How to make the German energy transition in the electricity sector affordable

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Christof von Branconi, Thomas Frewer

Abstract

GES assumes that the demand for electricity will be lower than the model calculations published in recent years, at least until 2035. This is because electromobility, heat pumps and electrolysers will be a long time coming. In order to make the costs of volatility in the electricity system manageable, GES proposes limiting new renewables to around 50% of the electricity supply. Volatile wind and solar energy generate high costs in the overall system: for stabilising the grid, transport, flexibilising demand and storage. A full expansion of renewables, as the German government wants, will lead to enormous costs. In addition to volatile renewables, a stable electricity system needs reliably controllable energy. GES sees gas-fired power plants with carbon capture and storage as an important alternative, with CO_2 being captured and disposed of. However, this would require the planned CO_2 transport network to be larger. All in all, GES anticipates investment savings in the order of € 300-350 billion compared to the projections for the German government's programme.

The targets for restructuring the German electricity supply are not affordable

National climate legislation determines energy policy, in particular the German government's goal of achieving climate neutrality by 2045. The targets for the electricity sector are also derived from this goal.

By 2030, greenhouse gas emissions are to be reduced by 65% compared to 1990 levels; annual emission limits have also been set for the years after that, until climate neutrality is achieved by 2045.

In addition, demand for electricity is expected to rise from the current level of approx. 500 TWh to approx. 780 TWh in 2035.[1]

In the so-called Easter Package 2022[2] , the German government has defined a path that aims to cover at least 80 % of gross electricity consumption from renewable energies by 2030 and almost all of it by 2035, with the phase-out of fossil fuels to be largely completed by 2035. All electricity consumption should be climate-neutral by 2045.

The costs of achieving the goals of the energy transition appear astronomical and are regularly revised upwards. According to the progress monitor published by BDEW and EY[3] in April 2024, investments totalling €721 billion will be required by 2030, 49% of which will be for electricity generation and 41% for the expansion of energy grids (electricity and gas). From 2031 to 2035, further investments totalling € 493 billion are estimated for the expansion of electricity generation and the transmission and distribution grids, i.e. a total of € 1,214 billion by 2035.

According to a study conducted by the European Commission in 2020[4] , Germany provides the most funding for the generation of energy from renewable sources such as wind, sun, water and biogas compared to other EU member states, with a direct financial volume of € 33.5 billion p.a. (which corresponds to around 1% of GDP). According to the study, the EU funding average for renewable energies as a proportion of GDP is around half (0.57 %): The question therefore arises as to whether German policy has taken a sustainable approach to achieving climate protection targets.

As the Federal Constitutional Court (BVerfG) ruled in November 2023 that the law on the second supplementary budget for 2021[5] is unconstitutional and the funds in the Climate and Transformation Fund (KTF) had to be reduced by around € 60 billion, the Federal Government's financial scope to support the transformation is limited. The so-called debt brake allows a

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[1] However, the grid load fell by a total of 5.3% to 456.8 TWh in 2023 (2022: 482.6 TWh) and (net) electricity generation fell by 9.1% to 448.5 TWh (2022: 493.2 TWh). Gross electricity consumption before power plants' own requirements and transmission and distribution losses totalled 517.3 TWh in 2023.

[2] www.bundesregierung.de/breg-de/schwerpunkte/klimaschutz/novelle-eeg-gesetz-2023-2023972

[3] Progress Monitor 2024 Energy Transition, BDEW & EY, 2024 EY Deutschland GmbH Wirtschaftsprüfungsgesellschaft Steuerberatungsgesellschaft

[4] Research Services of the German Bundestag, WD 5 - 3000 - 039/23

[5] BVerfG, Judgment of the Second Senate of 15 November 2023 - 2 BvF 1/22 -, para. 1-231,

ratio of debt to gross domestic product (GDP) of 60% and new federal debt of no more than 0.35% of GDP per year. In 2023, these figures were 63.7% and 2.0% respectively, corresponding to € 27.2 billion.

This raises the question of possible alternative courses of action.

The situation regarding the expansion of volatile electricity generation with wind and PV systems

The expansion programme for PV and wind power plants is only keeping pace with the targets of the Easter package in the case of PV systems. However, as these only generate electricity for an average of 917 hours per year, mainly from March to October, this progress tends to exacerbate the problem of volatile energy generation.

At the end of 2023, the total installed PV capacity in Germany was 81.7 gigawatts[6] , 14.3 GW were added over the course of the year, almost twice as much as in the previous year. 12% of net electricity consumption in 2023 was generated with PV systems. In future, 19 gigawatts would have to be added annually to achieve the expansion target of 215 GW for solar in 2030.

At the end of 2023, a total of 60.9 GW of onshore wind turbines were installed, of which 2.7 GW were commissioned in 2022 and 3.6 GW in 2023, according to the Federal Network Agency (BNetzA). The turbines generate electricity for an average of 1,770 hours per year, 26% of net electricity consumption in 2023 was generated by onshore wind turbines. With the EEG 2023, the expansion target for onshore wind energy was raised from 81 GW to 115 GW for 2030 and to 157 GW for 2035. In order to achieve these targets, an annual gross expansion of around 10 GW of wind energy is required over the next 12 years.

There is also the challenge of making land available for onshore wind turbines. The law stipulates that two per cent of Germany's land should be available for wind turbines. According to the study "Land availability and land requirements for the expansion of onshore wind energy" published by the BMU in June 2023[7] , the two per cent land area is sufficient to achieve the expansion target. The study analysed the areas designated for expansion and the identified restrictions on usability and derived the future area requirements from this.

However, according to the study, only 0.79 % of the federal territory was legally designated as areas for onshore wind energy in 2021. However, around 40% of these areas were so restricted in their availability due to legal or planning requirements that only 0.49% actually remained usable. In addition, around 30 % of the remaining areas could not be utilised, for

[6] Fraunhofer ISI, Electricity generation in Germany in 2023, Prof. Dr Bruno Burger, Freiburg, 25 January 2024, www.energy-charts.info

[7] Land availability and land requirements for the expansion of onshore wind energy, Federal Environment Agency, Series Climate Change 32/2023, June 2023

example due to species or monument protection concerns. This further restricted the amount of land available.

At the end of 2023, offshore wind turbines with a total capacity of 8.5 GW were in operation in Germany, built over a period of just over 10 years. Five per cent of net electricity consumption in 2023 was generated with these turbines, which supply electricity for an average of 3,331 hours per year. 1.0 GW of capacity was successfully auctioned in 2021 and 1.8 GW in 2023. The expansion targets for offshore wind energy in the Offshore Wind Energy Act (WindSeeG) stipulate that the installed capacity of offshore wind turbines should be increased to a total of at least 30 GW by 2030, to at least 40 GW by 2035 and to at least 70 GW by 2045. The statutory minimum target of 40 GW by 2035 is to be exceeded according to the current plans of the Federal Maritime and Hydrographic Agency (BSH): 50 GW are to be installed by 2035.

For 2024 alone, the payments guaranteed under the EEG in favour of wind and solar park operators are currently estimated to amount to €19 billion, borne by the federal budget. Without a fundamental change to the EEG, these burdens will continue to rise if the expansion targets for wind and PV systems formulated in the Easter package are to be achieved: The amount of subsidised electricity will continue to rise due to the 20-year fixed feed-in tariff. This can already be seen at present: for the first time from 9 to 16 May 2024, the BNetzA's market data recorded eight consecutive days with electricity prices at or below zero euros. The previous record was six days in 2023.

Negative electricity prices mean that electricity sellers have to give their buyers money so that they buy the electricity. Due to a lack of storage capacity, there are currently no alternatives. This also has a direct impact on the federal budget. The remuneration that the operators of photovoltaic systems, wind turbines, hydroelectric power plants or biomass plants receive for every kilowatt hour of electricity produced in accordance with the EEG remains the same, even if the marketing of the electricity on the exchange brings in less money or even negative prices occur. In extreme cases, this leads to the operators of pumped storage power plants pumping water up the mountain and then releasing it again without utilising the turbine - a kind of paid Sisyphus. And the additional electricity generated under the Renewable Energy Sources Act as a result of further expansion will have an ever lower market value due to uncontrolled generation, meaning that the need for subsidies will continue to increase with regard to the feed-in tariff fixed over 20 years.

In addition, redispatch costs are incurred due to the expansion of PV and wind energy that is not coordinated with the line capacities: More electricity is generated before a grid bottleneck than can be transmitted via the high-voltage line: this means that a feed-in must be curtailed before the grid bottleneck, for which the feeder is compensated, and additional electricity must be produced after the bottleneck, always with fossil-fuelled power plants. In 2023, the redispatch costs incurred for this amounted to around €3.1 billion.

The challenge of expanding transmission and distribution grids

This leads to the challenge of grid expansion. For the transmission grids alone (380 / 220 kV), the investment requirement up to 2045 is €320 billion, as shown in the grid development plan, somewhat reduced by possible government revenue from the offshore wind auctions. For the first time, the 2023 auction mentioned above generated almost € 13 billion in revenue for the federal government over the licence term. 90 % of the money raised is intended to help curb the rising expenses for grid expansion somewhat.

With a transmission grid length of around 36,300 km (end of 2022), there is a need to expand around 14,000 km of high-voltage lines according to BNetzA[8] . In order to implement the supply of renewable energy envisaged in the Easter Package 2022, the transmission grid would have to be expanded by an average of around 2,100 km per year between 2026 and 2035, which corresponds to an almost five-fold increase in the historical expansion rate: 423 km were completed annually between 2018 and 2022, and a total of 30 projects with a length of 2,822 km by the end of 2023. Permits for the construction of 2,800 km are to be issued by the end of 2024 and for a total of 4,400 km of lines by the end of 2025. The capacities for cross-border electricity flows are also to be significantly increased. This planned expansion will in turn have an impact on the markets of the respective partner countries, whose electricity supply will change as a result of the expansion.

Currently, some of the current owners of the four transmission system operators have signalled that they are interested in selling their shares in view of the very high investment requirements of € 320 billion. In the absence of other interested parties, the state would have to acquire the shares directly or indirectly (via KfW). The final negotiated case of Tennet is an example of this: the current majority shareholder, the Dutch state (75% stake), would like to sell its shares to the federal government for €22 billion (purchase price based on the current book value of the assets, i.e. the investment expenditure already incurred in recent years) (there are no other interested parties). Furthermore, Tennet has additional equity requirements to finance the HVDC investments of € 18 billion (required by the wind and PV expansion targets). The amount required for the 100 per cent takeover of all four transmission system operators alone is estimated to be around €50 billion. If the KfW were to take over instead of the federal government, the federal government would have to pay the annual interest on the necessary funding for the KfW.

The situation is similar for distribution grids. In Germany, around 900 distribution grid operators (DSOs) have regional grids of different voltage levels with a length of around 1.8 million kilometres. According to a study conducted by TU Berlin on behalf of the states of Baden-Württemberg,

[8] www.netzentwicklungsplan.de/nep-aktuell/netzentwicklungsplan-20372045-2023

North Rhine-Westphalia and Thuringia in June 2021[9] , an expansion requirement of up to 380,000 km is estimated. The 75 largest operators recently submitted their expansion plans to the BNetzA. Over the next ten years, the investment required to increase the transport capacity of the grids is around €110 billion and the BNetzA[10] estimates the costs at just over €200 billion by 2045. In addition, there will be pure replacement investments, which according to the BNetzA will amount to around € 10 billion by 2033 and around € 30 billion by 2045. Compared to the volume of the past ten years, annual investments will therefore increase three- to four-fold.

The grid reinforcement in rural areas for new wind turbines and PV systems in order to transport wind and solar power to urban centres is first paid for by the local/regional distribution grid operators and then charged to their customers via grid charges. This often means that these costs have to be borne exclusively by the inhabitants of sparsely populated rural areas. This particularly affects household and commercial customers in rural areas in Schleswig-Holstein and eastern Germany. They pay more than twice as much as some western German cities. A household in Schleswig-Holstein (3,500 kWh consumption) currently pays €500 per year for grid usage, while a household in Munich or Cologne pays €150 per year.

As a consequence, the BNetzA is expanding its concept for the distribution of electricity grid costs, which are incurred unevenly from region to region when integrating renewable energies. A "renewable energy ratio" (EKZ) based on the ratio of installed renewable energy capacity to the annual peak load in the grid is to serve as the basis. 26 Grid operators would initially be authorised to "roll over" their additional costs on this basis, i.e. to distribute them across Germany. Such additional costs are mainly incurred in northern and north-eastern Germany. The distribution grid fees for the affected grid operators would fall by up to 39%. The BNetzA described the resulting additional costs for all electricity consumers as "manageable". Applied to 2024, they would amount to €21 per year for an average household with an annual consumption of 3,500 kilowatt hours. The authority has not yet provided figures for 2025, but in view of the planned expansion of the distribution grid alone, significantly higher amounts are to be expected in the future.

In 2023, the BNetzA has once again formulated the expectations for the required flexibility in electricity consumption ("demand side management"). According to this, a huge 58.5 GW of flexible consumers will be required by 2031: industrial processes and cross-sectional technologies with throttleable output, emergency power systems, heat pumps, solar home storage, e-mobility, electrolysis for Power to X. And it plans to establish a flexibility incentive in the grid fee system. This catalogue of measures shows the efforts being made to manage generation peaks and supply shortages during "dark doldrums".

[9] Technical University of Berlin. "Expansion of the distribution grid on behalf of the states of Baden-Württemberg, North Rhine-Westphalia and Thuringia." June 2021.
[10] Federal Network Agency. "Monitoring Report 2023." November 2023.

The challenge of grid stability

In the course of the energy transition, the technological foundations of grid technology are also changing fundamentally, as large power plants (coal, nuclear) are being replaced by renewable energy plants (RE) and more and more electrical storage systems are being integrated into the system. While large power plants have so far ensured stable grid voltage, grid-forming inverters in renewable energy plants and storage systems will take over this task in future.

Two factors in particular are decisive for grid-forming power plants: i) the inertial mass of the generator together with the turbine and ii) the ability of a synchronous machine to be a "fat" controllable capacitor on the rigid grid through overexcitation, which supplies additional active power depending on the turbine output. And when the synchronous generator is underexcited, it is a controllable "fat" inductance that supplies active power.

This property of "fat" capacitors or coils can also be used to control an inverter if necessary. The inverter can be a current source (typically, when everything is OK) or a voltage source (when the grid "smears"). However, the DC voltage source that supplies the power converter must be able to provide a very large amount of energy so that the current to maintain the grid voltage can be supplied within the first two seconds or so (e.g. many farads at 10 kV). The grid frequency must not fall below 47.5 Hz (48 Hz), otherwise the grid will decay and it will go dark. In future, the inverter must increasingly be able to provide this energy.

And after the two seconds, the energy that was originally lost from the grid supply must continue to be supplied. Today, these are "hot" gas-fired power plants that have to accelerate from partial load to full load within two seconds and provide the grid energy that was originally lost when full load is reached (no more and no less). No wind or PV park can do this, as there is no guarantee that its energy will be available in the required quantity at the required time.

Today's wind turbine inverters have neither the regulation nor the reinforced DC link, as this would cost more and there are currently enough grid-forming power plants in the grid (coal, gas, water).

If the volatile output of 508 GW envisaged in the Easter package for 2035 were to feed in disproportionately depending on the time of day and weather conditions, this would potentially correspond to a multiple of the consumption of approx. 80-90 GW of load that Germany needs on a continuous basis. The excess power must be stored in batteries or controlled through demand side management, export or curtailment. The eight days of continuously negative prices quoted indicate that a considerable multiple of the daily demand of around 1.4 TWh must be managed.

The German government is aiming for 44 GW of battery storage capacity by 2030; at the end of 2023, battery storage systems with a capacity of 7.9

GW and an energy storage capacity of 11.6 GWh were installed, i.e. even full fulfilment of the government's battery storage capacity target would only be able to cover the electricity demand for a few hours at most.

Calculated at an optimistic € 100 per kWh (including modules, packaging and power electronics), the costs of 10 GWh of battery storage capacity easily rise into the billions of euros range, without the associated technical, regulatory and economic issues having been clarified yet. And with batteries, the current storage requirement of 130 TWh of energy from German natural gas storage facilities simply cannot be realised.

In view of the progress that has been made and the challenges that remain, the question arises as to what alternatives there are for achieving the goals of climate legislation while at the same time limiting the economic burden on citizens.

How is electricity demand developing?

In January 2024, McKinsey suggested significant corrections to the German government's programme[11] . The study adopts the prospective electricity demand for 2035/2040 and shows that the climate targets in the electricity sector can be achieved much more cost-effectively by significantly reducing the expansion targets for wind and PV, but with more dispatchable capacity and, as a result, less grid expansion and less battery storage capacity.

However, the basis for a price review should also be based on the scenarios for the expected electricity demand. In contrast to various forecasts for 2021, a number of assumptions turned out to be in need of correction. In addition, actual electricity consumption in Germany declined in 2022 and 2023.

The drivers of higher electricity consumption identified in the past have not materialised to the extent of previous forecasts: Expectations that the price of electricity will continue to rise tend to slow down the changeover. They are one of the reasons for the migration of electricity-intensive industrial companies and the associated decline in industrial electricity consumption. And in terms of overall economic development, Germany has recently been at the bottom of the OECD countries.

Electromobility is not achieving the growth rates expected by politicians. At the end of March 2024, there were 1.4 million electric vehicles (BEV) on the road in Germany, plus 0.9 million hybrid vehicles. The target of 15 million BEVs in 2030 is unrealistic; with approx. 3 million new registrations per year and 0.5 million BEVs of these most recently, 7-12 million BEVs still seem achievable at best if consumer attitudes towards BEVs were to become more positive again.

The switch to heat pumps for heating buildings is also progressing much more slowly than expected. At the end of 2023, 1.8 million heat pumps

[11] Future path of power supply, January 2024, McKinsey & Company

were installed in Germany, with 356,000 new installations at the last count. The target of 6 million installed heat pumps by 2030 is not realistic. Consumers are first investing in available efficiency reserves with shorter payback times (such as replacing better windows and electrical consumers, improving the insulation of buildings, solar thermal energy for hot water, etc.) before making the expensive purchase of a heat pump.

And the additional electricity demand from hydrogen electrolysis for Power to X projects or for the use or storage of green hydrogen also falls well short of expectations: compared to a target of 10 GW of installed electrolysis capacity in 2030, an analysis published by GES in May suggests that 3-4 GW is realistic at best. In addition, the costs of green hydrogen will be significantly higher than predicted 2-3 years ago: GES considers €9-11 per kg for hydrogen produced in Germany to be realistic due to the high cost of electricity in this country. This significantly restricts the areas of application.

Overall, we expect electricity consumption to increase much more slowly than forecast in 2021. From today's perspective, consumption of 600 TWh for 2035 appears to be a realistic base scenario, with a maximum of perhaps 650 TWh.

The long-term targets for 2045 and 2050 also need to be scrutinised. With a long-term target consumption of final energy of 1,400 TWh in 2050 according to the German government, is a 50-70% share of electrons in final energy consumption (according to the Fraunhofer study "Sector coupling through the energy transition") actually achievable?

Today, the proportion of molecules is around 80 %. If the economically and technically feasible share of electrons does not increase as predicted, the role of molecules will remain very large in the long term. Assuming that the share of molecules in the final energy demand can be reduced to 50 % by 2050, the share of electricity in the forecast final energy demand would be around 700 TWh, i.e. not too far above the GES forecast, and in any case significantly lower than the expectations of many studies and the German government for 2021.

GES proposals to reduce costs in the electricity sector and increase security of supply: target of 50 % solar and wind-based generation

What questions need to be asked with regard to the targets formulated in the Easter package if electricity consumption is to increase significantly more slowly and the rise in electricity prices is to remain economically and socially acceptable?

Back in 2015, Lion Hirth showed in "The optimal share of Variable Renewables"[12] that the share of wind and solar-based electricity generation is of key importance for an economically optimised electricity system. He

[12] Hirth, Lion. "The Optimal Share of Variable Renewables: How the Variability of Wind and Solar Power affects their Welfare-optimal Deployment." *The Energy Journal*, vol. 36, no. 1, 2015, pp. 149-184.

has shown that the less cost-effective dispatchable base load is available in an electricity system, the higher the share of volatile generation can be. This question remains relevant for the German electricity system, especially after the elimination of the low-cost base load capacities of nuclear energy and coal. How can base load be represented as cost-effectively as possible with the targets for the German electricity system? Of all the conceivable options, providing base load by reconverting green hydrogen into electricity is the most expensive.

Hirth has also shown that the greater the overall electricity demand, the greater the installed capacity of volatile generation can be. However, if electricity demand does not develop as forecast, an uneconomically high proportion of volatile generation will result in an overpriced electricity system due to the high integration costs generated by volatility, as is currently the case in Germany.

Various other studies in Europe suggest that both the specific geographical and meteorological conditions as well as the existing grid expansion are decisive for the integration costs associated with the strong expansion of renewable electricity generation based on wind and solar energy. Prof Werner Sinn already showed in 2017[13] in a comprehensive study that a share of PV and wind of around 50 % is the sustainable optimum for a country with the sunshine hours and wind yields such as Germany. Even if all realistically available electricity pump storage options are utilised, including those of neighbouring countries such as Norway, Switzerland, Denmark and Austria with higher shares of PV and wind, this order of magnitude represents a sensible maximum. The LDES (Long Duration Energy Storage) Council[14] also shows, with reference to the US Advanced Research Projects Agency - Energy, that the amounts of energy that are volatile or missing with an over 50 per cent expansion of solar and wind increase logarithmically (i.e. disproportionately). And higher shares of wind and solar-based generation cause sharply rising integration costs and overall higher total system costs.

GES recommends rebuilding the electricity system in Germany on two pillars: one pillar consisting of volatile energy from the sun and wind, and an equally important second pillar consisting of available generation capacity that is largely climate-neutral. The second pillar is indispensable for three reasons: it covers the demand for electricity during periods of darkness and longer periods of calm and when demand is higher in the winter months, it is essential for stabilising the electricity grid, which is essential for security of supply, and it prevents the costs of the electricity system from rising beyond an unavoidable level. This two-pillar system is essential for an industrialised country with a high proportion of continuous

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[13] Sinn, Hans-Werner. "Buffering Volatility: A Study on the Limits of Germany's Energy Revolution." *European Economic Review*, vol. 99, 2017, pp. 130-150. DOI: 10.1016/j.euroecorev.2017.01.004. Also published as CESifo Working Paper No. 5950 and NBER Working Paper No. 22467.

[14] LDES Council. "Driving to Net Zero Industry Through Long Duration Energy Storage." November 2023.
McKinsey & Company. "Net-zero power: Long-duration energy storage for a renewable grid." Published by McKinsey

electricity demand and energy costs that face global competition. The issue of grid stability is also much easier to manage with a share of around 50 % volatile generation and involves less investment than if the volatile share were to increase further.

GES therefore considers limiting the expansion of energy generated by PV and wind to around 50% of demand to be a significant alternative for optimising the climate neutrality of electricity generation that Germany is striving for. Assuming an electricity demand of 600-650 TWh in 2035, the expansion of wind and solar would have to be limited to 300 to 325 TWh in 2035 (feed-in volume in 2023: 192 TWh).

For the further expansion of the electricity system up to 2045/2050, it should also be ensured that the share of electricity generation from wind and solar power does not exceed around 50 %. Given the German government's expectation of final energy consumption of 1,400 TWh, this results in an electricity demand of approx. 700 TWh, not significantly above a realistically reduced expansion requirement from today's perspective.

Optimal proportions of solar and wind-based generation

How can the shares of the individual volatile forms of generation - offshore wind, onshore wind and PV - be optimally utilised under German conditions? Each of these three forms of generation has a specific volatility behaviour. In view of Germany's meteorological conditions (solar radiation, possible wind yields) and our consumption profile of high consumption in the winter months and lower consumption in the summer months with high proportions of PV-based electricity generation, a decision must be made on how to realise an economic optimum of the three volatile forms of generation.

To this end, GES analysed the quarter-hourly production data and the hourly consumption data for 2022 in a simulation: The result shows that a share of 28 % of electricity generated with PV systems triggers a minimum of surplus electricity production, given the ratio of wind onshore and offshore production. In an earlier study[15] , Fraunhofer ISE recommended a share of 30-40 % solar-generated electricity. The GES study shows in particular that the amount of temporary energy surplus increases significantly more with an increasing share of solar production than with an excessive share of wind-based generation. (GES is planning an in-depth study on this issue, which will appear in one of our upcoming newsletters).

For the assumed electricity demand in 2035 of 600-650 TWh and a limitation of the electricity generation share from wind & PV to approx. 50 %, the expansion targets for PV systems according to our calculations are approx. 93 to 96 GW, for onshore wind approx. 82 to 88 GW and for offshore wind approx. 21 to 23 GW. This means that an annual energy volume of around 300-325 TWh can be generated from wind and solar

[15] Fraunhofer ISE. "Levelised Cost of Electricity: Renewables Clearly Superior to Conventional Power Plants Due to Rising CO2 Prices." June 2021

under German geographical and meteorological conditions. This means a significant reduction in the expansion targets, a considerable reduction in the load on the grid from volatile generation and therefore significantly lower costs for integrating volatile generation into the electricity system.

The share of renewable generation in electricity demand would amount to a good 60 % on an annualised basis, as around 67 TWh of electricity is available through the use of existing pumped storage power plants (around 20 TWh), biomass power plants (around 40 TWh) and waste-to-energy plants (around 7 TWh). However, all three forms of generation have little scope for expansion. A 60 per cent share of renewable electricity generation would be a peak value for an industrialised country with Germany's geographical conditions.

Required new dispatchable generation capacities

So how can the necessary new available energy generation capacities in Germany be achieved in a climate-neutral way in the long term within the framework of the legally prescribed targets?

Both the German government (Easter package: 38 GW of gas-fired power plants by 2035) and McKinsey (50 GW of new power plants) as well as many other studies see an urgent need for the construction of new dispatchable power plant capacities. 80 GW of installed gas-fired power plant capacity is the target of the McKinsey study for 2035. This power plant capacity would also be sufficient for the electricity demand scenario outlined in this article and a 60 per cent generation from renewable energies and an electricity demand of 600 to 650 TWh in 2035. The required annual runtimes would be between 2,900 and 3,200 hours on average.

In all cases, the significant need for new construction of dispatchable generation is also due to the fact that the increased promotion of wind and solar-based electricity generation in recent years has led to a reduction in investment and new construction in new power plants. The conventional power plant fleet of gas and coal-fired power plants has aged accordingly - from an average of around 23 years (2010) to around 32 years (2022). At the same time, these power plants are operational less frequently: In recent years, the unavailability of the average fossil-fuelled power plant fleet (excluding Combined Cycle Gas Turbine (CCGT) power plants) in Europe has increased from 20 % to 30 %.

The construction of new dispatchable capacity will not come about in the private sector solely due to economic incentives (expected electricity revenues), as the state is massively promoting the expansion of wind and solar power through feed-in priority, among other things, but does not want the resulting strong electricity price volatility with phases of extremely high electricity prices (when it is dark and there is hardly any wind). As no private-sector investments are being made due to the price caps, the state must now create a regulatory capacity market in the electricity system. This means that electricity consumers will have to pay for the creation of available electricity generation capacity so that new capacity can be built. The investor is then paid for maintaining the capacity, regardless of the extent to which the capacity is utilised.

The new available power plant capacities to be built would be new gas-fired power plants, which, according to BMWK, are to be gradually converted to firing with green hydrogen between 2035 and 2040. The exact conversion date is to be announced in 2032. As GES showed in the position paper on the status of the ramp-up of the hydrogen economy in May 2024, green hydrogen will be much more expensive in Germany than forecast 2-3 years ago due to the high cost of electricity, and the capacity expansion will not reach the target of 10 GW of electrolysis capacity by 2030. As a result of this development, there will be a large demand for green hydrogen, which would have to be covered mainly by imports, combined with expected high costs.

The capacities to be created are to be awarded through auctions to those operators with the lowest subsidy requirements. This allocation mechanism, which is sensible in itself, should involve as much competition as possible, including between different technologies, in order to minimise additional costs for electricity consumers. This is because the foreseeably significant subsidy requirement (BMWK estimate for an initial capacity market tender of 10 GW: €16 billion)[16] must be paid for by all electricity consumers via a new levy.

This raises the question of how to minimise the need for subsidies in order to create the necessary disposable capacities.

The high costs of green hydrogen from German production, which are likely to remain high in the future, raise the question of other possible options. Some of the relatively new gas-fired power plants currently in operation can be retrofitted with carbon capture storage (CCS) and new gas-fired power plants can also be operated with natural gas and CCS instead of exclusively with hydrogen. Even operation with blue hydrogen would be conceivable in the future, even if this is not yet envisaged by the government. In an open political space, the question of retrofitting and also building new hard coal-fired power plants with CCS could also be raised, as this would also increase the supply options with primary energy in the long term and thus support the economic viability of the electricity system. However, this will not be discussed below.

In 2024, Germany will have around 5 GW of very young, highly efficient large gas-fired power plants (typically with CHP/district heat extraction) in operation. Their commissioning year is 2008-2011 and these power plants can therefore technically continue to run until at least 2050, possibly longer. With an efficiency that is the absolute best in the world (around 58-61 %) and a fuel utilisation rate of up to 80 %, these power plants are often an essential source of heat for the district heating networks of larger cities. As the existing district heating networks are to be expanded as part of the heat transition, which already means investments totalling billions of euros for

[16] Federal Government. "Power plant strategy: Climate-friendly and secure energy supply." February 2024.

the operators, the technically possible maximum service life of these plants could be exploited by retrofitting them with CCS.

In addition, two coal-fired power plants totalling 2.5 GW in Baden-Württemberg[17] will initially be converted to natural gas operation and then to hydrogen operation in the coming years. After conversion to natural gas, these could alternatively remain in operation well beyond 2050 by means of CCS retrofitting, possibly with partial combustion of green gases (e.g. by adding green biogas in order to achieve almost 100 per cent climate neutrality in addition to CCS (90 % CO capture efficiency$_2$)). The conversion pathway with its alternative actions is also suitable for further coal-fired power plants with a capacity of 4 GW completed in 2013-2020. The expected longer annual operating life of these power plants compared to McKinsey's alternative path should have a positive impact on the economic viability of retrofitting with CCS.

In a number of industrial parks belonging to companies in the process industry and in companies with a high demand for process heat, some state-of-the-art natural gas-based power plants are also in operation today for their own electricity and process heat requirements. The same applies to these.

The construction of new gas-fired power plants in areas with large future electricity deficits (such as in the west and south) is also necessary in terms of the grid and to maintain security of supply (frequency stability). All in all, it can be assumed that there will be no way around the construction of at least 40 GW of new natural gas power plants, even if the German government initially only wants to put 10 GW out to tender in several tendering rounds of 2.5 GW each. The urgently needed construction of dispatchable generation capacities should be organised in a technology-neutral manner.

In the long term, the question of using hydrogen or, alternatively, natural gas with subsequent capture of the CO_2 produced is primarily a technical/economic one. Assuming the existence of a large-volume CO_2 transport network in Germany, it will primarily become an economic issue, which will be influenced by the expected number of operating hours of the new gas-fired power plants, the expected costs of green (or blue) hydrogen compared to natural gas and the additional costs of CCS.

Overall, there is broad agreement among research institutions, the electricity industry and electricity consumer associations that the necessary electricity capacity market is already behind schedule. Appropriate technical options are available. The pending legislative and regulatory design may make it more or less expensive for electricity customers.

Requirement for CO_2 transport network

A large-volume CO_2 transport network was finally considered in Germany, with the Federal Cabinet approving the project at the end of May 2024: In

[17] official website of EnBW: EnBW Umbau Kohlekraftwerke.

the "Carbon Management Strategy"[18] presented by the BMWK in February 2024, CCS or CCU including the development of a CO_2 transport core network (with connection to the corresponding networks in the Netherlands, Belgium and Switzerland) was described as indispensable for achieving the GHG reduction targets.

Although the BMWK concept currently explicitly does not provide for direct funding of CCS in the electricity sector (in contrast to sectors with technically unavoidable CO_2 emissions such as the cement industry), it does allow CCS in the electricity sector in principle (although utilisation of the CO_2 network of coal-fired capacities has been ruled out). If the legal and regulatory framework conditions for CCS are also created in the coming years, GES believes that the electricity sector should also be taken into account in the possible dimensioning and utilisation of a CO_2 transport network and a possible CO_2 transport requirement from the electricity sector should be included in the CO_2 network planning.

A CO_2 transport network for Germany, for example, has been designed by the long-distance gas network operators OGE and GasUnie[19] . OGE's example envisages 4,800 km of long-distance pipelines to connect major CO_2 sources with "unavoidable CO_2 production" (such as the cement industry) with harbours on the German North Sea and Baltic Sea. From there, the CO_2 could be transported by pipeline to Norway, where it could be stored permanently and safely in depleted gas reservoirs. The costs for this essentially new CO_2 core network are estimated at around € 14 billion[20] . Additional utilisation by electricity-generating companies is expected to result in higher costs due to increasing volumes. However, the group of companies that would be eligible to finance this investment would also increase. In addition, the investment in one or more underwater pipelines to Norway could be borne by interested CO_2 storage providers from Norway such as Equinor.

There are a number of research studies from various countries on expected transport costs up to final storage under the North Sea. They assume around €100-120 per tonne for CO_2 capture from a large point source (such as a cement plant, a chemical plant or a power station), CO_2 transport and final storage. This puts CCS costs in a range that can also be expected for 2035 and subsequent years as the CO_2 price under the European Emissions Trading Scheme (ETS). Even in the event of even higher costs of €120-170/t CO_2 , the use of CCS would still be competitive with green hydrogen for power plants with an annual capacity utilisation of over 30 %, even taking into account the reduced efficiency resulting from the use of CCS. CCS could therefore also become economically attractive for new power plants with a longer annual utilisation period.

[18] Federal Government. "Cabinet adopts key points for carbon management strategy." 29 May 2024.
[19] OGE and TES develop a CO2 transport network, Pipeline Technology Journal; Gasunie CO2 network, Pipeline Technology Journal
[20] German Cement Works Association (VDZ). "A CO_2 roadmap for the German cement industry

The additional costs for the installation of a CCS plant in a new gas-fired power plant are roughly 50 % of the new construction costs (new construction costs of around € 0.5 billion for a 500 MW gas-fired power plant with CCGT)[21] . Due to the lack of economic incentives in the current regulatory framework, only a few CC plants are in operation worldwide. This means that there is certainly still potential for optimisation compared to previous cost estimates. Technically, the use of amine scrubbers to capture CO_2 is largely tried and tested[22] , as they have been used for many years in numerous process plants to produce hydrogen from natural gas.

The captured CO_2 would be transported via a CO_2 pipeline network for safe final storage under the North Sea floor. Corresponding projects have been in operation for many years (such as Sleipner in Norway) or are being realised (such as PORTHOS in the Netherlands and other projects such as "Northern Lights" in Norway). And Norway has officially offered Germany to take over all the CO_2 produced from CCS this century.

It should also be noted that key organisations such as the International Energy Agency (IEA) and the Renewable Energy Agency (IRENA) consider the use of carbon capture to be crucial to achieving the net zero targets. Germany should not turn its back on this option and support the use of carbon capture for climate-friendly electricity generation. A first step has been taken with the Carbon Management Strategy.

Savings potential of the GES proposals

In January of this year, McKinsey showed that, according to their estimates, investment savings of €150 billion are possible compared to the German government's Easter programme. The main levers were a lower expansion of volatile electricity generation from PV and wind power plants and, as a result, lower expenditure for the expansion of the transmission and distribution grids with increased expenditure for the construction of dispatchable capacities. In this way, an 11 % lower household electricity price of 42-44 ct/kWh was projected for 2035 in the long term.

The GES proposals go one step further. Firstly, the electricity demand is scrutinised: due to lower growth in electromobility, heat pumps, hydrogen electrolysis and declining industrial output, we see the medium-term electricity demand in 2035 at only 600-650 TWh, i.e. around 15 % below the government's forecasts or the figures used by McKinsey.

In order to make the volatility of electricity generation with PV and wind systems more manageable and to limit the resulting investment requirements accordingly, GES shows that it is also wise in the long term to limit the share of volatile generation in electricity demand to around 50 %. Accordingly, investments in this area will be significantly reduced, with the additional benefit of significantly lower investment requirements in the transmission and distribution grid area and for battery storage. At this point,

[21] International Institute for Sustainable Development (IISD), "Why the Cost of Carbon Capture and Storage Remains Persistently High" (2023)
[22]IEA, "CCS Retrofit - Analysis" (2023)

we would also like to expressly warn against the high volatility costs of generation from PV and wind systems that is oversized for the electricity demand. The system costs of volatility have a disproportionately high impact on lower electricity consumption. In view of the expected lower demand for electricity, the investment costs for new dispatchable capacities are estimated to be similar to those of McKinsey.

As GES also considers the use of CCS for electricity generation to be an economically viable alternative, the planned CO_2 transport network must be larger. We anticipate a maximum doubling of the previously forecast costs of € 14 billion for the construction of a CO_2 transport network.

According to GES estimates, in addition to the €150 billion in savings mentioned by McKinsey, this could save a further €150-200 billion in investments for the German electricity system.

There would also be annual net savings in running costs of more than € 10 billion per year. Positive effects result from reduced re-dispatch costs, avoided expenses for measures to stabilise the grid frequency and significantly reduced future EEG feed-in tariffs.

From GES's point of view, the medium-term sensible expansion of PV capacities will already be reached in 2026; in particular, new ground-mounted systems would only be necessary if electricity demand continues to grow after 2035. This means that the subsidisation of new PV systems through fixed feed-in tariffs guaranteed for 20 years could expire by 2026 at the latest. The statutory obligation to connect new PV systems to the grid (at the expense of all electricity consumers) already provides considerable support.

In the case of onshore wind, the focus should also gradually be placed more on re-powering old turbines at relatively high-yield locations. The development of new, less windy locations only leads to an increased need for subsidies and is counterproductive from an economic point of view.

On the other hand, there are increased running costs for more EU ETS allowances due to the longer lifetime of available power plants with residual emissions compared to the McKinsey alternative pathway. The magnitude of these higher costs can be estimated at around € 1 billion per year.

These higher residual GHG emissions in the electricity sector, which also remain in the long term, can be avoided more cost-effectively from an economic and global perspective within the framework of international partnerships: for example, through the increased expansion of nature-based solutions in partnership with countries of the global South. Even if these costs (estimated at €1-2 billion per year), which would of course have to be paid by electricity consumers in Germany, are also included, the GES path is significantly more favourable in terms of running costs in the long term.

Incidentally, the area required for new ground-mounted PV and onshore wind farms is likely to be roughly equivalent to the area of the Saarland compared to the McKinsey scenario. And the resources required for implementation (skilled labour, scarce metals (such as copper for grid expansion), battery raw materials, etc.) are significantly reduced once again, which makes it much easier to achieve the target.

Summary

GES believes that there is an urgent need to correct the current targets for the energy transition in the electricity market. GES supports the target adjustments proposed in the McKinsey study in January 2024, which will already save €150 billion in investment costs by 2035.

GES proposes that the expansion targets for wind and PV in Germany should not be allowed to rise above around 50 %; more volatile electricity would make the system continuously less efficient due to the follow-up costs.

In addition, CCS can have a positive impact on the electricity system costs for the new dispatchable power plant capacities to be built. The adjustments to grid expansion and reduction in the expansion of PV and wind power plants proposed by GES, netted against the additional costs for a larger CO_2 transport network, could avoid a further €150-200 billion in investments over the next 20 years.

The GES proposals will make climate neutrality in the electricity sector possible. However, where achieving complete local climate neutrality would incur extreme costs, GES favours international solutions. In return, a comparatively small amount would have to be paid annually for nature-based solutions in the global South, which would support the urgently needed development in these countries.

This approach would prevent the foreseeable rise in electricity costs in Germany to a level far above that of our neighbouring countries. Germany would also regain its competitiveness as a business location. The progression of deindustrialisation, which is also triggered by the fear of further rising energy prices, would be slowed down.

The path to climate neutrality outlined by GES is also associated with lower resource consumption. In other words, too much volatile electricity generation generates additional costs, which leads to an overpriced consumption of resources that many countries cannot afford.

It has been shown in many other situations that an open-technology approach and market-based competition for the most cost-effective solution achieve much better results than government programmes. Investors are much better able to estimate the expected market prices for CO_2 , hydrogen and CCS than the state or research institutions.

If the share of electricity in final energy consumption reaches around 50 % in the long term, as outlined here, the other 50 % must be represented by climate-neutral molecules. This increases the importance of imported climate-neutral fuels and imported low-carbon hydrogen. It also raises the question of the extent to which "residual quantities" of CO_2 can be provided by nature-based solutions in countries of the global South, rather than through costly technical measures. This approach is also much more favourable from an economic perspective.

Translated with the help of DeepL