours per year and, thus, contributes to enabling its owner or operator make use of the "7,000 hours rule". The sum of discounts realized by all customers under the

“7,000 hours rule” amounted to approx. one billion Euros in 2019 according to the BNetzA. The amount has more than tripled since 2015 (approx. 325 Mio. €).

“**Atypical grid usage**” is another possibility for industry facilities to drive down the grid tariffs. Even if the conditions for the “7,000 hours rule” are not met, a tariff of only 20% of the regular tariff may be offered by the TSO if the customer’s peak demand occurs only at times when the aggregate load on the grid (from all other customers combined) does not peak. This rule is laid down in §19 StromNEV (subsection 2, sentence 1). Although LSBs may in principle also help to shift a customer’s peak load to the grid’s off-peak times (as is required by the atypical grid usage provision), it is much easier to see how LSBs can help to reduce the peak load and, thus, to make use of the “7,000 hours rule”.

Finally, there is a provision in the StromNEV (in §18) that is commonly referred to as “**Avoided grid charges**”. Grid customers that feed electricity into the grid may get a pay-out of the savings the grid operator realizes which are caused by the feed-in of electricity from the customer. If the grid operator (e.g. a DSO) can reduce its payments to the upstream grid operator from which it is supplied (i.e. a TSO), the saved amount is paid out to the customer that caused that reduction by feeding in electricity. This provision was aimed at benefitting producers of distributed renewable electricity generation. It will be phased out completely in 2023.

Black start capability

Power plants require a small fraction of the electricity they produce for their own operation, for all kinds of devices such as controls systems, pumps, safety equipment etc. During regular operations, that electricity is taken from the plant’s own generators; during a regular (non-black) start, it is taken from the electricity grid tow which the plant is connected. If, however, the electricity grid is shut down, a regular start is not possible for lack of electricity supply, and a “black start” is required.

Hence, the term “black start” describes the process of restoring operations of a power plant without external electricity supply from the grid. Usually, at the same time, the operation of the grid to which the power plant is connected is restored as well.

LSB are well-suited to enable black starts, since they are flexible, quickly activated, and they only need their own power to operate. Further, they are capable of supplying high power and of sustaining supply for up to a few hours to stabilize the run up after a shutdown. Up to now, black start capability has usually been ensured by hydropower stations including pumped storages, compressed-air energy storages, or by means of diesel generators located at thermal power plants. The latter systems may have better economics for the sole purpose of black start capability. However, if a LSB is installed to fulfil multiple functions, it may also be able to provide black start capability, in which case other systems for black starts may not be needed (or only to a lesser degree), thus improving the economics of the LSB.

In Germany, LSBs have only recently begun to be used to ensure black start capability. The proof of concept was successfully completed during an experiment in Schwerin, Germany in 2017. In this experiment, a battery storage plant was used to start up a gas turbine and to gradually restore grid operation. In April 2019, the Bordesholm energy storage became operational. While its primary purpose is to provide primary control energy, it is also used to provide black start capability on a regular basis (see box below) as well as islanding capability.

Bordesholm energy storage project

Discharge Capacity:	10 MW
Storage capacity:	15 MWh
Commissioning:	April 2019
Owner & Operator:	Versorgungsbetriebe Bordesholm (local utility company, Germany)
Main Purposes:	primary control energy provision, black start capability, islanding capability

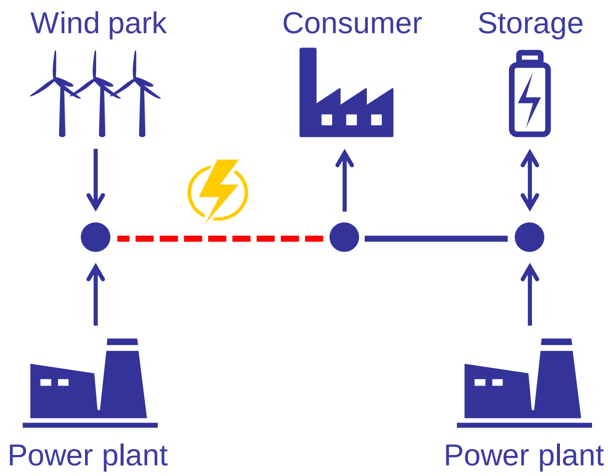
It is expected that LSBs can help shortening the duration of power outages and, thus, limiting the damages resulting from unplanned outages in the future.

Grid boosters

The expansion of renewable power generation in Germany has led to a need to substantially expand the electricity grids and to invest into their transport capacities as well as their flexibility. Load changes are steeper and more frequent, and congestions occur more often and in more places than in the past.

There are several cases in which new power lines are being built to address the congestions. However, in cases where congestions only occur rarely and for a very limited period of time, it can be more efficient to use so-called "grid boosters" in order to expand the grid capacity beyond existing technical limits.

In the grid booster concept, (n-1) grid security[65] is ensured **reactively**, as compared to the traditional, **preventive approach**. Grid boosters are fast power sources in the shape of a LSB that allow for a power load on existing power lines beyond the present stability limits. For example, a LSB can be installed at the end of a grid congestion point. Another possibility is to install two spatially separated LSBs on both ends of a grid congestion point, acting as source and sink of a "virtual power line" in case of emergency, as shown illustratively by the red dotted line in Figure 30. LSBs can be scaled to form high power (> 50 MW) and very fast (within milliseconds) grid booster to stabilize the grid.



Source: Team Consult Illustration

Figure 30: Illustration of grid congestion point that could be addressed by a grid booster

Area-wide solutions

In Germany, the word "Quartierslösung" is an umbrella term referring to different kinds of energy-related services, which are supplied for a housing complex in a certain area (quarter). It can be freely translated with area-wide solution. Area-wide solutions are provided by energy service companies which analyze the energy needs of customers in the respective area (quarter), including electricity, heating, cooling, electrical vehicle charging stations and so on. The service company develops the solution, which most efficiently fulfils the energy needs, taking into consideration the surrounding infrastructure and making use of different energy technologies. These technologies may include e.g. small thermal cogeneration units, installation of PV modules, heat pumps, heat storages, batteries and more.

LSBs in this context can increase the degree of self-sufficiency and reduce the need to expand distribution grids. For example, the capacity of the distribution grid may not be sufficient to allow the desired number of electric vehicle charging stations in the respective area (quarter) to operate at the same time. In that case, a LSB may be installed to cover short periods of peak demand resulting from the parallel charging of many electric vehicles.

On-site battery for integration of PV or wind park

Operators of PV or wind turbine parks can use LSBs on-site to avoid the violation of technical limits that could result from sudden changes in generation load and to optimize revenues from the direct marketing of the electricity produced. This is increasingly important, as the intermittent nature of PV and wind generation could otherwise destabilize the power grid. The use of LSBs can help accommodate load changes.

An example of an LSB used for this purpose in Germany is the Energy Storage Alt-Daber in the Northeast of Germany which is operated by Upside Group, one of the largest operators of electrical energy storages and providers of primary control reserve in Europe. It is located in proximity to one of the country's largest PV facilities with a peak capacity of approx. 68 MW. The battery is based on lead-acid cells and provides a storage capacity of 2 MWh and a discharge capacity of 2 MW. The energy storage facility features a hybrid controller that allows using the storage for different purposes, including the provision of primary control energy and the balancing of volatile renewable energy supply.

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[65] Grid security according to the n-1 criterion means that a system of n capacity elements (e.g. electricity lines) will still function properly if any one of the n elements fails, meaning that the remaining n-1 elements can provide the service required from the system.

Energy Storage Alt-Daber

Discharge Capacity:	2 MW
Storage capacity:	2 MWh
Commissioning:	October 2014
Owner & Operator:	Upside Group
Main Purposes:	primary control energy provision, balancing of volatile PV generation

Business Case A: Participation in the Primary Control Energy Market

Basic principle

Control energy is procured by the TSOs from other market participants and used for stabilization of the grid, e.g. to balance the amount of generated and consumed power. Physical balancing of the grid is either performed by positive control energy, that is power which is fed into the grid if consumption is higher than generation, or negative control energy, that is power which is extracted from the grid if consumption is lower than generation. It is worth noting that, for the case of primary control energy, the provision of negative and positive power is compensated, but not the energy itself.

LSB offer a variety of advantages for the provision of control energy, especially for primary control energy, which needs to be made available particularly fast and only needs to be provided for up to 15 minutes:

- The short reaction times needed for the activation make them well-suited to compensate fluctuating loads in the power grid.
- LSB can provide up to 100% of their nominal capacity as positive primary control energy (discharge) and offer up to 100% of their nominal capacity for negative primary control energy (charge). Conventional power plants offer a much smaller power range since they cannot absorb electricity from the grid.
- LSB follow a predefined load profile accurately.

These advantages explain the high amount of LSB already participating in the market, which are deployed for primary control energy. The multitude of participants in the primary control energy market is one reason for the falling prices in the primary control energy market from around 4.000 €/ MW in 2015 down to nearly 1.000 €/ MW in 2018, which, as will be shown below, impacts the economic operation substantially. For the participation in the secondary and tertiary control energy market, the energy needs to be provided for a longer time (30 and 60 min) and within slower activation times (5 to 15 min). These requirements in combination with the higher amount of minimal pre-qualified power of 5 MW offers less favorable conditions compared to the primary control energy market regarding LSB capabilities.

Assumptions and parameters

In the following analysis of the utilization of LSB for the primary control energy market, a capacity to marketable power ratio of 1.5 is chosen. The marketable power is the share of the installed power, which is actually utilized for the participation in the primary control energy market. The LSB is identical in size with the WEMAG Schwerin 1+2 storage and has an installed power of 14 MW, a marketable power of 10 MW and a capacity of 15 MWh (capacity to marketable power ration: 15 MWh / 10 MW = 1.5) . We assume total investment costs of 10.5 Mio €, based on the latest LSB projects in 2018 and 2019 installed in Germany, which exhibit an average cost-to-power ratio of 0.75 Mio € per MW of installed power. The investments arise in 2018 and 2019 and profits are generated beginning in 2020 for 10 years of operation.

Even though the operation time of LSB is generally assumed to be around 20 years, based on modern battery cell cycle life of 5000 full cycles and 250 full cycles per year for LSB[66,67] and guarantees given by battery manufacturer[68], we limit the operation life to 10 years, due to the uncertainties in the dynamic power market.

We use actual data for the primary control energy prices in Germany from 2015 (case 1) and 2018 (case 2) to model the profits and compare the results. For both cases, we will evaluate the profitability of the LSB for the primary control energy market separately; all other parameters and assumptions stay the same.

[66] VDE - Batteriespeicher in der Nieder- und Mittelspannungsebene – Anwendungen und Wirtschaftlichkeit sowie Auswirkungen auf die elektrischen Netze (2015)
[67] Fleer and Stenzel - Impact analysis of different operation strategies for battery energy storage systems providing primary control reserve (2016)
[68] WEMAG - WEMAG-Batteriespeicher testet erfolgreich Schwarzstart nach Blackout, https://www.wemag.com/aktuelles-presse/wemag-batteriespeicher-testet-erfolgreich-schwarzstart-nach-blackout, accessed on the 12.12.2019

Maintenance costs are included with 2 % per year of the initial investment costs[69]. Determination of the discounted cash flow uses the weighted average cost of capital (WACC) of 5.9%[70]. The operator of the LSB bids based on the weighted average of the primary control energy and is assumed to get each weekly bid accepted during the year. The control energy prices are assumed to remain stable over the considered time period of 10 years.

Results

The results of the primary control energy business case are displayed below. For the revenues from primary control energy, the cash flow before taxes and the present value are displayed for the price data from both years.

With the revenues from the primary control energy market of 1.901 k€ per year for the price data from 2015, the maintenance costs of 210 k€ per year and the WACC of 5.9% the amortization period results in exactly 10 years and therefore within the planned duration of operation assuming the price data from 2015. The net present value for a 10-year lifespan amounts to 1.4 Mio. €, i.e. the LSB is commercially advantageous under the assumptions taken and with the price data from 2015.

Using the price data from 2018, the picture is quite different. The revenues amount per year only to 1.120 k€, resulting in a negative net present value indicating the investment is uneconomic. Even if the operation life were extended to 20 years, the net present value would still be negative (-0.4 Mio. €).

		2018	2019	2020	2021	…	2029
Investment [k€] / (1)		-8.400	-2.100	0	0	…	0
Maintenance costs [k€] / (2)		0	0	-210	-210	…	-210
WACC		5,9%					
Case 1: 2015 prices	Revenues from primary control energy [k€] / (4)	0	0	1.901	1.901	…	1.901
	Cash flow before taxes [k€] / (5) = (4) – (1) – (2)	0	0	1.691	1.691	…	1.691
	Present value [k€] (6) = (5)*DF(t)	0	0	1.508	1.424	…	900
Case 2: 2018 prices	Revenues from primary control energy [k€] / (4)	0	0	1.120	1.120	…	1.120
	Cash flow before taxes [k€] / (5) = (4) – (1) – (2)	0	0	910	910	…	910
	Present value [k€] (6) = (5)*(3)	0	0	811	766	…	484

With an operation time of 10 years:

Price data from 2015:
- Net present value = **1.424 Mio. €**

Price data from 2018:
- Net present value = **- 4.026 Mio. €**

Figure 31: Results of the participation of the LSB in the primary control energy market using price data from 2015 and 2018

The participation in the primary control energy market based on the assumptions and model parameters can be economically advantageous as a stand-alone business case under certain conditions. However, the decreasing primary control energy prices create a difficult market environment for LSB. The decrease of the primary control energy prices over the last years are likely responsible for the decelerated growth of newly installed LSB in Germany.

Business Case B: Power Price Arbitrage

Basic principle

The basic idea of power price arbitrage is buying power at low prices in the trading market and storing it, until the power price reached a higher level to sell it back with a profit. Pumped-hydro storage is also used for this. Power price arbitrage requires a volatile and dynamic power price, which covers enough hours during the year to store electricity at low prices and sufficient time during the year to feed in the stored electricity from the storage into the grid. The gap between the lowest and highest power price during the day should be sufficiently wide to generate reasonable earnings. Patterns in the power price can be used to specify the moments during the day, when energy is taken from the grid and stored and when

[69] BVES - Anwendungsbeispiel Speichertechnologien - Lithium-Ionen Großspeichersystem zur Bereitstellung von Primärregelleistung sowie weiteren Systemdienstleistungen (2016)

[70] KPMG – Kapitalkostenstudie 2017 (2017)

energy is discharged from the LSB and fed back into the grid. On average, there is a daily pattern in the power price with low prices during the night and morning and higher prices during the evening, as can be seen in the following figure.

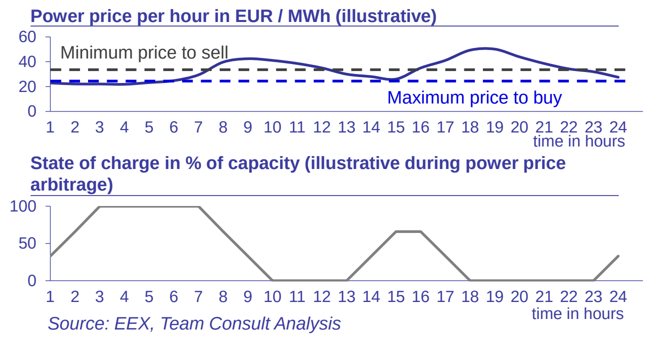


Figure 32: Basic idea of power price arbitrage during the day using predefined minimum and maximum power prices

LSB can be used to store the energy during times of low demand and therefore low power prices and provide the power during high demand times. We assume no end-consumer taxes and levies, i.e. the exemptions discussed above apply to the LSB.

In the chart above, the typical power price development during a day is displayed. Power price arbitrage can be performed by defining a minimum price for sale and maximum price to buy. If the power price during the day falls below the predefined maximum buy price, electricity is bought from the grid and stored in the storage. If the power price rises above the predefined minimum sell price, the electricity is sold to the grid and discharged from the LSB. The daily pattern and the definition of the minimum and maximum power prices lead to a pattern of LSB charging during the morning and discharging during the noon and evening. We set the minimum price to sell equal to the maximum price to buy. The operator is assumed to be a participant in the trading market and to have a trading floor at his disposal, i.e. the overhead costs are not attributed to the LSB.

Assumptions and Parameters

The assumptions and parameters are collected in the following bullet points and based on actual data from real applications:

Model assumptions:

- The storage capacity can be used from 0 to 100%.
- The storage losses are 10%.
- The German power prices from 2018 are used in this business case.
- The revenue is evaluated over the whole year.
- Maximum price to buy is 4.47 ct/kWh.
- Minimum price to sell is 4.47 ct/kWh.

The LSB, which will be used for the power price arbitrage, exhibits a usable capacity of 1MWh with charge and discharge capabilities of 0.3 MW. The investment costs are 750.000 €, based on the latest LSB projects in Germany (0.75 Mio. € per installed MW). Maintenance costs are included with 2% of the investment costs per year and the WACC is set to 5.9 %. The power price level and patterns are assumed to stay constant through-out the operation time of 10 years. We calculate the profits once without any levies, assuming all of the relevant exemptions apply, and compare it with the results, when including all levies except the EEG levy ("other levies") which amounts to 1.01 ct/kWh for industrial consumers. We calculate the results before taxes, which represents the situation, if all exemptions from the taxes are met.

	2018	2019	2020	2021	…	2028
Investment [k€] / (1)	-750.0	0.0	0.0	0.0	…	0.0
Maintenance costs [k€] / (2)	0.0	-15.0	-15.0	-15.0	…	-15.0
WACC	5.9%					
Revenues from power price arbitrage [k€] / (3)	0.0	15.1	15.1	15.1	…	15.1
Costs resulting from power price arbitrage [k€] / (4)	0.0	-11.3	-11.3	-11.3	…	-11.3
Cash flow before taxes [k€] / (5) = (3) – (2) – (4)	0.0	-11.1	-11.1	-11.1	…	-11.1
Present value [k€] / (6) = (5) * DF(t)	0.0	-10.5	-9.9	-9.4	…	-6.3

With an operation time of 10 years:

- Net present value without taxes and levies = **- 832.738 €**

Figure 33: Results from power price arbitrage using a LSB

Power price arbitrage under the assumptions taken does not generate enough revenues to cover the investment, maintenance and electricity purchase costs and results in a negative net capital value of -833 k€ after 10 years of operation. Including "other levies" in the calculation leads to a slightly more negative net capital value of -840 k€ after 10 years of operation.

Conclusion

The results of the analysis and other studies show, that power price arbitrage alone as business model is not profitable, even when the operator is exempt from all relevant taxes and levies[71, 72]. However, power price arbitrage can be used as an additional application of the LSB next to other applications in order to maximize utilization and economics. In case power price arbitrage is pursued as an "add-on", the revenues may be lower than in the results shown above, since not 100 % of the capacity would be accessible for power price arbitrage, as some capacity would have to be reserved for the primary application for which the LSB is used. This relation will be further discussed in the following section.

Creating a multi-use application

Business case A has the possibility to offer a profitable stand-alone business, but with difficult prospects, especially regarding the primary control energy prices from 2018 on. A further decline in primary control energy prices and more competition will make it substantially more difficult to generate profits. Business case B itself is as a stand-alone business far from profitable. However, the participation in the control energy market may offer possibilities to generate additional revenues from power price arbitrage, since the LSB offers wide working range.

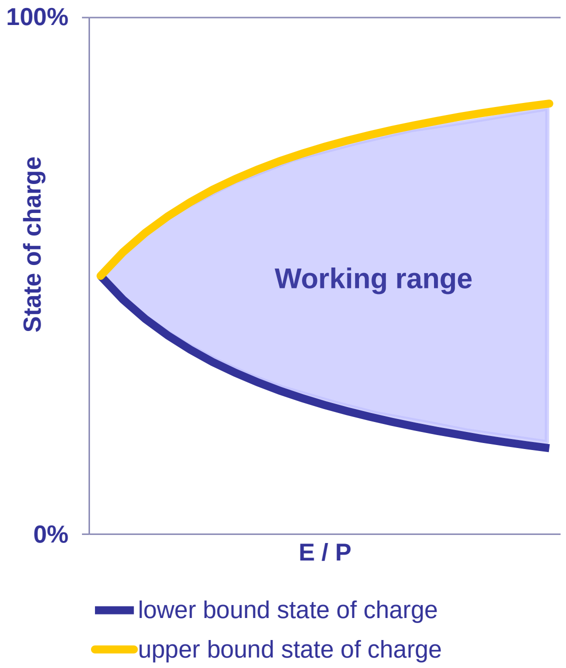
For example, a LSB with a capacity of 1 MWh and a pre-qualified power of 1 MW participating in the primary control energy market has to be able to provide negative and positive control energy for up to 15 minutes at all times. With 1MW power and 1 MWh capacity, 15 minutes of charging or discharging equals 25 % change of its state of charge. Therefore, the LSB needs to stay below 75 % (upper limit) and above 25 % (lower bound) of its storage capacity. This leaves the working range between 75 % and 25 % to be utilized for additional applications, such as power price arbitrage.

More generally, this relation can be described as follows[73]:

$$\text{Upper limit} = \frac{E - d \cdot P}{E}$$

$$\text{Lower limit} = \frac{d \cdot P}{E}$$

In the equations, d denotes the duration for which control energy has to be supplied (15 min. in above example), E the storage capacity (1MWh in above example) and P charge/discharge power (1 MW in above example). The working range can be plotted depending on the ratio of E to P as shown in the chart below.



Source: Deutsche ÜNB, Team Consult Analysis

Figure 34: Working range of the LSB for the control energy market

In general, a higher pre-qualified power offers more diverse opportunities to participate in the primary control energy market; however, a high pre-qualified power leads to a lower relation between E/P and therefore a small working range, which in turn limits the multi-use capability of the LSB. A good starting point from which optimization can be performed is an E/P ratio between 1 and 1.5.

The LSB from business case A had a nominal power of 14 MW and capacity of 15 MWh, the marketable power was limited to 10 MW, due to the defined E/P ratio of 1.5. These settings lead to a working range of the LSB ranging from 17 % to 83 %, which offers flexibility for additional purposes which can be operated within that range, such as power price arbitrage. In that case, the power price arbitrage from business case B would be able to operate with 66 % of the capacity from the LSB from business case A, which results in an available capacity of 9.9 MWh. With such a capacity and the power capabilities from business case A, the power price arbitrage could generate over an operation time of 10 years additional revenues in

[71] BVES - Faktenpapier Energiespeicher (2017)
[72] Svoboda - Märkte für Batteriespeicher: Wo ist der „Market Pull" für Batteriespeicher? (2017)
[73] Deutsche Übertragungsnetzbetreiber - Anforderungen an die Speicherkapazität bei Batterien für die Primärregelleistung (2015)

the lower six-digit range from power price arbitrage, assuming all exemptions from taxes and levies apply.

The combination of power price arbitrage and participation in the control energy market are just two examples for a possible multi-use application of LSB. Regarding the current difficult economic circumstances in the German power market for storage operators, multi-use applications are effectively the standard for the economic operation of LSB. The multi-use application can be a combination of two or more utilizations, such as optimization of power consumption, peak-shaving and demand-management in the industry or ensuring the voltage stability of the grid, participation in the control energy market and provision of black start capabilities. Combining two or more utilizations increases the complexity of the LSB operation and demands for a more sophisticated battery management system in comparison with a single-use application.

Conclusion

Investments into LSBs have surged in Germany in previous years. The experience in Germany has shown that

- There is a substantial role to play for LSBs in an ever-more complex energy system with increasing (intermit-tent) renewable power generation
- In an unbundled electricity system with competition, LSBs can and will be invested into by those market participants which are unregulated and subject to competition. This, however, is not to say that the operation of LSBs by regulated actors (such as TSOs) should be entirely ruled out; on the contrary, the grid boosters planned by German TSOs (and to a large extent approved by the German regulator BNetzA) show that that under specific, well-defined circumstances there is a case to be made for operation of LSBs by regulated entities as well.
- Although the investment costs of LSBs have been continuously decreasing and, thus, economics of LSBs have been improving, it is in most cases economically necessary to pursue multi-use approaches when in-vesting into LSBs – especially since the success of LSBs has driven down primary control energy prices
- The regulation of LSBs and their operation should enable investments into LSBs where economically feasible and avoid distorting competition between LSBs and other means of providing electrical flexibility (i.e. for example, the electricity stored by LSBs should not be doubly burdened with taxes and/or levies)

In any case, LSBs will have a crucial role in advanced energy systems, and further advancements in battery technologies and mass production will help to reduce overall systems costs.

5 Small-scale batteries

Small-scale batteries are an emerging contributor to the energy transition and have the potential to play a crucial role in the integration of renewable energies into the electricity system and in the stabilization of the public power grid.[74]

Definitions

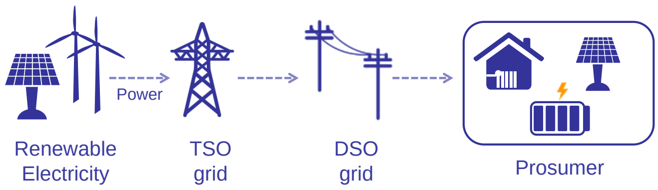
Function and classification within the system

Batteries are electrochemical energy storage devices, which store the energy in chemical form within the battery and transform it when needed into electricity. Modern batteries are highly efficient with only minimal short-term losses and can provide up to 95% of the energy, which was put into the storage. The primary utilization of batteries is the short-term storage of energy and provision of dynamic load.

The term small-scale is generally used for batteries with a smaller power and capacity than 50 kW and 50 kWh, however, a clearly defined standardized classification does not exist yet. The special focus in this section will be on small-scale batteries for household and small business applications, which have in average power capabilities below or around 5 kW and storage capacities below 15 kWh. These batteries are in any case connected to the low-voltage power grid, since they represent a unit in the household electrical system. Batteries for industrial or commercial applications provide higher power and capacity, but this segment will not be further analyzed in the chapter.

The battery technologies, and specifically the Lithium-Ion batteries, are from a technological standpoint market-ready and a proven and reliable technology for different applications. The main disadvantage of batteries for small-scale applications in households is the relatively high initial investment costs, which make their application in different cases not economically viable. The increasing penetration of Lithium-Ion batteries especially for electric vehicles (EV) will scale up the production capacities and decrease costs, which will likewise lower the system costs for small-scale household batteries.

The standard battery storage for household applications has a power capability of about 3 kW, which basically equals a normal household power connection of 230 V and a maximum current of 16 A. Therefore, the power of the battery represents about 100% of the household power connection. Comparing the storage capacity to the yearly consumption of a standard household leads to a quite different picture. A standard battery has about 5 kWh storage capacity. For a household with a yearly



Source: Team Consult Illustration

Figure 35: Small-scale batteries are located at the "prosumer" at the end of the electricity supply chain

consumption of 4,050 kWh the storage capacity of the battery represents only 0.1% of yearly consumption.

The example shows that the advantage application of batteries is the provision of short-term power, while the storage of large amounts of energy for long durations represents the non-ideal application for which other technologies are better suited. Based on the properties of batteries, certain applications are more suitable than others, a more detailed description of the applications will be given in the following chapters.

In case of household and most industrial and commercial applications, the small-scale batteries are connected to the low-voltage power grid and are located at households or small business, as can be seen in Figure 35. For certain industrial applications with small-scale batteries at the border of small to large-scale batteries, the batteries can be connected likewise to the medium-voltage power grid[75].

Utilized technologies

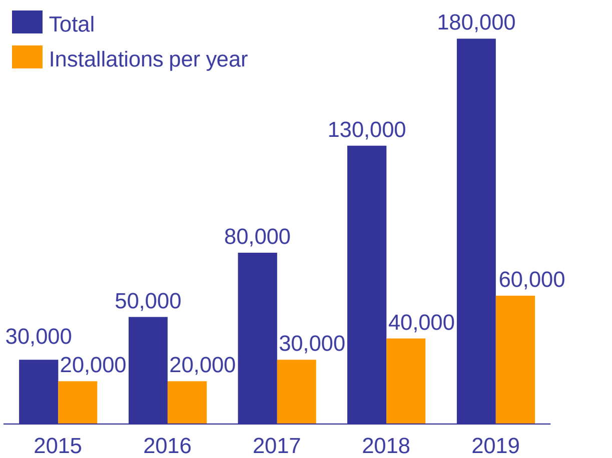
Small-scale battery systems nowadays mainly use the Li-ion technology. While the lead-acid battery technology

[74] Please note slight changes to the conclusions of the study "German experiences with large-scale batteries: regulatory framework and business models" in the context of German-Turkish-Cooperation published in June 2020. Changes in the text are due to revisions in the German regulatory framework.
[75] Smart Power (2017): Praxisbeispiel: Produzierendes Gewerbe

had a market share of more than 60% in 2013 it basically disappeared in newly installed storage systems (Figgener et al., 2019b, p. 10). Next to the dominant Li-ion technology, a variety of further battery storage technologies exist, which could provide higher energy storage capabilities. These technologies are, however, not commercially viable yet, but energy storage research focuses on the commercialization and mass production for cost reduction of these technologies.

Current status in Germany

Since 2015, the amount of installed small-scale batteries shows a six fold increase from 30,000 to 180,000 batteries in 2019 in Germany (see Figure 36). Yearly growth increased from 20,000 newly installed batteries in 2015 to about 60,000 batteries in 2019, which is more installations per year than total installed batteries up to 2016 in Germany. In 2018, the majority of newly installed batteries (about 55%) are used in combination with PV rooftop systems. At the same time, about 10% of the yearly sold small-scale batteries are used to upgrade a pre-existing PV rooftop system with a battery storage. Germany represents the largest market for residential small-scale batteries in Europe with a market share based on available capacity of 66%[76].



Source: Figgener et al. (2019), EuPD Research, Team Consult Analysis

Figure 36: Numbers of installations (cumulated and per year) of small-scale batteries in Germany

Based on the amount of installed batteries, the total installed power can be estimated. Assuming an average installed power of 3.5 kW for the batteries installed up to 2018 and an average power of 3.75 kW for the batteries installed since 2019, all installed small-scale batteries add up to about 650 MW, as can be seen in Figure 37. The total installed power is equivalent to about 200 modern wind turbines or roughly the size of a modern hard-coal power plant in Germany.

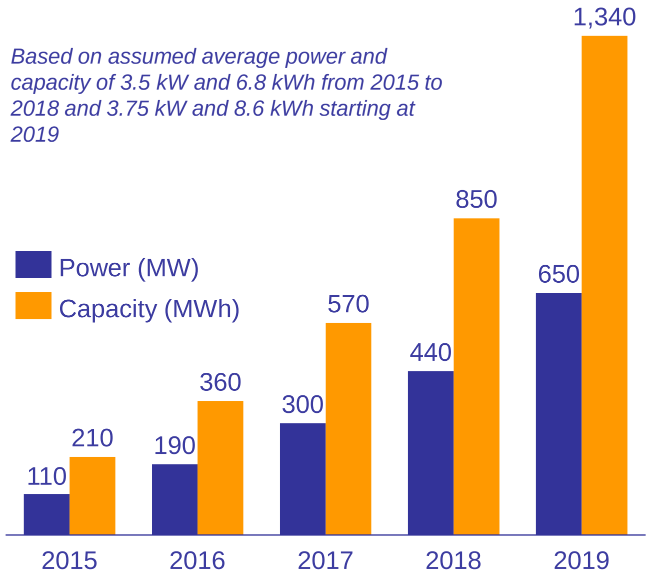


Figure 37: Total installed power and capacity of small-scale batteries in Germany combined

The storage capacity of installed batteries increased from less than 6 kWh per battery on average in 2015 to roughly 9 kWh per battery in 2019, which was accompanied by falling system costs from batteries as well PV rooftop systems. The capacity of these small-scale batteries amounts to roughly 1,300 MWh in 2019, which is a more than a six-fold increase from 210 MW in 2015. The total capacity could provide enough electricity for about 400 households for one entire year.

Regulatory conditions and economic incentives

The current scope regarding regulations for batteries is comprised of different regulations:

- Stromsteuergesetz (StromStG) (Electricity Taxation Act)
  - The StromStG defines the taxation of electricity in Germany

[76] SolarPower Europe – European Market Outlook for Residential Battery Storage, 2020, p. 15

  - Regarding batteries, it lays out the regulatory definition of the battery and the possibilities for exemptions from the electricity tax
- Erneuerbare-Energie-Gesetzt (EEG) (Renewable Energy Sources Act)
  - The EEG aims to promote the integration of renewable energies
  - It is relevant for batteries, since it lays out the possibilities for exemptions from the EEG levy
- Energiewirtschaftsgesetzt (EnWG) (Energy Industry Act)
  - The EnWG defines the ground rules for a safe, economical, customer friendly, efficient and sustainable electricity and gas system
  - Regarding batteries, it comprises the regulations for the exemption from the grid charges for the feed-in and take up of electricity from the grid

Based on the current status of the regulations, the battery is at the same time viewed as a power generation facility and a final consumer of electricity. That classifictation is important, since the electricity used by final consumers is burdened with taxes and levies.

For some years, storage technologies have been playing an increasingly important role in the overall power system. Regulations have been adapted to integrate storage technologies and treat them equally to other means of providing flexibility, such as conventional power generation. For the promotion of investments into renewable energies and batteries by households, certain rules exist that reduce taxes and levies paid by final consumers who operate such devices. These include:

- Electricity from PV rooftop systems with less than 30 kW peak power is exempted from the EEG levy (§61a EEG)
- For electricity which is generated in facilities with less than 2 MW power and consumed by the same entity, the electricity tax is omitted (§9 subsection (1) StromStG)
- The amendment to the EnWG in June 2021 put an end to most double charging of fees and levies on electricity storage facilities. The revision of the EEG in 2021 improved the regulatory conditions for battery operation significantly (§61l EEG 2021)

Support and funding programs

Different support and funding programs exist on a national and state level. One example of statewide funding for the further adaption and utilization of small-scale batteries including PV rooftop facilities was conducted in 2013 to 2018 by the German KfW bank. The funding program supported newly installed PV rooftop facilities in combination with small-scale batteries for private households and commercial entities as well the upgrade of existing PV rooftop systems with a battery. The aim of the program was to stimulate the market penetration of battery storage systems in Germany and to facilitate the integration of electricity generated by small and medium sized PV rooftop systems.

The financial support was offered in form of loans at reduced interest rates and subsidies for the investment. The loans and subsidies were limited to the investment costs of the battery, but in case a PV rooftop system was installed in combination with the battery, an additional fixed subsidy of 1,600 EUR/kWp was granted.

The program was focused on battery systems and PV rooftop systems with a peak power of up to 30 kWp. An important requirement in the funding program from the KfW bank was the limitation of the peak power from the PV rooftop system that can be fed into the grid. It limits the peak feed-in power to 50% of the installed PV system power for at least 20 years. This requirement limits the load on the power grid, especially during sunny days, when a lot of PV electricity is fed into the grid. Additionally, the batteries were needed to be equipped with tools, which made a remote control and data analysis possible.

The program resulted in the funding of more than 32.000 small-scale batteries until the end of 2018 and generated an investment volume of about 700 Mio. EUR based on a credit volume of roughly 530 Mio. EUR[77].

About 60% of states in Germany have or had support and funding programs for small-scale batteries[78]. One example of state wide funding system (in Baden-Wuerttemberg) had i.e. additional bonus systems for the adaption of the battery and PV rooftop system to specific properties such as an additional investment into a demand manageable charging station in combination with a battery system.

Based on surveys conducted within the local funding program in Baden-Wuerttemberg, the participants largely

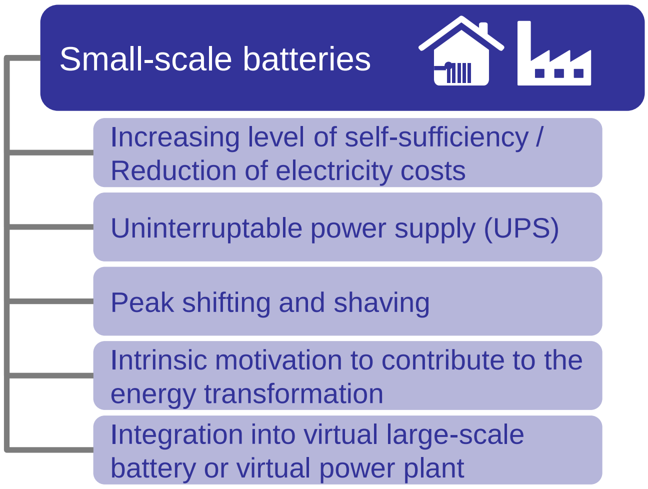
[77] Figgener et al. (2019): Markt und Technologieentwicklung von PV Heimspeichern in Deutschland

[78] SolarPower Europe – European Market Outlook for Residential Battery Storage, 2020, p. 28

agreed on the positive influence of the funding on their decision to invest into small-scale batteries.

Functions and applications

Small-scale batteries are used in a variety of applications, which demand for rapid and dynamic adaption to high loads and short-term storage of energy. These requirements are met by current battery systems. The applications are summarized in Figure 38 and described in the following sections in more detail. Applications include the provision of ancillary services, mostly via aggregators, based on small-scale batteries, to grid operators.



Source: Figgener et al., 2019; Smart Power, 2017, Team Consult Analysis

Figure 38: Applications for small-scale batteries

In households, industrial and commercial applications, small-scale batteries are used in combination with a PV rooftop system to store the generated electricity for the short-term, in case it is not consumed immediately by the household itself. The aim of this set-up is the **increase of the level of self-sufficiency** and the decrease of the electricity withdrawn from the power grid. The motivation for this application are the increasing electricity prices for consumers, while at the same time, the costs for battery and PV systems and the remuneration for feed-in of PV electricity into the public grid are declining. The battery can therefore shift the consumption of the generated PV electricity to later times during the day or the early morning, when not enough or no PV electricity at all is generated. While this application is financially attractive to the owner of the battery, it does not per se provide any benefit from a system perspective.

Small-scale batteries can be utilized as **uninterruptable power supply** (UPS) during power supply failures from the public grid. Especially when their duration is only limited to a few hours they can replace fossil based diesel generators as back-up systems or limit the operation times of these. The average duration of a power supply failure in the German power grid in the low-voltage level is on average 16 mins considering the period from 2006 to 2018[79], making batteries well suited as UPS, due to their fast reaction times and storage capacities. In this case, the battery does not provide a benefit to the electricity system, unless it is used for other applications at the same time.

Another application of small-scale batteries, especially in small sized industrial and commercial fields, is **load shifting and peak shaving of power demand** from the grid. When shaving the power demand from the public grid, lower electricity and grid connection costs can be achieved for the industrial and commercial consumer, due to a lower maximal capacity and therefore lower capacity price. Since the peak power demand of the users is a main driver of grid expansion and costs, this incentive drives the users to lower their maximum peak power[80]. Additionally, batteries assist in the reduction of steep load gradients in the power system due to rapid changes in the weather dependent PV feed-in.

Another case is the operation of a PV rooftop system in combination with a battery. In this situation, the battery allows the feed-in power of the PV system into the power grid to be capped, e.g. to between 50% and 70% of the peak power of the PV system, and the electricity is used to charge the battery instead of feeding the electricity into the public grid. In this case, the total loads for the public grid on the low-voltage level decreases, if enough single, small-scale PV system operators are participating in the feed-in limitation.

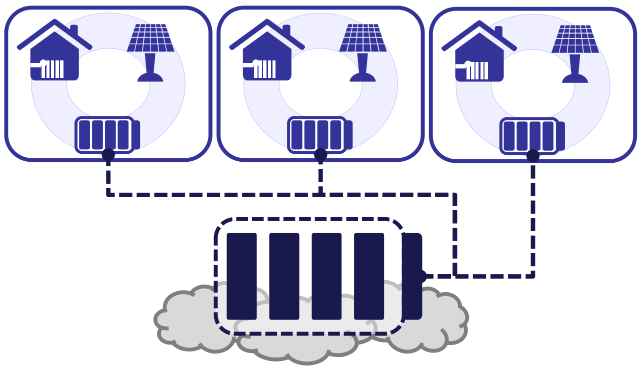
The personal **contribution to the energy transformation** by the operators of the battery and PV rooftop system represents another rather intrinsically motivated application. In this case, the economic prospects of decreasing costs are not the main driver for the operation, but the utilization of renewable energy and decrease of greenhouse gas emissions.

Lastly, small-scale batteries can be digitally integrated into a virtual set of several small-scale batteries to create

[79] Bundesnetzagentur (2020): Monitoringbericht 2019, p. 138

[80] Bundesnetzagentur (2015): Netzentgeltsystematik Elektrizität, p. 14

a **virtual large-scale battery** (also called virtual power plant, VPP), see Figure 39 for the illustration. This approach combines the capabilities of each individual small-scale battery and creates a significantly larger battery, which provides new applications and revenue streams for the aggregator and individual battery owners. In case of excess renewable energy, for example during storms when wind turbines are operated near their peak power and produce large amounts of electricity, the aggregator distributes the excess renewable energy onto the participating small-scale batteries in the VPP by dividing the excess energy into small portions, which are afterwards stored in the household batteries. The aggregator generates revenues by providing storage space at times when this is especially needed and the households collect small fees and receive low-cost electricity. Additionally, the storage of renewable energies in VPP avoids the costs affiliated with the curtailment of wind power and therefore limits not only the power load on the grid but also the financial burden for the grid operators and customers.



Source: Team Consult Illustration

Figure 39: Creation of a virtual power plant (VPP) based on combination of small-scale batteries

Participation in wholesale markets

The relevant wholesale market comprises power exchanges and the control energy market, whereas bilateral contracts between parties (Over-the-Counter, OTC) are not considered. Small-scale batteries and their owners themselves do not have access to the power exchanges nor the control energy market.

Access to power exchanges is related to upfront costs (for access and equipment), which is not viable for individuals with small energy systems. For the control energy market, the primary control energy market or the related product "Frequency Containment Reserves" (FCR) requires at least 1 MW of marketable power, which is out of the range for a standard home storage system. Therefore, individuals with small-scale batteries are excluded from these markets as single users.

They have, however, the possibility to participate via a VPP. In that case, the aggregator and operator of the VPP is participating in the wholesale markets, the individual owners of the small-scale batteries do not actively participate in the wholesale market but provide their storage capacity for the VPP.

Batteries and PV rooftop systems

The utilization of batteries in combination with a PV rooftop system represents the most common use case for small-scale batteries. The integration of a small-scale battery into a PV rooftop system is an effective way to increase the self-sufficiency of operators of PV rooftop systems. Especially with falling prices for the feed-in of generated electricity and increasing prices for the consumption of electricity drawn from the grid, the installation of a battery system is becoming more and more interesting for consumers.

In combination with PV rooftop systems or as participant in virtual power plants, individual consumers are no longer only consumers but likewise producers of electricity or providers of additional services for other participants in the energy market. Therefore, these market participants are referred to as "prosumers", since they produce energy or provide services and withdraw electricity from the public power grid at the same time.

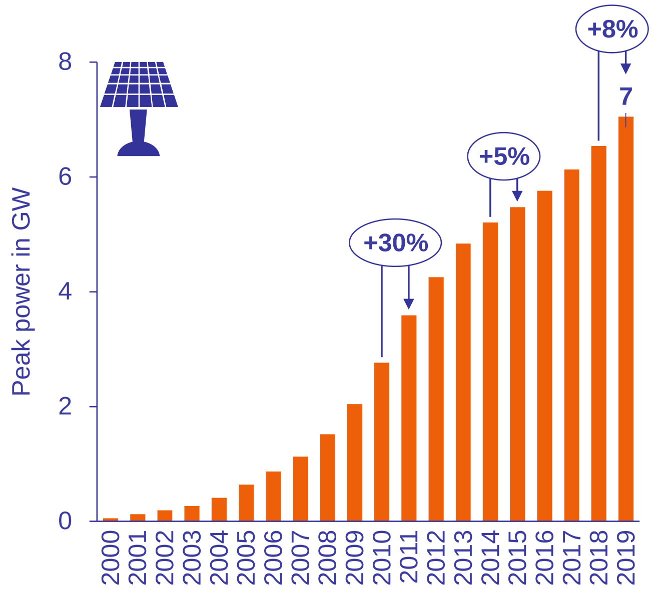
The installed power of small PV systems with a peak power equal or less than 10 kWp exhibit a steady growth in Germany with the first installations going back to the 1980s. The total power increased in the last 20 years from 54 MW to more than 7,050 MW in 2019. The maximum increase per year was in 2011 with more than 800 MW of peak power installed in Germany. Since then, the yearly installed peak power declined to less than 300 MW in 2015, followed by a continuous increase to about 500 MW installed peak power in 2019.

There are roughly 1.13 Mio. PV-rooftop systems with a peak power of less than 10 kWp installed within Germany up to the end of 2019. All these systems add up to a total power of about 7.05 GW[81], as can be seen in Figure 40.

[81] Using the average PV system size of 6.13 kW for the current installations in Germany

The total installed power of PV rooftop systems ≤ 10 kWp is close to the installed power of all nuclear power plants still in operation in Germany with more than 8 GW.

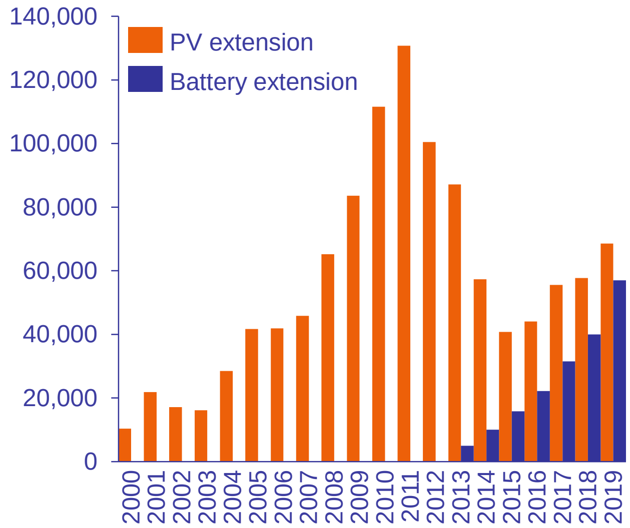
The largest increase in installed power of PV rooftop systems was observed in 2011, when the total installed power increased by 30% compared to 2010. Since then, the annual addition of PV systems with less than and equal to 10 kWp remained below the peak in 2011. The smallest increase was in 2015 with an increase of only 5% compared to the previous year. In 2019, the total installed power increased by 8% compared to 2018.



Source: netztransparenz.de, Team Consult Analysis

Figure 40: Total installed power of PV systems with equal or less than 10 kWp in Germany

The yearly extension of PV rooftop systems with a power of less than 10 kWp gained traction again in 2015, which coincides with the expansion of small-scale battery systems in Germany. The extension of small-scale batteries is mainly linked to PV rooftop systems. Therefore, more than 80% of PV rooftop systems are equipped with small-scale battery system in 2019.



Source: netztransparenz.de, Figgener et al. (2019), Team Consult Analysis

Figure 41: Yearly extension of PV systems < 10 kWp and small-scale batteries in Germany

Economic aspects

Small-scale batteries are commonly used in combination with a PV rooftop system. Therefore, the following evaluation of the economics will focus on the standard use case.

Outline of the standard use case

The idea behind the combination of PV rooftop systems and small-scale batteries is to increase the share of the relatively inexpensive electricity produced by the PV system and to decrease the share of the expensive electricity purchased from the public power grid. The electricity from the public power grid includes several taxes, charges and levies, which represent more than 75% of the German power price in 2020 (BDEW, 2020, p. 16). The electricity, which is generated by the PV system and not consumed can either be fed into the power grid, which is remunerated by a predefined amount under the EEG (§48 subsection (3), EEG) of 10.72 ct/kWh on average in 2019, or stored in the battery for later consumption.

The price difference between the EEG remuneration for the PV rooftop operator and the power price for households has changed significantly in the last 20 years, as displayed in Figure 42. The EEG remuneration exceeded the power prices by 37 ct/kWh in 2000 and in 2020 was 22 ct/kWh *below* the power price for households. While the EEG remuneration in 2020 represents only 17% of the maximum price, which was ascribed to PV rooftop operators in 2004, the power price for households more than doubled in the last 20 years from 13.94 ct/kWh to 31.71 ct/kWh[82] in 2020. Price parity was reached in 2012. Before 2012, the EEG remuneration exceeded the power price. Since 2012, the power price has exceeded the EEG remuneration and in 2020 amounted to more than three times the EEG remuneration. With the significant change in the relation between cost and remuneration, the strategy for the economic operation for the households switched from maximizing the feed-in of the PV electricity in the early years to maximizing the self-consumption of the PV electricity. The difference between the power price and the EEG remuneration represents a potential for power price arbitrage by the households.

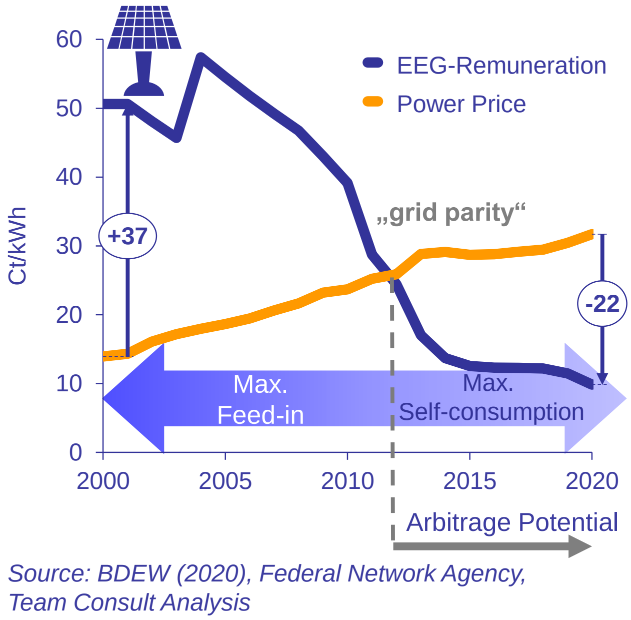


Figure 42: Price development of the EEG-remuneration for PV and power price in Germany

Investment and operation costs

The prices for battery systems reached on average about 1125 EUR/kWh for complete systems in 2019 (estimated from Figgener et al., 2019, p. 15). However, certain providers offer battery systems with prices down to nearly 500 EUR/kWh for complete systems. The systems have on average a capacity of 8 kWh for private households and about 17 kWh for small industrial and commercial users (Figgener et al., 2019, p. 13). Operation costs are about 1.5% per year of the initial investment costs (ZSW, 2018, p. 42).

Evaluation of the standard use case

For the basic evaluation of a single use case the operation of a PV rooftop system in combination with a small-scale battery is further evaluated. The numbers stated in the following are order-of-magnitude estimations. The illustrative set-up is displayed in Figure 43. The basic idea is to compare a household with only a PV system to a household that uses a PV rooftop and battery system to increase the degree of self-sufficiency and minimize the electricity withdrawn from the public power grid.

The household is located in Germany and electricity prices from 2020 with 31.37 ct/kWh are used. The household consumes 4,050 kWh per year. The PV rooftop system has a peak power of 7.5 kWp[83] and produces with the assumed annual working hours of 960 h per year in total 7,200 kWh electricity. For the case of no installed small-scale battery, the share of the generated PV electricity, which is self-consumed, is about 25%, while the share increases to 50% with a small-scale battery installed in the system.

[82] Using 19% VAT as of beginning of 2020
[83] Based on the mean value from the average installed PV rooftop system in 2018 of 8,2 kWp (based on Figgener et al., 2019b) and the average installed PV rooftop system below 10 kWp in Germany with 6.3 kWp.

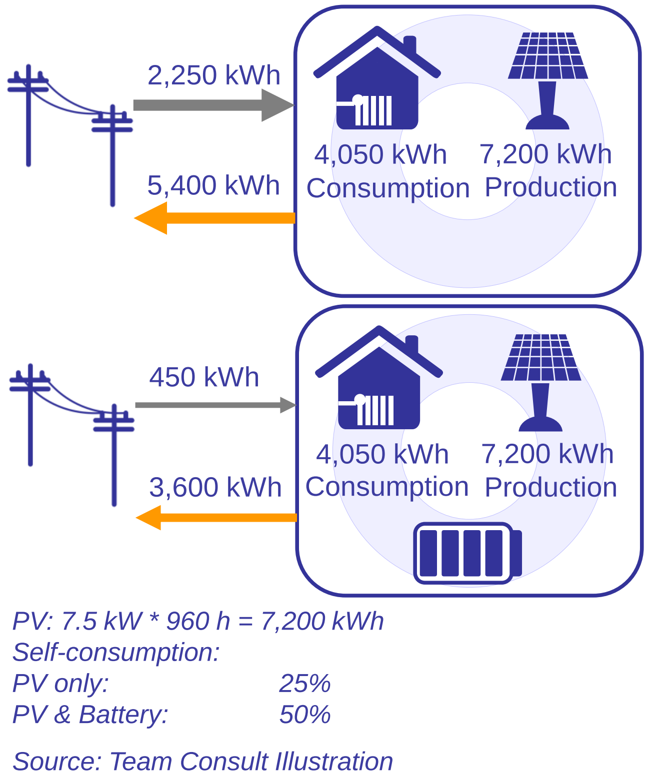


Figure 43: Basic usage case of "PV only" and "Battery & PV" systems

The resulting costs and incomes are displayed in Figure 44. In case no battery is installed, the household feeds-in 5,400 kWh per year and consumes 2,250 kWh of electricity from the grid. With the power prices and EEG remuneration in 2020, the cost of electricity withdrawn from the grid amounts to 710 EUR, and the EEG remuneration is 500 EUR per year. This results in a net payment for electricity by the prosumer of 210 EUR per year.

The arbitrage potential represents 22.13 ct for each kWh of *additional* self-consumption (1,800 kWh/a, due to the use of the battery). It represents the difference between the price for electricity from the grid and the (opportunity) cost of consuming PV electricity from the rooftop system. The use of the battery improves the annual net payment by 400 Euros. This means there is a net payment of about 190 EUR per year that the prosumer *receives*.

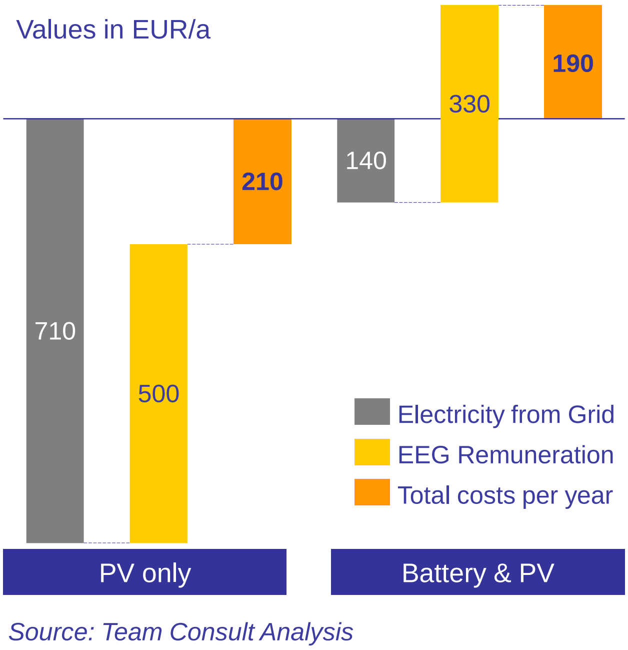


Figure 44: Cost comparison between the "PV only" and "Battery & PV" case

This basic evaluation of the PV rooftop system with a small-scale battery shows that in the current situation, the core strategy for households with a PV rooftop system is the maximization of self-consumption of the PV-generated electricity. The small-scale battery is the building block needed to implement this strategy.

Potential

Avoidance of grid expansion

Small-scale batteries can assist in the reduction of loads for the low-voltage power grid. Today, there are 1.13 million Household PV rooftop systems with below 10 kW peak power per system and 7.05 GW peak power combined.

If all of those PV systems were equipped with a small-scale battery that allows capping the feed-in power of the PV rooftop system to 50% of the peak power without curtailment of PV electricity, the total PV feed-in power from those systems would decrease from 7.05 GWp to a peak power of max. 3.53 GW. Assuming a low-voltage power grid with 5 million connected households of which 3% are equipped with a PV rooftop system of in average 6 kWp, the feed-in power of the PV electricity could be reduced from 900 MWp to 450 MWp with the usage of small-scale batteries and a feed-in power limitation[84]. From a system perspective, this could be especially helpful at times of excess renewable generation, i.e. when the residual load is negative, as the capping of PV rooftop systems' feed-in reduces the need for renewable curtailment elsewhere.

By supporting the maximization of self-consumption of electricity produced from PV rooftop systems, batteries also contribute to a reduction of electricity volumes transported by the grids. Whether or not this is a benefit from a system perspective depends on when the grids are relieved of the volumes, i.e. if this happens at times of congestion. Regarding the timing aspect, there is certainly still potential for optimization. Nevertheless, it is worth looking at the magnitude of volumes the grid could be relieved of by small-scale batteries combined with PV rooftop systems.

For this, two cases are compared. The first case (called "PV only") looks at the PV rooftop systems below 10 kWp and assumes that no small-scale batteries are installed with them. In this case, only 25% of the generated PV electricity is assumed to be self-consumed by the households. The rest is fed into the power grid. The remaining electricity needed for the households is drawn from the public power grid and amounts to 50% of the annual power consumption of the household. The second case (called "Battery & PV") assumes that all these PV rooftop systems are equipped with a small-scale battery system, which increases the share of the self-consumption. In that case, 50% of the PV electricity is assumed to be self-consumed by the households and only 20% of the annual power consumption is drawn from the public grid. The results are shown in Figure 45. In the Battery & PV case, self-consumption is 1.7 TWh higher and grid withdrawals are 1.7 TWh lower than in the "PV only" case. That means, on a grid level, the transported electricity volume decreases by 3.4 TWh.

Currently there are in total about 220,000 small-scale battery systems installed in Germany. The large majority of these are installed in combination with a PV rooftop system. However, assuming all of these battery systems are installed with a PV rooftop system, they only cover 20% of the existing systems. Since the incentive for operators of PV rooftop systems shifted from maximizing the feed-in of PV electricity to maximization of self-consumption, there is a big potential for further growth in the home storage sector, subsequently, there are still

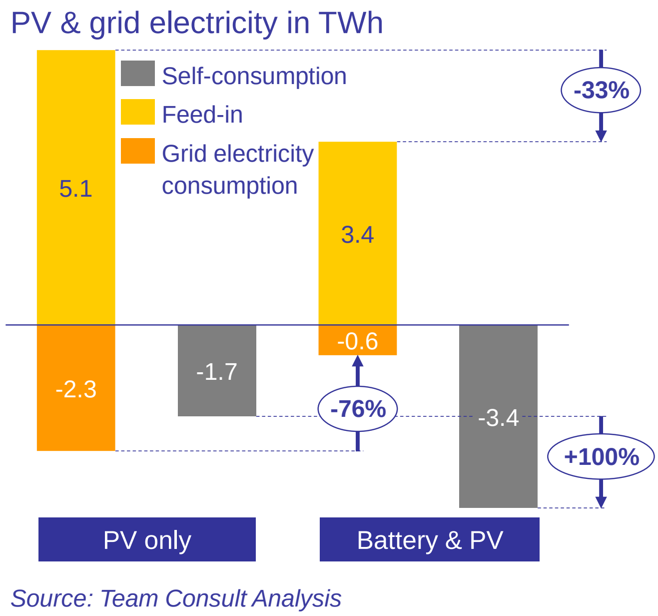


Figure 45: PV-only vs. Battery & PV systems – amounts of feed-in, self-consumption and grid electricity consumption

about 900,000 PV rooftop systems, which can be equipped with a small-scale battery system.

There is a critical point worth mentioning about the maximization of self-consumption of PV electricity by households. By decreasing the electricity withdrawals from the grid, the respective household pays less in grid fees (since these are generally charged per kWh, i.e. by the commodity, not the capacity). In Germany, this is referred to as a "de-solidarizing" effect, because the grid operator (whose costs remain the same) has to make up for the lost revenue by increasing tariffs for all customers. However, the magnitude of this effect is still limited, since self-consumed PV electricity is still a rather small fraction of all electricity consumed by German households. If this effect ever becomes problematic, there is an easy solution – charging grid fees as a fixed amount per household or by capacity instead of by commodity. This would neutralize the "de-solidarizing" effect.

Chances and risks

Decline of costs

The further upscaling of battery production mainly driven by battery electric vehicles will lead to a further decline in battery cell prices, which will translate into lower

[84] IASS Potsdam - Integration von Photovoltaikanlagen in die deutschen Niederspannungsnetze, 2017, p. 5

investment costs for small-scale battery system for households and industrial or commercial applications. The prices of small-scale battery systems on a per-kWh basis declined by roughly 60% from 2013 to 2019. At the same time, the cell costs declined in roughly the same range. The absolute price difference between system and cell costs on a per kWh basis more than halved since 2013, from about 2000 EUR/kWh to less than 800 EUR/kWh. The costs decline of battery systems and cells are expected to slow down in the following years, however, the increasing production volumes and improvements in manufacturing will continue to drive down costs.

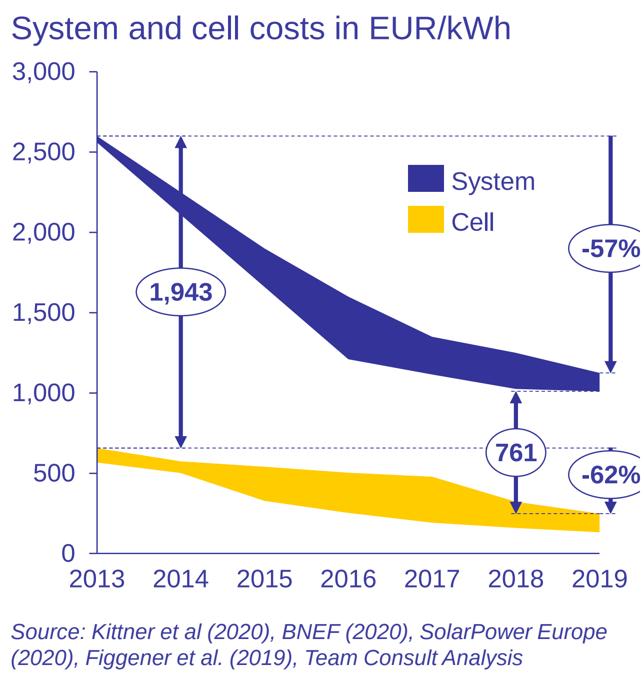


Figure 46: Battery cells and system prices have been declining for several years

Therefore, the customer will be able to install a battery with higher capacity for the same price. An investment of 10,000 EUR resulted in a small-scale battery with less than 4 kWh capacity in 2013. By 2019, the same investment volume results in storage capacity of nearly 9 kWh.

Technological development

It is unlikely, that new battery chemistries, such as Li-Air and Lithium-Sulphur will penetrate the mass market in the near future. These technologies could, however, generate significant progress in energy density compared to the current Li-ion technology. Nevertheless, the current Li-ion battery technology is expected to experience further progress in the energy density as well. Improvements in energy density can decrease the footprint of battery systems, while keeping the storage capacity constant or increase the storage capacity, while keeping the footprint of the battery constant.

Another potential development is the utilization of the second life (2nd) concept for batteries. In the 2nd life concept, the battery is utilized in a second, less demanding application, once the requirements for the first and initial application are not met anymore. The first application could be the utilization within an electric vehicle and the second utilization the home storage application for households. The concept of second life use can further improve economics by adding an additional use and revenue stream, before the materials are recovered during the final recycling process.

Regulatory development

Small-scale battery systems can provide, especially in combination with PV rooftop systems, valuable services to the grid. Small-scale batteries can shift the loads from households into times during the day, when there is a lower load in the power grid and limit the feed-in power and energy from PV rooftop systems provided for the power grid. However, the current pricing system lacks the remuneration of flexible load adaption for households and therefore the incentive to exploit the full potential of these technologies to the benefit of the public grid. If the pricing system is adapted and flexibility and controllability of the feed-in power is remunerated, the households with batteries and PV rooftop systems will be able to provide stability for the grid and support the further integration of renewable energies into the grid. Without appropriate incentives and coordination, however, it is also possible that small-scale batteries impose a stress on the grid. If e.g. the electricity price in the spot market is high, both PV and storage could sell and feed electricity into the grid. This could cause an unexpected high use of certain grid lines and hence stress the distribution grid.

The Federal Network Agency recently presented ideas on how to develop further the role and regulatory treatment of “prosumers”, i.e. households acting as consumers and as producers of electricity at the same time. These include remuneration schemes and balancing rules. Three models were proposed by the regulator from which the prosumer would be able to choose. The models vary in how actively prosumers would have to manage their own electricity production, consumption and flexibility.[85]

A revision of the EEG came into force in January 2021, bringing about improvements for PV rooftop systems. For example, a full exemption from the EEG levy for self-consumed PV electricity was previously only granted to PV rooftop systems with up to 10 kWp. This limit was raised to 30 kWp.

Conclusion

The majority of small-scale batteries installed are used in combination with a PV rooftop system. Based on the current incentives, the battery and PV systems are operated to maximize self-consumption of PV electricity by households, which is not always congruent with the requirements of the public grid. Also, they do not provide a solution for longer periods without sufficient renewable energy generation. The electricity stored in small-scale batteries is usually enough to power a household for about two to three hours at maximum power. However, there are several use cases, in which small-scale batteries are capable of providing services to the public grid.

- The concept of aggregation of a multitude of small-scale batteries to form a virtual large-scale battery or virtual power plant (VPP) can be used to provide services to the grid, which require a higher power and energy than a single small-scale battery could provide. The newly formed VPP can provide grid services such as control energy and storage space for renewable energies.
- To some degree, small-scale battery systems can decrease the capacity load from the public power grid by increasing the share of self-consumed PV electricity and therefore decrease the volume of electricity drawn from the public grid. However, they can also impose stress if prosumers are engaged in market activities selling electricity from both their PV and their storage using the distribution grid.
- In combination with PV rooftop systems, small-scale batteries can facilitate the limitation of feed-in power from the PV system and therefore decrease the load on the grid, especially at times of abundant sunshine, when a lot of PV electricity is generated.

The battery operator needs to be incentivized to participate in the provision of such services; an example of such an incentive is time-of-use tariffs. Additionally, to maximize the potential, a digital infrastructure and automation technologies are necessary, to properly integrate small-scale batteries into the public grid and to establish a communication with other devices. At the same time, declining costs of small-scale batteries and PV systems and increasing power prices continue to work as incentives for the wide spread usage of these technologies.

[85] BNetzA - Marktintegration ausgeförderter und neuer Prosumer-Anlagen (2020), p. 11.

6 Power to Gas

Power-to-Gas attracted a lot of attention in recent years as it offers a high potential for large-scale, long-term energy storage as well as for sector coupling, based on the transformation of electricity into hydrogen. It thereby offers a way for the decarbonization of industrial processes that cannot be electrified. In the long term, PtG will play a crucial role in the energy system. In the electricity system, it will not just be a consumer of electricity but also a source of flexibility.

Definitions

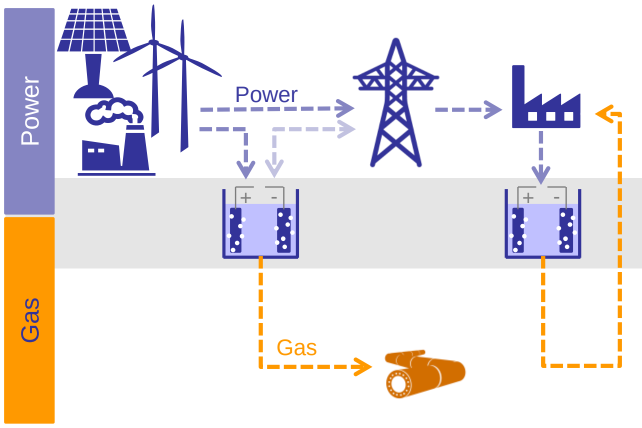
Function and classification within the system

Power-to-X technologies provide the possibility to transform electricity into chemical energy carriers, which can be either gaseous or liquid. This section focuses on the transformation from electricity into gaseous media by the Power-to-Gas technology (PtG). The resulting gases are either hydrogen (H_2) or methane (CH_4).

The technology of separating water into its chemical elements hydrogen and oxygen using electrical energy in a process called electrolysis is more than 100 years old. A share of the energy needed to separate the elements is stored in the generated hydrogen, which can be stored for later use. In a subsequent step, hydrogen can be combined with a carbon source such as CO_2 to form methane (CH_4), which is the main component of natural gas. The generated methane is called “synthetic methane” or “synthetic natural gas” (SNG) and exhibits the same properties as natural gas, which depending on the source is composed of up to 98% methane.

In the last years, the PtG technology received a lot of interest from the energy markets, since it offers the potential to integrate further renewable energies into the power grid and store energy for longer durations, such as months or even seasons. Certain applications are currently assumed to offer high potential for the transformation of the energy system:

- By transforming electricity into chemical energy carriers, PtG can contribute to “sector coupling” and act as a link between the electricity, industry, heat and mobility sectors.
- In the form of hydrogen, the energy can be used as a fuel, as feedstock and for energy storage. Alternatively, hydrogen can be processed further to methane or to liquid energy carriers (“power fuels”).
- In the form of methane, the energy can be stored and transported in the existing natural gas infrastructure and used in all natural gas based applications.



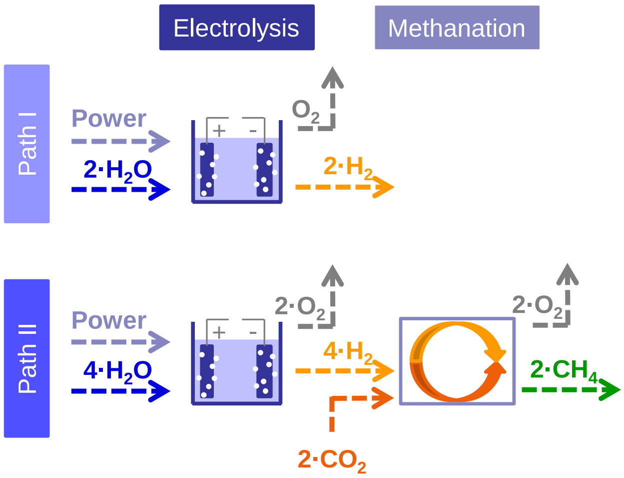
Source: Team Consult Illustration

Figure 47: Classification of Power-to-Gas within the electricity system

The PtG projects in Germany are usually located at two different kinds of locations in the electricity system. They are either located close to renewable electricity production such as PV and wind or close to industrial consumers.

- The location close to renewable generation provides clean and low costs electricity for the electrolysis process without placing additional loads onto the power grid. In certain cases, the PtG projects are installed as island-solutions and not connected to the public power grid. The electricity is only provided by renewable energy sources. If the projects are connected to the public power grid, they can withdraw additional renewable electricity from the grid to increase their utilization (full-load hours during the year). On the other hand, the grid connection also allows PtG plants to offer flexibility services to grid operators.

- In case the projects are located at industrial sites, the projects are mainly used for the production of hydrogen, which is directly used as fuel or feedstock in the industrial processes for the decarbonization of CO2 emitting processes.



Source: Team Consult Illustration

Figure 48: The transformation paths of the PtG technology: electrolysis and methanation

Utilized technologies

There are two major transformation paths for the PtG technology for the conversion of power and water into gaseous products. The first path leads to hydrogen; the second path adds an additional transformation step to generate methane.

The first step in both paths is the electrolysis process, i.e. the generation of hydrogen from renewable electricity and water. Oxygen as a side product is either stored separately or released into the atmosphere. The hydrogen is stored for later usage. Modern electrolysers are capable of adjusting their load and, thus, hydrogen production within a few seconds; this allows them to follow a dynamic load profile. The inherent flexibility can be made available to the power grid.

In the second path, the electrolysis is followed by a methanation process in which the generated hydrogen is combined with a carbon source (usually CO_2) to form synthetic methane (or synthetic natural gas, SNG). The CO_2 can either be taken from industrial emitters, captured from the atmosphere or extracted from bio waste.

Since methane has the same properties as natural gas, it is stored and transported in the existing gas infrastructure. Oxygen is formed as a side product and stored for another usage or released into the atmosphere.

The efficiency of the electrolysis depends on the process type and varies between 67% and 82%. For the methanation stage, the reported efficiency on average is about 80%. Thus, in the best case, the efficiency of the two stages combined is 66%, i.e. 100 kWh of electricity are transformed into 66 kWh of CH_4 (not considering the energy required for auxiliary components such as pumps)[86].

The operation of PtG plants is usually optimized towards maximum load factors. Therefore, the question arises, if the PtG technology is capable of acting as a provider of flexibility for the electricity system or if it creates additional demand for flexibility in the electricity system. This chapter will explore the properties and likely role of PtG concerning electrical flexibility.

Current Status in Germany

Germany produces between 55[87] and 69[88] TWh of hydrogen per year. The production of hydrogen is currently based on fossil fuels. The chemical industry is the main consumer as well as the main producer of hydrogen, especially the refinery sector and the production of ammonia and methanol. The share of hydrogen produced currently by electrolysis includes other generation paths such as the chlor-alkali electrolysis in the chemical industry.

[86] Milanzi et al.(2018): Technischer Stand und Flexibilität des Power-to-Gas-Verfahrens
[87] German Gouvernement (2020): National Hydrogen Strategy
[88] FfE (2019): Studie zur Regionalisierung von PtG-Leistungen für den Szenariorahmen NEP Gas 2020 – 2030

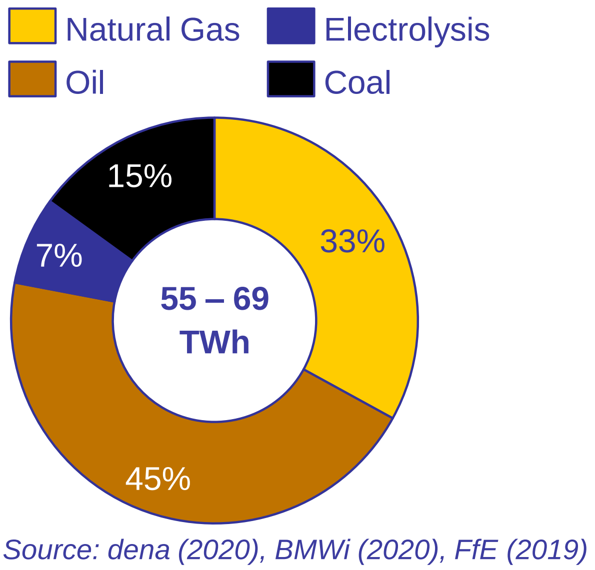


Figure 49: Origin of the hydrogen produced in Germany

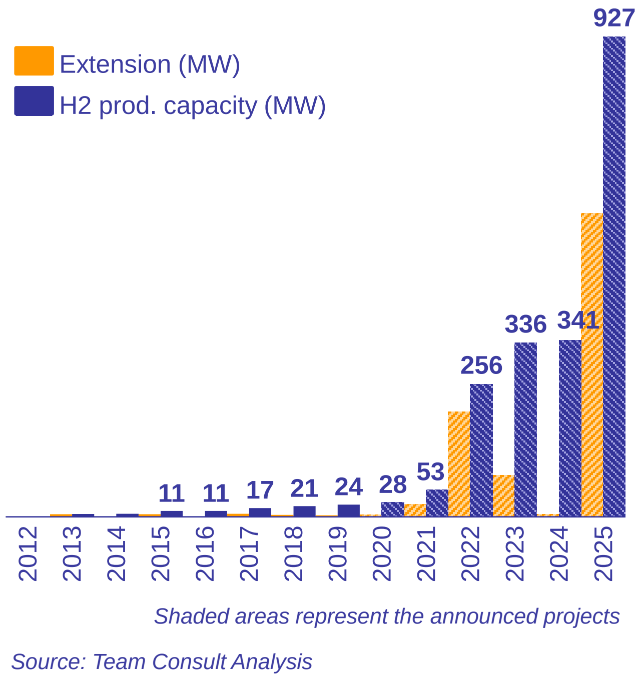


Figure 50: Installed capacity and expansion of green hydrogen production projects in Germany

The demand and production of hydrogen is planned to increase significantly over the next decades. In its national hydrogen strategy published in June 2020, the German government assumes an increase of hydrogen demand to between 90 and 110 TWh per year in 2030. A small share of that hydrogen is supposed to be supplied by German production with an electrolysis capacity of 5 GW. Assuming on average 4,000 operating hours per year and 70% efficiency, domestic hydrogen production would amount to 14 TWh/a according to the National Hydrogen Strategy (NHS). Therefore, a large share of the demand for hydrogen will have to rely on imports[89].

Analysis of the current projects in Germany shows that there is still a large gap between the goals stipulated in the NHS and actual projects. Up to end of 2019, a total cumulated electrolysis capacity of approx. 24 MW was installed in Germany, which is based on 23 operational projects. The announced projects (to the extent a start-up date is already specified) amount to a capacity of 927 MW for 2025. Until 2030, there is currently no further green hydrogen project announced. The total capacity of announced projects of 927 MW equals less than 20% of the national goal for 2030.

Green hydrogen represents hydrogen produced by electrolysis based only on renewable electricity. Based on capacity, 4% of green hydrogen projects are already in operation, a further 5% are under construction, and the remaining 91% are still in the planning stage. The operational plants produce mainly green hydrogen as a final product (70%). The remaining facilities generate green methane (20%) and green methanol (10%).

The hydrogen demand is projected to increase over the next decades, due to the replacement of fossil energy carriers such as natural gas and coal with carbon-neutral energy sources like hydrogen and synthetic methane. However, the range of projections varies significantly, depending on the assumptions taken in different studies. The estimates for the domestic hydrogen demand in 2050 range from 169 TWh[90] to almost 700 TWh[91]. All of these estimates have the underlying assumption of 95% reduction of greenhouse gas emissions by 2050.

There are several studies containing forecasts of hydrogen demand in Germany in the next decades. The demand of hydrogen heavily depends on which sectors are assumed to switch to hydrogen-based fuels and

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[89] German Gouvernement (2020): National Hydrogen Strategy
[90] EWI (publisher: dena) (2018): dena-Leitstudie Integrierte Energiewende, p. 235, p 292.
[91] NOW (2018): Studie IndWEDe Industrialisierung der Wasserelektrolyse in Deutschland: Chancen und Herausforderungen für nachhaltigen Wasserstoff für Verkehr, Strom und Wärme, p. 72, p. 184.

which sectors pursue other means of decarbonization (such as electrification). The supply side of the equation is equally uncertain. The split between domestic production and imports will heavily depend on how domestic production costs compare with the sum of production costs and transportation costs of hydrogen from other regions.

The technology mix 95 (TM 95) scenario from the dena study "Integrated energy transition" represents the lower range and expects a total installed electrolysis capacity of 63 GW, operated at 2,600 hours per year in 2050. Almost the entire hydrogen demand is met with domestic supply and only less than 5% of the demand is provided by imports. The upper end is the scenario SO-95 from NOW, which predicts a steady increase of hydrogen demand in the industry, a replacement of coal in the steel industry by hydrogen and the existence of an import infrastructure for hydrogen. In 2050, the scenario forecasts a total installed electrolysis capacity of about 140 GW, operated at about 2,500 hours per year. Only a third of the demand is supplied by domestic production, the remaining share is provided by imports.

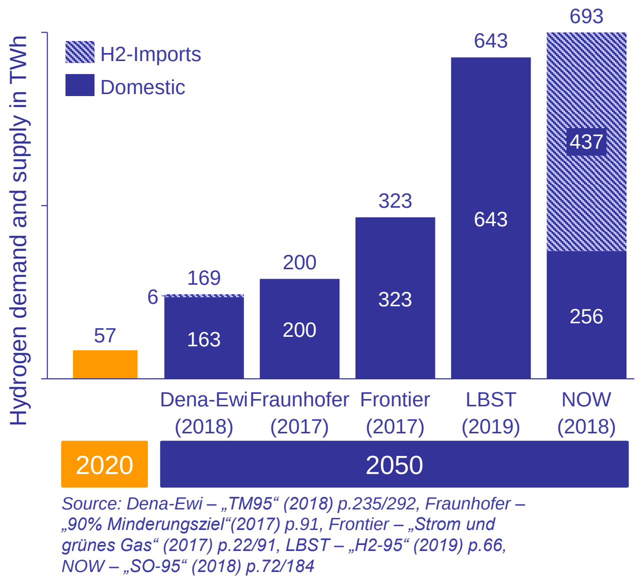

Figure 51: Estimated hydrogen demand and supply in Germany in TWh per year

The projections show that the hydrogen demand is linked to various other parameters in the interconnected energy system. Nevertheless, hydrogen will be used in sectors, which cannot be electrified and which need hydrogen-based products as a fuel or feedstock.

Policy and regulation

Current regulations

Hydrogen was not explicitly considered during the creation of the current regulations regarding the gas and electricity market in Germany. Therefore, a comprehensive legal framework does not yet exist. Since the PtG projects are part of the electricity and gas system, both regulatory frameworks affect them.

The German regulations use a broad definition for biogas in the EnWG to overcome the lack of hydrogen-specific regulations in the gas framework.

Paragraph 3, nr. 10c of the EnWG states:

„Biogas: Bio methane, gas out of bio mass, landfill gas, gas from purification plants, mine gas and **hydrogen, which is produced by water electrolysis and also synthetic methane**, if the energy for the methanation and the carbon source mainly and verifiably originate from renewable energy sources."

The classification "mainly" means here that the energy is based on at least 80% of renewable energy sources[92]. In case the requirements are met, hydrogen and the synthetic methane receive the same benefits as biogas, such as:

- § 34 subsection (1), GasNZ93: Priority treatment for the injection and withdrawal, if the gas is compatible with the gas infrastructure
- § 35 subsection (1) GasNZ: More flexible balancing conditions compared to natural gas
- § 19, subsection (2), sentence 2 GasNEV94: No fees for the injection into the gas transmission grid
- §20a GasNEV: Remuneration of the injection into the grid by the grid operator for each injected kWh for 10 years, based on the avoided grid charges

However, the injection of larger amounts of hydrogen into the existing gas grid as an add-on to the natural gas is hindered by the limited compatibility of current gas consuming technologies concerning the amount of hydrogen in the gas mix. The share of hydrogen in the

[92] Bundesnetzagentur - Regulierungen von Wasserstoffnetzen (2020)
[93] GasNZ: Gasnetzzugangsverordnung (gas grid access ordinance)
[94] GasNEV: Gasnetzentgeltverordnung (gas grid charges ordinance)

gas grid is currently limited to maximum of 10 %. Additionally, certain applications will require pure hydrogen, which makes it necessary to provide an infrastructure for both gases[95].

In the electricity market, PtG is seen as the final consumer of electricity (based on § 3, Nr. 33, EEG), leading to the burdening of the electricity price with final consumer fees such as electricity tax and EEG-levy. However, there are exemptions, which reduce the burdening for PtG projects:

- § 118 subsection (6), EnWG[96]: grid charges are omitted for up to 20 years after the initial start up
- §61a, §61b, §69b, EEG[97]: a reduction of or complete exemption from the EEG-levy is possible under certain conditions
- § 27b, KWKG[98]: exemption from the cogeneration fee, in case the hydrogen or methane is used for power generation
- § 9a subsection (1), StromStG[99]: the electricity tax is omitted from the power price for the manufacturing industry, if the electricity is used to run an electrolyser

Revision of the EEG 2021

An important change to the EEG in 2021 was the exemption of PtG facilities from the EEG-levy (§69b EEG) that is possible under certain conditions. A requirement for the exemption is that the facility is used for the production of green hydrogen, as defined in § 12i of the Renewable Energy Ordinance (EEV).

Additionally, the revision points towards an upward adjustment of the expansion paths for renewable generation capacities to accommodate the increasing demand of renewable energies for the production of green hydrogen. The assembly of experts, which advises the German government on the development of the hydrogen strategy, estimates the additional electricity demand due to electrolysers to amount to about 30 – 35 TWh in 2030. The additional electricity demand would require about 15 GW of onshore-wind or about 30 GW of solar power[100].

National Hydrogen Strategy (NHS)

Germany plans to achieve greenhouse gas emission neutrality by 2050, while at the same time, a stable, cost-efficient and sustainable power system with adequate security of supply is needed. Alternatives to the fossil energy carriers are needed to ensure that transition, and hydrogen is supposed to play a central part.

The idea is the development of a market for hydrogen as well as the related technologies such as electrolysers and fuel cells on a national level. These technologies are also meant to be exported to the global market. By developing a domestic hydrogen market, the technologies can be scaled up over time. This would reduce the production costs of hydrogen, which are currently one of the main obstacles for a widespread application. In addition to the domestic production, the import of hydrogen will also be required. Only around 13% of the hydrogen demand in Germany by 2030 is expected to be supplied by domestically produced green hydrogen. The remaining share will have to be imported or produced from fossil fuels.

In a program from the Federal Environment Ministry, the German government is initiating a plan with Brazil and Morocco for the generation and export of green hydrogen to satisfy hydrogen demand in Germany and generate export opportunities in the countries with beneficial conditions for renewable energies[101]. Further, there are several countries, which are actively planning exports of hydrogen or hydrogen-based fuels such as Australia, Chile, Norway, Australia and Saudi Arabia[102].

Several measures are listed in the national hydrogen strategy, which are needed for the ramp up and development of a domestic hydrogen market in Germany. These measures are planned to be implemented until 2023. The second phase from 2024 to 2030 is supposed to expand the hydrogen market to include other European and international partners and provide additional potential for the German industry. The measures included the reduction of electricity procurement costs for the electrolysis and the increase of hydrogen based fuels in the transportation sector including aviation.

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[95] Bundesnetzagentur – Regulierungen von Wasserstoffnetzen (2020)
[96] EnWG: Energiewirtschaftsgesetzt (Energy Industry Act)
[97] EEG: Erneuerbare Energien Gesetz (Renewable Energy law)
[98] KWKG: Kraft-Wärme-Kopplungsgesetz (Combined Heat and Power Production Act)
[99] StromStG: Stromsteuergesetz (Electricity Taxation Act)
[100] Assuming about 2,000 h of operation for onshore-wind and 1,000 h for solar
[101] BMU - Aktionsprogramm PtX „Power-to-X“ (2019)
[102] IRENA – Hydrogen: A renewable energy perspective (2019)

Some measures are especially tailored to the steel and chemical industry, since these will be the industries with a large demand for hydrogen and high potential for the reduction of greenhouse gas emissions by the transformation from fossil based to cleaner energy sources. One measure is the implementation of a support scheme, which remunerates the avoidance of CO_2 emissions by using the currently still more expensive hydrogen technologies (so-called Carbon Contracts for Difference, CfD). Another option for the steel and chemical industry is the auction system of green hydrogen, which is solely produced for these industries. The Federal Ministry for the Environment specified in a position paper that the production of 5,000 t or 0.2 TWh[103] of hydrogen per year starting in 2021, with an increase of 5,000 t each year would support the steel and chemical industry and assist in the ramp up of the electrolyser capacity[104]. That would result in about two TWh per year of hydrogen by 2030, just for the steel and chemical industries, an amount which represents almost 15% of the green hydrogen production goal for 2030 (14 TWh/a).

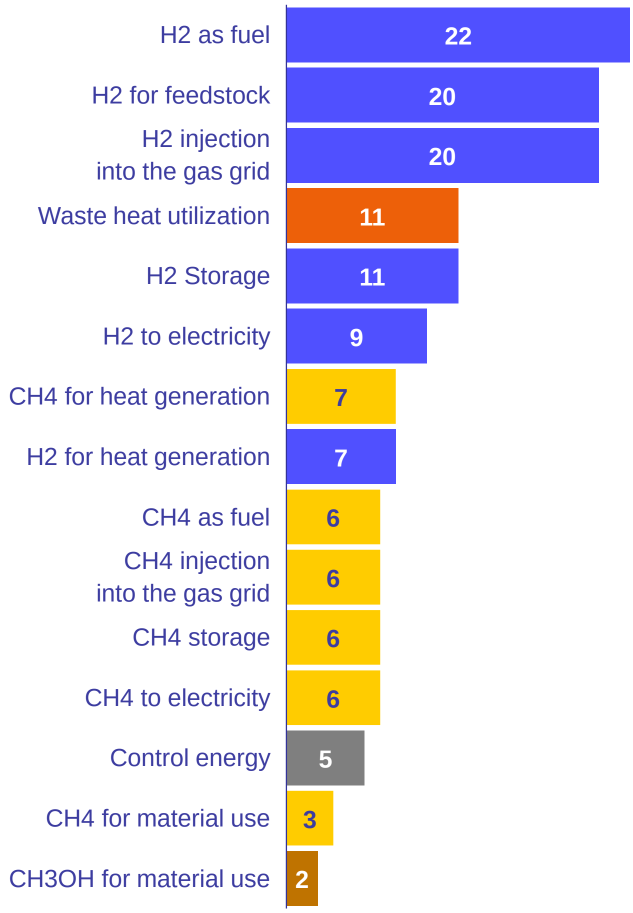
Hydrogen Infrastructure

The national hydrogen strategy points out that the implementation of a viable hydrogen infrastructure represents a critical requirement for the development of a domestic and European hydrogen market. The TSOs of the German gas grid evaluated the market needs up to 2030 in their latest national gas grid development plan. In that plan, they identify the need for an initial hydrogen pipeline system with a length of in total 94 km. Additionally, 1,142 km of existing natural gas pipelines are foreseen to be converted into pipelines capable of transporting hydrogen. The costs for the newly constructed hydrogen pipelines are estimated to about 220 Mio. EUR, the conversion of existing natural gas pipelines to hydrogen pipelines is estimated at 310 Mio. EUR[105]. The financing of these hydrogen pipeline projects is not clarified under current regulations.

The Federal Network Agency states that it is worth considering expanding the current gas regulation to hydrogen infrastructure. In the initial growth phase of the market and the pilot projects, the regulatory treatment of green hydrogen as equivalent to biogas with all its privileges is considered a viable path[106].

Functions and Applications

The PtG projects in Germany have a variety of different applications. They are usually not focused on one single application. Instead, they pursue a multi-use strategy, similar to the large-scale batteries in Germany, which combine various single applications to generate enough revenue for a positive business model (see chapter "see chapter "Large-scale batteries" and the report on large-scale batteries in full length[107]).



Source: powertogas.info, Team Consult Analyses

Figure 52: Use cases of the PtG projects in Germany

The PtG projects in Germany have a clear focus on the generation of hydrogen as a fuel or as feedstock and the injection of hydrogen into the existing gas grid where it is

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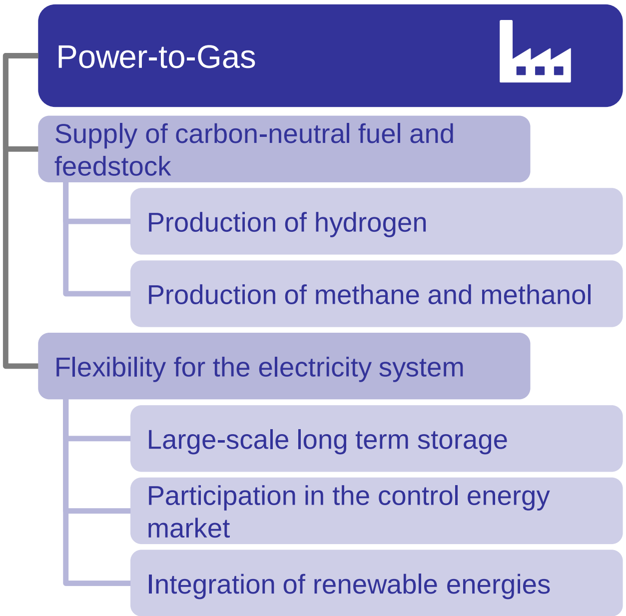
[103] Using 39.41 kWh/kg hydrogen
[104] BMU - Markthochlauf für eine grüne Wasserstoffwirtschaft (2020)
[105] FNB Gas – Netzentwicklungsplan 2020 – 2030 – Entwurf (2020)
[106] Bundesnetzagentur – Regulierungen von Wasserstoffnetzen (2020)
[107] Team Consult, dena (publisher): German experiences with large-scale batteries – regulatory framework and business models, 2020 (A study supported by the Federal Ministry for Economic Affair and Energy of Germany)

blended with natural gas, as can be seen in Figure 52. The analysis is based on 67 projects, with projects usually pursuing a multi-use approach. The utilization of waste heat for residential heating or an industrial process is another major application of the PtG projects. The generation of methane or methanol and the participation in the control energy market currently play only a minor role.

The applications can be classified into two main fields. The first and primary field is the production and supply of carbon-neutral fuel and feedstock for the industry and other sectors such as mobility and transportation. The production of hydrogen, methane and methanol falls into that category. The second field is the provision of flexibility for the electricity system. PtG serves as a means for long-term energy storage spanning months and even seasons. It acts as a player in the control energy market and as a tool for further integration of renewable energies into the power grid.



Source: Team Consult Illustration

Figure 53: Applications of PtG projects

The main application is the **production of hydrogen.** As a fuel, hydrogen is used in fuell-cell vehicles for transportation or special hydrogen-compatible gas turbines for the production of electricity. As a feedstock, hydrogen is used in industrial processes such as the synthesis of ammonia (NH_3), the desulphurization of oil products in refineries (hydrotreating) and the cracking of long-chain into short-chain hydrocarbons (hydrocracking). Next to the usage in the chemical industry, hydrogen will become more and more important in the steel industry to replace coke for the production of steel out of iron ore. A further possible application is the decarbonization of space heating.

Hydrogen-based **methane and methanol** also serve as fuel and feedstock and can be stored in existing infrastructure. Methane is used as a fuel in all natural gas applications including gas-fired power plants. Methanol serves in a variety of different applications. As a fuel, it can be used directly in internal combustion engines (ICE) or in fuel cells. As a feedstock, it is utilized for fuel additives, as basis for biodiesel and further chemical primary products[108].

In addition, PtG facilities provide flexibility services to the electricity system. Most importantly, these include large-scale and long-term storage of energy, the provision of control energy for grid balancing and the integration of renewable energies into the grid.

Various different storage technologies exist for small scale and short- to mid-term energy storage. However, **long-term storage of large amounts of energy** in a cost-effective way is more difficult to achieve. For that purpose, PtG represents the most advantageous option available. The advantage of the PtG technology is the utilization of the existing gas storage infrastructure, especially in the case of synthetic methane. Once the electricity is transformed into gas, it can be stored for several months. The underground gas storage capacity in Germany amounts to about 234 TWh, which is almost a quarter of the German natural gas consumption in 2019.[109] Assuming a power plant efficiency of 50%, that gas storage volume is equivalent to 117 TWh of electricity.[110]

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[108] Shell – Shell Wasserstoff Studie – Energie der Zukunft? (2017)
[109] This storage capacity refers to energy stored chemically in the form of methane. In the form of hydrogen, the same storage volume would accommodate less energy (due to the lower calorific value of hydrogen compared to methane). Moreover, some underground storage facilities – e.g. depleted natural gas fields – may not be suited to accommodate hydrogen, which would further reduce hydrogen storage capacity.

[110] This number is by orders of magnitude higher than any other form of electricity storage. It amounts to approx. 25% of annual German electricity consumption. However, it is worth noting that existing gas storages are primarily needed for the storage of natural gas to provide the seasonal swing of space heating demand. Therefore, only a fraction of the storage capacity is available for purposes relating to the electricity market.

Imbalances in the power grid are compensated by means of control energy, which is procured by the TSOs. Electrolysers are capable of dynamically adjusting their load and ramp up from low to full power within less than 30 seconds. The fast response capabilities of modern electrolysers make it possible to participate in all branches of the control energy market – primary, secondary and tertiary control energy. The participation in the control energy market represents a side-business for PtG projects that generates additional income for the operators. Currently there are only five projects in Germany participating in the control energy market in all three branches, which might be connected to low prices in the control energy market and, thus, limited revenue expectations.

The **integration of renewable energies** is facilitated by connecting the PtG facility directly to renewable electricity generation, primarily wind and PV parks or plants that provide the electricity needed to run the electrolysis process. The PtG facilities provide additional demand for renewable electricity that the grid might otherwise not be able to absorb. Therefore, PtG in such cases acts as an enabler of additional renewable electricity generation.

PtG facilities also adjust their load to the situation in the electricity market by the operators' **optimization of electricity procurement costs in the intra-day spot market**. Although this aspect is not explicitly mentioned in the list of PtG applications in Figure 52 above, procurement price optimization is certainly mandatory for operators. This is because current PtG projects struggle with high production costs for hydrogen and a lack of competitiveness with hydrogen from fossil fuels. This means operators have to find the optimum between maximizing plant utilization and running the plant only when electricity spot prices are low. Because of this optimization, PtG plants are usually in operation when electricity is abundant and prices are low, and they are usually idle when electricity is scarce and prices are high. As a result, PtG plants contribute to the alignment of (residual) electricity demand and electricity supply.

There are some further options for PtG operators to maximize utilization and earn additional revenues. These include back-up solutions and waste heat utilization. **Back-up solutions** require a fuel cell or turbine to be installed in addition to the electrolyser. In case of power outages or overloads in the power grid, the hydrogen, methane or methanol is used to generate electricity for the local grid.

Waste heat utilization makes use of the limited efficiency of the electrolysis and methanation process. An efficiency of 60 to 80% means that 20 to 40% of the input electricity is lost as waste heat. The temperature of the waste heat from the electrolyser depends on the electrolyser technology. The low-temperature electrolysers (proton-exchange membrane (PEM) and alkaline water electrolyse (AEL) electrolyser) work in the temperature range of 50 to 80 °C. Such temperatures provide potential for space heating[111]. The high-temperature electrolyser (HTEL) has a working temperature range from 700 to 1000 °C and the methanation from 200 to 600 °C. Low-temperature electrolysis produces waste heat that can be captured and used elsewhere while high-temperature electrolysis requires heat from external sources.[112]

Example cases

Production of hydrogen in Haßfurt

In the PtG plant in Haßfurt, excess electricity from renewable energy production is used to produce green hydrogen. The project is operated by a partnership formed by the municipal utility in Haßfurt, the virtual power plant operator and aggregator Next Kraftwerke and gas retailer Greenpeace Energy. The project has been in operation since 2016 and has the following parameters:

- Investment volume of about 2 Mio. EUR without any external funding
- The PEM electrolyser has a maximum electrical power of 1.25 MW
- It produces up to 225 m³/h and about 1 GWh/a of hydrogen
- The plant is equipped with a hydrogen tank with a storage volume of 1,750 m³ or about 6 MWh
- The project is equipped with a cogeneration plant, which is operated either by natural gas or hydrogen

The generated hydrogen is either injected into the public gas grid, delivered to a malting plant located nearby the PtG plant or stored in the hydrogen storage tank. The PtG plant is controlled by the aggregator and the operation is dependent on the load in the power and gas grids. The PtG project may operate in three modes:

- In the first mode, hydrogen is produced from excess electricity from renewable energies and either delivered to the customers or stored in the hydrogen tank.

[111] Fraunhofer ISI – Eine Wasserstoff-Roadmap für Deutschland (2019)

[112] Milanzi et al. – Technischer Stand und Flexibilität des Power-to-Gas Verfahrens (2018), p. 3.

- The second mode is the provision of primary control energy. The electrolyser adjusts the power quickly and automatically.
- In case of electricity shortages, the cogeneration plant is activated and provides electricity and heat from natural gas or hydrogen.

The project is financed by a premium charged to customers who purchase the respective premium gas product from Greenpeace energy. The operator plans for an amortization period of 10 years, even though the profitability is complicated by the currently high electricity costs, which is due to the EEG-levy.

Methanation in Werlte

The PtG project operated by car manufacturer Audi produces green methane from renewable energies and by using CO_2 from biomass. The produced synthetic methane is injected into the public grid. The project details are:

- The AEL electrolyser has an electrical power of 6 MW
- The plant produces 520 t or 20 GWh of hydrogen as intermediate product and 1,000 t or 15 GWh of methane per year as final product
- The waste heat is used in the biogas plant for the cleaning and upgrade of biogas to bio-methane

The project is located close to an offshore wind farm and next to a biogas plant, which limits the transportation distances for electricity and CO_2 for the operation. The oxygen from the electrolysis and the waste heat from the methanation process are transferred to the biogas plant close-by for the processing of biogas. The production of about 1,000 t of methane per year absorbs about 2,800 t of CO_2. The operation of the PtG plant is coupled to the power price at the power exchange and operates intermittently at low prices and times of low demand. By adjusting the PtG electricity demand to the electricity price it contributes to the demand and supply balancing and optimizes the electricity procurement costs.

Additionally, next to the production of hydrogen and methane, the project is prequalified for the provision of positive and negative control energy and provides mid-term balancing power in cases of severe imbalances in the public power grid.

The electricity costs for the electrolyser represent the main share of the operational expenditure, which can be partially offset by the provision of control energy.

Hydrogen production for direct use in the chemical industry in Hamburg

The currently largest PtG project in operation in Germany is located in Hamburg. At the start of operation in 2017, it was the largest electrolyser worldwide. The project details are:

- Total investment costs of 13.7 Mio. EUR of which 2.4 Mio. EUR as a contribution from European funding program
- PEM electrolyser with an electric power of 5 MW
- Reduction of 2,400 t of CO2 per year
- The production amounts to about 14 GWh/a of hydrogen[113]

The plant is located at a refinery and produces green hydrogen for the production of oil-based products within the plant. The project uses renewable energies and produces therefore green, carbon-neutral hydrogen. Next to the production of hydrogen, the project provides positive control energy for the power grid. The electrolyser adapts the power load rapidly to the supply-demand balance in the grid.

Potential

The examples above show that operators of PtG plants pursue multiple applications including the provision of flexibility services to the electricity system. The demand for flexibility will increase further with the growing share of renewable energies in the electricity system.

PtG projects are able to absorb the dynamic electricity production from wind and solar systems and support the expansion of renewable energies. As it is shown in Figure 58 in the section "7 Further operational and market design flexibility options", the curtailment of wind power reached more than 6 TWh in 2019. If the wind farms were equipped with a PtG plant, the excess power could hypothetically be transformed into hydrogen. About 4.2 TWh of hydrogen could have been produced from the electricity that was curtailed.

However, PtG plants need to maximize utilization to recoup the investment costs, which means several thousand hours of operation during the year. In case only excess energy of renewable energies was used, the operation hours of the PtG plants would be limited to only few hundred hours per year at best[114]. Therefore, for the production of green hydrogen, the expansion of electrolyser capacity needs to be accompanied by an additional expansion of renewable energies to provide

[113] Assuming operation hours of 4000 h and an efficiency of 70%

[114] Drehpunkt – Einsepeisemanagement gestern und heute (2018)

the required electricity. Otherwise, the demand from electrolysers is in conflict with the electricity demand from other sectors, which are set to be increasingly electrified in the future, such as heating and mobility.

The following table shows the ratio between planned eletrolyser capacity, hydrogen production and electricity demand from renewable energies. The electrolyser capacity is determined in the national hydrogen strategy to increase to 5 GW by 2030 and then again by 5 GW until 2040 at the latest. Based on 70% efficiency and 4,000 full load hours per year, the hydrogen production is 14 TWh/a in 2030 anf 28 TWh/a in 2040. This means that the green hydrogen production volume expected for 2040 would not be sufficient to cover present-day hydrogen demand, let alone higher future demand.

Additional electricity demand for green hydrogen production amounts to 20 TWh in 2030 and to 40 TWh in 2040. In comparison with present-day electricity demand, this would mean an increase of 4% (2030) or 8% (2040), respectively.

The additional electricity demand requires an expansion of renewable energies such as wind and solar. In case the electrolyser is primarily powered with electricity from offshore wind, the required generation capacity will be in the same magnitude as the electrolyser capacity (this is because electrolyser and offshore wind both operate at about 4,000 hours per year[115]). If the electricity for the electrolysers is primarily provided by solar energy, the required peak generation capacity will be much higher, since solar power only has about 1,000 hours per year in Germany[116].

	2030	2040	Units
Electrolyser (EL) capacity	5	10	[GW]
Prod. volume of H_2	14	28	[TWh/a]
Additional RE electricity demand	20	40	[TWh/a]
Additional RE capacity	> 5	> 10	[GW]

Figure 54: RE electricity and capacity demand for the planned expansion of electrolysers in Germany

PtG plants not only integrate renewable energies but already contribute to the stabilization of the power grid. There are currently about 12 MW[117] of electrolyser capacity used for the provision of control energy, which represents only a small fraction of the 6.85 GW of prequalified capacity for primary control energy. Conventional power plants based on nuclear, lignite and coal will, however, slowly retire from the control energy market and leave a large power share of several GW to fill, which represents potential for PtG plants to step in.

Next to the provision of control energy, the demand driven operation of PtG plants can contribute to the balancing of the power grid. The provision of interruptible loads from PtG plants represents another grid-dedicated service, which can be provided by PtG plants due to their dynamic load adjustment capability. Therefore, PtG has the potential to provide more flexibility for the power grid. The expansion of PtG capacity will make it necessary for PtG plants to interact with the power grid by providing flexibility to ensure stability, while integrating renewable energies.

Chances and Risks

The production price for hydrogen is driven by the capital expenditures (CAPEX), the electricity costs and other costs for the operation such as provision of water or maintenance. Initial investment costs for electrolysers are expected to decrease significantly over the next decades[118]. All current electrolyser technologies are projected to cut the specific investment in half by 2050, resulting in about 900 EUR/kW for the HTEL, 800 EUR/kW for the PEM and 500 EUR/kW for the AEL technology. For methanation, a reduction of about 30% down to about 480 EUR/kW is expected over the same period. Technological improvements and the upscaling of manufacturing will be the main drivers for the decline of the specific investment costs.

[115] BDEW – Jahresvolllaststunden 2018/19 (2020)
[116] Ibid.
[117] www.powertogas.info
[118] Prognos - Kosten und Transformationspfade für strombasierte Energieträger (2020)

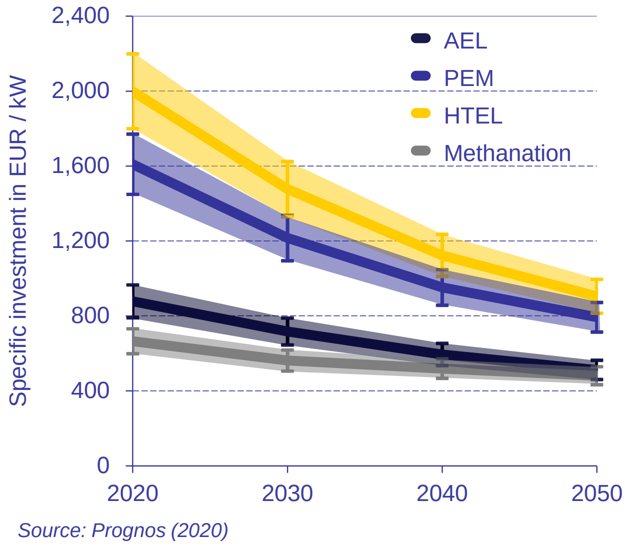


Figure 55: Declining costs for electrolyser and methanation technology

An even higher impact on the production price of hydrogen has the power price. It is responsible for about 60% of the final production costs of hydrogen, while the share of the CAPEX in the final hydrogen price is about 30%[119]. A large influence on the production costs has the EEG-levy as part of the power price. It amounts to 6.756 ct/kWh in 2020 and is set to decrease slightly to 6.500 ct/kWh in 2021.

In general, the power price for PtG plants is burdened with the EEG levy, unless one of the following provisions applies:

- § 61b, EEG: reduction of the EEG levy to 40% of the regular level for electricity that is self-produced
- § 61a, EEG: complete exemption from the EEG levy in case the electricity is self-produced in an island-solution (i.e. without connection to public supply grids)
- § 69b, EEG: complete exemption from the EEG levy for PtG plants that produce green hydrogen

The newly introduced exemption from the EEG-levy for green hydrogen production under §69b EEG will substantially decrease the power price and, thus, improve the profitability of PtG plants in the short term. It will, however, not make green hydrogen competitive in and of itself.

The question if, to what extent and under what circumstances PtG facilities should be exempted from fees, levies and taxes on electricity has been – and will likely remain to be – a topic of controversial discussion. An obvious argument to make is that for an efficient allocation of resources, the full costs of electricity used by a PtG plant should be reflected in the price of electricity paid by the plant operator. This would incentivize decisions that minimize overall system costs.

For example, the costs caused by a PtG plant may vary considerably depending on its location. As mentioned in the introduction to this chapter, PtG plants can be constructed close to renewable electricity generation or close to the industry facilities that need hydrogen. In case the PtG plants were constructed close to industrial and hydrogen demand centers in Germany, they would be installed mostly in the southern and central part of Germany. That, however, would increase the imbalance in the electricity system, since additional power demand would be generated in the central and southern part of Germany while onshore and offshore wind parks are located in the north. This would increase the need for electricity grid expansion. If instead, PtG plants were installed close to onshore and offshore wind parks in the northern part of Germany, the hydrogen could to be transported to the demand centers in pipelines which may be more cost-effective (e.g. when natural gas pipelines could are rededicated to transport hydrogen).

Hydrogen production costs are another uncertainty. Figure 56 shows the development of the hydrogen production costs for 2050 in comparison to 2020. The underlying electricity price assumptions (5.0-10.2 ct/kWh in 2020 and 4.5-6.9 ct/kWh in 2050) reflect the full costs for renewable electricity production prices from wind and solar in Germany.[120]

Today, the production of fossil-based hydrogen by steam reformation exhibits the lowest costs (2.8 to 4.5 ct/kWh), while the production costs of green hydrogen amounts to 21 to 24 ct/kWh. By 2050, the production costs of green hydrogen are estimated to decrease to between 2[121] and 14[122] ct/kWh, which is potentially competitive with fossil-based hydrogen. However, the large range in the costs estimations indicates a high level of uncertainty. To put

[119] BMWi – Optionen für ein nachhaltiges Energiesystem mit Power-to-X Technologien (2019)
[120] DECHEMA – Optionen für ein nachhaltiges Energiesystem mit Power-to-X Technologien (2019)
[121] Navigant (2019): Gas for Climate. Theoptimal role for gas in a net-zero emissions energy system
[122] Prognos (2020): Kosten und Transformationspfade für strombasierte Energieträger

that further into perspective, the year-ahead price for natural gas on average was about 1.4 ct/kWh[123] in 2020, which shows the difficulties of hydrogen to compete with cheaper fossil fuels in the market.

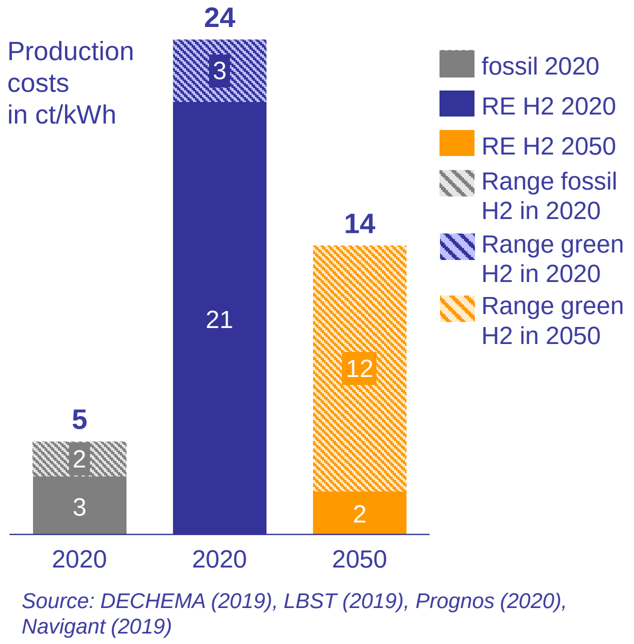


Figure 56: Hydrogen production costs in 2020 and 2050

Conclusion

The PtG technology will play an essential role in the future energy system by linking different sectors through the provision of chemical energy carriers such as hydrogen, synthetic methane and methanol. To provide at least a share of the demanded energy carriers, the capacities of the PtG plants will need to increase significantly over the next decades. This is supported by the German government.

The increase of the PtG capacity must be accompanied by an increase of the renewable energy expansion to avoid electricity shortages and to enable sufficient utilization of PtG facilities. The operation hours of the dedicated renewable generation units will determine the utilization of PtG plants. This will ensure that the produced hydrogen is based only on renewable electricity (that it is green) and that PtG plants do not create additional flexibility demand in the electricity system. A coordinated expansion of PtG plants and of renewable energies is able to integrate renewable energies further into the energy system and assist in the decarbonization of currently still fossil-based processes. Since the fuels from PtG plants – hydrogen and methane – can be used for electricity generation, the PtG technology represents a sustainable and emission neutral way to bridge longer periods of insufficient renewable generation, which would otherwise only be manageable by fossil-based electricity generation.

An increasing share of renewable energies in the power system will bring a higher demand for flexibility with it. PtG plants already provide flexibility services such as demand-driven operation via power exchanges and assist in aligning power demand and supply. Further grid dedicated services such as control energy and interruptible loads are applications, which can and are already provided by PtG plants. Therefore, PtG plants are promising players in the energy system capable of performing very different essential tasks all at once.

A major hurdle for the PtG technology currently is the burdening of the electricity price with fees and levies. As these are being lifted, the PtG business case will improve. However, the price paid for electricity used in a PtG plant should always reflect the full costs of that electricity.

Additional income from the provision of flexibility services and future cost decreases from economies of scale will also help improve the business case of PtG. However, competitiveness with fossil-based hydrogen and fossil fuels is still a long way to go.

[123] I.e. OTC-NCG for Calendar year 2021, source: METANOPOLY

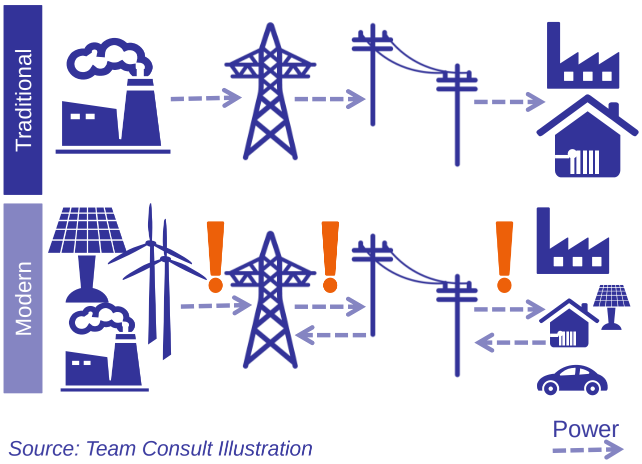
7 Further operational and market design flexibility options

There is a variety of measures that TSOs and DSOs have at their disposal to optimize system operations. In addition, it is up to the legislator and the regulator to revise the market design in order to enable the utilization of all flexibility sources in the electricity system. This ensures that infrastructure expansion is limited to what is actually required.

Definitions

The task of TSOs in the traditional energy system was to manage and control the electricity flow from central and large-scale power plants to demand centers in the industry and residential areas. The balancing relied on the control of these central, large-scale power plants and the forecast of demand by traditional consumers. The traditional system had few parameters which influenced power generation and demand. The balancing of the electricity flow was therefore a rather straightforward exercise. By contrast, the current electricity system depends on electricity supply from weather-dependent, intermittent sources such as wind and solar. These units are located at places that offer beneficial weather conditions, and they are distributed over larger areas.

Alongside with power generation, electricity consumption changed likewise. The traditional, unidirectional physical flow of electricity from the TSO via the DSO to the consumer changed into a bidirectional flow of electricity with many consumers producing and feeding electricity into the power grid; consumers have become "prosumers". These changes in power generation and consumption increase complexity and the need for management and flexibility by system operators.



Source: Team Consult Illustration

Figure 57: Traditional and modern electricity system

The flexibility measures in the above-mentioned chapters are services mainly provided by other actors in the energy system to the TSOs to manage imbalances and overloads in the power grid. These services are usually remunerated, i.e. they represent expenses for the TSO. In addition, TSOs can apply certain measures unilaterally to stabilize the grid. These can be classified in different groups, the first group being ancillary services and stabilization measures:

- Ancillary Services: Procurement of services and products from various markets to ensure the balance of the grid. These are among others products on the control energy market and interruptible loads.
- Curtailment of renewable energies: in case of overloads in the grid, the TSOs can reject feed-in of renewable energies in which case the respective unit is temporarily shut down (curtailed).
- Redispatch: In case a transmission line exhibits an overload, the TSO can demand operators of power plants to increase their electricity generation on one side and to decrease the electricity production on the other side of the transmission line.

The second group of measures, which are part of the optimization of the system operation, comprises the following measures:

- Higher utilizations of existing grid: The transport capacity of a transmission line is limited by its maximum temperature and therefore depends on the ambient temperature and wind conditions. This means, the capacity can be adjusted according to local weather conditions and deliver temporarily higher power. This is referred to as "dynamic line rating" (as opposed to the traditional approach of static rating).
- Advanced forecasting of variable renewable generation: The generation of electricity from renewable energies is dependent on the weather conditions and the quality of predictions of electricity generation depends on the accuracy of weather forecasts. Deviations between actual and predicted electricity generation from renewable energies create imbalances in the power grid.
- Cooperation between DSO and TSO: Renewable energies are connected not only to the high-voltage level transmission grid, but also lower-voltage grids operated by DSOs. The DSOs and TSOs need to interact and cooperate to manage the stability of the overall electricity grid.

Furthermore, there are certain measures, which can be implemented by the adaption of the overall market design and therefore fall into the hands of the regulatory agencies and the legislator:

- Support Schemes for renewable energies: These include guaranteed remunerations for the feed-in of electricity or premiums.
- Increasing granularity in electricity markets: The granularity of electricity products depends among others on the duration and exact location of deployment, which can be adapted over time as market liquidity increases.

Curtailment

To increase the share of renewable energies in the electricity mix, the feed-in of renewable energy is prioritized over other forms of electricity generation (§ 11 subsection (1), EEG). However, the system operators have the permission to reduce or curtail the amount of renewable energies, which are fed into the grid, "to ensure the safety and reliability of the electricity supply grid" (based on §14 subsection (1) nr. 2, EEG). The amount of curtailed energy from renewable energy sources in Germany increased from 0.4 TWh in 2011 to more than 6 TWh in 2019. The curtailed electricity represents about 3% of total electricity generated by renewable energies in 2019[124].

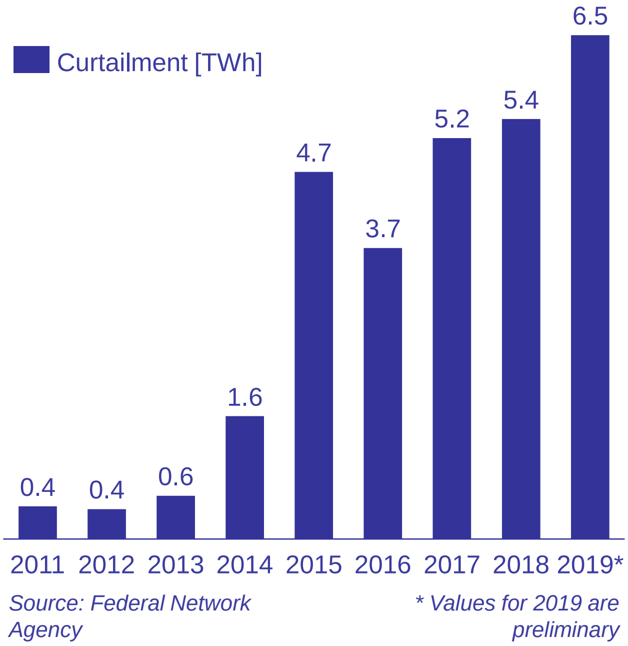


Figure 58: Increasing volume of curtailment in Germany

As can be seen in Figure 59, curtailment affects mainly wind onshore and offshore, which together represent 97% of curtailed electricity in 2019, while solar represents only a small fraction. The curtailment of renewable energies is coupled to compensations for operators of renewable energy power plants and amounted in 2019 to roughly 710 Mio. EUR[125]. Since these costs are born by all consumers in Germany, each household is affected by these costs.

Curtailment affects TSOs as well as DSOs, but in a mismatch regarding cause and effect. In 2018, about 83% of curtailment is caused by events in the grid of TSOs, however, the actual curtailment itself is done at the level of the DSOs, which perform about 81% of the curtailment, measured by amount of electricity. That means, the renewable energies feed electricity into the grids of DSOs, but the high-voltage grid of the TSOs

[124] Bundesnetzagentur (2020) – Quartalsbericht Netz- und Systemsicherheit Gesamtes Jahr 2019
[125] Ibid.

cannot absorb the total amount of electricity provided by the DSO and therefore calls for curtailment of the renewable energies at the DSO grid[126].

Sometimes, curtailment is not based on capacity restrictions and not triggered by the TSO or DSO, but happens due to economic reasons. For instance, in case of an oversupply of electricity in the market place in a given time period, the operator of a renewable energy power plant may unsuccessfully offer electricity to the market for that time period, and thus curtails renewable electricity output and delivery in the respective period (market-driven curtailment).

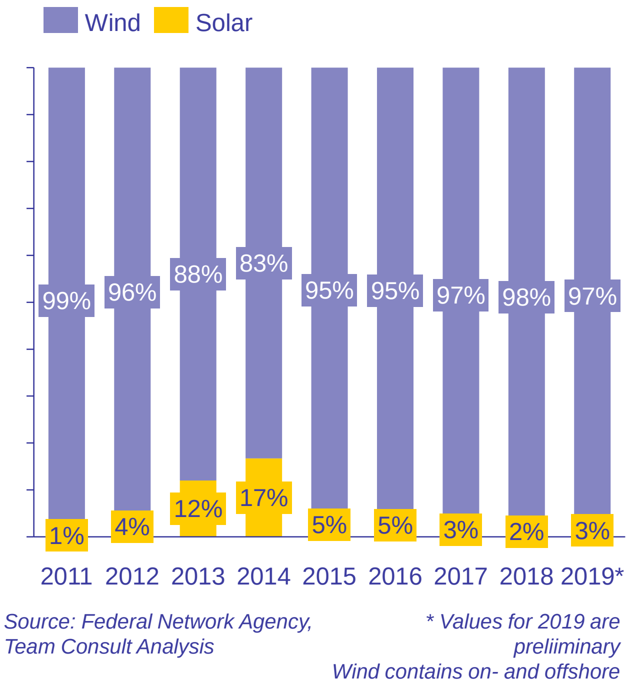


Figure 59: Distribution of curtailment between wind and solar in Germany

Since the curtailment mainly affects wind turbines, it is highly concentrated in Northern Germany where the bulk of wind turbines is located. Three states in Germany are affected by more than 80% of the curtailed renewable energy at the DSO level and for the entire curtailment at the TSO level. These states are Schleswig-Holstein, Lower Saxony and Brandenburg, all of which are located in Northern Germany and have shores to the North Sea or Baltic Sea[127].

The regulatory aspects regarding the curtailment measures are laid out in the EEG:

- § 12 subsection (1): Grid operators are compelled to increase their grid capacity to ensure that renewable energies can be connected to and integrated into grid. The obligation is not limited to the grid to which the renewable energy plant is directly connected, but applies likewise to operators of upstream grids up to the 110 kV level.
- § 14 subsection (1): The grid operators have the right to curtail electricity from renewable energies, in case the stability of the electricity grid is at risk.
- § 15 subsection (1): The operators of renewable energy plants receive compensation payments by the system operators for the income loss caused by the curtailment measure; the payment amounts to at least 95% of the guaranteed feed-in tariff.
- § 15 subsection (2): The costs incurred by system operators from compensation payments are passed on to electricity consumers and included in the grid charges.

Requirements of the EEG (EEG 2021)

The legal basis of curtailment is the EEG. The newest revision of the EEG (the EEG 2021) requires newly built renewable energy systems with more than 25 kW to be equipped with the appropriate metering systems that allow monitoring and curtailing of electricity feed-in power (§ 9 subsection (1a), EEG 2021). For systems between 7 kW and 25 kW, the metering system only needs to be able to monitor the feed-in power. These limits are lower than in previous versions of the EEG, so that PV rooftop systems on large residential buildings as well as industrial or commercial buildings which were previously not affected by curtailment are now included in the curtailment.

Curtailment represents one of the last resort measures for the balancing of the power grid. Nevertheless, it is an important tool, since it has a fast and direct impact on the power grid stability.

Redispatch

TSOs and DSOs may order an increase or decrease of electricity output from power plants. This occurs in case of grid overloads. It is referred to as redispatch. When an overload occurs on a specific transport path, the system

[126] Bundesnetzagentur – Monitoringbericht 2019 (2019)
[127] Bundesnetzagentur (2020) – Quartalsbericht Netz- und Systemsicherheit Gesamtes Jahr 2019

operator orders a decrease of electricity output of a plant located at the beginning of that transport path, and at the same time orders an increase of electricity output from a plant located at the end of that path. The volume of the increase and decrease of electricity generation net out, i.e. the overall electricity fed into the grid remains the same, only the location is shifted.

Redispatch can be classified in current- based and voltage-based measures[128]:

Current-based redispatch:
- measure to compensate short-term overloads of transmissions lines or transformer station
- implemented using conventional power plants
- represented about 87% of redispatch measures in 2019

Voltage-based redispatch:
- measures to ensure the stability of the voltage level in the grid
- implemented using conventional power plants and procurement at power exchanges

The volume of the redispatch measures increased from 4 GWh in 2011 to more than 13 TWh in 2019. This is based on the increasing share of renewable energies in the electricity gird and the phase-out of nuclear power plants[129]. The phase-out of coal and lignite power plants in the coming years will additionally put pressure on the power grid resulting in a potentially additional demand for flexibility measures. Nevertheless, the TSOs estimate in their latest yearly system analysis that the redispatch volume will be reduced to 5 TWh by 2025. The estimated reduction is based on the planned expansion of the grid infrastructure[130].

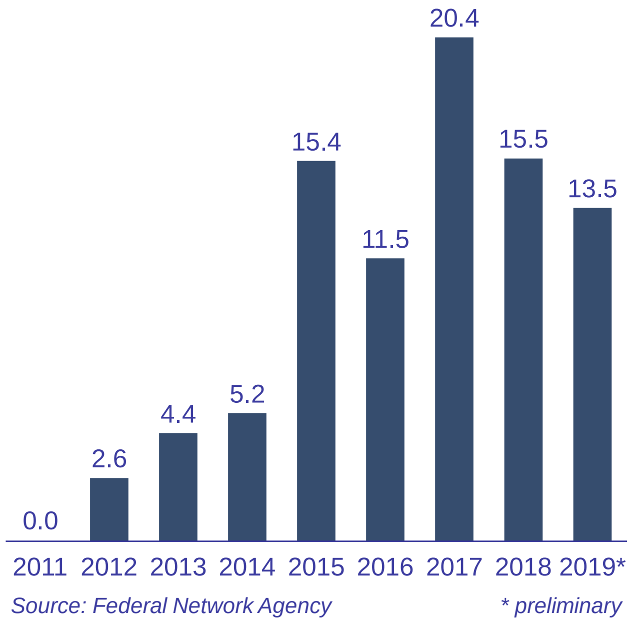
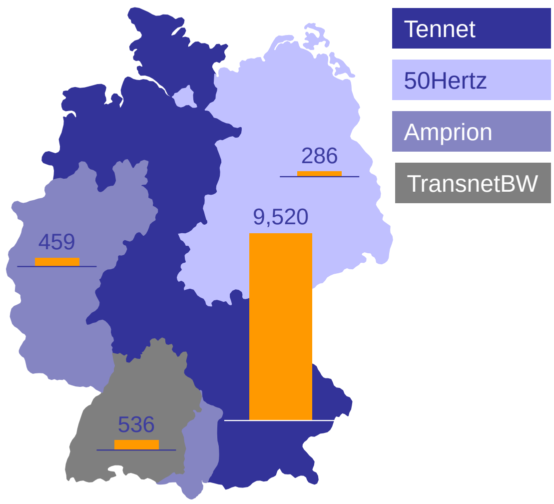


Figure 60: Volume of redispatch measures in Germany in TWh

Similarly to curtailment, the redispatch measures are distributed non-homogeneously in Germany. The main share of redispatch in 2019 and in previous years[131] occurred in the region of Tennet, the TSO that links the northern part of Germany with high generation of onshore and offshore wind power with the electricity demand centers in the southern part of Germany.

[128] Bundesnetzagentur – Monitoringbericht 2019 (2019)
[129] Bundesnetzagentur - https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Engpassmanagement/Redispatch/redispatch-node.html, accessed on the 22.11.2020
[130] TSO - Prognose des Umfangs und der Kosten der Maßnahmen für Engpassmanagement nach § 13 Abs. 10 EnWG (2020)
[131] BDEW – Redispatch in Deutschland (2020)



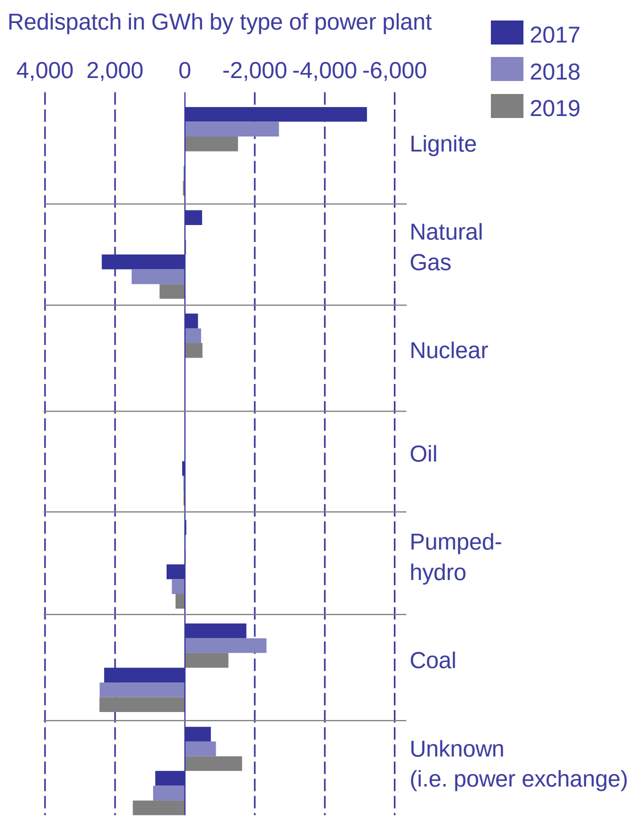
Source: Federal Network Agency, Team Consult Analysis

Figure 61: Distribution of redispatch measures between the German TSOs in 2019, in GWh

Redispatch uses conventional power plants to ensure the stability in the power grid. Figure 62 shows how redispatch measures were distributed between different categories of power plants in the period from 2017 to 2019. A positive value represents an increase of the electricity generation, while a negative value represents a decrease. Lignite plants were mainly ordered to decrease output under redispatch measures between 2017 and 2019, while the volume of such measures declined. Natural gas plants were ordered to increase output under redispatch measures in the same period, also at a decreasing rate. Nuclear plants are hardly affected by redispatch. Hard coal plants were ordered to increase output in some instances and to decrease output in other instances; their contribution to the redispatch measures remained roughly constant during the period from 2017 to 2019. The utilization of unknown sources however, which includes the procurement of electricity at the power exchanges, increased.

The regulatory basis for the redispatch is the EnWG:

- § 13 subsection (1): In case of instabilities and impairment of the reliability of the power grid, the TSO is entitled to influence controllable facilities, use products from the control energy market and activate reserves to balance the grid
- § 13a subsection (1): Operators of electricity generation and storage facilities with a power of more than 10 MW are obligated to follow the demands from the TSO in regard to the adaption of their power generation
- § 13a subsection (2): the plant operator receives a remuneration for the redispatch measure; the remuneration is calculated such that the plant operator neither suffers a financial disadvantage nor receives a financial benefit because of the redispatch measure, so his economic situation basically remains the same.



Source: Federal Network Agency, Team Consult Analysis

Figure 62: Redispatch measures by type of power plant in GWh, 2017-2019

Redispatch 2.0

The redispatch measures are currently limited to conventional power plants with an installed power of more than 10 MW. With the revision of the Grid Expansion Acceleration Act[132] in October 2021, the scope of the included facilities for redispatch measures is widened. With the revision, renewable energies and

[132] NABEG 2.0: Netzausbaubeschleunigungsgesetz (Grid Expansion Acceleration Act)

cogeneration plants down to an installed power of more than 100 kW will be included in redispatch measures. The revision leads to an increasing necessity for DSOs to participate in the redispatch measures, because the newly included smaller generation units are overwhelmingly connected to distribution grids[133]. The integration of renewable energies in the redispatch measures is supposed to decrease the costs caused by redispatch measures, since the renewable energies are often more closely located at the point of overload and are therefore quite efficient in resolving the imbalances[134].

Nevertheless, conventional power plants will still be prioritized for the redispatch measures. Renewable energies will only be used for redispatch, if the their use is 10 times cheaper compared to the use of conventional power plants. The Federal Network Agency set the so-called minimum factor (Mindestfaktor) to 10 for renewable energies and to 5 to for cogeneration plants[135].

Advanced forecasting of renewable energy generation

The total amount of electricity fed into the power grid is adapted to the expected demand from all consumers. Since renewable energies are prioritized for the feed-in of electricity into the grid, conventional power plants are compelled to fill the gap between renewable energy provision and consumer demand. As a result, the utilization of conventional power plants depends to a certain extent on the actual feed-in of renewable energies and their generation schedule is adapted to the forecasted feed-in of renewable energies. Therefore, deviations from the forecasted feed-in from renewable energies influence the generation schedule of conventional power plants and the utilization of other means of power provision for the TSOs.

High precision and accurate forecasts for the renewable energy provision are the key to prevent imbalances in the power grid and reduce the need for complex, short-term and expensive interventions in the energy system by the TSOs. With a more accurate renewable energy forecast, the time to plan and implement short-term adjustments is prolonged compared to the short-term interventions in case of an imminent overload in the grid, due to a weather forecast error.

A completely exact and accurate weather forecast is impossible due to the chaotic nature of the atmosphere. Nevertheless, sophisticated methods exist, including artificial intelligence and cloud computing, which help to improve the weather forecast and as a result the renewable energy feed-in forecasts. The forecasts are updated in short periods, down to every 15 mins[136], and have a forecast period from 5 min[137] up to 48 hours[138].

The accuracy of the forecasts is displayed in Figure 63, which shows the deviation from the actual to the forecasted generation from three days at the end of November 2020. The bottom figure shows the deviation from the forecasts to the actual generation. A positive value represents an overestimated generation, a negative value an underestimation. The deviations for onshore- and offshore-wind vary between ±500 MWh in the considered period. The deviation of solar shows one extreme deviation of almost +1000 MWh. In relative terms, the deviation of offshore-wind is worse compared to onshore-wind and solar, since the overall generated energy of offshore-wind is much lower. The forecast represents the predicted generation of renewable energies for the entire day and is published the day before and updated at 8 a.m. of the day of delivery[139]. Typical errors for hour-ahead forecasts are in the range of 3% to 6% and in the range of 6% to 8% for the day-ahead forecasts based of the rated power[140].

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[133] BDEW - BDEW-Branchenlösung Redispatch 2.0 (2020)
[134] Next Kraftwerke - https://www.next-kraftwerke.de/energie-blog/redispatch-2-0-erneuerbare-energien, accessed on the 17.12.2020
[135] Bundesnetzagentur – Beschluss Aktenzeichen PGMF-8116-EnWG § 13j (2020)
[136] DWD - https://www.dwd.de/DE/forschung/wettervorhersage/num_modellierung/07_wettervorhersage_erneuerbare_energien/vorhersage_erneuerbare_energien_node.html, accessed on the 17.12.2020
[137] IRENA – System Operation: Innovation Landscape (2020)
[138] IRENA – Innovation Landscape for a Renewable Powered Future (2019)
[139] EU - Commission Regulation (EU) No 543/2013, Article 14
[140] IRENA - Innovation Landscape for a Renewable Powered Future (2019)

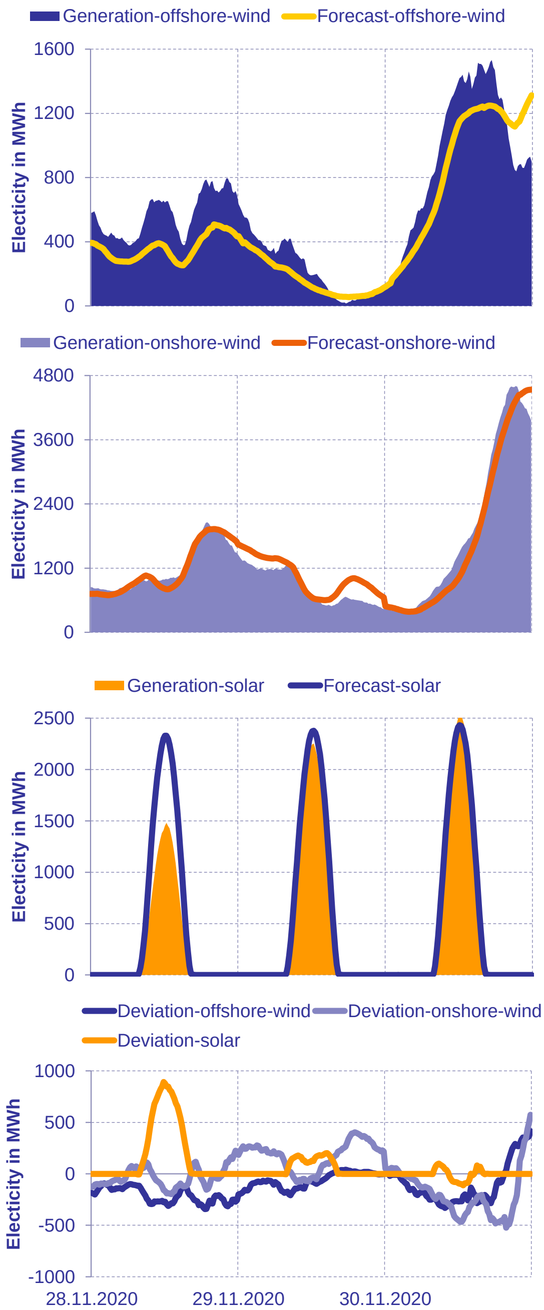
Several research projects were conducted in Germany since 2012, which aimed to improve the accuracy and the spatial resolution of renewable energy forecasts. One recent project called “Gridcast” aims to improve the overall forecasting of renewable energies and predict the feed-in at specific transformer stations in the grid. In addition, non-weather related parameters such as load, prices and the availability of power plants are integrated into the forecasts to improve the accuracy. The forecasts are planned to differentiate between the actual feed-in, the potential feed-in based on weather data and the possible feed-in based on restrictions from the grid[141]. Another research project in Germany called “PerduS” focused on the influence of Sahara dust outbursts on the performance of solar system. The Sahara dust reduces the solar radiation and pollutes the surface of solar systems; both effects lead to a reduction in solar power output[142]. Sahara dust lead to a forecasting error in the order of 10 GW in 2014 in Germany, representing about 25% of installed solar power at that time[143].

On one hand, errors in forecasting can have serious consequences in the power grid, as they increase the need for flexibility and generate costs for the operation of the grid. On the other hand, accurate and precise forecasts can reduce the need for expansive short-term interventions for TSOs and reduce the need for flexibility measures. Improvements in the weather forecasts represent one of the most cost-effective tools for TSO to prevent and reduce imbalances in the power grid[144].

The accurate weather forecasts and renewable energy forecasts are not only important for the TSOs to maintain a stable power grid, but for the operators of renewable energy units as well. With the improved generation forecasts, the operators can buy missing electricity or sell surplus electricity at short notice in the intra-day spot market. This helps avoid account imbalances and, thus, the use of costly balancing energy.

Increasing granularity in electricity markets

The balancing of a mismatch in demand and supply can be performed using products from the power exchange. The power exchange can be classified in different sections, depending on delivery period of the power product. The future markets represent products, which are delivered the next month (month-ahead) or the next



Source: SMARD, Team Consult Analysis

Figure 63: Difference between forecasted and actual power generation from renewable energies in Germany

[141] Fraunhofer IEE - Umgang mit markt- und netzbasierten Abregelungen von Erneuerbaren Energien in Bezug auf Prognose und Einspeisung (2018)
[142] Energiesystemforschung - https://www.energiesystem-forschung.de/news/stromnetze-projekt-perdus, accessed on the 10.12.2020
[143] IRENA – Innovation Landscape for a Renewable Powered Future (2019)
[144] Ibid.

year (year-ahead). Next, there is the day-ahead section, with products, which are delivered the next day. These products can be used for electricity generators and consumers likewise to cost-effectively optimize their generation schedule and procurement. Then there is the intraday market with products, which are delivered on the same day. These products represent among others the flexibility options for different participants and also TSOs to balance the grid and fill gaps due to forecast errors or other incidents.

There is a trade-off between product granularity and market liquidity. A large liquidity in the market leads to cost-efficient prices and competition between different market players, since various different options for a trade are available. A large product granularity allows market participants to balance supply and demand at a higher accuracy in terms of time and space.

In the early stages of the development of a trading market, liquidity is naturally low, since there are only a few market participants. This limits the granularity of products that can be traded. However, as liquidity increases over time, this creates the chance to improve product granularity as well.

The granularity of the products in the electricity market can be measured by the lead time, the product duration, price increments and spatial resolution. The **lead time**, which represents the time up to which the product is open for trading before delivery, was reduced in Germany in the intraday market from 45 min to 30 min in 2015 and down to 5 min in 2017[145]. The reduction of the lead time represents an important step towards a precise resolution of imbalances in the power grid using intraday power exchange products.

Next to the lead time, the **duration** of the products is an important factor for their usefulness in regard to short-term flexibility. The products in the intraday market are available in periods of 30 minutes, 1 hour and blocks of several hours. In 2014, a product with a delivery period of only 15 minutes was introduced. These products can be used to offset any account imbalance arising from i.e. errors in renewable energy forecasts or technical incidents in power plants.

Another significant parameter regarding the granularity of products in the electricity market is the **price increment** in EUR/MWh. It is set to 0.1 EUR/MWh. That means offers and bids in the trading market can be made in incremental steps of 0.1 EUR/MWh. The prices in the intraday market are limited to ±3,000 EUR/MWh[146], which is considerably lower than the price cap in the control energy market, which currently is set to a limit of ±99,999.99 EUR/MWh[147].

Another dimension in the granularity is the **spatial resolution** of the electricity product. Today, products traded in Germany refer to the German and Luxembourgian market. Austria used to be included as well. However, in October 2018 the German-Austrian price zone was dissolved, which increased the spatial resolution of electricity products. The reason for the separation were overloads in the physical electricity flow in between Germany and Austria and side effects on the Polish and Czech power grid[148].

The development of the intraday trading volume is depicted in Figure 64 in comparison to the control energy tender volume. The intraday trading volume in Germany (which includes Luxembourg as well) tripled from 19 TWh in 2013 to almost 60 TWh in 2019[149], which is in the order of about 10% of the annual electricity consumption in Germany in 2019. Out of the 60 TWh in 2019, about 10% are based on trades with 15-minute products[150]. At the same time, the tender volumes for control energy decreased for tertiary (manual frequency restoration reserve, mFRR) and secondary (automatic frequency restoration reserve, aFRR) control energy products by more than 50% and 20% compared to 2013. Only the primary (frequency containment reserve, FCR) control energy product increased by 10% during the same period. For secondary and tertiary control energy, the values represent the yearly average of the positive and negative control energy product.

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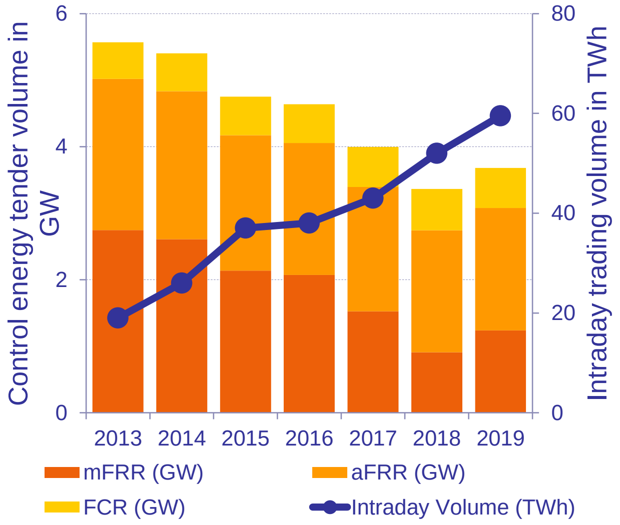
145 EPEX - Kurzfristhandel in Europa –Day-Ahead & Intraday Märkte der EPEX SPOT (2017)
146 EPEX – Trading on EPEX spot (2020)
147 Bundesnetzagentur - BK6-18-004-RAM (2019)
148 Next Kraftwerk - https://www.next-kraftwerke.at/wissen/strommarkt/strompreiszonentrennung, accessed on the 14.12.2020
149 EPEX – Trading on EPEX spot (2020)
150 EPEX - Kurzfristhandel in Europa –Day-Ahead & Intraday Märkte der EPEX SPOT (2017)



Source: EPEX, Federal Network Agency, Team Consult Analysis

Figure 64: Development of the control energy tender volume and intraday trading volume in Germany

The steady increase of the intraday trading volume in combination with the decrease of the control energy tender volumes indicates, that short-term flexibility is increasingly managed by market participants. This development was enabled by an increase of the product granularity in the intra-day spot market.

Ancillary Services

The stabilization of the power grid represents the core business of the TSOs, next to the transmission of electricity. The ancillary services are a specific set of tools, which TSOs can use to accomplish stability in the power grid. The ancillary services comprise the following[151]:

- Control energy
- Provision of lost energy
- Provision of reactive power
- Supply of black start capability
- Provision of reserve power plants
- Interruptible loads

For the balancing of feed-in and withdrawal of electricity into the power grid, the TSOs use the three different **control energy** products. The fastest response is used for the containment of the frequency of 50 Hz in the power grid (called primary control energy or frequency containment reserve). It is activated automatically, needs to be made available within 30 seconds and can be used for up to 15 minutes, after which it is released. The remuneration is based on a capacity price. The service provider has to either provide power (positive control energy) or absorb power (negative control energy). A commodity payment does not apply, since it is assumed that positive and negative control energy balance out over time.

Secondary control energy is an automatically activated reserve used to restore the frequency of 50 Hz in case of larger and longer lasting deviations. It needs to be made fully available within 5 minutes after activation and supports the grid for up to 15 minutes. Since November 2020, capacity and energy are auctioned and remunerated separately. The auctions are separated in six blocks of four hours per day and divided into positive and negative control energy.

Tertiary control energy is manually activated. It takes over after secondary control energy. It has to be fully available within 15 minutes after activation for up to one hour. The auctions follow the same structure as for secondary control energy.

The costs of control energy are allocated primarily to the market participants who caused the need for control energy by account imbalances. The rest is included in the grid charges. Total costs for control energy amounted to 123 Mio. EUR in 2018[152] or about 14% of the entire ancillary service costs.

The **provision of lost energy** represents the electricity losses due to the physical transport of electricity. The Federal Network Agency defines a reference price based on year-ahead futures, which defines the expenses the TSOs can claim and allocate onto the grid charges. In case the TSOs remain below the reference price for the provision of electricity, they can keep the savings. If they are above the reference price, they need to burden the additional costs themselves. The costs for the provision of lost energy amounted to 273 Mio. EUR in 2018[153] or 32% of the total ancillary service costs.

Reactive power is required to compensate for a phase difference between the voltage and current in the alternating current grid. Phase differences stress the power grid and put a load on the grid that cannot be used for anything. Currently, the TSOs suggest transforming decommissioned coal-fired and nuclear power plants into

[151] Bundesnetzagentur – Monitoringbericht 2019 (2019)
[152] Ibid.
[153] Ibid.

facilities that provide reactive power[154]. The costs for the provision of reactive power amounted to 11 Mio. EUR in 2018[155], representing 1% of the total ancillary costs.

In case of a blackout, the TSOs have to be able to restore the power grid. For such an event, the TSOs need a restoration plan and maintain facilities with **black start capabilities**, which can assist in the restoration of the power grid. This is based on article 1 of the EU ordinance 2017/2196 from 2017[156]. The costs for the provision of black start capable facilities amounted to 7 Mio. EUR in 2018[157] representing less than 1% of the total ancillary costs.

The active trading of the TSO in the intraday market with the aim to stabilize the power grid is also known as **countertrading**. The TSOs attempt to minimize and counteract the physical flow by using appropriate trades in the electricity market. The costs for the countertrading measures amounted to 36 Mio. EUR in 2018[158] and represents about 4% of the overall costs.

Reserve power plants are specifically defined power plants, which are used for stabilization measures. Based on § 13, EnWG, the TSOs conduct a yearly system analysis to determine the capacity needed, which is afterwards checked by the Federal Network Agency. The capacity of reserve power plants since 2015 varied between 1,600 MW and 10,400 MW. For the winter of 2020, it is specified as 6,596 MW[159]. The provision and application of reserve power plants is separately remunerated by the TSOs and amounted combined to 416 Mio. EUR in 2018[160], representing 48% of the overall ancillary service costs.

Interruptible loads are controllable facilities, which can be turned off rapidly and on demand from the TSO to decrease the overall load and relieve the power grid. More information on interruptible loads can be found in the chapter regarding DSM. The costs for the application of interruptible loads amounted to 28 Mio. EUR in 2018[161] or 3% of the overall ancillary service costs.

The variety of ancillary services shows that the TSOs possess a comprehensive set of tools to manage imbalances in the power grid. All of the here described ancillary services from the TSOs in Germany amounted to 858 Mio. EUR in 2018.

Cooperation between DSO and TSO

The changes in the electricity system discussed above – the shift from a unidirectional to a bidirectional electricity flow and increasing shares of intermittent renewable generation – make system operations more complex and reshape the role of DSOs. DSOs not only distribute the electricity provided by the TSOs but also increasingly act as intermediaries, managing flows and flexibility in cooperation with TSOs.

The cooperation between DSOs and TSOs will become more important with the introduction of the Redispatch 2.0, since the revised guidelines include smaller electricity generation units (down to 100 kW) in the redispatch regime. These smaller units are connected to distribution grids, making it necessary for the DSOs to monitor and – if necessary – control their electricity output. The DSOs need to coordinate with the TSOs, include the operators of these smaller electricity generation systems in the balancing of the grid, define the flexibility potential in their power grid and communicate the potential with other participants[162].

Each TSO in Germany has to communicate with several hundreds of DSOs and other participants such as balancing group managers, which makes the coordination between all involved parties a challenging and data intensive task. The current cooperation between the TSOs and DSOs is based on the MaBiS[163] guidelines and the EU directive "System Operation Guideline" 2017/1485[164] from 2017, which became effective in October 2019 in Germany and is implemented in a step-by-step process. The MaBiS defines the responsibilities and processes on which the current information and data exchange is based.

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[154] Energate - https://www.energate-messenger.de/news/201905/blindleistung-uebertragungsnetzbetreiber-wollen-mehr-kraftwerke-umruesten, accessed on the 10.12.2020
[155] Bundesnetzagentur – Monitoringbericht 2019 (2019)
[156] EU - Commission Regulation (EU) 2017/2196 (2017)
[157] Bundesnetzagentur – Monitoringbericht 2019 (2019)
[158] Bundesnetzagentur – Monitoringbericht 2019 (2019)
[159] Bundesnetzagentur - https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Netzreserve/netzreserve-node.html, accessed on the 10.12.2020
[160] Bundesnetzagentur – Monitoringbericht 2019 (2019)
[161] Bundesnetzagentur – Monitoringbericht 2019 (2019)
[162] Pwc - Redispatch 2.0: Neue Verantwortung für Betreiber von Verteilnetzen (2020)
[163] MaBiS: Marktregeln für die Durchführung der Bilanzkreisabrechnung Strom (market rules for the execution of balancing group settlement for electricity)
[164] EU – Commission Directive (EU) 2017/1485, acticle 40 and following

In a simplified description, the DSO allocates each amount of electricity to a balancing group and collects all information regarding electricity fed into and from his grid. That information is transferred to the TSO. The TSO checks if all electricity is correctly accounted for, identifies mismatches and ascribes these to balancing groups. Further, the TSO checks if the balancing groups are balanced. Any imbalances are settled by using balancing energy[165].

The EU directive aims to set a harmonized framework for the exchange of information and data between the TSOs, DSOs and other significant grid users. It lists additional data to share, which are currently not included in the MaBiS guidelines. The data to share should be provided in real time and include among others the active and reactive power in different components of the power grid (i.e. lines and transformers), the voltages at different points in the grid and the generation and consumption of electricity.

One example of a more advanced cooperation between DSO and TSO is the project "enera" in Germany, which is part of the SINTEG[166] program initiated in 2017 by the German Federal Ministry of Economy. The project introduced a coordination process between one TSO and two DSOs, which operate grids at different voltage levels. The system operators create a common flexibility market and trade capacity in that specific market to balance overloads in the different voltage levels. The system operators share their grid capacities in real time and can offer available and unused capacities in case they are needed.

The system operators can trade grid capacities in the flexibility market with a defined size in MW and durations of multiples of 15 minutes. The lowest available capacity from one of the involved system operators limits the tradeable volume in the flexibility market. The coordination processes are conducted by an automated mail transfer system, which is linked to a database with the actual and forecasted power feed-in[167].

Support Schemes

The support scheme for renewable energies in Germany is defined in the EEG[168]. It was first introduced in 2000 and aims to enable a sustainable development of energy supply and to significantly increase the share of renewable energies in the overall power generation in Germany. The support schemes introduced with the EEG aimed to make renewable energies more cost competitive with conventional power generation technologies.

The **EEG 2000** introduced individual **guaranteed feed-in tariffs** for the renewable energies. The feed-in tariffs are guaranteed for a period of 20 years. The **EEG 2009** introduced a **direct marketing scheme** (§17, EEG 2009). Under this scheme, operators of renewable capacities can choose on a monthly basis whether to market electricity on their own at the spot market or under the regular compensation system. This system was intended to prevent producers from optimizing their profits (selling directly to the market while prices are high while sticking to the regular compensation scheme when prices are low) while placing the market risks on grid operators[169].

The **EEG 2012** revision introduced the possibility to **directly market the electricity to consumers**. Linked to the direct marketing option, a **market premium model** (or feed-in premium) was introduced. Producers of renewable energies that chose to market their electricity directly can request a market premium from their grid operator. The market premium serves as an essential instrument for the integration and demand-oriented generation of renewable energies. It covers the difference between the EEG tariff and a reference price, which is based on the achievable market price minus the technology specific marketing costs (management premium).

With the revision of the **EEG in 2014**, an auctioning system was introduced (§ 2, EEG 2014) to determine feed-in tariffs. The auctions were stepwise introduced and started with ground mounted solar installations in 2015. All other renewable generation units had to market their electricity directly under the market premium model, until the transition towards the auction system was finalized in 2017.

The **EEG 2017** introduced further changes to the system and a general shift towards auctions to determine the feed-in tariffs for almost all renewable energies, that included (§ 22, EEG 2017):

- Onshore-wind (>750 kW)

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[165] Tennet – Marktprozesse für die Bilanzkreisabrechnung Strom (MaBiS) (2015)
[166] Smart Energy Showcases – Digital Agenda for the Energy Transition (SINTEG)
[167] Enera - https://projekt-enera.de/blog/netzbetreiberkoordinationsprozess/, accessed on the 10.12.2020
[168] EEG: Renewable Energy Act (Erneuerbare Energien Gesetz)
[169] Thau and Nebel - Direktvermarktung von Strom aus Erneuer-baren Energien im EEG nach der Energiewende (2011)

- Solar (>750 kW)
- Biomass (>150 kW)
- Offshore-wind

The revision of the **EEG 2021** sets a focus on the alignment of further market integration of renewable energies into the power grid and the expansion of the transmission grid capacities. It defines the auction volumes for renewable energies up to 2028 and lowers the maximum bid amount to further reduce the costs of renewable generation. The EEG-levy will partially be financed by the federal budget to assist in the reduction of the EEG-levy for all consumers. Small-scale units, which drop out of the guaranteed feed-in tariffs after 20 years, will be able to sell their electricity directly to the TSO, which will remunerate the electricity with the market price minus a marketing fee.

As can be seen in Figure 65, the remuneration for large-scale renewable energies changed significantly within the last 20 years. The remuneration of solar power decreased from 54 ct/kWh guaranteed by a feed-in tariff down to 5 ct/kWh, which was the mean awarded bid for auctions in 2020. Similarly, the remuneration for onshore-wind decreased from 9 ct/kWh in 2000 to 6 ct/kWh in 2020. However, the remuneration for biomass increased from 9 ct/kWh in 2000 (based on feed-in tariffs) to 14 ct/kWh on average in 2020 (based on EEG-auctions).

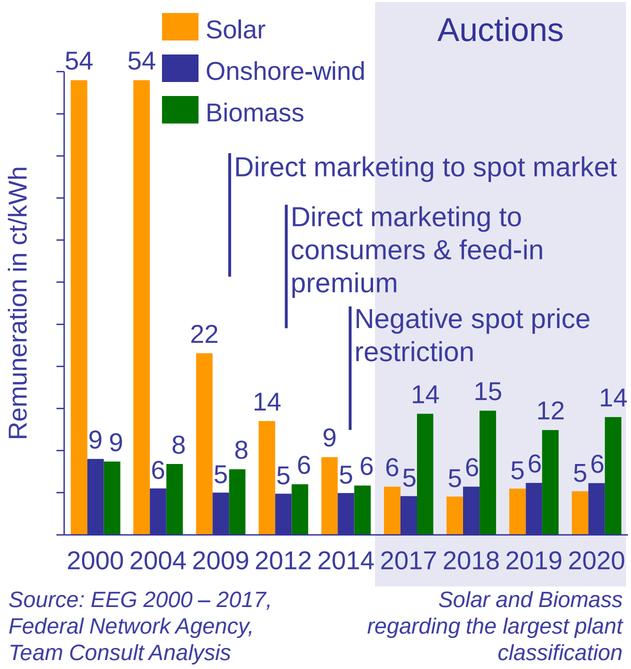

Figure 65: Remuneration of large-scale renewable energies in Germany since 2000 based on the EEG and EEG-based auctions

Since 2017, the solar auctions had a subscription rate of 3.3, meaning the total bid volume amounted to more than three-times the tender volume. The subscription rate for onshore-wind at the same time was around 1.1, meaning the total bid volume represents about the same volume as the tender volume. In 2020 and 2019, the onshore-wind auctions had a subscription rate of only 0.7 on average, showing that the expansion of onshore-wind was slower than intended in recent years. The auctions for biomass showed since 2017 a subscription rate of only 0.4, showing that the incentives for the biomass facilities did not motivate interested parties for the participation in the auctions.

Next to the large-scale renewable energies, the small-scale solar and biomass plants experienced different developments during the last 20 years. The guaranteed feed-in remuneration for small-scale solar power was reduced from 57.4 ct/kWh to 8.32 ct/kWh in December 2020[170]. For biomass small-scale power the guaranteed feed-in remuneration increased slightly from 10.23 ct/kWh to 12.60 ct/kWh until end of 2020[171].

[170] VBEW - EEG-Vergütungsübersicht für Inbetriebnahmejahr 2020 (2020)
[171] Ibid.

Higher utilization of the existing grid

The expansion of the power grid is usually an expensive and tedious endeavor for the TSOs. Construction of new power lines takes several years[172]. The German TSOs estimate the costs for the expansion of the exiting power grid until 2030 at up to 62.5 bn. EUR for about 4,950 km of additional power lines[173]. However, the performance of the existing power grid can be improved in other ways, which are possibly more cost-efficient and take a shorter time to implement. These measures include the utilization of large-scale batteries as virtual power lines or “grid boosters” and the dynamic adjustment of the capacity of transmission lines to the ambient climate, which is referred to as “dynamic line rating” (DLR).

The performance limit of transmission lines and transformers in the power grid are linked to their maximum allowed working temperature. The working temperature is mainly influenced by the current electricity flow and the ambient climate (such as temperature and wind). The standard (static) capacity rating of transmission lines is derived from the most unfavorable conditions (i.e. no wind, high ambient temperature). This means that the capacity of the power lines can be significantly increased during days with more favorable weather conditions. The mean potential capacity increase for European power lines ranges in between 10% to 15% for about 90% of the time[174]. Especially for regions with a high wind power feed-in, DLR can significantly enhance the local power grid capacity, due to the correlation between wind power generation and beneficial wind speed for the application of DLR[175].

There are two different measuring methods for the application of DLR in the grid, which are distinguished by their spatial resolution concerning the weather conditions. The regional method considers the regional weather conditions and adjusts the parameters of the power grid utilization depending on the summer and winter times in a rather general way. The local method is also based on the regional weather conditions, but in addition, it considers the local weather. Therefore, it enables a more precise adjustment of the local grid capacity rating.

All German TSOs use regional or local DLR in their grids (see Figure 66). Currently, the regional method is used more widely. Only Tennet does not use the regional method, but already uses the local method in 33% of its power grid. TransnetBW, 50Hertz and Amprion use the regional method in 37% to 86% of their respective power grid. Until 2025, the TSOs are generally planning to implement the local DLR method in a large share of their power grid. A similar trend is observed at the 220 kV voltage level, with shifts towards the implementation of the local DLR method.

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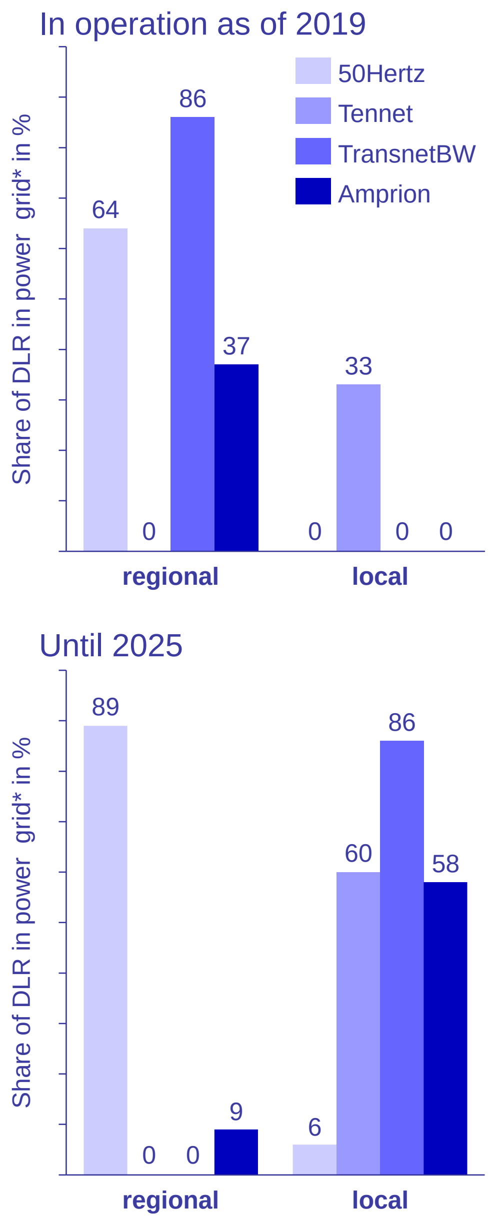
[172] Bundesnetzagentur - Monitoring des Stromnetzausbaus, Zweites Quartal 2020 (2020)
[173] TSOs - Netzentwicklungsplan Strom 2030 – Zahlen, Daten und Fakten (2019)
[174] Entsoe – Dynamic Line Rating (https://www.entsoe.eu/Technopedia/techsheets/dynamic-line-rating-dlr), accessed on the 14.12.2020
[175] IRENA – Innovation landscape brief: Dynamic line rating (2020)



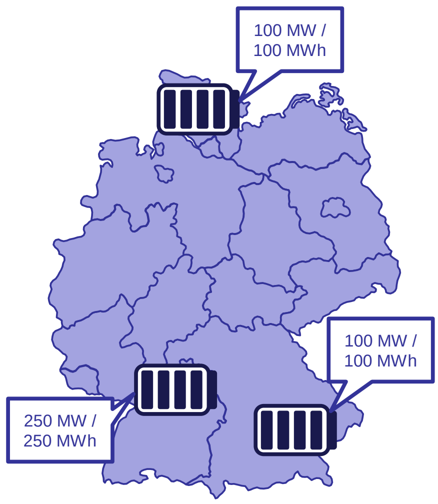
*Only considering the 380 kV voltage level

Source: Federal Network Agency, Team Consult Analysis

Figure 66: Regional and local application of DLR by the German TSOs

DLR is an essential part of the grid development plan of the TSOs and is considered as a measure for grid optimization under the NOVA[176] scheme. Under this scheme, grid optimization measures such as DLR have to be implemented before further steps for grid optimization such as the construction of new power lines are considered. The DLR measures do not need an official approval by the Federal Network Agency and, based on the NOVA scheme, the Federal Network Agency expects the TSOs to implement such measures if they are feasible[177].

As mentioned at the beginning of this section, grid boosters or virtual power lines are another possibility to increase the utilization of the existing grid. Grid boosters are part of the grid development plan of 2019 with in total 450 MW and 450 MWh based on three large-scale batteries.



Source: Federal Network Agency, Team Consult Analysis

Figure 67: Distribution of the three Grid booster projects in Germany

The grid boosters are intended to relieve the transmission grid short-term north-south imbalances. The TSOs expect a 9% reduction of curtailment with savings of up to 25 Mio. EUR due to the installation of grid boosters[178].

Conclusion

As the need for flexibility in the electricity system increases, it is crucial to mobilize the entire flexibility

[176] NOVA: grid optimization before reinforcement before expansion (Netz-Optimierung vor Verstärkung vor Ausbau)
[177] Bundesnetzagentur – Bestätigung Netzentwicklungsplan 2019 (2019)
[178] Bundesnetzagentur – Bestätigung Netzentwicklungsplan 2019 (2019)

potential that already exists in the system – be it on the generation side, on the demand side or in the realm of electricity networks. If existing flexibility potential is wasted, this will lead either to unnecessary (and costly as well as time-consuming) expansion of generation and/or transmission capacities or to constraints in the expansion of intermittent renewable generation.

As shown in this section, there are various kinds of measures the system operators, in particular the TSOs, can take to utilize the entire flexibility potential and do so in an efficient manner, i.e. use the least costly measures first and the most costly last. In addition, the lawmaker and regulator can facilitate efficient system operation and use of flexibility, i.a. by creating incentives for operators of renewable generation units to align electricity generation and marketing with market circumstances and by creating a market design that fosters high liquidity and granularity in the spot market, which allows market participants to fine-tune their demand-supply balance.

List of abbreviations

AbLaV	*Verordnung zu abschaltbaren Lasten* (Ordinance of Interruptible Loads)
AEL	Alkaline-Water-Electrolysis
aFRR	Automatic Frequency Restoration Reserve/ Secondary Control Energy
BDEW	*Bundesverband der Energie- und Wasserwirtschaft* (German Association of Energy and Water Industries)
BEE	*Bundesverband Erneuerbare Energie* (German Renewable Energy Federation)
BEV	Batterie Electric Vehicle
BMS	Battery-Management-System
BNetzA	Bundesnetzagentur (Federal Network Agency)
BVES	Bundesverband Energiespeicher (German Energy Storage Association)
CCGT	Combined Cycle Gas Turbine
CH4	Methane
CO2	Carbon Dioxide
DLR	Dynamic Line Rating
DSM	Demand-Side Management
DSO	Distribution System Operator
EEG	*Erneuerbare-Energien*-Gesetz (Renewable Energy Act)
EEX	European Energy Exchange
EnWG	*Energiewirtschaftsgesetz* (Energy Industry Act)
FCR	Frequency Containment Reserve/ Primary Control Energy
GasNEV	*Gasnetzentgeltverordnung* (Gas Grid Charges Ordinance)
GasNZ	*Gasnetzzugangsverordnung* (Gas Grid Access Ordinance)
HTEL	High-Temperature Electrolysis
KfW	*Kreditanstalt für Wiederaufbau* (State-owned German development bank)
KWKG	Kraft-Wärme-Kopplungsgesetz (Combined Heat and Power Production Act)
LSB	Large-Scale Batteries

MaBiS *Marktregeln für die Durchführung der Bilanzkreisabrechnung Strom* (Market Rules for Balancing Group Settlement in the Electricity Sector)

mFRR Manual Frequency Restoration Reserve/ Tertiary Control Energy

NHS National Hydrogen Strategy

OTC Over-the-Counter

PEM Proton-Exchange-Membrane

PtG Power-to-Gas

PtH Power-to-Heat

RE Renewable Energies

SNG Synthetic Natural Gas

StromEinspG Stromeinspeisungsgesetz (Electricity Feed-In Act)

StromNEV Stromnetzentgeltverordnung (Electrical Network Charges Ordinance)

StromStG Stromsteuergesetz (Electricity Taxation Act)

SSO Storage System Operator

TSO Transmission System Operator

UPS Uninterruptible Power Supply

VPP Virtual Power Plant

WACC Weighted Average Cost of Capital

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Flexibility Options for the Turkish Electricity Grid (Part C)

Table of contents

1 Introduction to the Turkish Electricity Market

The Turkish electricity market underwent significant reforms over the last two decades following the adoption of the new Electricity Market Law in 2001. In line with the rapid growth in electricity demand in this period, the total installed capacity of Turkey increased from 27.3 GW in 2000 to 94.9 GW in 2020. The growth and sophistication of the Turkish electricity market also caused novel necessities concerning the market to emerge. Increasing the flexibility of the Turkish energy system remains one of the top priorities of the policymakers in the wake of further renewable energy penetration in the system.

Latest Reforms and the Increasing Installed Capacity in the Market

The Turkish electricity market underwent significant reforms towards liberalisation since the 1980s which accelerated following the adoption of the Electricity Market Law No. 4628 in 2001. As a result of the rapid growth in electricity demand and the processes of reform, Turkey now has a complex electricity market with a diverse set of participants in the different segments of the market such as generation, transmission, wholesale trade, retail trade and distribution. Currently, Turkey has a wholesale price for the entire country, assuming there is only one bidding zone.

In line with the rapid growth in electricity demand, the total installed capacity of Turkey increased from 27.3 GW in 2000 to 94.9 GW in 2020, with an annual compound growth rate of 6.4%. Electricity generation increased from 124,701 GWh to 305,431 GWh in the same time period.

Installed Capacity and Generation

The share of privately owned capacity has been gradually increasing since the early 2000s. For 2020, this figure was around 77.5% up from around 20.1% in the year 2000. At the same time, the share of generation from private companies increased to 76.2% in 2019 up from 26.0% in 2000. It is expected that the share of the state-owned company EÜAŞ will further decrease in the near future.

Build-Operate (BO) and Build-Operate-Transfer (BOT) plants emerged as an alternative in the period when private sector involvement in the electricity generation sector was prohibited under the constitution. These power plants were built by private sector investment and operated with purchase guarantees extending to 15-20 years. After their contract periods end, the BO power plants become IPP's and are compelled to operate as merchant power plants. On the other hand, the BOT power plants are transferred to the state-owned generation portfolio as their cotracts end.

In Turkey, especially in the second half of the 1990s, many build-operate-transfer power plants were put into operation. This model was later abandoned as the constitutional reforms in 2001 made private sector involvement in the sector possible. Majority of the BO and BOT contracts have ended by 2020, increasing the share of private companies in the total installed capacity.

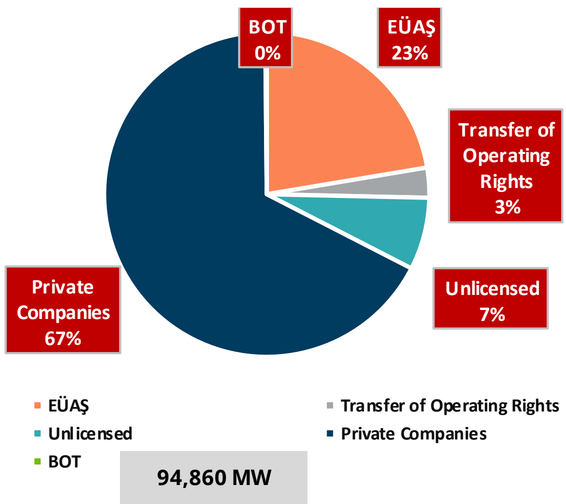

Figure 68. Installed Capacity by Ownership as of the end of 2020[179]

[179] TEİAŞ Load Dispatch Information System, accessed from https://ytbsbilgi.teias.gov.tr/ytbsbilgi/frm_istatistikler.jsf

Electricity generation in the country is fuelled by a mixture of thermal and hydropower plants with an increasing share of generation from other renewable sources in recent years. For the year 2019, the share of thermal power plants in total installed capacity was 48.8% while the share of hydropower plants and other renewables in total electricity capacity was 32.2% and 19.0% respectively[180].

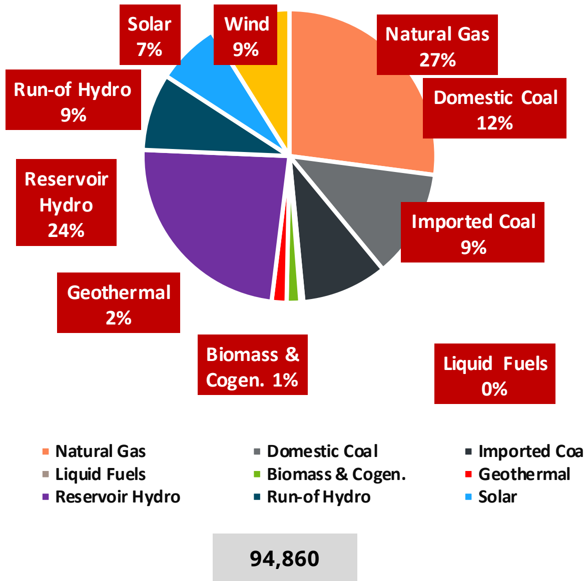

Figure 69. Installed Capacity by Source as of the end of 2020[181]

Meanwhile, the share of generation from variable renewables was 11.88% and the share of other power plants such as thermal and hydro power plants was 88.12% in 2020[182].

Overview of Fundamental Actors in the Market

The Ministry of Energy and Natural Resources (MENR) is the main governmental body responsible for carrying out energy policies in Turkey.

The Energy Market Regulatory Authority (EMRA) is the independent body responsible for regulating and supervising Turkey's electricity, natural gas, downstream petroleum and liquefied petroleum gas markets.

There are 4 state-owned and 1,115 private license holders active in the electricity generation market[183]. The Electricity Generation Company (EÜAŞ) owns and operates the state-owned power plants. Following July 2018, it is also responsible for the wholesale trading responsibilities formerly held by the Turkish Electricity Transmission Company (TEİAŞ).

TEİAŞ is the state-owned monopoly that owns and operates the electricity transmission sector in the country. It is also responsible for the operation of the balancing power market and the ancillary services market.

Both private and state-owned companies are active in wholesale activities. EÜAŞ (after July 2018) is the publicly owned wholesale company responsible for selling electricity to distribution and retail companies. There are currently 155 licenced private companies in the wholesale market, although there is condensation on this segment with around 10-15 companies dominating the market[184].

Since the conclusion of the privatization process in 2013, electricity distribution activities are being carried out by 21 privatized regional distribution companies (DSO). These companies also have retail arms which are legally unbundled and serve as last resort suppliers in their respective regions.

Companies with a retail license can sell electricity to end-users without distribution zone restrictions. Consumers who have an electricity consumption that exceeds the annual eligible consumer limit have the right to choose their suppliers. As of 2021, the eligible consumer limit is 1,200 kWh per year[185].

The Energy Market Operation Company (EPİAŞ) is the market operator, responsible for operating the day-ahead and intraday markets in the country. The company also operates the spot natural gas market since April 1, 2018. EPİAŞ is currently working on building the “electricity futures market with physical delivery” and “natural gas futures market”.

The Key Role of Flexibility in Realizing Future Policy Targets

Increasing flexibility will be a key component in realizing the Turkish energy policy targets which include energy security, increased liberalization and climate change

[180] TEİAŞ, accessed from https://www.teias.gov.tr/
[181] TEİAŞ Load Dispatch Information System, accessed from https://ytbsbilgi.teias.gov.tr/ytbsbilgi/frm_istatistikler.jsf
[182] TEİAŞ, accessed from https://www.teias.gov.tr/
[183] EPİAŞ Transparency Platform, as of December 2020
[184] EPİAŞ Transparency Platform, as of December 2020
[185] Official Gazette No: 30992, dated December 28, 2019

mitigation. Main goals of Turkey's energy policy include providing affordable energy while increasing energy security and the level of liberalization in the market. Currently, the country is highly dependent on imported fuel sources for electricity generation. Therefore, one of the main goals of the country's energy policy involves increasing the utilization of domestic sources for electricity generation.

Since the country lacks significant reserves of fossil fuel sources outside of lignite, the Turkish government intends to increase the utilization of domestic lignite sources for electricity generation[186]. Significant steps have been taken towards this direction and several domestic lignite reserves are aimed to be tendered for privatization in the near future with an obligation involving the construction of power plants.

However, this strategy looks increasingly unrealistic with challenges in financing coal projects. Even the Çayırhan coal power project -which has already been tendered in 2017 with a purchase guarantee of 60.4 USD/MWh- could not be completed and the future of the project is currently up in the air[187]. Although, the current government targets include an increase of 4,000 MW in local coal capacity over the next 4 years, there is currently no progress made in realizing this goal. A considerable environmental opposition is also present in the country against new coal projects which decreases the likelihood for these projects' completion.

The local coal targets set by Turkey are in conflict with the climate change mitigation goals highlighted under the Paris Agreement as the local lignite sources are highly polluting and have considerably lower calorific values. In 2015, the Turkish Government has determined it's Intended Nationally Determined Contribution (INDC) target as 21% GHG emission reduction by 2030 compared to the Business -as-Usual (BAU) scenario. Even though the current emission levels in the country are well below the pledged amounts, pursuing policies aimed at promoting local coal sources runs the risk of locking the country to a high-carbon development pathway for the decades to come.

On the other hand, increasing the share of renewable energy sources constitute another important part of the state's strategy. For this purpose, a feed-in tariff mechanism has been in place since 2011. The current mechanism is set to expire after the first half of 2021 and a new feed-in tariff has been announced which is set to be which is in the midst of being transformed into a support mechanism based on an auction system.

Table 1. Installed Capacity targets (MW) set under the Strategic Plan 2019-2023[188]

Year	Hydro	Wind Energy	Solar Energy	Geo + Biomass	Local Coal
2019	29,748	7,633	5,750	2,678	10,664
2020	31,148	8,883	7,000	2,717	10,664
2021	31,688	9,633	7,750	2,772	10,664
2022	31,688	10,633	8,500	2,828	11,464
2023	32,037	11,883	10,000	2,884	14,664

Moreover, the introduction of nuclear power into the generation mix is one of the main topics in the policy agenda. It is aimed for the first nuclear power plant to start operations in 2023[189].

Increasing the levels of energy efficiency is also one of the top priorities of the policymakers. As per the 'National Energy Efficiency Action Plan' published in 2018, Turkey aims to achieve increases in energy efficiency totaling 86,369 kilotonnes of oil equivalent (ktoe) by 2033[190].

Generation Incentives Provided in the Country

There are currently several generation incentives being provided in the market in a bid to realize the country's energy targets.

Turkey has introduced a Renewable Energy Resources Support Mechanism (YEKDEM) in 2011, which has been the key regulatory support for the development of the use of renewable energy resources. The feed-in tariff applied within this support mechanism provides different level of incentives according to the type of renewable energy resource used.

[186] Turkey's natural gas discovery in 2020, estimated to reach 405 bcm, is also expected to contribute to the usage of domestic sources. The details about the field, the timeline for extraction and commercialization of this natural gas are to be announced following further studies on the field.
[187] 'Report and Recommendations regarding the utilization of coal Fields', Coal Producers Association, accessible from https://www.komurder.org/pdf/Ozel-Sektor-Komur-Sahalar%C4%B1n%C4%B1n-De%C4%9Ferlendirilmesine-Iliskin-Rapor-ve-Oneriler.pdf
[188] 'Strategic Plan 2019-2023', Ministry of Energy and Natural Resources, accessible from https://sp.enerji.gov.tr/ETKB_2019_2023_Stratejik_Plani.pdf
[189] Even though the official target for the commissioning of the Akkuyu NPP is 2023, given the current level of progress a commissioning date of 2025 2026 seems more likely.
[190] 'Energy Efficiency Action Plan', Ministry of Energy and Natural Resources (2017)

In addition to the regular feed-in tariffs levels, there is an additional incentive for renewable power plants using domestically manufactured products. Generators within the support mechanism can benefit from these additional incentives for a period of five years.

The prices within the feed-in tariff are applicable for the first 10 years of operation for the renewable power plants commissioned prior to July 2021 (the previous 2020 deadline extended due to the COVID-19 force majeur).

Details regarding the scope of the YEKDEM to be implemented after July 1, 2021 have been recently declared. The guaranteed purchase prices will be applied for the electricity generated in power plants holding a RES certificate, provided that they are commissioned between July 1, 2021 to 31 December 2025. The purchase guarantees announced for each resource type are determined in TL, as opposed to the previous USD based support. However, these determined values will be revised every three months based on a indexation of PPI, CPI and exchange rates of dollar and euro. In addition to these purchase guarantees, it was stated that if domestic equipment is used in these plants, an additional support up to a level of 8 kuruş/kWh will be provided for a duration of 5 years.

Leaving renewable sources aside, lignite is seen as one of the most preferable sources of electricity generation in Turkey by the policymakers due to the abundant reserves. Before its merger with EÜAŞ, TETAŞ announced the extension of the purchase guarantee[191] to coal plants working fully or partially on domestic coal to the next seven years with a price indexation (expiring after 2024). This deadline is expected to be extended to the end of 2027.

In addition to these incentives provided for targeted energy sources, the capacity mechanism is the main support mechanism being utilized in the market. The current capacity mechanism scheme was inaugurated in 2018 and the scheme provides a fixed income for power plants to help maintain an adequate reserve capacity in the electricity market. Although Turkey doesn't have a supply deficit problem today, the mechanism aims to ensure security of supply in the long-run and provides an income stream for power plants to stay operational albeit the lower-than-expected market prices in the last years.

Electricity Trade in the Market

As per the current market architecture, it is possible to engage in electricity trade through a multitude of channels. Electricity trade in Turkey can be investigated under the two main divisions of financial and physical electricity trade. While financial trade is mainly carried out through the derivative markets under Borsa İstanbul, physical electricity trade for different time periods is carried out through bilateral agreements, organized spot markets and real-time markets.

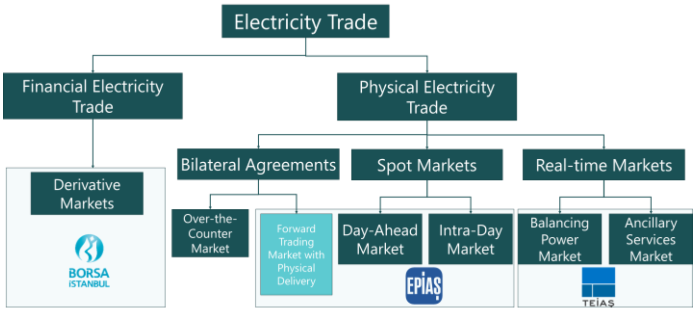

Figure 70. Trade Options in the Turkish Electricity Market[192]

Another option for electricity trade is through bilateral agreements (PPA's) that can be made for varying time periods. Bilateral agreements allow suppliers and consumers to agree preemptively on an electricity purchase price. This enables hedging against the current spot prices.

In order to address the problem of unpredictability in the market, which can at times hinder bilateral trading, EPİAŞ has announced the pending launch of a newly organized electricity market, which will enable forward electricity trading with physical delivery under EPİAŞ supervision. This will create a new channel for forward trading in the country in addition the existing over-the-counter markets. The new market is expected to start operations in June 2021.

In the new futures market, players will be directly trading with EPİAŞ, which removes counterparty risks commonly observed in typical bilateral agreements. EPİAŞ will also be providing a daily indicative price, which will help with signalling in the market.

Organized spot markets are used to determine the market price of a given commodity for shorter time

[191] Purchase guarantee applies to 50% of the local coal power plants' generation.

[192] EMRA, APlus Enerji Analysis

periods. For electricity, spot prices are determined through the intra-day and day-ahead markets.

The day-ahead market and the intra-day market are the two electricity spot markets operated by EPİAŞ. Participation in the spot markets is not obligatory for market players. Market participants must sign the Day-Ahead Market Participation Agreement and deposit the required guarantee. Participants can offer their bids including price and quantity to buy or sell electricity from the day-ahead market for each hour of the following day.

The market-clearing price, referred to as Day Ahead Market Price (DAMP), and the traded volume are determined for each hour through matching the bids of buyers and sellers. After the day-ahead market gate closure, participants have the option of supplying their needs through the intra-day market.

The main difference between intra-day and day-ahead trading is the time horizon. The transactions in the day-ahead market are decided one day earlier from the actual transaction. On the other hand, the intra-day market is a continuous market where orders will be immediately executed given there is a matching offer in the opposite direction. The day-ahead market determines a uniform market price and clearing volume for all transactions for each hour of the next day. By contrast, the prices in the intra-day market fluctuate throughout the day.

Real-time markets are used to fix any mismatches between market supply and demand. Some deviations occur in real-time electricity supply and demand for various reasons during operations. Two main reasons for these deviations can be identified. One is related to unpredictable power plant failures and the variability of the renewable energy generation, while the other is related to unpredictable changes in consumption.

The real-time markets in Turkey include the balancing power market and the ancillary services market which are operated by TEİAŞ. The ancillary services market is responsible for primary and secondary frequency control, while tertiary frequency control is provided by the balancing power market.

The balancing power and ancillary services markets aim to address such uncertainties in the electricity market. The main objective is to prevent possible real-time imbalances in the event of the disruption of bilateral agreements and spot markets. Abnormality in the system directly affects system frequency, which is the most important indicator of electric system quality. Real-time markets (ancillary and balancing) have been established to correct system quality; in other words, to rebalance generation and consumption.

Under the ancillary services market, the Transmission System Operator (TSO) buys the right to load/de-load certain power plants according to their set points in specified time interval. This is made through auctions that are made from two days ahead. Therefore under the ancillary services market the TSO has a certain capacity it can use to address any imbalances that may arise in the system at all times.

However, there are instances when this capacity is not enough and the balancing power market enters the picture here. Large power plants enter daily bids for the balancing power market for different hours (involving the price they are willing to accept for receiving loading/de-loading instructions). In times of need, the TSO can choose among these bids to issue instructions for a certain power plant in a bid to balance the system.

Possible Options to Increase Flexibility in the Market

Increased flexibility in the market will be key in integrating the expected expansion in intermittent renewable energy capacity into the future and ensure the smooth operation of the system.

In this context, several technology and policy options can be utilized to increase the overall flexibility of the electricity system. In this report, six of such promising options are investigated. These include:

- Large-scale Battery Storage
- Small-scale Battery Storage
- Flexibility Options for Conventional Power Plants
- Demand Side Management
- Power-to-Gas
- Further Operational and Market Design Flexibility Options

Each technology option is assessed in terms of the current regulatory and market-related situation in Turkey. Moreover, recommendations are provided as to how the utilization of each option can be increased through employing different policy choices and market structure.

2 Large Scale Batteries

Battery storage is expected to be a key technology in future energy markets. Since electricity cannot currently be stored in a feasible manner (except for reservoir hydro power plants), renewable energy facilities such as wind and solar plants have to instantaneously sell their generation to the grid. The intermittent nature of renewable energy generation from these sources creates several problems for the electricity system. With the expected developments in technology, large scale battery installations can ease the strain on the transmission grids by providing several services.

Current Status

Large scale battery systems can provide several services for the transmission system such as frequency response, regulation reserves and black start services. Such installations can also help the transmission system over the long-term by reducing the need for peak generation and grid investments. For renewable energy generators, battery applications can reduce curtailment requirements, enable capacity firming and permit arbitrage income from the wholesale markets[193].

Two main types of large-scale battery applications can be identified. Batteries aimed at flexibility can provide the aforementioned services such as frequency control and black start services. These operations can help the system operator in the day-to-day market operation and decrease the overall system costs. On the other hand, battery installations aimed at wholesale markets enable renewable energy generators to increase their income by storing a portion of their generation in hours with low prices and selling the stored electricity in hours with higher prices.

Both types of battery installations can facilitate in increasing the flexibility of the transmission system as well as the integration of more renewable energy into the grid. Both options are set to be utilized in the Turkish market in the near future.

Battery Storage Goals Included Under the Current Policy Targets

Increasing the utilization of battery storage is one of the aims of the Turkish energy policy despite the current lack of regulations in the market. Currently, there is no regulation concerning electricity storage applications in the market, leaving aside a draft regulation published in January 2019. Therefore, the establishment of a legal and regulatory framework is one of the priorities of Turkish policy makers. The utilization of electricity storage systems is one of the main policy goals identified under the 'Strategic Plan 2019-2023' published by the Ministry of Energy and Natural Resources in May 2020. According to the plan, it is targeted that Turkey will prepare a regulation regarding electricity storage and finalize the necessary revisions based on market developments by the year 2022. The plan also asserts that the R&D studies carried out on electricity storage will be concluded by the same year[194].

Installation of a battery system was one of the technical requirements in the second Solar YEKA Project (large scale solar capacity auction) in Turkey. Within the technical specifications of the auction determined under the draft document, it was stated that the winner of the Niğde-Bor region of 300 MW solar capacity was obligated to establish a Li-on battery storage facility with a 30 MW / 90 MWh (AC) capacity[195]. Even though this auction, initially planned for early 2019, was cancelled on 13 January 2019 due to the lack of interest amidst an exchange rate turmoil, the inclusion of a battery scheme in the technical specifications of the auction indicates the willingness of the government to prioritize battery

[193] Utility-Scale Batteries
Innovation Landscape Brief, IRENA (2019)
[194] 'Strategic Plan 2019-2023', Ministry of Energy and Natural Resources, accessible from
https://sp.enerji.gov.tr/ETKB_2019_2023_Stratejik_Plani.pdf

[195] Solar YEKA-2 Technical Specifications Draft, accessed from
https://www.solar.ist/turkiyenin-ikinci-en-buyuk-gunes-enerjisi-ihalesi-yeka-2-ges-icin-basvurular-ocak-ayi-son-haftasinda-alinacak/

applications. Future auctions are likely to include similar provisions to spur the utilization of battery utilization in the country.

Several services which may be provided by large scale battery installations are defined under the current Ancillary Services Regulation such as reactive power control and black starts. Although these services are currently not procured by the transmission operator, these may be applied in the future creating more opportunities for battery installations in the market. Battery installations can also potentially participate in the secondary and primary frequency control reserve auctions which are held in the market on a daily basis two days ahead of the market operation.

Currently, the regulation regarding large scale batteries is not yet finalized and there is no indication when the final regulation will be finalized. According to the aforementioned strategic plan, 2022 is targeted for the finalization of all the regulation related to electricity storage. Despite this, the draft regulation on electricity storage published in January 2019 hints at some of the main applications that will be possible in the market. Market participants were invited to submit their recommendations on the draft regulation over a period of two weeks. Later in February 2020, the 'Regulation on The Approval of Electricity Generation and Storage Facilities' was published which details the technical and administrative processes regarding the official approval of electricity storage facilities[196]. This regulation on general electricity storage will also set the framework for battery installations in the country.

Policy and Regulations

The aforementioned Draft Regulation on Electricity Storage Activities outlines the main electricity storage activities possible in the market. Four main types of electricity storage facilities are defined under the draft regulation[197]:

Energy storage facility related to the licensed generation plant: The maximum capacity of the energy storage facility must be 20% of the licensed power plant capacity, while the pumped storage capacity can be equal to the hydropower plant capacity. The storage capacity cannot be used before the commissioning of the power plant. The stored electricity cannot benefit from the purchase guarantees or incentives.

Energy storage facility related to the consumption point: The minimum consumption point capacity must be 50 kW. The energy storage facility can be integrated into a consumption facility providing the surplus of electricity that is not sold. The energy storage facility must only be associated with that one consumption facility.

Independent energy storage facility: The installed capacity of a storage facility providing ancillary services must be over 10 MW. If the storage facility is used to serve both ancillary services and the wholesale market, it must have a minimum capacity of 15 MW.

The energy storage facility installed by network operators: The storage facilities installed by distribution operators can have a capacity of up to 10 MW and those installed by transmission operators can have a capacity of up to 50 MW per transformer.

It is also indicated that energy storage facilities installed for research and development purposes at universities or technology development areas are allowed to have a maximum capacity of 500 kW.

Potential and Applications

There are several potential applications for large scale battery storage installations in the Turkish Energy Market. In the 2019-2023 Strategic Plan published by the Ministry of Energy and Natural Sources, , failure to develop a regulation framework for electrical storage systems within the anticipated time was considered as a risk. However, due to the current cost of implementing storage systems, there is not enough interest on the part of the industry. It was also stated in the strategic plan[198] that there is a necessity for a cost analysis and financing model for energy storage systems. In light of this information, it is apparent that steps towards dissemination of battery storage systems in Turkey will be taken in the near future.

However, in this aspect, the actions undertaken by the government will not be sufficient. Market players should take an active role in the investing in battery storage technologies to increase their utilization. In this respect, positive developments are taking place in Turkey in terms

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[196] Regulation on the 'Approval Of Electricity Generation and Storage Facilities', 19 February 2020, Energy Market Regulatory Authority

[197] Draft Regulation on Electricity Storage Activities, 24 January 2019, Energy Market Regulatory Authority

[198] 'Strategic Plan 2019-2023', Ministry of Energy and Natural Resources, accessible from https://sp.enerji.gov.tr/ETKB_2019_2023_Stratejik_Plani.pdf

of reducing the cost of battery technologies. In Kayseri, the construction of a Lithium-Ion Battery Production Facility begun on October 2, 2020. With such investments, Turkey is also trying to reduce its dependence on imported resources[199].

There are several ways that large scale battery systems can be utilized in the Turkish market such as use in frequency regulation, congestion management and energy arbitrage. In the following section, such potential applications, and outcomes of implementing large scale battery systems in the Turkish Energy Market are analyzed.

Frequency Control

Frequency control stands out as one of the main potential utilization of battery storage systems in Turkey. The unpredictable and intermittent nature of renewable energy systems can cause frequency fluctuations in the power network. Large-scale battery storage systems are planned to be used in frequency regulation and meeting rapid power requirements.

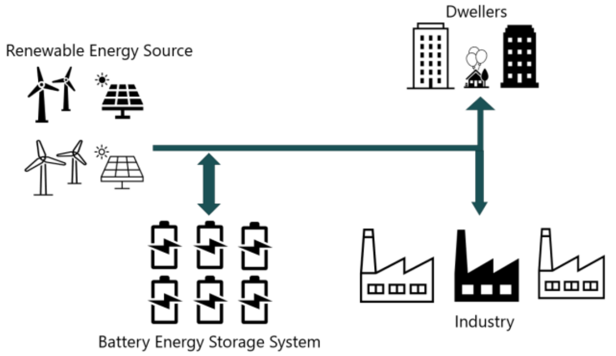

Figure 71. Representative Battery Storage System

In Turkey, frequency regulation is carried out initially through the ancillary services market operated by TEİAŞ. Under the ancillary services market, daily primary and secondary frequency control tenders are carried out by TEİAŞ two-days ahead of the reserve capacity obligation.

The winners of the tender are obliged to generate electricity in their set point capacities and follow any instruction from TEİAŞ regarding loading or de-loading. The winners of the auctions are also eligible to join in the day-ahead market. Since these plants are obligated to operate at their set point levels, in any case, their offers to the day-ahead market are price independent. Therefore, relatively high SFC volumes cause lower day-ahead market prices.

Figure 72 shows the decrease in the day-ahead market prices in response to the COVID-19 crisis in the second quarter of 2020. Very high SFC and PFC prices[200] occurred in this period due to the unusually low day-ahead market prices.

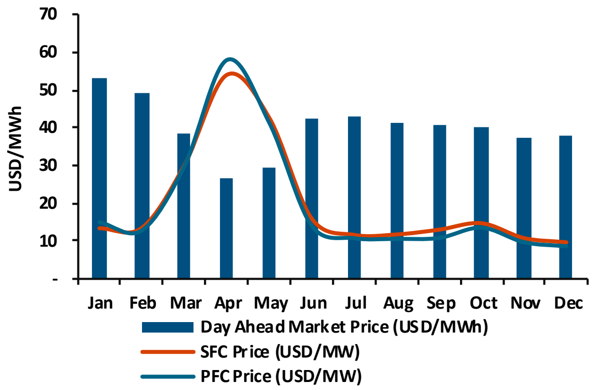

Figure 72. Average Monthly PFC, SFC and Day-ahead Market Price in 2020[201]

Congestion Management

Battery installations can alleviate one of the main problems faced by the Turkish transmission network in congestion management, one of the critical issues the network faces. The increased investments and capacity growth in renewable energy resources, differences in seasonal demand and the concentration of renewable energy resources in certain regions are some of the reasons that can cause overload in the power network.

Moreover, these factors also affect the grid characteristics of the Turkish power network. According to congestion profiles, new investments should be made to handle congestion management. Applying large scale battery systems is one way to increase system efficiency and avoid congestions even though it is currently a costly option.

The structure of the power network and the costs of battery storage systems are factors that affect the

[199] Anadolu Agency, 2 October 2020, accessed from https://www.aa.com.tr/tr/bilim-teknoloji/turkiyenin-ilk-lityum-iyon-pil-uretim-tesisinin-temeli-kayseride-atildi-/1993400
[200] TEİAŞ accessible from https://tpys.teias.gov.tr/tpys/app/report.htm
[201] EPİAŞ, accessible from https://seffaflik.epias.com.tr/transparency/piyasalar/gop/ptf.xhtml

decision of whether to invest in batteries. Due to the high costs of implementing large scale battery storage systems in Turkey, this solution may currently be less feasible compared to European markets.

In the current situation, congestion problems are managed by the balancing power market with load-increase or load-shedding instructions issued to balancing units. This creates an extra cost for the system operator, TEİAŞ. The utilization of battery systems in the balancing power market can potentially increase the competition and decrease the costs in this market.

Four different cases that cause congestion in the Turkish power network can be identified. As shown in Figure 73, excessive wind energy generation in the western region of Turkey causes a congestion problem. To avoid this, conventional power plants in the western region are at times required to reduce their energy output. In the meantime, conventional power plants in the Anatolia region increase their generation to meet the demand.

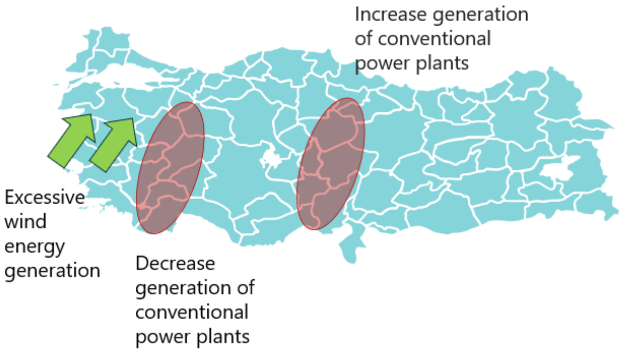

Figure 73. Wind Energy Concentration and Congestion in the Market

As shown in Figure 74, due to the agricultural applications, electricity demand in the south-eastern region of Turkey increases in summer and causes voltage regulation problems in the region.

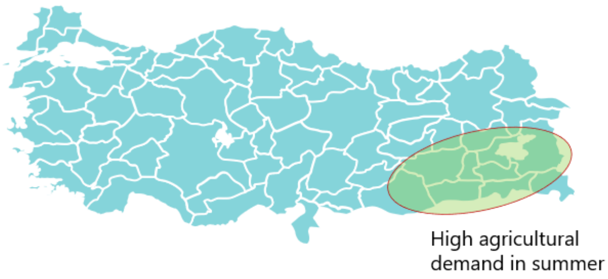

Figure 74. Seasonal Agricultural Demand

The Marmara Region has the highest demand since this region has the highest population and industrial production in the country. Istanbul is the most populous city by a wide margin, holding almost 20% of the country's population. Moreover, Istanbul consumes the most energy (17% of the total electricity consumed in Turkey). Yet, its generation to consumption ratio for electricity is below 14%. It can be expected that the electricity demand in Istanbul will continue to grow while the prospects for new power plant investments around Istanbul is limited at best.

Also, there are many industrial cities in the Marmara Region such as Kocaeli, Bursa and Sakarya. These industrial cities consume approximately 13% of the total electricity generated. Turkey's second-largest industrial city after İstanbul is Kocaeli, which has a generation/consumption ratio of 30%[202]. Transfering the electricity from other regions to the Marmara Region leads to considerable transmission losses and may cause congestion problems.

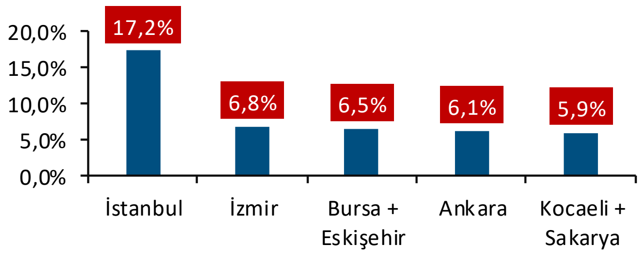

Figure 75. Share of Cities in Electricity Consumption in 2019[203]

[203] EMRA, Electricity Market Development Report 2019 (2020)

Figure 76. Cities with High Demand in the Marmara Region

Hydropower plants in the country are generally concentrated in the Eastern and Black Sea Regions of the country due to the topographical characteristics of the region. On the other hand, the demand in these regions is considerably lower compared to the country average. As a result, the generation from these hydropower plants needs to be transmitted over great distances to the western parts of the country where most of the demand is concentrated. This energy flow can lead to congestion problems in the power network.

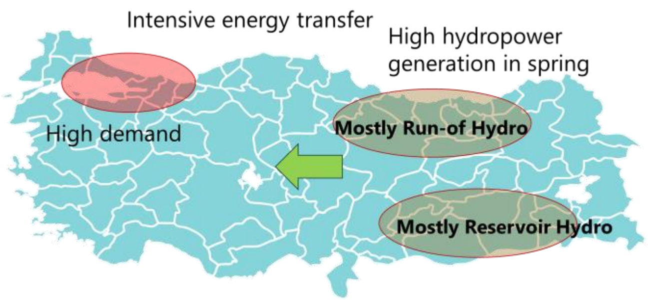

Figure 77. Effect of Hydro Generation on Energy Congestion

In 2019, a total of 2,954 GWh of electricity generation was purchased by TEİAŞ for the handling of congestion problems[204]. Due to the significantly higher capacity factors realized in hydropower plants compared to historical averages, a high amount of electricity demand was met from hydropower plants located in the Northern and East Anatolian region especially in the first half of 2019.

As mentioned, these problems related to regional congestion are handled by load-shedding and load-increasing instructions issued the system operator TEİAŞ on power plants regarded as balancing units. This is done through the balancing power market which significantly increases the overall system costs borne by TEİAŞ.

The instructions issued through the balancing power market are divided into classes according to the problem addressed by the instruction. The *0-coded instructions* are those aimed at maintaining the overall supply and demand balance in the system while the *1-coded instructions* are those aimed at solving transmission congestion problems.

Therefore, the prevalence of the congestion problem in the system can be discerned by observing the volume of these instructions made publicly available through the EPİAŞ Transparency Platform. It has been observed that this congestion tends to be the most severe in the spring due to high hydro generation in this season and the aforementioned geographical distribution of hydropower assets since the regions with high hydro capacity have generally lower levels of demand and this hydropower generation has to be transmitted to regions with higher demand.

Naturally, the problem is worse for wet years with above-average hydropower generation. Such an unusual year occurred in 2019 when the capacity factor of reservoir hydropower plants in Turkey for the year (34%) was way above the historical averages of 27-28%. As a result, in May 2019, a share of 58% of the total instructions in the balancing power market issued by TEİAŞ was aimed at addressing the regional discrepancies in consumption and generation. The volume of these *1-coded instructions* amounted to 2.5 TWh for the month. In comparison, the congestion-related instructions issued in the first 11 months of 2020 was at a relatively modest 0.5 TWh[205].

However, such wet or dry years are likely to occur in the future as annual hydrological conditions are stochastic processes which are very hard to predict. Therefore, it is very likely that there will be years when the costs associated with congestion will be substantially higher than the historical trends.

The situation is likely to get exacerbated in the near future due to the regional distribution of prospective power plant investments. In Figure 78, some of the

[204] EPİAŞ, accessible from https://seffaflik.epias.com.tr/transparency/piyasalar/dgp/yal-talimat-miktarlari.xhtml

[205] EPİAŞ, accessible from https://seffaflik.epias.com.tr/transparency/piyasalar/dgp/yal-talimat-miktarlari.xhtml

largest power plants and the nuclear power plant which is expected to be commissioned in the mid-2020s are shown. As shown in the figure, some of the largest power plants currently under construction such as the Akkuyu NPP (4,800 MW), the EMBA Hunutlu Imported Coal TPP (1,320 MW) as well as the new large scale solar YEKA projects (up to 1,000 MW) are located in regions far away from the main consumption center at the northwest of the country.

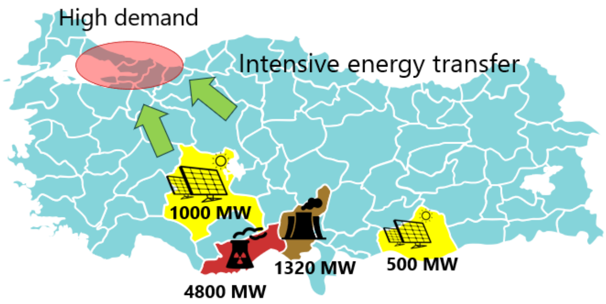

Figure 78. Expected Capacity Increases in the medium-term[206]

In summary, there is an ongoing congestion problem faced by the Turkish transmission system which is likely to get exacerbated in the foreseeable future. Among other options, the deployment of large-scale battery installations can potentially help in reducing the costs associated with this problem. This is hinted at the draft regulation on electricity storage, the expectation is that these facilities are going to be allowed to join the Balancing Power Market after the regulation is finalized.

Arbitrage in Wholesale Markets

Battery installations aimed at arbitrage can potentially benefit from the hourly variations regularly observed in wholesale electricity prices. Battery storage systems can also be utilized to benefit from energy arbitrage in wholesale energy markets. The main premise behind the energy arbitrage concept using battery storage systems is to buy the electricity from the market at a lower price level and sell it at a higher price. In order to realize this, battery systems can make use of the differences in prices between different hours of the day. Figure 79 shows the maximum and minimum hourly DAM prices that occurred on each day in 2020.

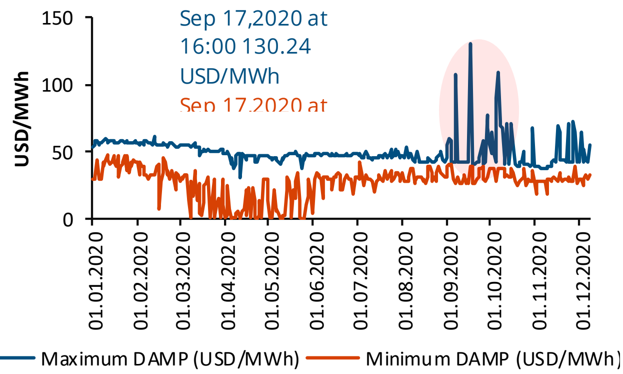

Figure 79. Min and Max DAM prices in the day[207]

According to the data, the average difference between hourly max and min prices in a day ranges from 24 USD/MWh to 92 USD/MWh. These differences are shown in Figure 80.

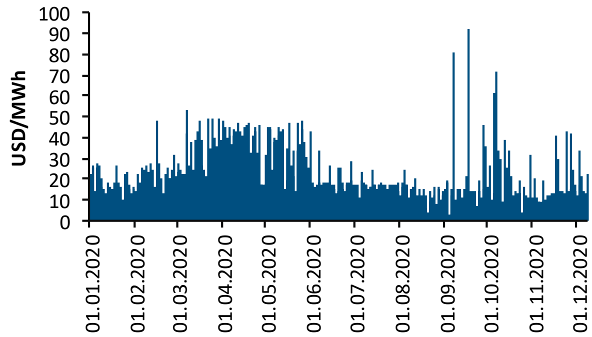

Figure 80. Difference between Max and Min DAMP[208]

In Figure 81, the average DAM price profile for peak and off-peak hours is shown on a daily basis[209]. The gap between the peak and off-peak hours provides an opportunity to obtain energy arbitrage for longer hours.

[206] EMRA, APlus Enerji Analysis
[207] EPİAŞ Transparency Platform, accessible from https://seffaflik.epias.com.tr/transparency/piyasalar/gop/ptf.xhtml
[208] Ibid.
[209] Peak hours shown in the figure include the hours between 08:00 and 20:00

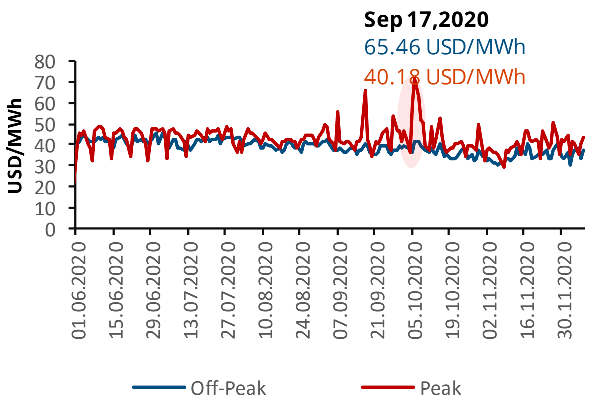

Figure 81. DAMP for peak and off-peak hours[210]

Policy Recommendations

Given the wide range of potential battery applications in the market, several policy measures can be taken to increase the utilization of battery installations in the market.

Up until recently, the price range for all kinds of offers in the spot electricity market was applied as 0 - 2,000 TL/MWh. However, according to the EMRA Decision dated October 6, 2020, the maximum limit will be calculated as twice the weighted average of the past 12 months retrospectively. The previous two months will not be included in this average. For example, for the maximum limit for October 2020, the weighted average between October 2019 and July 2020 is considered and the limit is determined 563 TL/MWh 211. This effective reduction in the price cap reduced the attractiveness of battery installations aimed at energy arbitrage.

The general approach in the world is to set the ceiling prices in day-ahead markets at a sufficient level to encourage market participants. Under the current situation, the maximum price determination methodology in Turkey is not a liberal approach. This approach should be changed to allow for the establishment of a more liberal market environment. In case of the removal or increasing of the maximum price limit, the margin between the maximum and minimum price levels would increase and this would provide additional arbitrage opportunities for battery systems. In Turkey, the minimum price level in the day-ahead market is applied as 0 TL/MWh in contrast to many European countries which allow negative prices. This approach also limits the gap between maximum and minimum prices. Likewise, the arbitrage opportunities can be increased by removing the floor price and permitting negative prices.

Besides the set price limits in the market, other external factors restrain the price variability in day-ahead markets. Using its abundant reservoir hydro capacity, the government has been applying a sort of 'soft cap' on the market prices by increasing reservoir hydropower generation in periods of high market prices to keep the price under a certain level. This price level can change depending on the water levels in the state-owned reservoirs. The soft cap application causes the price to be limited at a certain level and prevent price increases. This effective cap on prices has a constraining effect on the profitability of potential battery installations aimed at energy arbitrage by limiting the margin between the lowest and highest day-ahead market prices that form in any given day. Additionally, the state-owned generation company EÜAŞ still holds a significant amount of thermal installed capacity. It has been observed in the past that the occasional price independent operation of these power plants can have a distorting effect on market prices. If the state intervention in the market is ceased, the market can become more cost-reflective. Thus, the difference between the maximum and minimum prices can increase to provide an opportunity for battery systems targeting energy arbitrage. Such interventions in the market thus need to be ceased and the state-owned generation portfolio should be operated in a cost-reflective manner.

According to the latest Ancillary Services Regulation, power plants with an installed capacity over 30 MW can participate in the market. For battery systems to join in the ancillary services market, this limit should be decreased and eventually lifted to allow all technically-feasible units to participate in the market.

[210] Ibid.

[211] EMRA Decision dated October 5, 2020.

3 Small Scale Batteries

In addition to utility size battery installations, small-scale battery installations can also be instrumental in increasing the flexibility in the transmission grid. Small scale batteries are generally those battery installations that are used in off-grid applications mainly aimed at self-consumption, agricultural irrigation and illumination.

Potentials

Small-scale batteries can serve the electricity system by enabling an enhanced integration of small-scale renewable energy sources. When paired with independent renewable energy generation units, small scale batteries can meet the needs of electricity consumers in remote locations. Increased application of such distributed off-grid applications could optimize self-supply and mollify the effects of intermittent renewable energy generation. Even though the electrification rate in a country like Turkey is 100%, off-grid applications can be feasible for practices like irrigation and illumination in locations removed from residential areas.

Current Status, Policy and Regulations

According to the prior regulation concerning unlicensed electricity generation, micro-cogeneration and renewable power plants with a maximum capacity of 1 MW for on-grid applications were exempt from obtaining a generation license. Currently, the vast majority of the solar energy installed capacity in the country consists of unlicensed power plants commissioned under this regulation. The installed capacity of unlicensed solar energy power plants rose rapidly over the last 5 years to reach 6,265 MW by the end of November 2020[212]. Since these power plants have the right to receive the YEKDEM tariff (133 USD/MWh for solar) for a period of 10 years, they were mainly built for selling to the grid as opposed to being aimed at self-consumption.

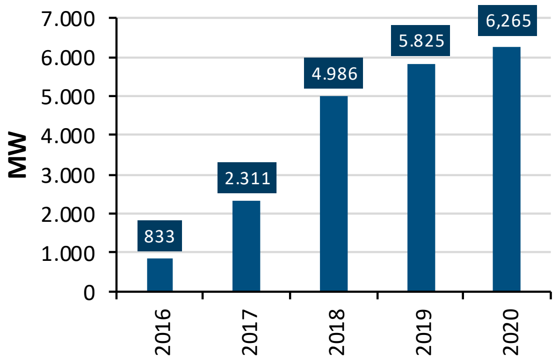

Figure 82. Evolution of Unlicensed Solar Energy Capacity[213]

With the Presidential Decree which was published in the Official Gazette on May 10, 2019, the limit for unlicensed electricity generation was raised to 5 MW up from the previous 1 MW. There is no limit currently applied for off-grid installations. There is also no provision regarding the pairing of battery storage and rooftop solar PV systems[214].

The new unlicensed generation facilities are set to benefit from a new purchase guarantee which will be based on the 'active energy cost'[215] and be applicable for a period of 10 years. This points to a significant decrease compared to the prior feed-in tariff applied to unlicensed power plants. The active energy cost denotes the overall cost of energy generation for a certain period and includes items like the day-ahead market price and the YEKDEM unit cost. This amount is significantly lower compared to the national tariffs and the current feed-in tariff previously applicable for unlicensed solar power plants. The current 133.0 USD/MWh Feed-in-Tariff applicable for earlier unlicensed solar facilities is much higher compared to the active energy cost for industrial customers at 67.7 USD/MWh in April,2021[216].

[212] TEİAŞ, accessed from https://www.teias.gov.tr/
[213] Ibid.
[214] Official Gazette No: 30763, dated May 10, 2019
[215] Active energy cost is a component in regulated electricity tariffs. The full tariff also includes other components such as renewable support unit cost, distribution cost and etc. in addition to the active energy cost.
[216] The USD/TL exchange rate is taken as 8.15 applicable in April 12, 2021.

The new regulation also allows for monthly net metering. This means that the difference between consumption and generation that the generator sells to the grid will be calculated on a monthly basis. If the total monthly generation exceeds the total consumption, the generators will be able to sell the excess generation based on the aforementioned active energy cost. If the opposite is true, the consumer needs to buy the additional electricity from the national tariff. Thanks to this scheme, any potential negative effects of the intermittent nature of solar energy can be disregarded by prospective investors.

Due to the effect of net metering and the reduced tariff, it is expected that the new regulation shifted the focus of new unlicensed power plants to roof-top and facade applications aimed at self-consumption. This is especially attractive for large industrial consumers which can significantly reduce their costs via self-consumption. Most of the additional solar energy capacity is expected to come from such installations in the near future. On the other hand, the new regulation will effectively halt any unlicensed investments aimed at selling to the grid.

One reason that will compel the large industrial consumers to invest in unlicensed generation facilities has to do with the relatively recent change regarding the supply of last resort tariff. 'The Notification on the Regulation of Supply of Last Resort Tariff' has been published in the Official Gazette dated 20 January 2018 No: 30307[217]. The regulation concerns the large electricity consumers who choose not to supply their electricity utilizing bilateral contracts even though they are eligible as free consumers under the current regulation.

For 2018, the regulation increased the electricity tariffs for commercial and industrial consumers with an annual demand exceeding 50 million kWh. As per the regulation, the consumption limit is determined at the start of each year by the Energy Market Regulatory Authority. It is determined that the supply of last resort tariff at a certain period cannot be set lower than the retail electricity tariff in the same period. The limitation was set as 10 million kWh for 2019 and reduced to 7 million kWh in 2020. Although the limit was kept constant for 2021 at 7 million kWh, it is expected that the limit will be slowly decreased in the coming years.

The tariff for large consumers is determined by summing up the costs that form in the competitive electricity market and the 'reasonable profit margin' that will be decided for each retail tariff period. The equation used to calculate the supply of last resort tariff is as follows:

*Supply of Last Resort Tariff = (Monthly DAM Price + Monthly YEKDEM (FiT) Unit Cost) * (1+Profit margin)*

The profit margin was set at 9.38% for 2020 and remains unchanged for 2021[218]. Under the new system, several factors that influence the cost of electricity generation will be immediately reflected in the electricity bills of large consumers.

As a result of this change, the large industrial consumers can no longer benefit from the (relatively cheaper and subsidized) national tariff. Under this circumstance, investing in an unlicensed generation for self-consumption becomes commercially interessting.

The Effect of Monthly Net-Metering

Despite the expected increase in unlicensed electricity generation installations, due to the monthly net-metering scheme, the energy facilities to be commissioned will not need to install battery systems as their hourly generation profile will not be of consequence.

With this in consideration, it seems that the main opportunity for small-scale battery installations in the country lies in off-grid applications which may be built for purposes like irrigation and illumination.

There is uncertainty regarding the situation of unlicensed solar plants currently benefiting from the feed-in tariff scheme after their 10-year terms expire. These power plants are currently not allowed to participate in the wholesale markets since they do not hold generation licenses. The general expectation is that they will be given the right to sell their generation in the market in a future policy revision. In a recent change made in the Electricity Market Law in October 2020, the right to determine the status of these power plants after their feed-in tariff period has been given to the Office of the Presidency[219].

Later, with a legislative revision on December 2, 2020, it has been indicated that there will be two options for these unlicensed power plants after their 10-year period ends[220]:

[217] Official Gazette No: 30307, dated January 20, 2018
[218] Official Gazette No: 31287, dated 27 October 2020
[219] Turkish Grand National Assembly Legislative Proposal October 5, 2020, accessed from https://www2.tbmm.gov.tr/d27/2/2-3116.pdf
[220] Official Gazette No: 31322, dated December 2, 2020

- These power plants can obtain licenses and be eligible to join the day-ahead market under the condition that they pay 15% of their revenues as a contribution fee to the YEKDEM mechanism
- These power plants can continue as unlicensed power plants and can sell their excess generation based on a tariff to be determined at a later stage and will not exceed the day-ahead price.

The details regarding the exercise of these options will later be determined by the Office of the Presidency.

According to the legislative change, it seems that after their YEKDEM period ends, most of these power plants will be compelled to participate in the day-ahead market. The attractiveness of the two options will depend on the level of the tariff to be set. This tariff will likely be substantially below the day-ahead price. Under such a condition, it can be surmised that the vast majority of the unlicensed power plants in Turkey will opt for the first option since most of these power plants are not integrated with consumption facilities on a large scale. Since they were commissioned before the new unlicensed electricity legislation, these power plants were originally commissioned to benefit from the feed-in tariff instead of being aimed at self-consumption.

As a result of this regulatory change, investing in small scale battery systems can potentially be a feasible option for these power plants who are set to obtain licenses after their YEKDEM period. This will naturally depend on future cost reductions in battery technologies. Installing battery systems can particularly make sense since the real capacities of these power plants are generally around 20% higher than their nameplate (usually 1 MW as per the limit) capacity. These power plants are currently not allowed to sell their excess generation over 1 MW in the market.

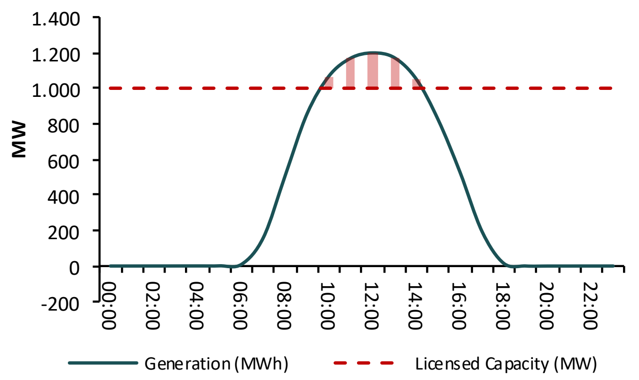

Figure 83. Representative Hourly Generation Profile of an unlicensed solar power plant with 1 MW nameplate capacity

In the past, the investors of these power plants installed higher capacities than that allowed under their licenses, in order to be able to sell more of their generation by the feed-in tariff in hours where their output is lower than peak levels. Investing in battery storage systems can help enable these facilities to fully utilize their generation potential by storing a part of the generation at peak output levels.

Policy Recommendations

Several steps can be taken to increase the role of small-scale battery installations in the energy system.

- Widespread installations of small-scale battery systems are not likely for the foreseeable future due to the current net-metering scheme. Consumers that have invested in small-scale unlicensed generation facilities currently have no incentive to install battery storage systems since the services that could be provided by such installations are currently being provided by net-metering. While the net-metering mechanism is a useful policy tool for promoting distributed generation in the energy system, it should also be noted that the policy mechanism does not address the problems that may be caused by increased penetration from intermittent renewable energy sources. After a significant amount of investments are realized under the new unlicensed regulation, battery storage systems can be promoted as an alternative to net-metering. Under such circumstances, targeted incentives can be promoted to ease the switch from net-metering to battery storage installations.
- Another opportunity for small-scale battery installations lies in the unlicensed generation facilities built under the older unlicensed regulation. Allowing these power plants to operate in the wholesale electricity markets after their feed-in tariff periods would prevent a significant amount of available generation capacity from being wasted. Establishing subsidies for these facilities to invest in battery technologies would help introduce widescale battery applications to the market and increase the flexibility of the energy system.
- Different policies options such as tax cuts, credits or grants can be used to promote small scale off-grid battery installations. However, it should be noted that the potential for such installations in Turkey is quite limited due to the completed electrification process in the country. The opportunities for such installations are mostly limited to purposes like irrigation or illumination in some remote locations.

4 Flexibility Options for Conventional Power Plants

Conventional power plants like natural gas and coal power plants are increasingly struggling in markets with high renewable energy penetration. Increased generation from renewable energy sources changes the load profile significantly, at times even reducing the residual load to negative figures. These circumstances challenge the operation of such conventional power plants with high start-up/shut-down costs and slow ramp rates in the market. There are several options these power plants can choose to utilize to increase their flexibility.

Current Status, Function and Application

All over the world, a vast majority of the conventional power plants were initially installed to supply baseload electricity. For example, in Germany, more than 80% of the total thermal power plants were built before the penetration of a significant amount of wind and solar installed capacity into the electricity generation mix[221]. A similar situation is also true for the Turkish market where a large amount of thermal installed capacity predates the 2000's while the majority of the intermittent renewable energy investments in the country took place over the last decade. Therefore, the majority of the thermal power plant fleet in Turkey was designed for baseload provision as opposed to cycling operations. As an exception, the natural gas power plants that have entered the installed capacity since 2012 were designed for flexibility and are sufficiently flexible for the current market structure.

Older power plants have inelastic operations, some even have difficulties maintaining a stable output level, so the expectation of a quick response to instructions is highly unrealistic. As a result of these problems, a second wave of conventional power plant investments become compulsory, this time not solely aimed at capacity increase, but aimed at addressing the flexibility problems that appeared after the increased penetration of intermittent renewable energy sources.

Conventional power plants can potentially increase their flexibility in a variety of ways. Operational flexibility of conventional power plants can be reviewed based on three main parameters:

- Minimum load
- Start-up time/Shut-down time
- Ramp rate

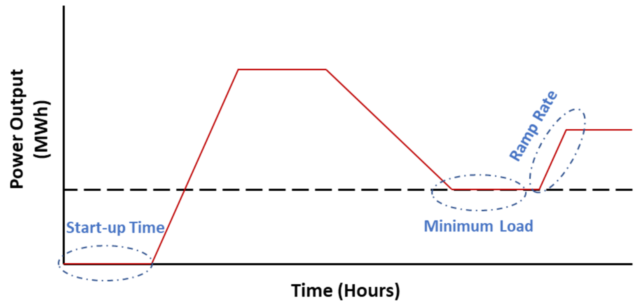

Figure 84. Flexibility Options for Conventional Power Plants[222]

Operating power plants with close to minimum loads can increase the bandwidth of their operation which increases flexibility. This is important as most thermal power plants experience a high reduction of their fuel costs at lower output levels.

The reduction in start-up and shutdown periods can enable the power plants to reach full loads and shutdown faster. This can increase the operational flexibility of power plants and reduce the costs associated with start-ups and shutdowns.

Ramp rate is defined as the rate at which a plant can change its net output during operation. Higher ramp rates allow power plants to alter their generation quickly according to the needs of the system.

Several investment options can help in increasing the flexibility of thermal power plants such as indirect firing, switching from two-mill to single-mill operations, control system optimization, auxiliary firing with dried lignite ignition burner, repowering, "new" turbine start, thin-

[221] Assessing the flexibility of coal-fired power plants for the integration of renewable energy in Germany, Deloitte (2019)
[222] Ibid.

walled components/special turbine design and thermal energy storage for feed water preheating[223].

Such measures are increasingly becoming relevant for Turkey due to the changing characteristics of the electricity market and the increasing penetration from renewable energy sources.

The Current State of Affairs

Conventional power plants in the Turkish context refer to thermal power plants which consist of natural gas power plants, imported coal power plants and domestic coal power plants. Nearly all of the natural gas power plants in Turkey are fueled by imported sources. Imported coal power plants are fueled by hard coal while the vast majority of local coal power plants are fueled by lignite sources with lower quality. There is also a limited level of local coal capacity fueled by domestic hard coal and asphaltite. There is also a limited installed capacity based on liquid fuels like fuel oil that is still operational but mostly inactive. Some renewable power plants that have high capacity factors like geothermal can also sometimes be regarded as conventional power plants.

In Turkey, the total natural gas installed capacity amounts to 25.6 GW as of the end of November 2020. On the other hand, the imported coal capacity amounts to almost 9 GW. These two sources constitute the vast majority of imported fuels used for electricity generation. The installed capacity of liquid fuels has dwindled over the past years and currently amounts to 0.3 GW. Meanwhile, the total installed capacity of local coal amounts to 11.3 GW of which 10.1 GW is lignite and the remaining 1.2 GW consists of hard coal and asphaltite[224].

Increased renewable energy penetration in the Turkish market over the last decade necessitates thermal power plants to invest in flexibility. The increased generation from variable renewable energy sources changed the load profile in Turkey over the last decade. At times, this can even result in negative residual loads creating a difficult position for thermal power plants with low flexibility which can not increase or decrease their output levels rapidly. As a result of this situation and the current state of oversupply in the market, several large-scale thermal power plants have decided to be mothballed or even decommissioned. A new capacity mechanism had to be designed in order to limit the installed capacity that becomes inoperational. Increased investments into flexibility can be a viable option which many thermal power generators are currently considering.

As is apparent from Figure 85, a significant portion of the current thermal power plant fleet in Turkey is considerably old and unflexible. This is especially true for the domestic coal power plants in Turkey, a majority of which were built before 2000.

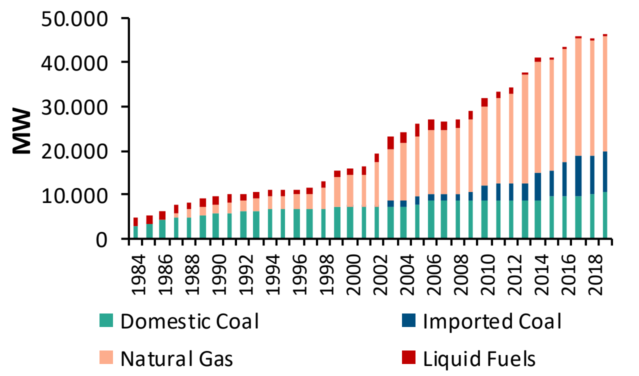

Figure 85. Evolution of thermal-powered Installed Capacity in MW[225]

An important share of the domestic coal power plants are less efficient and were commissioned in the 1980s and 1990s. Meanwhile, most of the imported coal and natural gas power plants were built over the last two decades in response to the increasing demand and liberalization in the market. For 2019, the share of thermal power plants in total generation amounted to 56.4% despite 2019 being a year with record hydro capacity factors[226].

Due to their marginal costs and respective place in the merit order, domestic coal power plants and to a lesser degree imported coal power plants mostly operate as baseload power plants. In contrast, with their higher marginal costs, the natural gas power plants in the country are generally the marginal power plants and the price setters in the market along with reservoir hydropower plants. A representative merit order in the market is given in Figure 19.

[223] Flexibility In Conventional Power Plants Innovation Landscape Brief, IRENA (2019)
[224] TEİAŞ Load Dispatch Information System, accessed from https://ytbsbilgi.teias.gov.tr/ytbsbilgi/frm_istatistikler.jsf
[225] Ibid.
[226] TEİAŞ, accessed from https://www.teias.gov.tr/

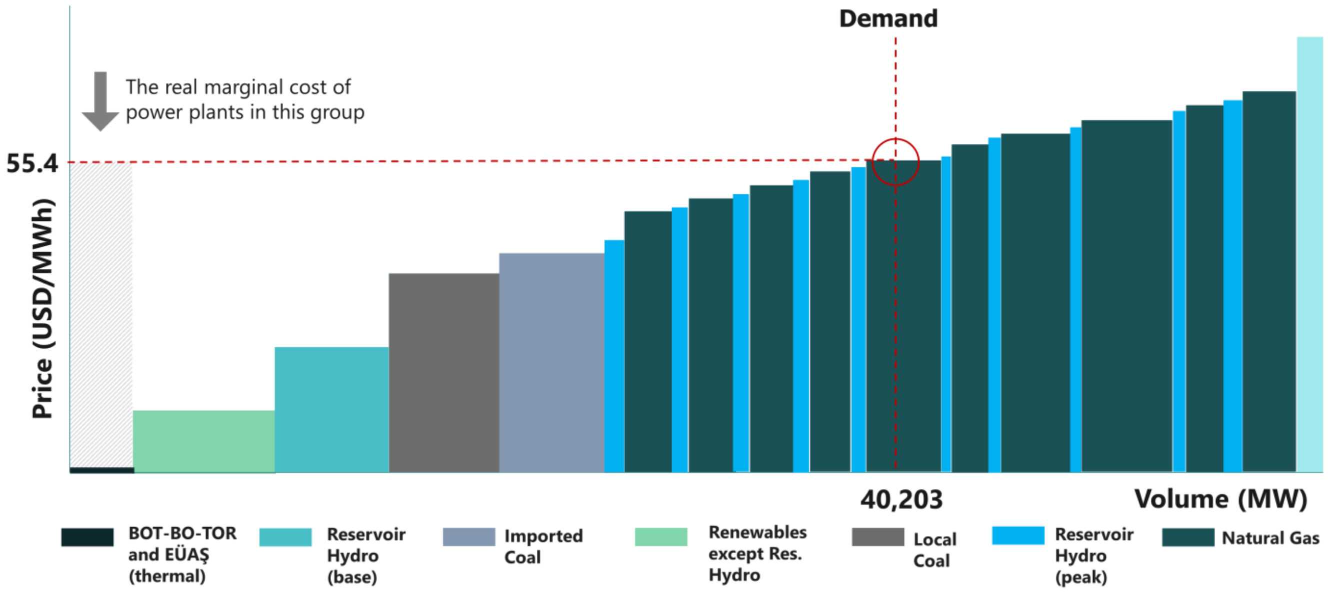

Figure 86. Representative Merit Order in the Market

Several schemes have been proposed in Turkey to address the issue of flexibility and avoid regional grid constraints. One such scheme was the "Regional Capacity Rental Service", which would enable some power plants in favourable locations (in terms of security of transmission system) to benefit from a sort of purchase guarantee similar to BO & BOT contracts. Even though the scheme was in the end not adopted, the need to devise such schemes demonstrates the flexibility needs of the energy system concerning regional grid constraints. The development of market-based mechanisms that favour flexibility would reduce the need for such measures.

Another effect of the increased generation from intermittent sources has been seen in the ancillary services needs of the transmission system. In a bid to address these increased needs, the new ancillary services market in the country became operational after 2018. The new market serves as an additional incentive for thermal power plants to invest in flexibility.

Policy and Regulations

Ancillary Services Market in Turkey

Based on its architecture, the ancillary services market in Turkey acts as an incentive for conventional power plants to increase their flexibility. The active ancillary services markets in Turkey consist of the primary frequency control and secondary frequency control markets.

The primary frequency control service aims to keep active power in balance and to stabilize the system frequency as soon as possible. Primary Frequency control generators provide a balance between supply and demand through the speed regulators automatically and quickly. The primary frequency control service is procured through tenders from generation facilities that meet the required conditions and have passed the test. Units that provide this service must activate within a maximum of 30 seconds and must be able to maintain this power for at least 15 minutes.

On the other hand, secondary frequency control (SFC) is a system that the system operator TEİAŞ uses to maintain system frequency in cases of excess capacity or demand surplus. Secondary frequency control is slower tham primary frequency control, the participating units must be able to activate in 2 minutes be able to maintain this power for at least 15 minutes.

The facilities which will provide primary and secondary frequency control services are selected from among the facilities that have this qualification via tenders. The secondary frequency control allows the primary reserve power plants to return to their pre-fault operation points. In this way, the primary frequency services will be ready for the next possible fault. This is managed by the automatic system located at the Gölbaşı National Load Dispatch Center of TEİAŞ.

Under the current system, tenders are made two days ahead for providing primary and secondary reserve services. TEİAŞ is designated as the system operator. Each day, the power plants which are the winners of the tender from two days earlier are obligated to operate at their 'set point' value in order to be able to shed or increase their loads as per the requests of the system operator[227].

The new mechanism is expected to decrease the overall balancing costs borne by the system. Moreover, natural gas power plants with secondary frequency control capabilities are expected to benefit from the new mechanism.

To be eligible to join in the secondary frequency control mechanism, power plants should:

- Make an agreement with TEİAŞ for being part of the system,
- Have an installed capacity of at least 30 MW
- Have the technical requirements specified by TEİAŞ (e.g. load increase and shedding time),
- Operate in their set point of generation for the specified day and follow any requests from the system operator

In order to make a profit, the power plants have to estimate market prices for two days ahead for bidding at an optimum price level in the secondary frequency tender. The plant receives the specified payment regardless of whether the system operator requests load shedding or increase in the specified time period.

TEİAŞ receives bids and provides necessary information for the ancillary services market (primary and secondary frequency control) through its market management system (TPYS).

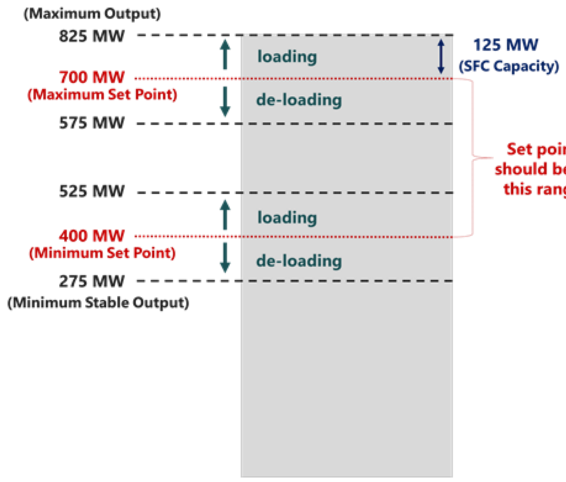

Figure 87. Operation of a Power Plant Holding an SFC Reserve[228]

For the ancillary services market, the day is divided into different blocks and the tender is made separately for each block of the day. Therefore, there is a determined price and ancillary services demand for each block. The demand is determined by TEİAŞ and the price is set at the end of the auction. There can be a maximum of 6 blocks for each day.

The SFC tender works in a merit order structure, where power plants bid for the following:

- SFC capacity that can be provided in each block (start-end hours of a block may differ)
- Price bid (TL/MWh) to provide SFC capacity in the given block

Because of the auction-based merit order structure, the new ancillary services system operates in a way to reward thermal power plants with increased flexibility in the market.

Due to their relative flexibility, the newest CCGT's are better equipped to compete in the Secondary Frequency Control Tenders with their high set-point capacity. This is a great advantage for them to acquire extra income from the ancillary services market in addition to the revenues received from the Day-Ahead Market. Together with reservoir hydropower plants, the CCGT's are the main participants in the ancillary services market in Turkey.

With this flexibility, the newer CCGT's serve an important role in maintaining the quality of electricity in the system

[227] Electricity Market Ancillary Services Regulation, Official Gazette No:30252 dated 26 November 2017
[228] APlus Enerji Analysis

and supplying the necessary ancillary services capacity to ensure system security.

The New Hybrid Power Plant Regulation

Allowing for hybrid power plant installations is another method that can be utilized for achieving an increased level of flexibility for conventional power plants.

Hybrid generation plants are formed by the combination of electricity generation plants that use different technologies. The main purpose of these plants is to generate electricity with maximum efficiency. Hybrid systems provide a high level of energy security through the mix of generation methods and often will incorporate a storage system (battery, fuel cell) or small fossil fuel generator to ensure maximum supply reliability and security. With hybrid generation, the mechanical losses of the power plant are tolerated, energy generation is increased, operating expenses are reduced, more stable energy generation and better voltage and frequency control are achieved.

Several new definitions have been added to the Electricity Market License Regulation with the Official Gazette dated March 8, 2020, allowing the establishment of hybrid generation plants in Turkey[229]. The hybrid plant regulation came into force on July 1, 2020. Between July 1 and August 4, the applications for hybrid installations had to be delivered in a written form to EMRA. However, since August 4, applications are collected through the electronic application system of EMRA. Some minor changes were also made in the regulation on July 28, 2020, bringing the regulation to its current form[230].

Eight new definitions were added in the Electricity Market License Regulation with the Official Gazette dated March 8, 2020:

Multi-source power generation facility: Includes combined power generation facility, combined renewable power generation facility, co-fired power generation facility and supportive power generation facility.

Combined power generation facility: A single power generation facility established to generate electricity from more than one energy source connected to the grid from the same connection point.

Combined renewable electricity generation facility: A single power generation facility established to generate electricity from more than one fully renewable energy source connected to the grid from the same connection point.

Co-fired power generation facility: A single electricity generation facility where sources other than renewable energy sources are used, in addition to the main source, the renewable auxiliary source is burned in the same facility.

Supportive electricity generation facility: A single power generation facility where another energy source is also used in the thermal process in generation facilities.

Main source: The preferred source for associate or license applications in power generation facilities with multiple sources.

Auxiliary resource: Any resource or resources other than the main resource, which is not the main resource type used in the pre-license or license application in multi-source electricity generation facilities.

Floating SPP: Power generation units based on solar energy installed on water surfaces within the scope of power plant sites of hydroelectric generation facilities with reservoirs or regulators.

For the combined renewable energy generation plants, the lowest price defined in the YEK Mechanism will be applied for net electricity generation from these plants. For the supportive electricity generation plants, in case all supportive generation is from renewable energy sources, the main source will be taken into consideration for the YEKDEM tariff.

The auxiliary source unit used in power generation facilities with multiple sources is considered as a unit of the facility based on the main source and the facility is evaluated within the scope of a single pre-license or license. With this, it is possible for large thermal facilities to meet their internal consumption by using hybrid configurations and without any additional procedure. This enables them to significantly reduce their internal consumption costs. Under no circumstances can the auxiliary source be converted to the main resource in the combined electricity generation facility and the combined renewable electricity generation facility.

As per the regulation, the total output that can be fed into the system from the hybrid facilities cannot exceed the total electrical installed power of the units that are part of the hybrid facility. If the generation amount is more than the energy amount corresponding to the installed power

[229] Official Gazette No: 31062, dated March 8, 2020

[230] Official Gazette No: 31199, dated July 28, 2020

of the units with temporary acceptance based on the main resource, no accrual and payment are made for the generation exceeding the said amount. As a result, the secondary source can be used to cover the internal costs of the main electricity generation facility but can not be utilized to generate electricity at a level higher than the installed capacity stated under the license of the facility.

According to the regulation, no new license application is needed for auxiliary generation power plants. If power plants that already own generation licenses or pre-licenses will be converted to combined renewable energy generation plants, their total installed capacity can not exceed the electricity capacity that was confirmed before. According to the Geothermal Power Plants Investors Association Chairman Ufuk Şentürk, a total capacity of around 400 MW hybrid power plants is set to be built in Turkey in the near future. He also stated that with the hybrid capacity, the security of supply in the electricity system will increase and the share of geothermal energy in total generation will increase from 4% to 5%[231].

For geothermal power plants, hybrid generation facilities will be able to provide additional income in order to meet the geothermal plant's internal consumption which can cause reductions in electricity sales by around 20%. As a result, geothermal power plants can meet their internal consumption from other renewable energy sources and increase their electricity generation from the same source. However, there is currently a barrier in the regulation regarding the Soil Protection and Land Usage Law No: 5430 which prevents these power plants from installing additional solar or wind capacities within their vicinities. This barrier will need to be removed before the full benefits of hybrid power plants can be utilized.

In power plants based on geothermal energy, especially established in agricultural regions, biomass-based auxiliary resource units can be established in order to both eliminate these wastes and increase electricity generation by using the agricultural residues and wastes in the region.

Also, it will be possible to use renewable energy sources such as solar or biomass together in power plants based on conventional energy sources such as coal and natural gas. The auxiliary renewable energy sources can be utilized to decrease the costs of these facilities in start-up and ramping times.

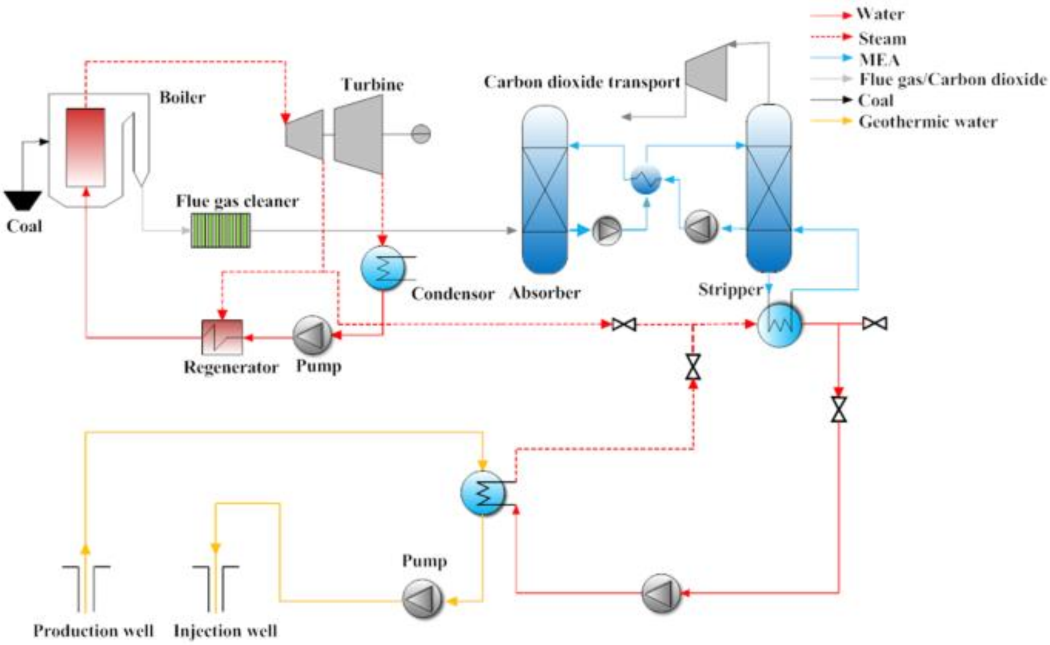

Figure 88. Configuration of a Geothermal and Conventional Thermal Hybrid Power Plant[232]

[231] Anadolu Agency May 24, 2020, accessed from https://www.aa.com.tr/tr/ekonomi/gunes-ve-ruzgar-destekli-hibrit-sistemler-jeslere-can-suyu-olacak/1852111

[232] Integrating geothermal into coal-fired power plant with carbon capture: A comparative study with solar energy (2017), F. Wang et al, http://dx.doi.org/10.1016/j.enconman.2017.06.016

The change in regulation enables conventional power plants to include an alternative source of electricity generation into their operation. As presented in Figure 88 and Figure 89, geothermal, solar or any other potential renewable source can replace the boilers during critical periods such as start-up and ramping times. As a result, the main heat provider, the boiler in this example, does not have to respond as rapidly to changes in electricity output. Instead, alternative sources can take part in supplying the output before the boiler starts operating to its full potential. This property of hybrid power plants can enable highly flexible operations compared to conventional power plants.

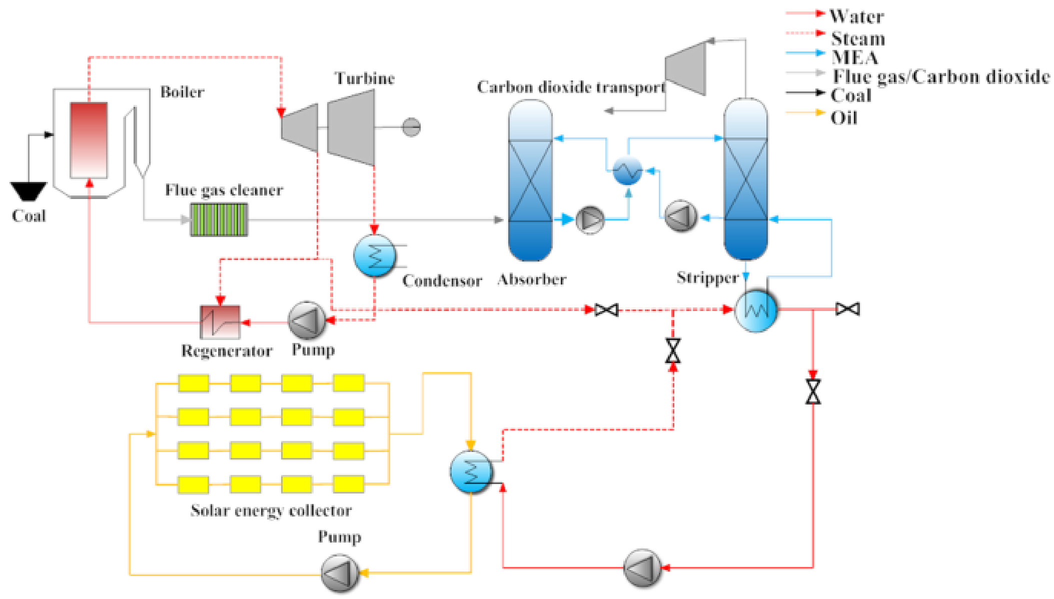

Figure 89. Configuration of a Solar and Thermal Hybrid Power Plant[233]

Policy Related Barriers in Front of Further Flexibility for Conventional Power Plants

On the other hand, several aspects of the current market structure work to hinder the attractiveness of making flexibility investments for thermal power plants.

Leaving renewable sources aside, from the government's perspective lignite is seen as one of the most preferable sources of electricity generation in Turkey due to the abundant domestic reserves. Before its merger with EÜAŞ, TETAŞ announced the extension of the purchase guarantee to coal plants working fully or partially on domestic coal for the next seven years with a set price of 201.35 TL/MWh (expiring after 2024). The price is regularly indexed to inflation on a quarterly basis (based on the percentage of domestic coal used).

Currently, 50% of the power generated by domestic coal sources is being bought by EÜAŞ in a bid to support the use of domestic sources in electricity generation. The purchase guarantee is set to be expired at the end of 2024 although there is a possibility that the guarantee may be extended to the end of 2027. Such purchase guarantees hinder the attractiveness of flexibility investments by allowing these power plants to operate mainly as baseload even on periods with very low wholesale prices.

Although the price for each quarter is not disclosed, the price for the 3rd quarter of 2020 is estimated to be around 360 TL/MWh. It has been determined by EÜAŞ that the price has to be between 50 and 55 USD/MWh at all times. If the price is calculated below 50 USD/MWh, it is fixed to 50 USD/MWh. Conversely, if the price if calculated above 55 USD/MWh, it is fixed to 55 USD/MWh for any given quarter[234].

Another prominent support mechanism provided for conventional power plants is the capacity mechanism. The capacity mechanism aims to provide adequate installed capacity in the electricity market. Even though

[233] Ibid.

[234] EÜAŞ, Announcement dated December 17, 2019

there is no supply scarcity in the market under the current situation, the concern is that excess capacity may be required with increasing demand in the near future. The relevant regulation was published in the Official Gazette on January 20, 2018[235]. According to the regulation, power plants meeting at least one of the criteria below will not participate in the capacity mechanism:

- Power plants where state companies hold more than 50% shares
- Build-Operate and Build-Operate-Transfer power plants (those within their contract period and those which have fulfilled their contract period)
- Power plants built with a privatization model under the scope of Article 18 of the Electricity Market Law no. 6446
- Nuclear power plants built with an intergovernmental agreement
- Power plants that have participated or have the right to participate in the Renewable Energy Support Mechanism
- Power plants privatized following the enactment of the Capacity Mechanism regulation
- For local resources (lignite, hard coal etc.), those with a capacity below 50 MW
- For imported resources (mainly natural gas), those with a capacity of below 100 MW and those above 13 years of age
- Natural gas fired power plants with an efficiency level below 50%
- Wind and solar power plants
- For local resources, power plants with a weighted average capacity usage ratio below 10% in the last four quarters
- For imported resources, power plants with a weighted average capacity usage ratio below 15% in the last four quarters
- Imported coal power plants can only benefit from the capacity mechanism if they use a percentage of their fuel mix from local coal depending on the share of local coal

However, a new draft regulation has been recently published regarding the capacity mechanism as of April 13, 2021. According to the draft document, imported resources older than 13 years and power plants that had Build-Operate contracts will also be eligible to benefit from this mechanism. The rational behind the draft regulation is explained as the need to ensure energy security in the long term by ensuring that some power plants which could not operate due to low electricity demand and prices due to the Covid-19 effect, are kept in operation. If this draft regulation is passed, it will be easier for some older and less efficient power plants to remain in the system which will reduce system flexibility in the coming years[236].

The total budget for the capacity mechanism is identified at the beginning of each year. The capacity mechanism budget determined for 2021 is 2.6 billion TL. Based on the average exchange rate in the first 3 months of 2021, this amounts to 291.5 million Euros.

The mechanism favours local resources (lignite, hard coal) and should the total budget be higher than the required budget, the capacity payment to these sources will be made, with the remaining budget to be distributed among other sources (imported coal & natural gas).

The regulation has been revised as of January 9, 2019. According to the effective regulation, the capacity payment is now based on installed capacity and the fixed cost of power plants based on fuel type. The previous regulation also considered the realized day-ahead market prices and the marginal running costs of the power plant.

Although the mechanism is a tool used to ensure he country's electricity supply security, it can also hinder the modernization process in the electricity market. Under the current capacity mechanism, there is no provision that rewards flexibility. The mechanism instead enables some older and less efficient power plants to remain in the system.

Policy Recommendations

Several improvements can be made on the market architecture which may incentivize increased flexibility for conventional power plants

- The current ancillary services market provides a significant incentive for thermal power plants to realise flexibility investments. However, there are also some changes that can be made to increase the effectiveness of the system. Currently, only power plants with an installed capacity of over 30 MW are allowed to participate in the ancillary services market. Allowing for smaller generation units to join the market would increase competition and decrease the costs in the market. Such a change would also

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[235] Official Gazette No: 30307 , dated January 20, 2018

[236] Accessed from the EMRA website on April 13, 2021

effectively support flexibility investments in some smaller power plants such as gas engines which are more suitable to provide frequency control services. The eligibility criterion for participation can be lowered to 10 MW or even to 1 MW.

- The recent regulatory change which permits hybrid power plant installations is a positive step which can potentially enable increased flexibility for thermal and geothermal power plants. Further policy schemes should be developed that would incentivize such installations. Meanwhile, further changes should be made to the regulation in order to enable more geothermal power plants to benefit from this change. The current regulation has some shortcomings that prevent some geothermal power plants from constructing auxiliary solar or wind power plants in their vicinities. Due to the locations of the current geothermal power plants in Turkey, these power plants are also subject to the Soil Protection and Land Usage Law No: 5430. The regulations under this law currently prevent these power plants to install additional solar or wind power plants within their vicinities. The necessary changes or exceptions should be made in this legislation in order to allow for the full potential of hybrid power plant installations to be realized.
- The current lignite purchase guarantees should be abolished as they are incentivizing older and less flexible power plants. The purchase guarantee scheme enables some of the older lignite power plants to operate as baseload in the market. This effectively prevents any flexibility investments to be made into these power plants and distorts market prices by providing a purchase guarantee at a level higher than wholesale prices.
- The capacity mechanism in its current form enables less efficient and flexible power plants to remain in the electricity generation fleet. Since the mechanism favors domestic generation sources, it effectively subsidizes inflexible power plants and gives them a competitive advantage. The specifications of the mechanism should be changed to incentivize flexibility in the market rather than solely making a distinction between local and imported sources. Considering the current oversupply situation in the market, the abolishment of the mechanism can also be considered.
- Another important change can be made in the day-ahead market design. In contrast to many European countries, negative prices are currently not allowed in the day-ahead market with the floor price set as 0 TL/MWh. The abolishment of this floor and allowing negative prices to form in the market would increase the attractiveness of flexibility investments. Under such a change, especially some less flexible coal-fired power plants would be compelled to make flexibility investments that would enable them to avoid potential negative prices by decreasing their shut-down and start-up costs and periods.

5 Demand Side Management

Demand-side management (DSM) is an umbrella term for any policy aimed at balancing the electricity supply and demand in the transmission network by adjusting or controlling the demand. DSM can also be used to increase the flexibility of electricity systems especially with a high share of renewable energy sources.

Function and Applications

DSM can be accomplished through various means such as energy efficiency programs, peak load management and demand response.

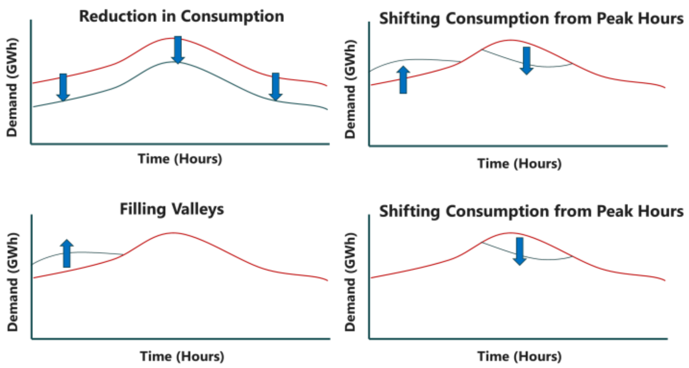


Figure 90. Types of DSM Applications

DSM can be carried out in four main ways. An overall demand reduction can be achieved by increasing energy efficiency and energy saving measures. Shifting consumption from peak hours to off-peak hours can be possible by time-of-use tariffs and in response to market prices. Filling valleys can be possible through electricity storage systems such as pumped hydro or battery installations. Finally, a reduction in peak hour consumption can be possible through interruptibility services and automatic load management[237].

DSM can also be used to increase the flexibility of electricity systems, especially those with a high share of renewable energy sources. With the help of DSM, large consumers can manage the quantity and the time the energy is consumed in a targeted manner. New policy schemes allow large electricity consumers to participate in the balancing power market by decreasing their load with instructions from the system operator at certain times, in a way similar to the generation facilities that receive additional revenue from the balancing power market. Such a scheme would be beneficial both for large consumers, who would receive an incentive to shift their consumption and for the system operator, by allowing for the less costly and more efficient running of the transmission system.

DSM applications are set to become more widely used in Turkey due to expected policy and regulatory changes in the market for the near future.

Potentials

Turkey has accountable potential in terms of DSM applications that can play a part in providing this flexibility demand. This is especially true for energy-dense regions such as İstanbul, İzmit and energy-intensive sectors such as iron&steel, cement, aluminium, glass industries.

The industrial electricity demand makes up a large part of the total electricity demand in Turkey. In 2019, the industrial sector was responsible for more than 41% of the total electricity demand in Turkey. As a result, a significant part of the demand-side management potential in the country lies in the participation of large industrial consumers.

[237] GO15 Reliable and Sustainable Power Grids, Working group FLEXILWATTS Demand for flexibility (2013)

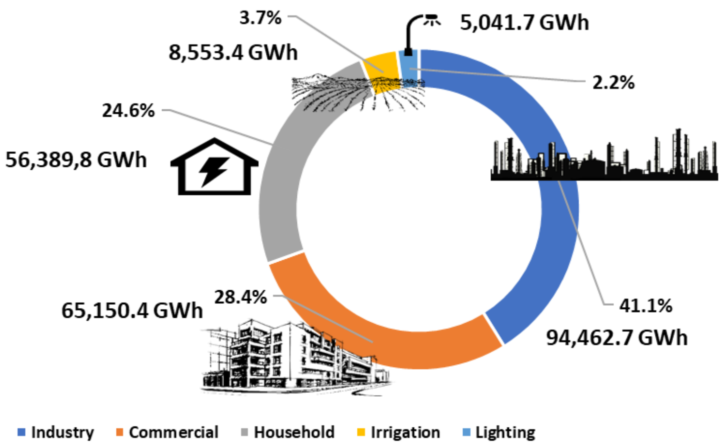
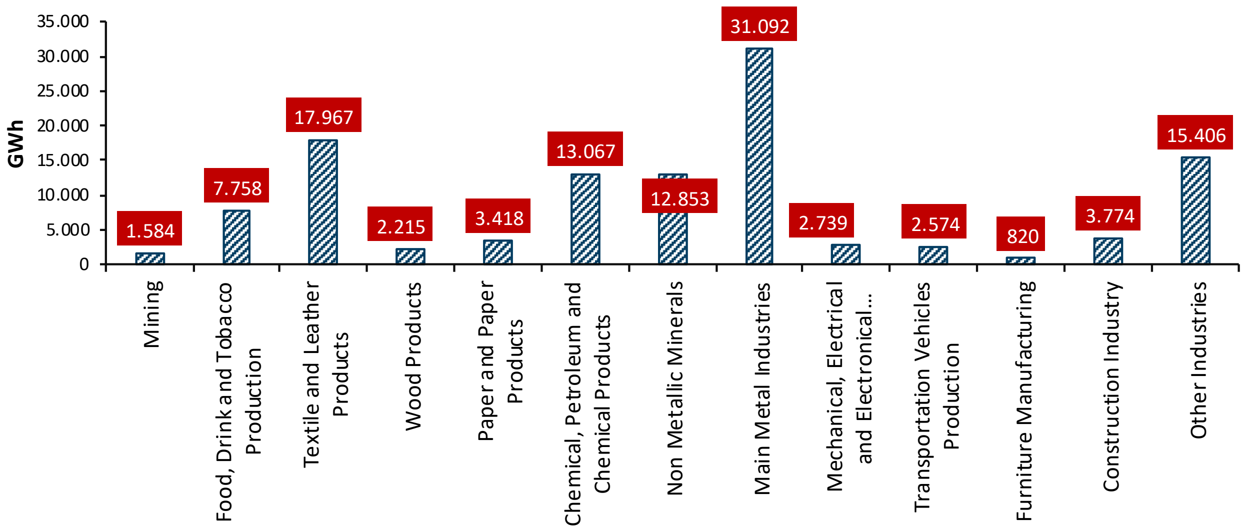


Figure 91. Sectoral Electricity Demand in 2019[238]

As mentioned earlier, a significant portion of the electricity demand in Turkey is concentrated in the northwestern Marmara region due to the population density in large cities such as Istanbul, İzmit and Bursa. A majority of the industry in the country is also disproportionally located in this region

Figure 92: Annual Electricity Consumption of Industrial Sectors in Turkey (2019)[239]



Policy and Regulations

The utilization of DSM applications is stressed as one of the top policy targets for the Turkish energy market in the official strategy documents.

The 'National Energy Efficiency Action Plan', published in 2017, is one of the earlier documents including a mention of DSM as one of the policy instruments to be used in the energy system. As specified under the action plan, Turkey aims to achieve increases in energy efficiency totaling 86,369 ktoe by 2033. An accompanying measure for the realisation of the target was the establishment of a legislative framework on demand response. According to the document, the legislative framework was set to be developed in 2018 and 2019 and the institutional infrastructure would be completed in 2020 and 2021 with implementation starting in 2022[240].

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[238] Electricity Market Sector Report, EMRA (2020)
[239] Energy Balance Tables, MENR (2019)
[240] 'Energy Efficiency Action Plan', Ministry of Energy ans-d Natural Resources (2017)

A stress on DSM was also made on the recently published 'Strategic Plan 2019-2023' by the Ministry of Energy and Natural Resources. According to the document, it is targeted that a legislative infrastructure for demand-side participation will be formed and a pilot demand site participation project will commence in 2021[241].

Additionally, the use of DSM applications was included as a policy target in the 'Eleventh Development Plan 2019-2023'[242] and the '2020 Annual Presidential Program'[243].

'Turkey Smart Grid 2023 Vision and Strategy Roadmap' prepared by the Energy Market Regulatory Authority and Elder is another document that lays out a plan for the utilization of DSM applications in Turkey. According to the document, Turkey will deploy an Advanced Metering Infrastructure for Distributed generation by 2025, install smart meters at 80% of the final customer's premises by 2035 and implement large capacity flexibility resources around 10 GW for under demand-side management[244].

'2020-2023 National Smart Cities Strategy and Action Plan' has been published recently, and will play a role in reaching the more digitalized, flexible and efficient structure[245]. There is a substantial potential for achieving reductions in electricity demand through the utilization of smart cities.

The Current Status

Despite the aforementioned plans to expand the utilization of DSM, such practices are currently not widely used in the country. The current utilization of DSM in the country remains quite limited. Under the current electricity tariff regulation, small consumers can opt to switch to a time-of-use regulated tariff which divides the day into three time zones based on the level of consumption. This application is applicable on the small scale and currently not a common practice.

Currently, the main DSM application being actively utilized in Turkey is interruptibility services. Regional blackouts are occasionally applied for some periods with unforeseen surges in demand which may be due to several factors such as heat waves. This measure can be taken as a last resort in cases where the electricity system can not be operated through more conventional solutions.

Instantenous demand control is included in the current Ancillary Services Regulation as a possible ancillary service. However, the scheme is currently not applied in the market.

Table 2. The Situation of DSM in the Market[246]

Market	Type of Service	Demand Response	Direct Participation from Demand-side	Aggregation
Ancillary Services Market	Primary Frequency Control	No	No	No
	Secondary Frequency Control	No	No	No
	Instantaeno us Demand Control	Yes	Yes	No
Balancing Power Market	Energy	Yes	No	No
Day-ahead Market	Energy	Yes	No	No
Intra-day Market	Energy	Yes	No	No

Nevertheless, important developments are expected in the market in the near future due to the anticipated change in the Ancillary Services Regulation regarding DSM.

[241] 'Strategic Plan 2019-2023', Ministry of Energy and Natural Resources, accessible from https://sp.enerji.gov.tr/ETKB_2019_2023_Stratejik_Plani.pdf
[242] 'Eleventh Development Plan 2019-2023', Presidency of Strategy and Budget (2019), accessible from http://www.sbb.gov.tr/wp-content/uploads/2019/07/OnbirinciKalkinmaPlani.pdf
[243] '2020 Annual Presidential Program', Presidency of Strategy and Budget (2019), accessible from http://www.sbb.gov.tr/wp-content/uploads/2019/11/2020_Yili_Cumhurbaskanligi_Yillik_Programi.pdf
[244] Turkey Smart Grid 2023 Vision and Strategy Roadmap Summary Report (2018), Energy Market Regulatory Authority and Elder
[245] '2020-2023 National Smart Cities Strategy and Action Plan', Presidency of the Republic of Turkey, accessible from https://www.akillisehirler.gov.tr/wp-content/uploads/EylemPlani.pdf
[246] Status Of Demand Side Management In Turkish Power Market Industry and Large Consumers ' Perspective, Mehtap Alper Sağlam, Energy Market Regulatory Authority, September, 2020

Recent Changes in the Ancillary Services Regulation

Demand-side management is one of the ancillary services defined under the Ancillary Services Regulation. With the draft regulation announced in September 2020, details for demand participation services have been defined, including some details on the auction process. The draft document was left open to public comments until november 9, 2020[247] and the final regulation was published in January 27, 2021[248].

According to the regulation, TEİAŞ will open auctions for pre-defined periods and participants will make their offers on a TL/MW basis for these periods. The auction will operate on a merit order structure. Large consumers connected through the transmission grid with an annual consumption of over 10,000,000 kWh will be eligible to join the market. Participants will be allowed to make bids in the market for 1 MW and its multipliers. The minimum bid amount is specified as 0 TL/MW. The payments will be invoiced to the participants on a monthly basis.

According to the current figures, the potential participants to the demand control market include a total of 4,131 MW demand, of which 1,734 MW consists of customers from the iron and steel industry, 902 MW consists of customers from the cement industry and 1,495 MW consists of customers from other industrial sectors[249]. The scheme is not currently applied in the market but expected to be in force in the near future after the regulation takes its final form.

Future steps regarding DSM in the electricity market can include an implementation of demand side reserve service in ancillary services and exploring the options for demand side participation in other electricity markets such as the day-ahead market, intra-day market and the balancing power market. The consumption limit is set to be reduced over the years and some steps may be taken to include consumers connected through the distribution grid in the new market. The procurement of ancillary services may be based on the distribution system level in the future. Moreover, a definition of demand aggregation in the market can be made and the market can be opened to aggregators. The standards and technical specifications for smart meters will also need to be drafted before the proliferation of smart meters in the market.

Policy Recommendations

Several key points should be considered in designing policies to increase the utilization of demand-side management in the energy market.

- Determination of energy intensive regions is very important since both peak and total load figures in these regions will be more critical. Therefore, the application of DSM for industrial areas is much more favorable. Accordingly, conducting comprehensive surveys to pinpoint these regions is one of the key elements in designing successful policies.
- Another factor that needs to be considered while designing action plans is the consumer. Quick response to a system operator's instruction is vital in order to properly apply DSM measures. The opportunity costs and potential benefits of flexibility should be highlighted for demand-side participants. From this point of view, larger consumers have better potential to amortise their investments due to the economy of scale. The policymakers thus need to consider this priority of the large consumers but should appeal to as many actors as possible with incentivizing regulations. It needs to be mentioned that although energy-intensive regions and large consumers are the initial interests of DSM, after the steadiness and modernization of the infrastructure are achieved, small and less energy-intensive consumers also need to participate in the demand-side market.
- Lack of knowledge, digitalization and data quality are observed to be the main obstacles. Therefore, it is recommended to start DSM operations from less risky departments such as emergency generators or secondary services while in the meantime eliminating the deficiencies within the system.
- DSM is more applicable for electricity consumption during heating and cooling operations. Industrial operations that require these operations are more resilient to interruptions in electricity supply. These relatively longer industrial practices act similar to electricity storage due to their heat capacities and do not respond quickly to the electricity supply. As a result, their *value of lost load* is relatively less

[247] EMRA, accessed from https://www.epdk.gov.tr/Detay/Icerik/4-8206/elektrik-piyasasi-yan-hizmetler-yonetmeligi-degis
[248] Electricity Market Ancillary Services Regulation Changes, Official Gazette No:31377 dated 27 Ocak 2021

[249] Status Of Demand Side Management In Turkish Power Market Industry and Large Consumers ' Perspective, Mehtap Alper Sağlam, Energy Market Regulatory Authority, September, 2020

compared to other consumers. Because of the retarded effect, heating and cooling processes are ideal for the utilization of DSM. Moreover, meeting the heat demand partially or optionally from other sources allows to increase the flexibility of heating&cooling processes. With this consideration in mind, heat pumps (ground, water or air sourced) would help to increase flexibility of the electricity market.

- Studies on smart grids and a roadmap have already been been established. However, there is still long way to go under the scope of this program. Although advanced metering infrastructure and smart metering targets are planned under the 'Turkey Smart Grid 2023 Vision and Strategy Roadmap', only 3% of the final customers are currently benefiting from smart meters.
- In Turkey, end-users can select their tariff either in single-time or three-time (smart) format. If the consumer does not assert the contrary, the agreements are made in single-time type. On the other hand, the three-time tariff option enables the consumer to use electricity in regular prices during the morning, while charging higher during the peak hours and much more favorable during the nighttime. In order to spread use of three-time tariff and control the demand especially during the peak hours, the advantages of this choice should be emphasized. However, three-time tariff is an option only if the consumer has a smart meter, because regular ones cannot measure the consumption in three-time format. Therefore, the benefits of smart grids and metering need to be further investigated and information about the smart tariff should be disseminated. New tariff conditions might also be discussed and regulated, in order to further attract potential consumers' attention.

6 Power-to-Gas

Power-to-gas technologies are technologies that use electricity to produce gaseous fuels. These gases, consisting mostly of hydrogen can, in turn, be used in several ways including storage in the gas system for later use, industrial uses and injection into the natural gas grid. Power-to-gas systems can provide increased flexibility by allowing the excess electricity generated to be stored for later use. These systems are viable options that can be utilized for the Turkish electricity system over the coming years.

Function and Application

Hydrogen, as an energy carrier, needs a primary source of energy to be produced. The resources that can be used in this process can be fossil fuels, nuclear power and renewable resources such as solar, wind, and hydro power. The different colors used for hydrogen in the energy literature represent the primary sources utilized in the production process. The most common hydrogen types in use are the ones with green, blue and grey colours.

Blue hydrogen is the one that formed when natural gas is separated into H_2 and CO_2 either by Steam Methane Reforming (SMR) or Auto Thermal Reforming (ATR). However, emitted CO_2 is captured instead of releasing to atmosphere and then stored. As the greenhouse gasses are captured with the ratio of 85-95%, this mitigates the environmental impacts on the planet.

On the other hand, **grey hydrogen** has a similar production process to blue hydrogen and SMR or ATR are used to separate natural gas into H_2 and CO_2. However, the main difference is that the CO_2 is not being captured, instead released into the atmosphere.

Green Hydrogen is hydrogen produced by separating water via electrolysis. This chemical process produces only hydrogen and oxygen with no negative impact on atmosphere. To perform the electrolysis, required electricity is originated from renewable energy sources, such as wind or solar. Therefore, green hydrogen is the cleanest option.

There are three main water electrolysis methods currently being used in the context of power-to-gas conversion:

- **Alkaline Electrolysis:** Under this method, the reaction occurs in a solution composed of water and liquid electrolyte (KOH or NaOH) between two electrodes. It is the most mature and well understood power-to-gas application that has been in use for decades. It has the lowest cost in power-to-gas applications and relatively high lifetime. However, on the downside, the efficiency of the process is comparably lower depending on the source.

- **PEM Electrolysis:** This method is based on the utilization of solid polymer membranes. The advantage of this method is faster cold-starts, higher flexibility and high quality of produced hydrogen. Although the costs of this method are higher compared to alkaline electrolysis and the lifetime is shorter, due to the significant technological development over the last few years, PEM technology became competitive with Alkaline Electrolysis.

- **Solid Oxide Electrolysis:** Solid oxide electrolysis is a novel method that is currently under development. The main characteristic of this method is high temperature electrolysis. Lower lifetime is a main disadvantage of this method with higher efficiencies being the upside. However, this is only achieved at the high temperatures when the heat for high temperature is supplied externally (e.g. industrial waste heat or solar thermal energy). If electricity is used to heat the electrolyser, the (electrical) efficiency drops significantly. The costs are currently very high as the method is still in the research and development phase[250].

Today, the cost of producing green hydrogen is much higher than producing blue and grey hydrogen. Facility investment and electricity generation costs from renewable sources make green hydrogen more expensive than blue hydrogen. According to a study, the production cost of green hydrogen today is between USD 6 and USD 10 per kg which is around 4 times higher than natural gas-based production at the level of 1.5 €/kg[251].

Because green hydrogen technology is not yet economically feasible enough, it is mostly used by countries with very high technological level and environmental commitments. On the other hand, some minor attempts can also be observed in the Turkish Energy System, especially regarding blue hydrogen production.

[250] 'Renewable Power-to-Gas: A technological and Economic Review'(2016), M. Götz et al, Renewable Energy, Volume 85

[251] Priority Areas for Turkey's National Hydrogen Strategy, Shura Energy Transition Center (2021)

Current Status

Previously, Turkey has tried to increase its research and development about hydrogen by supporting UNIDO-ICHET in Istanbul. However, this support was closed after a while because it did not meet the expectations of the policy makers.

In a meeting held on January 15, 2020 MENR ("Hydrogen Search Conference") hydrogen has been included in Turkey's energy conversion vision concretely. According to "Hydrogen Study Map of Turkey" which took part in this conference, it is indicated that a total of 28,156 academic studies have been carried out across the country as of October 31, 2019 and the necessary theoretical competence for applications has been achieved.[252]

There is currently no legal framework concerning Power-to-Gas and hydrogen applications in the country and these systems are currently not being utilized. However, due to the lack of regulation, there is no obstacle that would legally prevent such a utilization. The expectation is that a move to address these inadequacies will be taken in the near future.

Despite the lack of a current regulation, there is a major ongoing R&D project in the country regarding Power-to-Gas systems. A regulation is expected to be drafted at the conclusion of this project. The drafting of a regulation will be completed after observing the results of the project. It is expected a new legislation to be introduced in 2021 that would allow 1-2% blends in transmission and distribution grids.

Within the scope of aforementioned R&D project GAZBİR-GAZMER CleanGas Clean Energy Center was opened in Konya. Distribution association GAZBİR has been conducting various laboratory tests starting from 2020 that allowed them to blend hydrogen in natural gas networks at 5, 10, 15 and 20% in this center. Within the scope of this project, an investment of 1 million Euro was made in 2020 with the financing provided by EMRA. In addition to EMRA, universities and private sector companies also support the project. In this way, 6 million TL of the required financing of 3-4 million Euros, which the project will need in 2021, was met by two private sector companies. [253] After the first positive results of the initial tests, combustion tests, economic and environmental impact analysis, efficiency and performance studies will be carried out in this center.

The project aims to contribute to the Turkish electricity market's security, flexibility and eco-friendly structure. The project's duration is specified as two years and alkaline electrolysis method is being utilized under the project.

According to the policy makers, although green hydrogen is the preferred option, Turkey may also consider producing hydrogen from natural gas or lignite for the upcoming projects in the near future because recent discovery of over 400 billion cubic metres of natural gas in the Black Sea combined with significant domestic lignite reserves provide sufficient resources to allow it to develop a sizeable blue and grey hydrogen sector.

These developments and the increasing electricity generation from renewable sources in the Turkish market make power-to-gas applications enticing options to be used in the future. However, a legal framework and an attractive market ecosystem will first need to be established for significant developments to happen.

Potentials and Risks

Although it is not possible to find a common and optimum solution for the last consuming sectors, especially green hydrogen has a potential that favours for many sectors. The hydrogen can be used in a variety of ways such as fuel for transportation, as a feedstock for industry, to generate power through gas turbines or fuel cells after being stored or being injected into the natural gas grid.

- In many industries such as iron, steel and cement that require high temperatures usually fossil sources are utilized, since it is not possible to reach those temperature levels by electrification provided by intermittent sources such as wind and solar. However, hydrogen has the potential to be an alternative fuel in these industries, making it possible to reach different temperature values as a clean source. Moreover, in countries such as Germany where "green steel" production is a hot topic, industrial processes using green hydrogen applications can be encountered. With the application of carbon border adjustment mechanism (CBAM), which is on the agenda of Europe, countries that export to this region must also decarbonize their production using similar renewable technologies. Green hydrogen utilization in the processes, when Turkey's thought to be an important European steel exporter, may be an effective solution to avoid CBAM. Thus, related regulatory adjustments

[252] Ibid.
[253] Enerji Günlüğü 04.04.2021, accessed from https://www.enerjigunlugu.net/gazbir-gazmer-temiz-enerji-merkezi-acildi-42180h.htm

to be made will be very important in terms of Turkey's economical and environmentally-based targets.

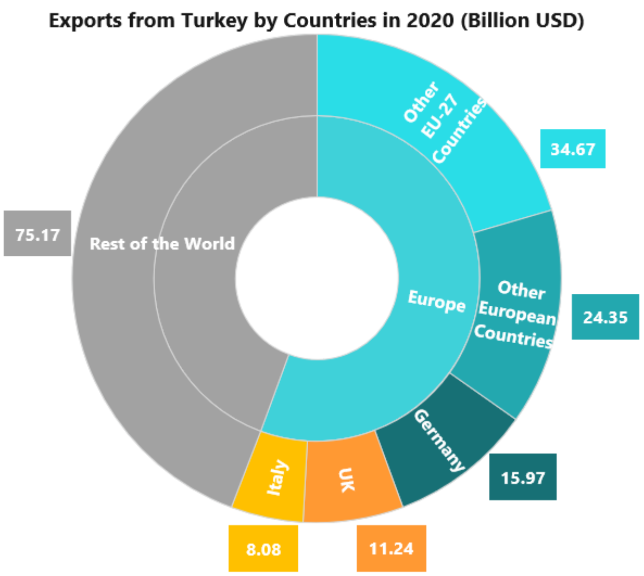

Figure 93. Exports from Turkey by Countries in 2020 (Billion USD)[254]

- Hydrogen can be mixed into the natural gas network as well as used directly in the heating system of buildings. Some countries, reached up to the 50% levels. In case of mixing natural gas with 10% of hydrogen, it is thought that Turkey's natural gas import bill will drop around 1.2-1.5 USD billion. This would decrease import dependence in energy security, accordingly.[255]

- Green hydrogen utilization in the electricity system serves as a solution to the congestion problem by providing demand flexibility in addition to meeting direct load demand. When stored, hydrogen clear up experienced imbalances during periods of the peak demand. The integration of electrolysis installed capacity into the renewable energy system will ensure that the electricity surplus is stored as green hydrogen and will be provided during later uses. Furthermore, the storage capabilities of power-to-gas applications have an advantage over battery storage systems since they can store larger quantities of power over longer time periods.

- Hydrogen is also a futuristic alternative fuel for the transportation sector. Some niche models such as Toyota Mirai, Honda Clarity and Hyundai Nexo have already been commercialized globally.

Despite all these potentials, there are some disadvantages and risks associated with hydrogen production and storage.

- The production method of hydrogen is very important. While green and blue hydrogen are produced in accordance with environmental commitments, grey hydrogen production may cause a significant increase in emissions.
- Facility and infrastructure investments and electricity generation costs from renewable sources prevent hydrogen production from reaching sufficient economic competitiveness today.
- There is a need for an increase in efficiency in hydrogen production technologies.

Policy Recommendations

Even though the Power-to-Gas applications in Turkey are in their nascent stages, several policy actions can be considered in advance to ensure future development.

- Direct injection of hydrogen into the natural gas grid can only be made under certain limits due to technical and safety related issues. Different countries have varying limitations on the share of hydrogen that can be injected into the natural gas grid. As mentioned earlier, some countries reached up to 50% the levels. Limitations in this mixing ratio are due to the different energy densities of natural gas and hydrogen. Since the energy density of hydrogen is much less, there are differences in mixing pressure and volume in order to reach similar energy levels. For this reason, a more complex infrastructure is required for hydrogen injections above 20%. In this respect, the current R&D efforts are crucial in creating a know-how base and facilitating the establishment of a regulatory framework in the country. These efforts should be sustained and expanded into the future[256].

- The injection of hydrogen gas into the natural gas grid may necessitate new arrangements to be made in the energy market. For example, the use of smart meters may be a necessary provision. Such considerations

[254] TÜİK (2021)
[255] Enerji Günlüğü 08.10.2020, accessed from https://www.enerjigunlugu.net/arslan-hidrojen-katkisi-dogalgaz-ithalatini-1-5-milyar-dolar-azaltir-39344h.htm
[256] Priority Areas for Turkey's National Hydrogen Strategy, Shura Energy Transition Center (2021)

should also be taken into account in designing a long-term hydrogen strategy.

- R&D investments should be increased in order to improve the efficiency and decrease the cost related to hydrogen-fueled vehicles, which are currently used only in a niche role.
- After the establishment of a regulatory framework and a long-term roadmap for hydrogen gas market, the development of specific subsidy mechanisms should be on the agenda. The production of hydrogen can potentially be supported by a type of feed-in tariff scheme which would enable the nascent technology to be applied on a utility-scale and become eventually self-sustaining. Such policy support may be necessary for the technology in its earlier stage, similar to the pathway observed for more conventional renewable energy sources over the last decades.
- Alternative policy options that could accelerate the utilization of hydrogen include financial mechanisms like loan guarantees or tax breaks or employing renewable or low-carbon obligation standards. The employment of an ETS scheme in Turkey has been on the agenda for some time. The realization of this target would facilitate the development of hydrogen energy as a low-carbon energy source.

7 Further Operational and Market Design Flexibility Options

In addition to the aforementioned technical solutions regarding system flexibility, there are also several operational and market design measures that can be implemented. Such measures are generally the options that can bring about benefits at the lowest cost since they don't require major investments to be made into the system. In this regard, there is a wide variety of policy options to choose from involving potential changes across several markets operational in the country, several of which will be detailed in this section.

Main Operational and Market Design Options for Turkey

Several main items can be listed among operational and market design flexibility options including:

1. Increasing temporal and spatial granularity in the market
2. Potential improvements in the ancillary services market
3. Renewable energy curtailment
4. Redispatch schemes
5. Higher utilization of the existing transmission grid
6. Increasing the cooperation between the TSO and the DSO
7. The adoption of advanced variable renewable energy forecasting techniques

The current situation in the Turkish electricity market regarding these options and the potential improvements will be deliberated on in the following sections.

Increasing Granularity in Electricity Markets

Before pointing at the possible improvements in the market regarding granularity, it is necessary to highlight some of the main characteristics of the current situation in the market.

Spot market provides a reference price for the electricity market in Turkey. Day-ahead Market and the Intra-day Market are the two electricity spot markets operated by EPİAŞ. Participation in the spot markets is not obligatory. Market participants can offer their bids including price and quantity to buy or sell electricity from the day-ahead market for each hour of the following day. The market clearing price (DAMP) and the traded volume are determined for each hour through matching the bids made by buyers and sellers. After the day-ahead market closes, participants have the option of supplying through the intra-day market.

There is a potential to finetune the design of these markets to improve the flexibility of the energy system and there are several means to achieve this. Increasing granularity in terms of both time and space is one of those ways to reach a more innovative market structure.

The Current Situation in the Intra-day Market and Existing Time Granularity

The transactions in the day-ahead market are made a day in advance of the physical transfer of electricity. Meanwhile, in the intra-day market, offers can be given, updated, canceled or disabled up to 60 minutes prior to physical delivery. Since the transactions are closer to real time in the intra-day market, there is more potential to develop the intra-day market in terms of time granularity.

Intra-Day Market acts as a balancing mechanism between the Day-Ahead Market (DAM) and the real-time markets. Gate closure in the market is made 60 minutes advance. This market provides an additional platform for trade of electricity in addition to decreasing imbalances of the power system. Currently, the operation is performed on an hourly basis. The delivery hours for the intra-day market start at 00:00 every day and end at 00:00 the next day. The offers for the following day can be issued at 18:00.

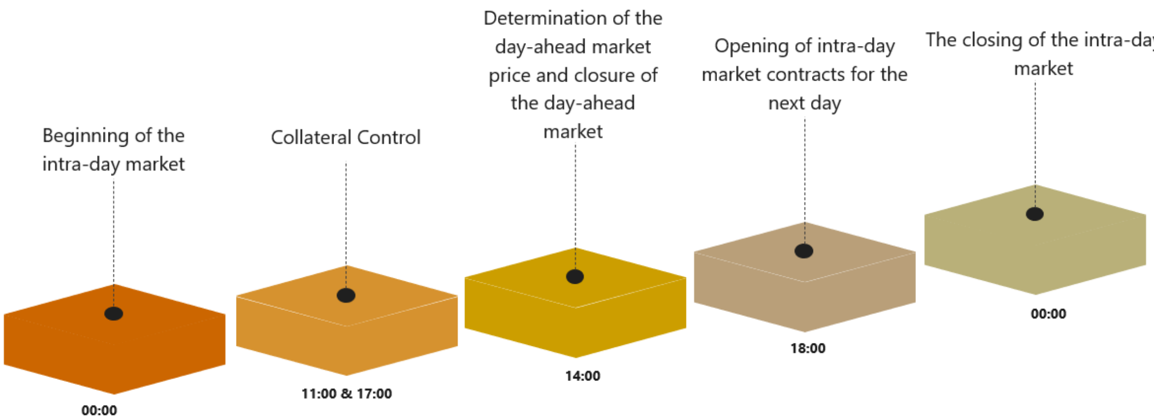

Figure 94. Current intra-day market mechanism in Turkey[257]

There are two types of offers available in the Intra-Day Market

- **Hourly Offers:** The hourly offers can match completely or partially. The order of offer is important. In other words, the first entered offer takes precedence over the following. There are 4 hourly offer options: Active Offer, Immediate or Cancel, Expiration Time and Fill or Kill.

- **Block Offers**: The block offers cannot be divided. These offers are either accepted or rejected for the whole of the time period. Block offers cover a minimum of 1 hour and a maximum of 24 hours. Block offers cannot include hours of two different days. There are 2 hourly offer options: Active Offer and Timely Offer.

The traded volume in the intra-day market has grown significantly following its launch in 2015, reaching almost 5.5 TWh in 2019. It is expected that the market will become more important in the near future with increasing penetration from variable renewable energy sources. The intra-day market is a useful platform for renewable energy power plants because it enables these power plants to make transactions closer to real time which improves the accuracy of their generation forecasts. Therefore, any improvement in the intra-day market is set to have a boosting effect on the general flexibility of the electricity system and enable the conditions for increased integration of variable renewable energy sources into the system.

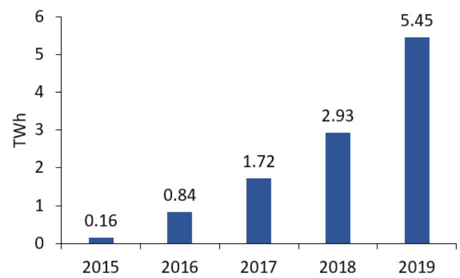

Figure 95. Intra-day Market Annual Matched Volume in 2019[258]

In **Figure 96**, the hourly generation forecast deviations of 4 different WPPs in different time frames in one month of 2020 are given. For all 4 plants, the deviations decreased as the estimation time became closer to real time. Therefore, increasing time granularity in the intra-day market and allowing the offers closer to the real time

[257] EPİAŞ, accessed from https://www.epias.com.tr/gun-ici-piyasasi/surecler/
[258] EPİAŞ Annual Market Reports (2015 figure includes the days between July,1st and December, 31st)

would increase the generation forecast accuracy of renewable power plants.

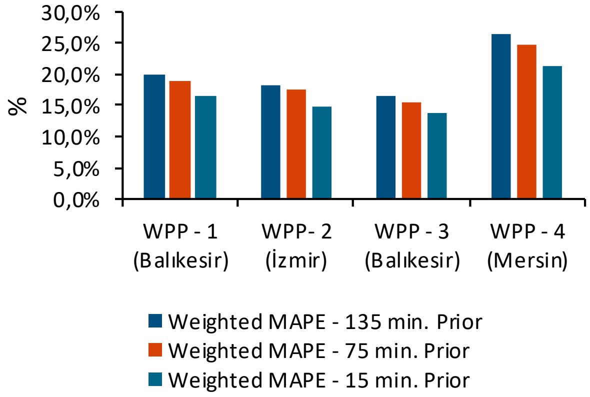

Figure 96. Hourly generation forecast deviations in different time periods for 4 sample wind power plants

The current 60 minute gate closing time in the Turkish intra-day market is relatively high in comparison to several markets.

For example:

- In Austria, Belgium, Germany and Luxembourg (in certain TSO areas only) the local intra-day gate closure time is five minutes before the beginning of physical delivery. Moreover, 15-minute products for continuous trading are available in Austria, Belgium, Germany, Hungary, Luxembourg, the Netherlands, Slovenia and Switzerland.

- 30-minute products for continuous trading in intra-day markets are introduced in France, Germany, Luxembourg, Switzerland and the UK.

- Australia also transitioned from a 30-minute to a 5-minute financial settlement, and from a 2-hour to a 30-minute gate closure time.[259]

Increasing time granularity by means of bringing trading intervals closer to real time could have a boosting effect on system flexibility. Moving the gate closure times closer to real time would increase the accuracy of generation forecasts and decrease the imbalance caused from renewable energy sources.

This issue is currently under consideration in the market and possible 15-minutes and 30-minutes scenarios are being considered. Correspondences with state agencies revealed that the EPİAŞ infrastructure is for the most part ready to accommodate for such a change but several optimization studies must first be conducted before a final decision is made.

The Current Status of Spatial Granularity in the Market

The flexibility of the electricity system can also be increased by the utilization of 'bidding zone review'.

The most common place practice in the world is to determine the electricity prices per bidding zone which is referred to as zonal pricing. This approach overlooks the capacity of the transmission lines within the zone and assumes an inifinite transmission availability. This increases the hidden transmission costs in the network especially arising from the increased share of variable sources in the electricity generation mix.

A possible solution to this problem is to break the bidding zone into smaller regions, a process called the bidding zone review. The extreme point of this process is referred to as nodal pricing under which each node of the transmission sector is priced separately. This allows for all the transmission lines in the system to be taken into account in the development of prices.

Even though it is currently not a widespread application, there are several examples of markets in the world that are moving toward nodal pricing. Several US states have implemented locational pricing since they have independent system operators. The pan-European market also uses a zonal pricing mechanism, and some countries have divided the national transmission system into more bidding zones, including Denmark (two bidding zones), Italy (six geographical bidding zones), Norway (five bidding zones) and Sweden (four bidding zones)[260].

The application of regional or nodal pricing would enable the sending of locational price signals which would reflect the contstraints in the system and in the long-run assist in curbing these constraints. The locational price signals would in the long-run guide the investments into the generation sector into the locations which would ease the strains on the transmission network.

Currently, Turkey has a wholesale price for the entire country (one bidding zone) which serves to hide the costs of congestion that been steadily increasing.

[259] Increasing Time Granularity in Electricity Markets, Innovation Landscape Brief, IRENA (2019)

[260] Increasing Space Granularity in Electricity Markets Innovation Landscape Brief, IRENA (2019)

As mentioned under 'The Large Scale Batteries Section', there are significant differences between different regions in Turkey regarding electricity consumption and generation patterns. To reiterate some of these:

- The majority of the demand in the country is concentrated on the Northwestern Marmara regions with overpopulated cities like Istanbul and large industries. A large share of the generation from other regions thus has to be transferred to this region.
- The majority of the hydropower capacity in the country is located in the East with relatively less electricity demand (majority reservoir hydro capacity being in the Southeastern region and the majority of the run-of hydro demand being in the eastern Black Sea Region).
- Wind power capacity in the country is generally concentrated in the Aegean Region with relatively less electricity demand.
- Most of the prospective investments in the country are also set to be made in regions with relatively lower demand. These include the Akkuyu NPP in Mersin, the Solar YEKA project in Konya and the EMBA Hunutlu TPP in Adana.

As a result of these characteristics of the electricity system, a vast amount of electricity generation has to be transferred over long distances which causes transmission constraints and high level of transmission losses. There is currently no mechanism in the energy market that offers locational signals for new investments outside of a fixed component of the transmission tariff which is distinguished between 14 transmission regions determined according to the demand and supply situation in each respective region[261]. This regional transmission tariff scheme is not sufficient by itself to offer locational signals for investment.

Moving to a nodal pricing scheme would theoretically be the most optimum solution to account for the transmission constraints. The benefits of nodal pricing increase with increased penetration from variable renewable energy sources. On the other hand, the move to a nodal pricing scheme is not easy. The introduction of such a scheme would require comprehensive changes such as a robust framework for dealing with market power and the establishment of financial rights for market participants. One important problem with nodal pricing is that structural congestions might change over time, thus requiring the reconfiguration of nodes, which would necessitate an ongoing and arduous process.

Due to such technical and administrative challenges, it seems that a regional pricing scheme can be a more realistic solution for Turkey for the foreseeable future. Although there are discussions in the country regarding a transition to a regional market scheme, this also is not likely in the near future due the the large amount of changes in the system such a shift would necessitate.

An initial and less costly transitional change could be the adoption of regional pricing based on the two broad regions of Anatolia and Thrace. If this could be implemented, the congestion costs through the electricity system of the country would decrease and it would potentially act as a step towards further spatial granularity in the market. As an important obstacle to this transition is seen as the very high prices that may occur especially in the region that includes Istanbul, compared to the rest of the country. Further discussions and studies are ongoing between EPİAŞ and TEİAŞ regarding regional pricing. After the optimizations to be made, 2 regions (Anatolia and Thrace) can be tried to see if the country's infrastructure is sufficient for this transition.

Potential Improvements in the Ancillary Services Market

Ancillary Services is the support services that must be provided by the generation units and some transmission equipment to ensure the safe operation of the network in real time. Real time frequency control is among the most important of these services since the frequency of the system must be maintained at all times to ensure the quality of the supplied electricity. Increasing the effectiveness of this market would reduce the costs associated with imbalance and increase the flexilibity in the market.

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[261] EMRA, accessed from https://www.epdk.gov.tr/Detay/Icerik/3-23478/teias-2020-yili-sistem-kullanim-ve-sistem-isletim

The Current Ancillary Services Market in Turkey

Ancillary services in Turkey consist of the systems defined under the Ancillary Services Regulation, in order to ensure the system integrity and operational safety of the system. The TSO, TEİAŞ is responsible for the operation of ancillary services. The following items are included under the ancillary services regulation in Turkey[262]:

- Primary Frequency Control
- Secondary Frequency Control
- Standby Reserves
- Instantaneous Demand Control
- Reactive Power Control, Black Start
- Regional Capacity Rental Service

Although these definitions are all included under the regulation, only primary and frequency control services are currently procured in the market. These services are acquired through daily auctions in the market since the new Ancillary Services Regulation was adopted in November, 2017. The Ancillary Services Market Management System (YHPYS) operated by TEİAŞ was also established with the adoption of the new regulation.

Primary and secondary frequency controls are referred to as automatic frequency control. The primary frequency control service aims to keep active power in balance and to stabilize the system frequency immediately. The primary frequency control reserve must be available at any time. Primary Frequency control generators provide a balance between supply and demand through the speed regulators automatically and quickly.

The generation facilities that will participate in the primary frequency control service must satisfy the conditions regarding the technical principles of the primary frequency control and the design principles and test that are included in the Regulation on Electricity Market Network.

The primary frequency control service is procured through tender from generation facilities that meet the required conditions and have passed the test.

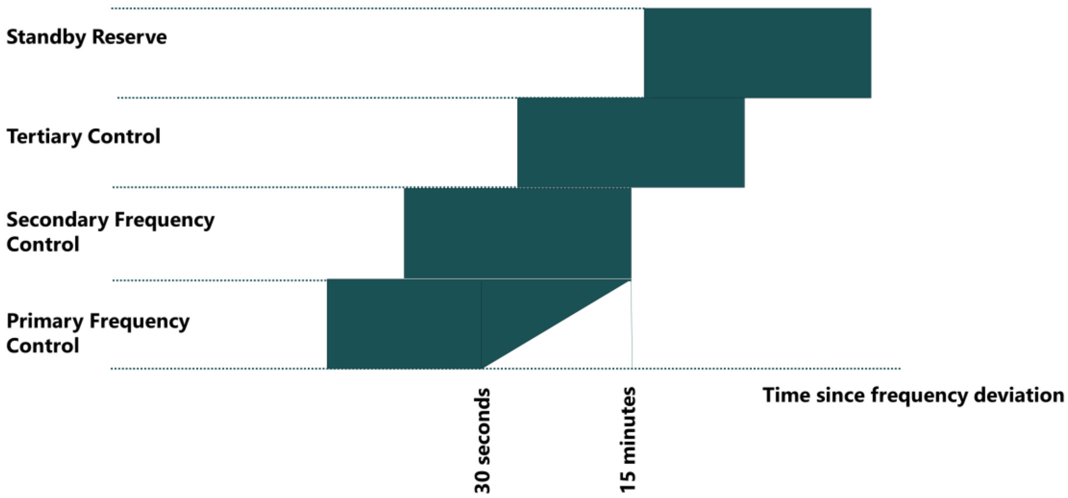

Figure 97. Timeframes for Ancillary Services in Turkey

Units that provide this service must activate within a maximum of 30 seconds and must be able to maintain this power for at least 15 minutes.

According to the working principle of the units providing primary frequency service;

- If the system frequency decreases, the output powers are automatically increased in response to the drop in frequency,
- The units automatically reduce their output power in case of increasing of the system frequency.

On the other hand, secondary frequency control (SFC) is a system that the system operator TEİAŞ uses to maintain

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[262] Electricity Market Ancillary Services Regulation, Official Gazette No:30252 dated 26 November 2017

system frequency in cases of excess capacity or demand surplus. Under the old system, this was done through compulsory instructions given to power plants in the balancing power market and it was compulsory for all participants to participate with as much as 0.5% of their installed power. Under the current system, the secondary frequency control service aims to set the system frequency to its nominal value through a market based approach with the utilization of auctions. The system is automatically activated through a central computer algorithm; however, it is slower than primary frequency control. It aims to address the potential problems in the electricity system for instances in which primary frequency control are insufficient.

The facilities which will provide secondary frequency control services are selected from among the facilities that have this qualification via tenders. The secondary frequency control allows the primary reserve power plants to return to their pre-fault operation points. In this way, the primary frequency services will be ready for the next possible fault. This is managed by the automatic system located at the Gölbaşı National Load Dispatch Center of TEİAŞ.

Under the new system, tenders are made two days ahead for providing primary and secondary reserve services. TEİAŞ is designated as the system operator. Each day, the power plants which are the winners of the tender from two days earlier are obligated to operate at their ‘set point’ value in order to be able to shed or increase their loads as per the requests of the system operator.

The new mechanism is aimed at decreasing the overall balancing costs borne by the system.

To be eligible to join in the ancillary services market control mechanism, power plants should:

- make an agreement with TEİAŞ for being part of the system,
- have an installed capacity of at least 30 MW
- have the technical requirements specified by TEİAŞ (e.g. load increase and shedding time),
- operate in their set point of generation for the specified day and follow any requests from the system operator

TEİAŞ receives bids and provides necessary information for the ancillary services market (primary and secondary frequency control) through its market management system (TPYS).

In recent years, the need for innovations in ancillary services is increasing, especially due to the increase in the share of variable renewable energy in generation. The intermittent nature of solar and wind power sources requires the power system to have more convenient and successful ancillary services. This becomes important for the Turkish market since the installed capacity of wind and solar power plants have been steadily increasing over the last decade and the increase is expected to continue for the foreseeable future.

Potential Improvement Points for the Ancillary Services Market in Turkey

Several methods exist for the improvement of ancillary services markets. One of these methods is the participation of battery systems in ancillary services. In Europe, Germany and UK introduced battery storage systems to have a better frequency regulation and more flexible power system. Turkey is also working for introducing battery systems to its power market. The public opinion regarding the draft regulation prepared within this scope has been received and the further efforts continues on it. However, there is no regulation about this field currently. The details of the related efforts are mentioned in the small-scale and large-scale battery systems sections.

With the ancillary services market experience in Turkey spanning over two years, it is apparent that there are several ways by which the market can be improved.

One way to improve the market is to bring the auction dates closer to real-time. Under the current situation, the market participants can enter the auctions two days in advance of their reserve obligations. This creates several optimization problems. Since the participants don’t have knowledge of the day-ahead market prices during the SFC auction, they have to use forecasted prices in calculating their optimum bids to the market. The design of the market can be improved by moving the auctions closer to real-time so that that participants can make more informed bids during the auctions. This would also enable the market to operate more efficiently in general.

Another important point is increasing the participation in the market. Currently, only generation units with over 30 MW capacity are allowed to participate in the market. The offers in the market are made in multiples of 1 MW and the minimum offer level is 1 MW. If a power plant agrees to hold 1 MW reserve capacity for a given hour, the TSO has the option to change the power plant’s output by 1 MW within the hour in either the positive or negative directions. Therefore, the actual generation of the power plant can vary within the hour.

The inclusion of smaller generations units would increase the competition in the market and decrease the overall costs. Also, as mentioned in earlier sections, the participation of battery systems in the market would also be key in this regard.

Redispatch Schemes

In order to provide grid stabilization, TSO's can decide to increase or decrease electricity generation from thermal power plants in the system by instructing the power plants to shift their electricity generation schedule. These instructions can generally be classified as redispatch schemes which constitute another option to provide balance in the transmission system. Redispatch measures are generally taken as last resort measures.

These instructions can be given from the day-ahead or in real-time. The redispatch measures in the day-ahead market are applied in several markets with high renewable energy penetration such as Germany. Under such a case, the daily dispatch plans for power plants are changed for the following day. Meanwhile, real-time interventions can be made via real-time balancing power markets through instructions.

In Turkey, there is currently no redispatch scheme applied for day-ahead planning. Meanwhile, the real time congestion and imbalance problems in the transmission system are handled through instructions issued through the balancing power market.

Balancing Power Market in Turkey

The balancing power market (BPM) aims to equalize the total electricity generation to the total amount of electricity consumption in real-time. The market is responsible for providing a reserve capacity for real-time balancing that can be activated within a maximum of 15 minutes.

According to the Balancing Market Regulation, balancing units that are able to handle a minimum of 10 MW up or down-regulation within 15 minutes are obliged to participate in the BPM. As opposed to the day-ahead market and intra-day market, plant-based operations are performed in the market.

The operation of the balancing power market is based on loading and de-loading instructions given by the system operator. If the frequency falls below 50 Hertz, it means that the consumption is higher than the generation. TSO requests to increase the generation and this instruction is called loading instruction. Likewise, if the frequency rises above 50 Hertz, the generation level is higher than consumption; therefore, generation should be decreased. This instruction is called de-loading (load shedding) instruction.

The system marginal price (SMP) is calculated on an hourly basis by taking into account the balancing needs and the loading and de-loading offers made in the Balancing Power Market. In case of a supply deficit in the market, the price is calculated to match the volume from the lowest of loading offers while in case of oversupply, the price is calculated to match the volume from the highest bid from the de-loading offers made in the market .

Main Principles of Balancing Power Market;

- The minimum amount of offers submitted to the balancing power market is 10 MW. All quoted loading and de-loading are expressed in 1 MW and multiples of 1 MW.
- All offers for the balancing power market apply to a certain balancing entity, a given offer zone, a certain day and a specific time period within that day. In the offers, it is essential to present all available capacity for the related balancing entity.
- The accepted YAL and YAT offers create an obligation for the market participant.
- The balancing power market instructions can be issued or changed at any time of the relevant day.
- The first price of loading and de-loading offers starts from the Day-ahead Market Price at that hour.

Curtailment of RES

Renewable energy capacity showed a worldwide increase in the last two decades. Renewable installed capacity in the world grew substantially in the last two decades thanks to several incentives, international agreements to cut CO_2 emissions and decreasing investment costs. As a result of renewable energy capacity growth in the market, electricity generation from renewable resources can exceed the total demand in certain hours. In such occurences, the electricity generation from renewable sources need to be curtailed by some amount in order to balance demand and supply. On the other hand, market participants can also decide to change their generation depending on market conditions. This reduction in renewable energy generation is called the curtailment of RES.

There are three types of curtailment that can be applied in the market:

- **Economic dispatch**: in case the power plant's bid to the spot market is above the market price, the offer is not accepted; therefore, the power plant can not generate electricity and decided to cut its electricity generation at that time period.

- **Self-scheduled curtailment**: power plants may prefer to cease their operations for some periods when they anticipate the price will be very low.
- **Exceptional dispatch**: The system operator can directly intervene in order to ensure the security of the system and give instructions to the power plants to reduce their generation.

Under the first two methods, power plants are able to reduce their generation according to their decisions, while the third method creates an obligation for market participants.

Curtailment of RES practices from the world

There are some countries that have been applying curtailment of RES in order to solve the renewable oversupply problem that is arising from the increasing share of renewable energy in the total electricity generation.

Curtailment of RES is one of the most common applications in California where there is an increasing rate of renewable energy systems.

In Texas, the wind curtailment rate is decreased from 17% in 2009 to 0.05% in 2014 thanks to investments in additional transmission infrastructure[263].

Germany also recently made investments in transmission lines and and increased its interconnection with neighboring countries in order to reduce the excess generation problem that causes a reduction in renewable energy generation.

RES curtailment can cause financial losses, even though the curtailment helps to reduce investments required for grid expansion. Many countries struggle with the finance of RES curtailments due to higher renewable energy integration and system constraints. There are some applications for curtailment compensation in some countries such as Germany, Denmark, Spain, and Ireland. In these countries, the compensation payments are made to the power plants that were obliged to decrease their generation[264].

The Current Situation of the Curtailment of RES in Turkey

In the current situation, the RES curtailment is not applicable in Turkey, as there is a significant need for additional electricity supply even during peak hours of electricity generation from variable renewable energy sources.

For example, in 2020, there were only 8 hours in which solar, wind and run of river hydro resources, which can be considered as variable renewable generation resources, met more than 50 percent of the total demand. All of these hours occurred on May 24 and May 25.

Even though the electricity demand was especially low on these days due to the COVID-19 outbreak and the Ramadan holiday, there was no need for renewable energy curtailment in the current situation.

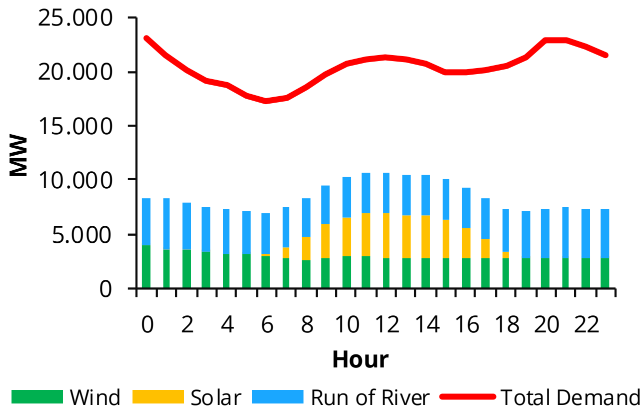

Figure 98. The amount of variable renewable generation vs total demand on May 24, 2020[265]

On July 15, 2020, when solar power generation was almost at its peak, only 19% of the total electricity demand was met by variable renewable energy sources. Since this remaining part of the demand was met from thermal power plants and dispatchable renewable energy sources whose generation levels can be adjusted, there was no need for an interruption in the system.

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[263] US Department of Energy, '2014 Wind Technologies Market Report'

[264] Wind Europe,'Views on Curtailment of Wind Power and its Links to Priority Dispatch' (2016)

[265] EPİAŞ Transparency Platform

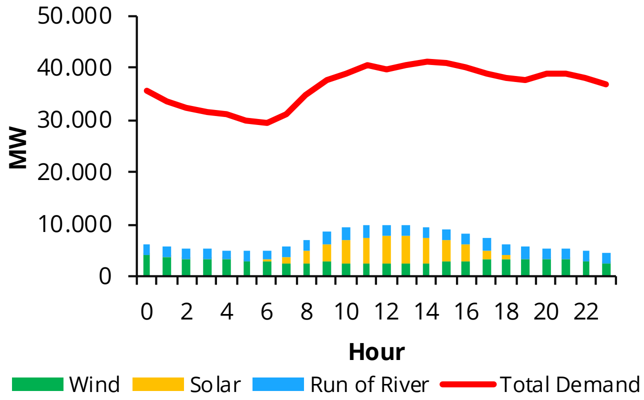

Figure 99. The amount of variable renewable generation vs total demand on July 15, 2020[266]

Likewise, although the peak wind generation on a daily basis was recorded on November 26, 2020, there was a significant difference between the total electricity demand and variable electricity generation for each hour.

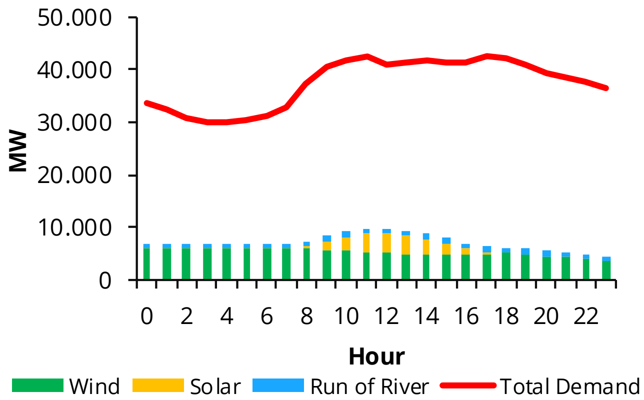

Figure 100. The amount of variable renewable generation vs total demand on November 26, 2020[267]

Even though RES curtailment is currently not included under the regulation, there is one instance where renewable energy generation had to be curtailed. This occurred in 2019 which was a record year in terms of hydro generation (with 34% run-of-river capacity factor as opposed to 27-28% expected for an average year). This high hydro generation still did not create a problem in terms of the share of variable generation in total demand but created some regional congestion problems.

As mentioned earlier, an important share of run-of-hydro generation in Turkey is based in the eastern Black Sea region where demand is relatively low. This created a problem in 2019 in terms of regional congestion and several run-of-river power plants had to cease their generation according to the instructions issued by TEİAŞ to alleviate the problem. These power plants were not reimbursed for their lost generation even though they were benefitting from the feed-in tariff mechanism.

It seems certain that RES curtailment applications will be on the agenda in the country for such periods with aberrant generation profiles which may cause congestion problems. In addition to this, the gradual increase of resources such as wind and solar in the coming years will necessitate the drafting of a regulation regarding RES curtailment. Even though such a regulation is surely necessary, this should be applied only as a last resort as the preference would be to minimize the need for these curtailments through other improvements in system design.

Higher Utilization of Existing Grid

Advancing technology creates an opportunity for existing grids to be transformed into more active facilities from traditional passive grid networks. Smart grid solutions for existing grids provide flexibility with the advanced technology. Some Smart Grid application practices that can utilize existing grid are Automated Load Transfer (ALT), Voltage Reduction (VR), Power Electronic Equipment, Virtual Power Lines, Dynamic Line Rating (DLR), Phasor Measurement Units (PMU).

- Automated Load Transfer allows the grid to move the power to solve constraint problems.
- Voltage Reduction helps grid to manipulate voltage sent to customers to increase and decrease the demand. It helps existing applications for DSO flexibility.
- Flexible AC Transmission System network devices can quickly adjust system voltage and can be dynamically controlled, and Flexible Power Links can also be used for flexibility by using real or reactive power flexibility.
- Virtual Power Lines can act as back-up energy storage during thermal overload and would be also beneficial to store energy that exceeds the capacity of the transmission lines.
- Dynamic Line Rating can help grids when weather conditions are tricky and affects the physical capacity of components in the network. Dynamic Line Rating can also be helpful for the flexibility of DSOs by mitigating grid congestion.
- Phasor Measurement Units is an advanced sensor technology that allows operators to measure grid

[266] EPİAŞ Transparency Platform

[267] EPİAŞ Transparency Platform

stability, reroute power for arising problems, report outages.

All of these applications can help in utilizing existing grids for to increase flexibility.

There are several countries that have employed best practices in terms of more efficient utilization of electricity grids. For example, Germany examined the Dynamic Line Rating and installed DLR to improve the integration of wind generation and transmission system. There are also 11 TSOs in Europe with a DLR in operation. UK Power Networks and Northern Power Grid in the UK uses DLR in their distribution network. Virtual Power Lines are also being used in The Republic of Korea and Australia. An Italian TSO, Terna, plans to utilize batteries. RTE, a French TSO, is also planning to increase Virtual Power Lines share in the grid[268].

Current situation in Turkey

The electricity transmission sector in Turkey is controlled by the state monopoly TEIAS. As of the end of 2019, the total length of transmission line in the country amounted to 70,034 km with 746 transformer centers and 1,889 transformers worth 181,360 MVA's in total. The transmission loss rate was 2.16% for 2019. Turkey is divided into 14 transmission regions and each region has its own transmission charges[269].

There are ongoing development projects about grid utilization and smart grid transformation in Turkey. There are research studies about dynamic line rating which are funded by Energy Market Regulatory Authority. Turkish Authorities give funding to research studies about modernization and transformation of existing grids[270].

There is also the 'Turkey Smart Grid 2023 Vision and Strategy Roadmap Summary Report' in which goals of Turkey for smart grids are explained and future investments for utilization applications are stated. Main goals of Turkey for Smart grid include the following:

- Flexible operation of network against natural disasters and attacks.
- Optimization of assets and efficiency of operations.
- Power quality and supply continuity.
- Autonomous self-healing grid applications that detect and eliminate problems by itself.

It is aimed for Turkey to reduce the electricity demand by 14% until 2023 with the planned improvements. 508 Million Turkish Lira for 2018, 555 Million TL for 2019, 1,24 Billion TL for 2020 and 1,59 Billion TL for 2023 are dedicated for smart grid investments according to the 2023 Smart Grid Vision of Turkey[271].

Increased Cooperation Between TSO and DSO

The distribution system in Turkey is separated into 21 regions and have been wholly privatized since 2013. Since this year, the distribution and retail sale activities in Turkey are legally unbundled and are carried out by separate legal entities. The Electricity Market Law prohibits distribution companies from being involved in any activity other than distribution. The incumbent supply companies (retail arm of the company) can sell electricity to previously ineligible consumers and end users within their designated regions. The supply company can also sell electricity to eligible consumers outside of their designated region. The 21 distribution regions each with their own designated distribution and supply companies can be seen in Figure 33.

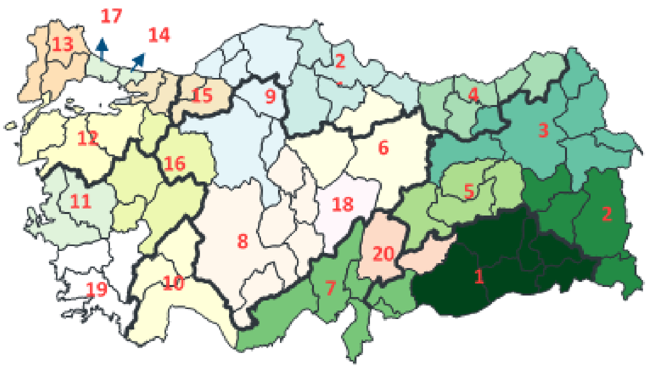

Figure 101. The Distribution Regions in Turkey

The increasing distribution of the energy resources and their participation in ancillary services; also, the enhancing capacity of renewable energy resources increased the need for cooperation between TEİAŞ and distribution operators.

Both TEİAŞ and distribution companies can benefit from a more flexible power market. Use of flexible resources can help TEIAŞ for congestion management, frequency and voltage control; furthermore, distribution operators can

[268] IRENA, 'Innovation Landscape for a Renewable Power Future'(2019)
[269] TEİAŞ, '2019 Activity Report' (2020)
[270] IPA, 'Elektrik İletiminde Enerji Verimliliğinin Teknik Gözden Geçirilmesi, Değerlendirilmesi ve Analizi' (2013)
[271] ELDER, 'Turkey Smart Grid 2023 Vision and Strategy Roadmap Summary Report' (2018)

utilize a more flexible power market to control local congestion problems and for voltage control.

In Turkey, there is not a comprehensible legislation to regulate the cooperation between transmission operators and distribution operators. There exist partial regulations such as ancillary services regulation and energy market law. Having a comprehensive TSO/DSO cooperation regulation would benefit both sides. By increasing the coordination between TEIAS and Distribution companies, they can support one another to make the grid operations more flexible and cost-efficient. Moreover, a well-designed regulation may avoid contradictions between system operators.

Coordination between TEIAS and distribution companies is mainly involved in using common data platforms, sharing of metering data, increasing the reliability and transparency of the data and network planning. Depending on the coordination framework, certain roles for TEIAS and distribution companies can be modified or shifted. Deciding the coordination framework depends on the current grid structure, legal concerns and situation of the power market of the country. More centered or more local cooperation approaches can be selected depending on the desired roles of TSO or DSO. In a centered approach the TSO is operating the market, in local approach distribution operators coordinates the flexibility options and resources to be used in balancing power market. Distribution companies can contribute to power system by supporting the TEIAS by providing local solutions for system-wide problems and eventually, minimizing total system costs.

Moreover, system operators can work together to increase the observability of the grid. Introducing improved data control and acquisition systems with cooperation between system operators may improve the quality and transparency of grid data. A new software with improved data acquisition and visualization interface can be implemented. It would be beneficial for both parties and consumers in terms of making sanity checks for the data and increased transparency between DSO, TSO and consumers.

This potential areas of cooperation will be more crucial with the expected increase in the unlicensed installed capacity in the country mainly spurred by solar energy investments. These investments will necessitate increased cooperation between the institutions as the unlicensed power plants are not responsible for their imbalances and are directly connected to the distribution grid under the current regulation.

Advanced Forecasting of Renewable Energy Systems

New operational requirements have arisen due to the changing technologies and market regulations in power systems. Higher RES penetration throughout the system also results in a higher margin of uncertainty among the total electricity generation, especially in short-time periods. Advanced techniques for the forecasting of RES generation is one of the main areas that offer new opportunities for development.

Increasing RES, namely wind and solar power penetration in the country's energy system causes a demand for the advanced forecasting of these sources. Forecasts mostly depend on weather conditions at the site locations and are conducted to forecast the amount of power that wind or solar plants would supply into the grid within following hours and days. By this means, market participants can adjust their expectations regarding the electricity that will be generated for the determined time periods.

RES forecasts can be categorized under different time scales including the shortest-term forecasts for the next minute to the next six hours, short-term forecasts for the next six to fourty eight hours and medium-term forecasts for the following two to twenty days depending on the requirements[272].

Many investigations related with the concept and the implementations of advanced forecasting have been conducted during recent years. As a consequence, several systems have been set into operation by various institutions in the light of those researches. Accordingly, it has been learned how to forecast RES more accurately. Recently established forecast systems generally use numerical weather prediction models since only these models can simulate what will happen in the atmosphere within hours or days.

Affecting Factors of Forecast Accuracy

In the following, the basic factors leading to accuracy variations on forecasting of RES are presented:

- Forecast error increases with increasing prediction horizon, meaning the further the forecast looks into the future, the lower the forecasting accuracy.

[272] Variable Renewable Energy Forecasting, Integration into Electricity Grids and Markets, A Best Practice Guide, GIZ (2015)

- Geographical formations such as hills and mountains increases complexity of the terrain and causes higher forecast errors. This is mainly related to the fact that the NWP models cannot consider all details, for example changing wind speeds due to channeling effects or solar irradiance due to the shading effects in area.
- Instead of a single site, using aggregated regions for forecasting gives better results in terms of accuracy. .

The Current Situation of Advanced Forecasting of RES in Turkey

In Turkey, the project regarding wind power monitoring and forecasting, RİTM has been introduced in April, 2014. The aim of the project was large-scale integration of wind power plants to Turkish Electricity System. A center for observation and forecasting of power generation based on wind energy has been established under the scope of the project.

The relevant legislation has been published in Official Gazette in February, 2015 and licensed power plants with an installed power of more than 10 MW were obliged to be connected to RİTM. For power plants below 10 MW capacity, the connection status is voluntary[273].

In this context, meteorological data such as speed, direction and temperature from existing wind power plants is retrieved via measurement stations. Turbine status is observed by means of supervisory control and data acquisition (SCADA) systems. In addition, with monitors established in the transformer centers of stations, power, current, voltage and similar data are transmitted in real-time to RİTM.

Accurate estimation of the electrical power to be produced from 48 hours wind on behalf of each wind power plant can mostly be done via aforementioned instrumentation. Still, the next target is set to predict 72 hours in advance with considerable accuracy.

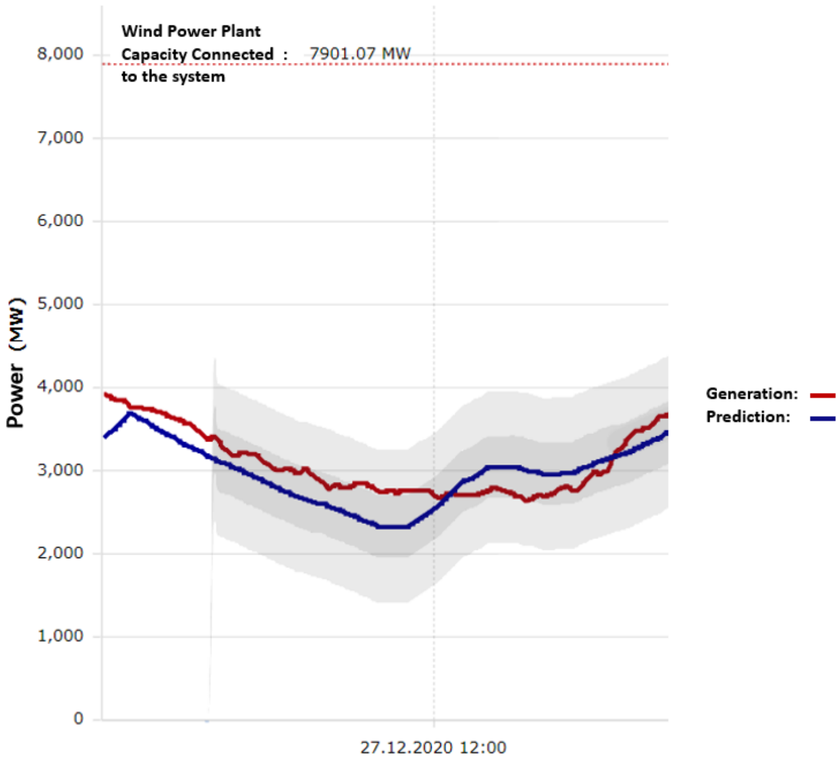

Figure 102. Wind Power Forecast throughout the Country (RİTM)

Apart from this, most of the solar power plants are unlicensed in Turkey and incentivized by YEKDEM. Therefore, they get paid regardless of the price that occurs in the market, moreover they do not have right to participate in spot market. As a result, forecasting algorithms are not well developed for solar predictions in

[273] Official Gazette No: 29278, dated February 25, 2015

Turkey since it is not rewarded to estimate solar irradiation accurately. However, uncertainty about the future of unlicensed power plants is resolved with the legislation published in November, 2020. Thus, after expiration date of YEKDEM, they will have a right to get license and participate in the spot market[274]. In other words, making predictions for solar irradition will also get credit. Hence, more sophisticated solar forecasting systems can be introduced in Turkish electricity market in the near future.

The accuracy and the detail of renewable energy generation forecasting could be improved by using recently developed technological methods and tools. These innovations might include better integration of cloud-based computing and digitalization, improved mathematical models, high-resolution weather forecasts, machine learning (artificial intelligence) based algorithms.

As it is mentioned above, solar weather predictions are not attractive in today's market structure. Therefore, imposing regulations on the market and making solar irradiation forecasts mandatory will help developments in this area.

In addition to this, there is also a lack of incentive for wind power plants to make significant investments in advanced forecasting methods due to the current structure in the market regarding imbalance penalties applicable in the market. There are currently two distinct penalties charged for imbalances in the market which can be classified as:

- Portfolio based penalty
- Power plant based penalty

After the legislation changed in 2016, all the renewable power plants under the YEKDEM portfolio except unlicensed power plants are obligated to join in the day-ahead market. Since 2016, these power plants are responsible for balancing their generation and are liable to pay imbalance penalties to the TSO.

Within the feed in tariff period, renewable energy power plants receive daily income from market operator, based on the day-ahead market prices. At the end of each month, a settlement process is carried out when the difference between the feed in tariff is then compensated (paid by market operator to power plant). During this settlement process a portion of the income from day ahead market is kept by the power plant in accordance with the tolerance coefficient as per the regulation in force. The tolerance coefficients vary according to the type of renewable energy source.

Table 3. Tolerance Coefficients Applied in the Market for Different Renewable Energy Sources[275]

Source	Tolerance Coefficient
Wind	0.97
Solar	0.98
Geothermal	0.995
Biomass	0.99
Reservoir Hydro	1.00
Run-of Hydro	0.98

Electricity market balancing and settlement regulation initially has been introduced in April, 2009[276]. This law allows market participants to aggregate and form portfolios in a way that reduces their overall deficit. By this way, it is aimed that market participants will be less exposed to imbalance by balancing within their groups.

With this regulation, power plants are allowed to form balancing groups to decrease their imbalances (through forming groups with renewable thermal power plants to provide flexibility) The group owners' renewable power plants can agree on different terms for this balancing service, but the general approach is that they share the additional income (from daily operations).

As a result of this scheme, the portfolio based imbalance penalty applicable for renewable power plants can be substantially reduced. For the whole group, the portfolio based imbalance penalty is calculated as follows:

For positive imbalance: *min (DAMP, SMP) * 0.97*

For negative imbalance: *max (DAMP, SMP) * 1.03*

As of 2020 the balancing group application is feasible for power plants as this calculation nets the positive and negative imbalances within the group and within the hour. However, real time physical imbalances continue to be a technical issue for the system operator and the operator needs to pay additional amounts to power plants for instructions to load/de-load.

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[274] Parliamentary Minutes, November 19, 2020
[275] EMRA Board Meeting, February 1, 2018
[276] Official Gazette No: 27200, dated April 14, 2009

This cost has been increasing during the last couple of years and as a result, the balancing group application is now under scrutiny.

The second type of penalty applied in the market is referred to as the Final Daily Production Program (KGÜP) Penalty. This penalty is applied for individual power plants in line with the divergence of their actual generation from their day-ahead generation plan. However, there is also a tolerance applied for this penalty and the penalty is only applicable in case there is at least a 10% positive or negative divergence. The KGÜP penalty is calculated as follows:

Divergence Volume max (DAMP,SMP) * 1.03*

As a result of the balancing group application and the current structure of these imbalance penalties, there is an ongoing lack of incentive for RES power plants to make the necessary investments in forecasting which can reduce their imbalances.

If these issues can be addressed, increased investments into advanced forecasting tecniques can be expected. In order to follow the recent progress of the related studies, advanced weather forecasting pilot projects in US, Germany, Netherlands, Spain and China can be analyzed[277]

Policy Recommendations

- There is a significant potential in the market in terms of increasing temporal and spatial granularity in the market.
    - The temporal granularity aspect can be thought of in terms of the intra-day market. In this respect, the trading intervals in the intra-day market can be pulled closer to real-time such as 30 minutes or 15 minutes before the physical transfer of electricity as opposed to the current 60 minutes. This would be beneficial for the flexibility in the market by helping improve the forecast accuracy of variable renewable energy sources as the forecasts would be closer to real-time.
    - On the other hand, spatial granularity in the market can be thought in terms of the day-ahead market. There is currently a single bidding zone in the Turkish day-ahead market which is comprised of the whole country. A radical move towards zonal pricing does not seem like a realistic solution for the foreseeable future. However, a regional pricing scheme can be gradually implemented which would help in reducing the transmission costs in the system and provide locational signals for prospective investors. The move towards such a regional pricing model can be initiated with a division between Thrace and Anatolia.
- The current ancillary services market in the country has been active for the last 3 years and contributed to the operation of the power system. However, there are also some areas by which the market can be improved. The primary and secondary frequency service auctions are currently held two days in advance of the reserve obligation. Moving the auctions closer to real-time would allow the participants to better optimize their bids by allowing for a more accurate anticipation of day-ahead prices. Additionally, under the current regulation, only generation units over 100 MW are allowed to participate in the market. Experience from the world suggests that smaller units can also be included in this market without major problems. The reduction of this installed capacity limit would increase the competition in the market and reduced the overall costs. There are also currently ongoing plans to include demand-side response and battery storage systems under the ancillary services market. These efforts should be continued and the ancillary services market should be expanded to cover new services other than primary and secondary frequency control.
- Redispatch schemes may be implemented in the future with the anticipated increase in renewable energy generation and if the balancing costs increase greatly. However, this scheme should only be used as a last resort and should not be common practice which could disrupt the functioning of the market.
- At this stage of renewable energy development in Turkey, renewable energy curtailment is not necessary given the current share of variable sources in meeting the demand. However, such schemes may be relevant in the following decade with the anticipated increase in the installed capacity of wind and solar energy and in certain periods with high hydropower generation. Since such a practice may be necessary, a renewable energy curtailment regulation should be drafted which would detail the instances and the application of this measure instead of resorting to ad-hoc solutions. The utilization of

[277] Advanced Forecasting of Variable Renewable Power Generation, Innovation Landscape Brief, IRENA (2019)

renewable energy curtailment can also incentivize flexibility investments for renewable energy power plants like battery or hydrogen electrolysis as a way to make alternative use of the curtailed electricity.

- There are currently several ongoing projects in Turkey regarding the transition to a smart grid. These should be pursued and expanded. Additionally, the cooperation between the transmission system operator and the distribution system operators should be expanded in several areas like sharing data and know-how on increasing the reliability and transparency of network planning. This can be more important in the future as more unlicensed installed capacity is set to come online which will be connected through distribution lines.
- The adoption of advanced variable renewable energy forecasting techniques is an area with a significant potential for development. The main problem in Turkey regarding this issue is that the current penalization schemes in Turkey do not provide satisfactory incentive for renewable energy generators to make substantial investments to try to curb their imbalances. Several aspects of the current design can be modified in this regard. The current balancing group scheme should be reassessed as the scheme is not very effective in curbing real-time balancing costs even though its provides support for renewable energy sources. The netting of energy imbalances inside the portfolio and inside the hour causes the actual imbalance costs to not be reflected in the penalties. This system can potentially be redesigned. Moreover, the KGÜP penalty is not as effective since it provides a 10% tolerance for imabalances for market participants. Since these imbalance costs can't be recovered through the imbalance penalties, they have to be reflected to the whole market via the transmission tariffs set by TEİAŞ.
- There are currently several support schemes being applied in the market which were touched upon in the previous parts of the report. These include the YEKDEM feed-in tariff, lignite purchase guarantee and the capacity mechanism in the market. The design of these support mechanisms can impede the flexibility in the market by distorting the market operation. The purchase guarantee supplied for local coal power plants should be abolished as it incentivizes the base load operation of these power plants and obviates the need for any flexibility investments for these power plants. The current capacity mechanism provided in the market does not have any provision to support flexibility. This mechanism could perhaps be modified in a way to incentivize flexibility invsetments instead of providing a uniform per MW support for different sources. The current YEKDEM feed-in tariff for renewable sources is set to expire in the second half of 2021. The new policy mechanism is yet to be declared. A feed-in premium could perhaps be devised for variable wind and solar sources instead of a fixed tariff which would increase their integration into the electricity market.

List of Abbreviations

ALT	Automated Load Transfer
BAU	Business-As-Usual
BO	Build-Operate
BOT	Build-Operate-Transfer
BPM	Balancing Power Market
CCGT	Combined Cycle Gas Turbine Plant
DAM	Day-Ahead Market
DAMP	Day-Ahead Market Price
DLR	Dynamic Line Rating
DSM	Demand Side Management
DSO	Distribution System Operator
EMRA	The Energy Market Regulatory Authority
EPİAŞ	The Energy Market Operation Company
ETS	Emissions Trading System
EÜAŞ	The Electricity Generation Company
KGÜP	Final Daily Production Program
INDC	Intended Nationally Determined Contribution
LMP	Locational Marginal Pricing
MENR	The Ministry of Energy and Natural Resources
NWP	Numerical Weather Prediction
PFC	Primary Frequency Control
PMU	Phasor Measurement Units
PPA	Power Purchase Agreement
RİTM	Wind Power Monitoring and Forecasting Center
SCADA	Supervisory Control And Data Acquisition
SMP	System Marginal Price
SFC	Secondary Frequency Control
TEİAŞ	Turkish Electricity Transmission Company
TETAŞ	The State-owned Wholesale Electricity Company (former)
TSO	Transmission System Operator
TPYS	TEİAŞ Market Management System
YEKA	Renewable Energy Zones

YEKDEM Renewable Energy Resources Support Mechanism (also called as YEK Mechanism)

YHPYS The Ancillary Services Market Management System

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