
Minimizing the cost of integrating wind and solar power in Japan

Insights for Japanese power system
transformation up to 2030

ANALYSIS

Agora
Energiewende



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IMPRINT

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Dear reader,

Japan has committed to reduce its greenhouse gas emissions to net zero by 2050. This pledge is a game changer for an industrialized nation such as Japan and a fantastic opportunity to fundamentally change the Japanese energy system, which still relies heavily on fossil fuels.

While in Japan the costs of renewable energy are still high compared to international standards, they are expected to continue their decrease. By 2025, the generation costs of solar PV and wind energy are expected to be close to or even lower than any other sources of electricity generation. With these sharply declining costs of solar PV, wind power and storage units, the transformation towards a low carbon economy in Japan can be massively based on renewables and electrification.

Yet, wind and solar power are different than conventional power. They may induce additional system costs, such as for reinforcing the grid, balancing, and variability.

These system costs of variable renewables – sometimes called “integration costs” – are a hotly debated subject in academic and policymaking circles. With this paper, we shed light on those controversies. We also offer some insights on how to quantify those integration costs in Japan, and more importantly on how to minimize them.

We hope to make a positive contribution to informed debate towards a renewable-based transformation of the Japanese energy system.

Yours,
Markus Steigenberger
Managing Director, Agora Energiewende

Key findings at a glance:

1	Between 2025 and 2030, the cost of generating electricity (LCOE) from solar PV and wind power in Japan expected to be lower than from any other technologies. In 2025, the LCOE of utility-scale PV should reach about 6.3 ¥/kWh (5.2 €cts/kWh). Onshore wind could reach those levels in 2030. Those costs will be significantly lower than those of new fossil-fuelled power plants, comparable to lifetime extensions of nuclear and far below new nuclear and CCS projects.
2	Adding the “integration costs” (costs for grid, balancing, and variability) on top of the LCOEs does not fundamentally change the competitiveness of variable renewables in 2030. Japan can reach a share of at least 45% renewables in 2030 (corresponding to a share of 35% wind and solar power) with integration costs below 1.5 ¥/kWh. Integrating 66% renewables (corresponding to 50% wind and solar power) would come only at a slightly higher cost of 2 ¥/kWh.
3	Integration costs for grids and balancing are well defined and rather low. These costs are estimated at below 1 ¥/kWh for Japan. Various measures exist to minimize those costs, in particular through optimal grid planning, optimised grid operation, and well-functioning and non-discriminatory intraday and balancing markets.
4	Integration costs for compensating the variability of renewables are much more disputed. The calculation of those costs can vary tremendously depending on the assumptions. A total system cost approach would circumvent some of the uncertainties, in particular the controversial attribution of system effects to specific technologies. Rather than to speak about integration costs, we should speak about interaction costs. If the system adapts to renewables (reducing baseload power plants), the cost of variability for integrating 50% PV and wind energy in Japan is estimated at about 1.25 ¥/kWh. If not, the costs of variability could be much higher. This finding calls for a refinement of energy markets design, so as to incentivize rather than to hamper flexibility.

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1 Introduction

Japan has committed to reduce its greenhouse gas emissions to net zero by 2050. This pledge represents a fundamental transformation away from fossil fuels over the next three decades.

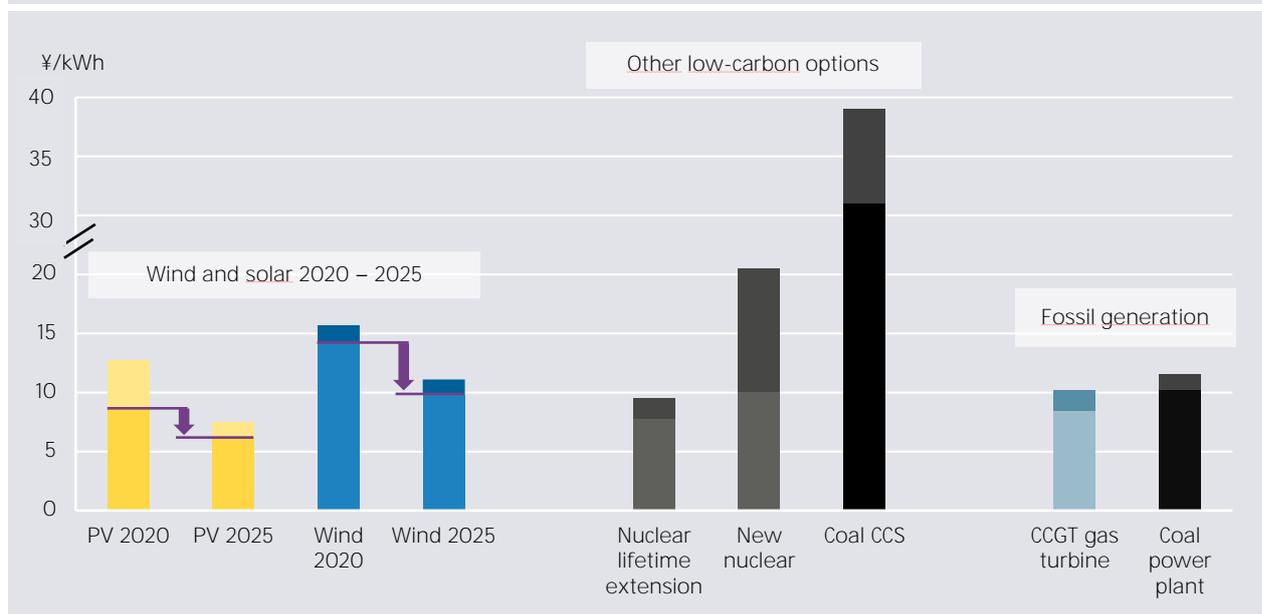
As the power system in Japan enters into a phase of transitioning to higher shares of variable renewables, system planners are faced with the complexities of shifting gears from a system powered by dispatchable fossil-fuel or nuclear power plants to a new system that is more environmentally friendly, but whose output also fluctuates according to weather conditions (as opposed to power demand). What's more, these new variable renewable energy

(VRE) units are more regionally distributed and subject to weather forecast errors.

In Japan, solar PV uptake has risen rapidly over the last seven years (62 GW installed at the end of 2019), making the country one of the most dynamic PV markets outside China. While the proportion of variable renewable energy sources (VRE) in Japan is increasing it remains rather low, however, at around 10% of total electricity production. In particular, the development of wind energy remains very slow (4 GW installed by the end of 2019).

In Japan, renewables costs are still high compared to international levels, but costs are expected to continue to decrease rapidly, bringing them close to or

Figure 1: Current and future costs of electricity generation (LCOE) in Japan for various technologies



Source: LUT-REI-Agora (2021), REI (2020), RTS (2020), Reuters (2016), METI (2015).

Exchange rate: 1 ¥=0.824 €cts (ECB 2020)

The graph represents the Levelized Cost of Electricity, a metric used to compare the generation costs (¥/kWh) of different technologies, taking into account fixed and variable costs, as well as cost of capital (WACC). The upper and lower ranges correspond to the following:

- for PV: upper range is for roof-top PV, lower range for utility scale (both 2020 and 2025);
- for wind: upper range is for offshore, lower range for onshore (both 2020 and 2025);
- for nuclear lifetime extension: the range depends on some exemplary retrofit project (upper range: Tokai-2, lower range: Mihama-3), not taking into account plants damaged by the Fukushima accident (such as Onagawa-2, which retrofit cost is significantly higher);
- for new nuclear: upper range of costs estimates worldwide, lower range from costs evaluation by METI (2015);
- for coal CCS: upper range in 2020, lower range in 2025;
- for CCGT and coal: upper range with CO₂ price of 2000 ¥/tCO₂ (2025), lower range for a CO₂ price of 265 ¥/tCO₂ (2020).

even below other sources of energy generation within the next few years.

The declining costs of solar PV, wind power and storage units offer many opportunities for a low-carbon transformation based entirely on renewables.

Today, the cost of generating electricity (known as the "levelized cost of electricity" (LCOE)) from ground-mounted solar PV in Japan is already below the cost of some nuclear lifetime extensions (such as the LCOE for the retrofit of the Mihama-3 and Tokai-2 power plants¹), as shown in Figure 1. The costs are also far below those of new nuclear power plants and new coal power plants with CCS. In addition, the generation costs of onshore wind and solar power (utility-scale as well as roof-top) should be comparable to or lower than those of all nuclear lifetime extension projects and outcompete new coal and gas power plants somewhere around 2025, as can be seen in Figure 1.

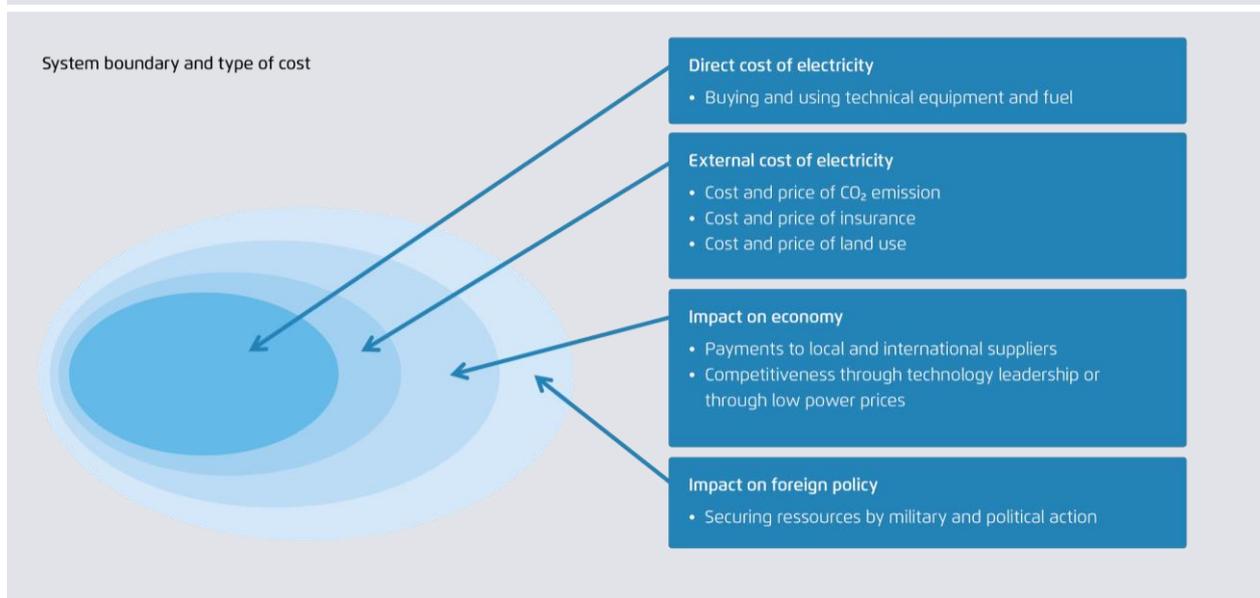
Despite this important progress, these generation costs do not tell the whole story as they do not include system costs of renewables, such as the cost of the grid, variability and balancing. The question is to what extent these integration costs change the equation. This paper investigates that issue, including ways to lower those costs, with a focus on Japan.

Germany and several other European and North American grid regions have already incorporated very large shares of variable renewables in their power systems. Several challenges related to the costs of integrating variable renewables have been solved in this way.

In Japan, a set of measures has also been introduced to promote renewable energy development, with particular emphasis on the rapid expansion of PV.

In this short paper, Agora Energiewende offers some insights for the Japanese power system transfor-

Figure 2: Overview of possible system boundaries and types of costs and benefits



Adapted from Nuclear Energy Agency (2012): Nuclear Energy and Renewables. System Effects in Low-Carbon Electricity Systems, commissioned by the Organisation for Economic Co-operation and Development.

1 REI 2019. Reuters 2016.

mation. Emphasis is given to the feasibility of integrating at least 35% of VRE in Japan in 2030, corresponding to a share of 45% of renewables². The impact of higher shares (more than 50% variable renewables, corresponding to about 70% renewables in total) are also assessed. Some calculations performed for this analysis rely on an open-source power system model developed and calibrated specifically for Japan, based on the free software toolbox PyPSA. The source code as well as input and output data can be provided on demand by the authors.

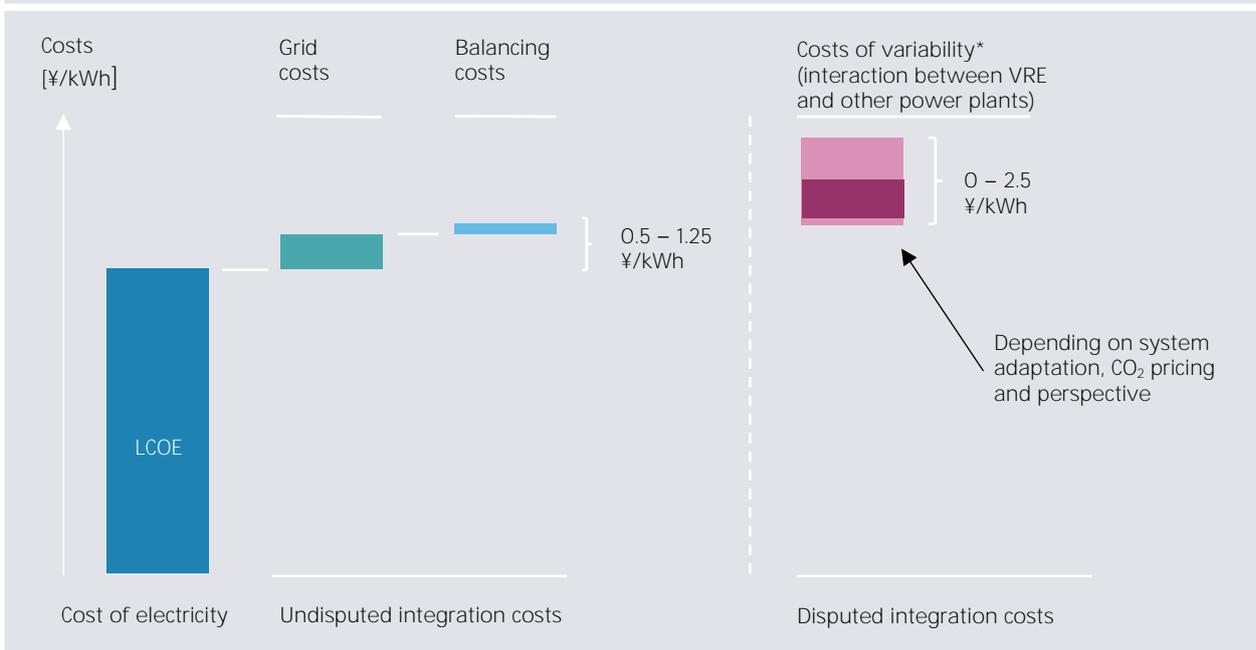
2 The challenge of calculating integration costs

The levelized cost of electricity generation (LCOE) is a widely used metric in the analysis of energy eco-

nomics to compare the generation costs of different technologies. It allows a seemingly neat comparison of technologies. According to this metric, wind and solar PV have become the cheapest technologies in several countries. Yet, LCOE does not capture system effects and does not value the time and place of electricity generation – two aspects that are increasingly important in the transition to decarbonised energy systems.

There is no perfect answer for how best to compare the costs of different power generation technologies from an overall system perspective. The concept of integration costs is one method for capturing those specific effects and comparing different technologies systematically.

Figure 3: Overview of components discussed under “integration costs”



Agora Energiewende, 2020 *The costs of variability capture the effect that renewables have on the other power plants that remain needed in the system. They are sometimes called “profile costs”, “back-up cost”, “cost of reduced utilization”.

2 Including hydropower, geothermal- and biomass-based power production.

While all power plants come with integration costs, the definition and the range of those costs are contested. Different calculations yield substantially different results, depending not only on the specific power system and its share of renewable energy, but also, and perhaps more crucially, on what costs are included, which methodology is applied and whose perspective is considered.

The most controversial element of integration costs comes from the variability of renewables: as the output of wind and solar energy depends on the time of day and the season, the power they generate requires a more flexible operation of conventional power plants. In short, they make baseload operation obsolete. Existing power plants, most notably gas power plants and to a lesser extent coal and nuclear power plants, can provide much of the needed flexibility at low cost. Well-designed markets can properly remunerate this flexibility. But the introduction of variable renewables fundamentally changes energy systems and ultimately impacts their economics. But while integration costs do exist, one should be careful not to inflate them.

There is still no generally accepted definition of integration costs; nevertheless, they are typically described as being the sum of three elements (see Figure 3):

1. Grid costs;
2. Balancing costs;
3. Cost of variability³.

While grid and balancing costs are relatively easy to define and determine, the effect of renewables on other power plants ("cost of variability") is the subject of much debate. It seeks to put a price on the economic effect of introducing more variable renewables on conventional power plants. The greatest

controversies here arise from the value given to existing power plants (value of past investments) and from the cost attributed to externalities (healthcare and environment costs, cost of adapting to climate change, cost of a nuclear accident, etc.).

Under realistic assumptions, the additional costs of integrating 50 percent wind and solar PV into the Japanese power system could be below 2 yen⁴ per kWh. Adding those integration costs on top of the LCOEs does not fundamentally change the competitiveness of variable renewables technologies, even at very high penetration shares.

To meaningfully quantify the integration costs, the boundaries of the system in question need to be defined. Most analysis consider only the direct costs of electricity (Figure 2, inner circle) and the external costs only to the extent they are internalized (through, say, CO₂ prices). Broader analyses consider external effects, macro-economic impacts, and other, more far-reaching effects of power generation on policy dossiers and thus on society as a whole, such as the impact on securing foreign resources by military and political action.

After describing the three elements of integration costs and recommending some pragmatic measures to lower individual costs in transitioning to higher shares of variable renewables in Japan, the paper will close by pointing towards the total system costs approach as a way to circumvent some methodological challenges.

3 The "cost of variability" captures the effect that renewables have on the other plants still needed in the system; these costs are sometimes called "profile costs", "back-up costs", or "costs of reduced utilization."

4 Exchange rate: 1 ¥=0.824 €cts (ECB 2020)

2.1 Grid costs

Cost perimeter

Grid costs are the transmission and distribution network costs related to the construction of a new power plant. Grid costs include investment costs, power losses and expenses for ancillary services. This definition applies no matter what type of power plant is connected to the system, be it a coal power

plant, offshore wind farms or a rooftop solar PV system. While a small rooftop PV unit in an industrial building that makes use of existing infrastructure may cause barely any costs for the grid, connecting an offshore wind park requires an offshore grid connection as well as an expansion of the transmission grid onshore. In most cases, wind farms and ground-mounted solar power plants are directly connected to the distribution grid, but a reinforcement of the transmission grid (above 220 kV) may be needed in some cases⁵.

Situation in Japan

In Japan, the current grid management regulations and practices are rather restrictive, leading to a low utilization rate of grid infrastructure. Today, only 50% of the total physical capacity of the transmission grid is utilized on average. The margin corresponds to security of supply and N-1 constraints. On some lines, such as the one from Kansai to Chugoku, this average utilization rate can fall as low as to 17%. This situation, which could be avoided with better management measures, discriminates against new (renewables) generators that must carry a disproportionate burden for reinforcing the grid. Furthermore, grid reinforcement is slow, and the planning of the grid infrastructure is insufficiently coordinated. To address this problem, the Organization for Cross-regional Coordination of Transmission Operators Japan (OCCTO) launched a program in August 2020 to develop a mid- to long-term power grid master plan.⁶ In addition, OCCTO developed the Connect and Manage framework to increase the use of the existing grid infrastructure.⁷

5 Several challenges remain when calculating grid costs:

- A distinction between grid costs and generation or balancing cost is not always clear-cut;
- grid costs caused by the integration of vRES must be dissociated from grid upgrading costs that would have been necessary anyway;
- optimised grid planning approaches and new technological development must be taken into account; and
- average grid costs are hard to calculate as each system and project tends to be different. The need for grid reinforcement depends on the distance between renewable resources and consumption centres, as well as on the level of existing grid infrastructure and cross-border interconnection.

6 The objective of the program is to identify the need for grid reinforcement and expansion while optimising the costs and benefits through a diversification of power supply, offering an opportunity to discuss the transformation of power grids in a future sustainable power system.

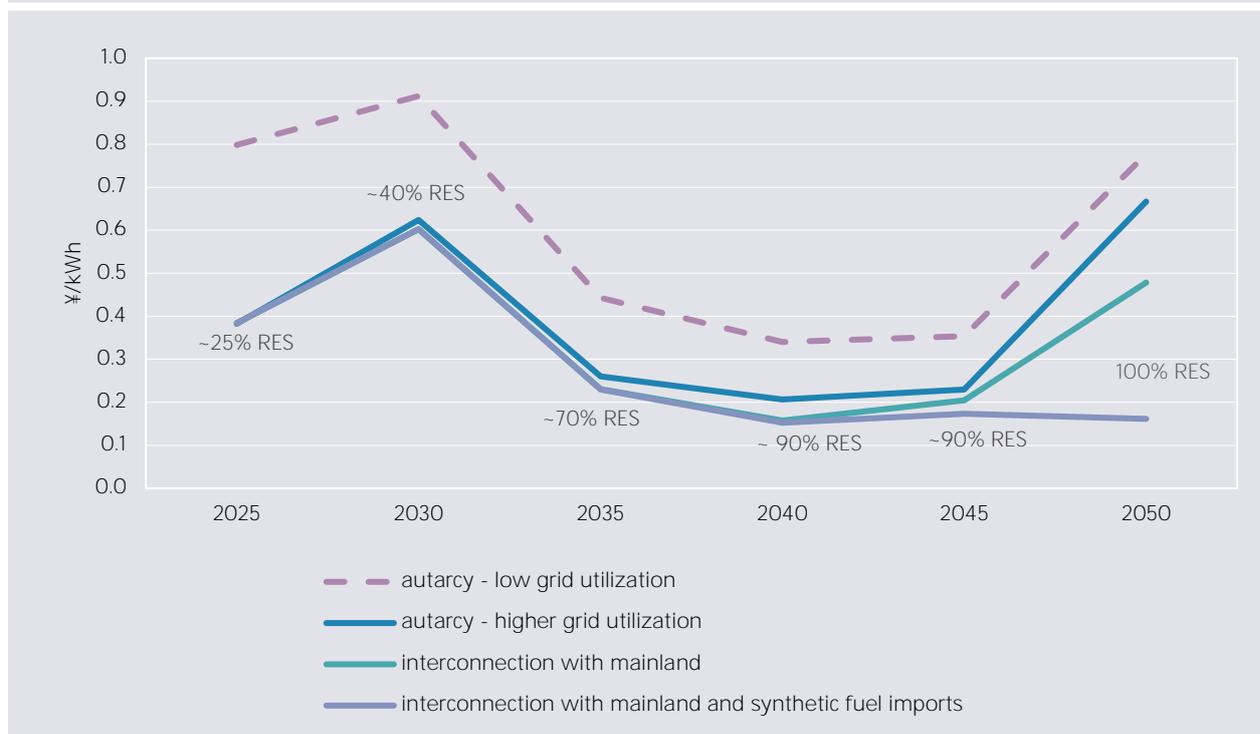
7 This framework covers three main initiatives. First, a probabilistic power flow modelling should help re-allocate grid capacity to the various power sources, based on their real utilization of the grid. Second, the introduction of N-1 intertripping measures that allow grid operators to cut the output of generators (especially renewables) in case of a violation of the N-1 criteria. This option in return better utilizes infrastructure in normal situations without the need to double the capacity of the lines. The benefit is expected to provide about 40 GW of additional transmission capacity nationwide. Third, renewable generators could be granted "non-firm access," i.e. curtailment in situations with an excess production level of variable renewables. Those new initiatives are currently being tested in some regions and are to be rolled-out in the whole of Japan by 2022. Further details can be found in the paper "Recommendations for Power System Restructuring" from REI (2020c).

Evaluation of current and future grid costs

The cost of reinforcing transmission grid infrastructure has been estimated based on modelling of the Japanese power system performed by LUT, REI and Agora Energiewende⁸ with higher shares of renewables (more than 40% in 2030, 70% in 2035 and 90% in 2040) and deep electrification (to decarbonize the heating and transport sectors). Starting from the results of this study⁹, an estimation has been performed under two different main assumptions:

1. Best case: through better management of the grid, the average utilization rate of infrastructure increases from the current 50% to 75% in 2025 (equivalent to the EU target).
2. Worst case: the utilization rate of the infrastructure remains unchanged (about 50% on average).

Figure 4: Transmission grid costs in high RES and electrification scenarios for Japan 2025–2050



LUT, REI, Agora Energiewende (2021)

8 REI, LUT, Agora (2021) – upcoming.

9 The model considers nine Japanese regions that are interconnected with a power transmission network based on the existing grid structure. The model considers the possibility to build additional grid interconnections, such as AC interconnection between adjacent regions, a direct sea cable connection between Hokkaido and Tokyo region, or DC connection from Tohoku to Hokuriku. Connection

costs are defined in the model based on the distance between the biggest consumption centers in each region, connection cost per GW*km and the overall line capacity. For HVDC lines the costs of the AC-DC converters are also included. It does not take into account the grids within the regions. For additional information, see also Agora Energiewende (2015), section 3.3.

In addition, two variants have been investigated in the best-case scenario for 2040 to 2050:

- Autarky: Japan is self-sufficient and all of its energy demand, including synthetic fuels, is met by local resources.
- Interconnection: 50% of synthetic fuels are imported, and Japan is electrically interconnected with Korea and Russia.

The main takeaways are (see Figure 4):

- Reinforcing the transmission grid in Japan costs between 0.15 and 0.65 ¥/kWh per additional kWh of VRE from 2020 to 2050 if transmission grid utilization increases to 75% on average from 2025 onwards;
- Without optimized grid utilization, those costs would peak at 0.9 ¥/kWh in 2030;
- After 2030, transmission grid costs decline, as new transmission capacities are made available, with coal and nuclear phasing down. Early investments therefore promote the integration of RES up to 2045, thereby reducing RES grid costs despite an increase in the RES share;
- From 2045–2050, the deep decarbonization of the Japanese system induces a new increase in grid costs, especially related to the development of wind energy to the north;
- International grid integration and more imports of synthetic fuel minimize the need for grid reinforcement and costs in Japan.

No analysis has been found for distribution grid costs in Japan. However, a review of several grid expansion studies in Germany and in Europe reveals various estimates of distribution grid costs depending on the power systems, the shares of renewables,

and the methodology applied¹⁰. While the costs differ in each case, they typically amount to approximately 0.15 €/kWh (0.18 ¥/kWh) for solar PV and 0.5 €/kWh (0.6 ¥/kWh) for wind power.

In total – and assuming optimized grid utilization – we estimate the costs for grid reinforcement (transmission and distribution) at between 0.35 and 1 ¥/kWh of additional wind and solar power from 2030–2045.

Measures to minimize grid costs

Based on the experience of countries such as Germany, a number of recommendations for Japan can be made to lower grid costs:

- Joint grid and resource planning helps mitigate the impact of wind and solar PV deployment on intraregional and interregional load flows. Increasing the proportion of vRES in the mix is expected to reduce power line loading in some regions and increase it elsewhere. The impact of vRES distribution on the grid must therefore be systematically taken into account in future grid development plans, in order to avoid creating line-loading hotspots.
- Optimal grid planning considers punctual curtailment of RES. As shown in Figure 5, the curtailment of about 2–3% of the annual generation
- output of a solar PV plant can reduce grid costs by around 25%¹¹;
- Incentivize investments in wind and solar PV where grids have spare capacity or can be upgraded at moderate costs.

10 See Agora Energiewende (2015).

11 Grids that connect wind and solar PV power plants do not necessarily need to be designed to transport the maximum power output because there is no guarantee that the plant would actually produce at maximum output during the hour of highest demand. A cost-optimal grid design for wind and solar PV power plants might look at the total costs of generation and grid connection and accept that a

small share is lost for the sake of lower grid costs. Figure 5 shows such an optimisation based on the feed-in data of an individual power plant. In this specific case, curtailing solar feed-in at 75 percent of rated capacity leads to a curtailment of only 3 percent of potential generation. Thus, while grid costs may be reduced by 25 percent, generation costs are increased by only 3 percent.

Figure 5: Cost effects of curtailing maximum in-feed of solar power



*Based on data of a solar power plant located in southern Germany, provided by EEG TU Wien and available at: http://portal.tugraz.at/portal/page/portal/Files/14340/eninnov2014/files/lf/LF_Hartner.pdf

- Grid planning and operation should follow the so-called GORE principle: Grid Optimisation prior to grid Reinforcement prior to grid Expansion. Several short-term and mid-term measures safely optimize or reinforce the capacity of existing lines, in particular the use of dynamic line rating and the introduction of high temperature, low sag power line conductors (HTLS). In addition, preventing overloads on specific lines may be achieved by means of active power flow control (such as phase shifting transformers)¹².
- Where infrastructure development lags behind the growth of renewables, curtailment of renewables in system operation should be used only as a measure of last resort. In case of congestion, conventional power plants should be redispatched first. Grid-relevant storage units can also help minimize grid congestions. Costs for re-dispatch and curtailment should be socialized among electricity consumers.
- Encourage wide consultation around grid planning, as well as independent power system studies on topics such as congestion management, adequacy, market integration, operational planning adaptation, connection requirements, and system defense.
- Design grid codes to enable high shares of wind and solar power and fault ride-through capability and voltage support.
- Improve grid operation using regulated distribution transformers that improve distribution grid voltage support and allow for larger feed-in without exceeding voltage limits.
- The right incentives encourage innovation and awarding smart technologies and cost-efficient investments.

12 For a review of existing technical solutions, see Agora Energiewende (2018).

2.2 Balancing costs

Cost perimeter

Balancing costs concern deviations between actual generation and forecast generation. Balancing power is used to keep the demand–supply balance at any given moment to ensure frequency stability (50 Hz in East Japan or 60 Hz in West Japan). Unbalanced frequency deviations can cause severe damage – destroying, say, rotating machines such as generators.

Wind and solar power production depends on the weather and, unlike conventional generation, can only be forecast, not controlled (save by means of curtailment). Reserves are thus required to offset the errors incurred in forecasting. The costs of activating reserves are borne by the producers, sellers and consumers that cause the imbalance. Obviously, the occurrence of such deviations depends on the level of renewables, the quality of the forecast and the time horizon for which the forecast is made.¹³

Situation in Japan

Japan has gradually introduced market mechanisms to balance supply and demand at lower costs.¹⁴ A full market-based balancing mechanism is due to commence operation in 2021. Ahead of this schedule, the regions Kansai, Chubu and Hokuriku have already started a cross-regional balancing mechanism for tertiary reserves in 2020.

Evaluation of current and future costs

No analysis has been found for balancing costs in Japan. However, many studies have assessed the balancing costs for integrating wind and solar power in other power systems.¹⁵ Those results are sufficiently robust and could also be applied to the Japanese situation. In power systems with mostly thermal power plants, balancing costs are estimated to be between 0 and 0.6 €cts/kWh (0.75 ¥/kWh) per kWh of VRE, even at wind penetration rates of up to 40 percent. In Germany, they are currently around 0.2 €cts/kWh (0.25 ¥/kWh). In power systems with significant shares of flexible generation, such as the Nordic region, balancing costs can be even lower.

A closer look at the balancing market development in Germany reveals that several factors may have a significantly larger impact on balancing cost than the integration of renewable energy. Indeed, as can be seen in Figure 6, combined wind and solar power doubled from 2011 to 2017, but the amount of capacity reserved for balancing power has declined by 50 percent.

Besides better forecasts, several market design factors might have driven this development:

- balancing markets have become more competitive, which encouraged more actors to provide balancing power, thus lowering prices;
- cooperation between transmission system operators has improved, increasing the size of the balancing area;
- the liquidity of the intraday market has increased; and
- margins on spot markets have decreased, changing opportunity costs for thermal plants.

13 While forecast errors are likely to be significant when made over a period of several hours or a day, they are likely to be close to zero if made over a period less than an hour.

14 Balancing mechanism based on planned generation, demand levels, and the hourly intraday market.

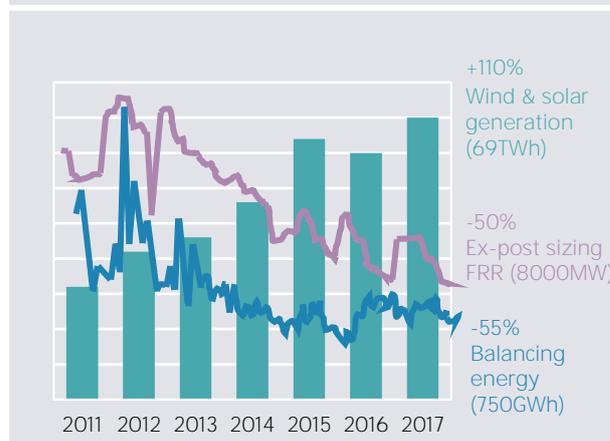
15 For a review of some studies, see Agora Energiewende (2015).

Measures to minimize balancing costs in Japan

Designing an efficient market framework enabling flexibility will be key to minimize the balancing costs in Japan.

- Some key design elements of intraday and balancing markets risk distorting wholesale power price signals, as do imbalance settlement rules, thereby increasing the cost of providing flexibility. Key market design elements therefore need to be adjusted in all market segments, requiring continuous political momentum to coordinate efforts regionally. On balancing markets, small minimum bid sizes and short contracting periods would be required.
- In addition, the market design must allow demand side response and renewables to participate. A regulatory framework enabling independent aggregation should also be implemented to fully tap the flexibility potential.
- Intraday markets are critical for integrating wind and solar, as they allow for trades responding to updated generation forecasts. As in Europe, renewables generators should have balance responsibility (potentially through third-party aggregators). This requirement provides a strong incentive to develop better forecasts and increase liquidity significantly on the intraday market.
- Cross-regional intraday trading also needs to improve efficiency and enhance liquidity. Thus, harmonized rules within Japan and improved implicit cross-border allocation methods are needed, such as improved continuous trading or intraday auctions.

Figure 6: Balancing reserve development in Germany since 2011



Source: Hirth & Koch (2019)

2.3 Effects of renewables on conventional power plant use (“cost of variability”)

Cost perimeter

The most controversial and complex aspect of discussions surrounding integration costs is the effect of wind and solar power on the remaining power plant fleet.

When introducing additional capacity (whatever the technology), the output and revenues of other power plants tend to decline. However, because wind and solar power depend on the weather, their output is neither constant nor specifically tailored to electricity demand. Consequently, other power plants and storage units still need to provide capacity when there is no wind or sun to ensure the adequacy of the system. Wind and solar power also alter the structure of remaining demand (the “residual load”¹⁶),

16 The residual load is defined as the total demand minus the generation of variable renewables during each hour of the year.

which now follows different temporal patterns over the day and year.

As a result, the remaining conventional power fleet will be used differently and less frequently. In other words, a power system featuring high shares of variable renewables incentivizes a different cost-effective portfolio of power plants: power plants running fewer hours per year (so-called mid-merit and peak load capacities) will be of greater value to the overall system than baseload power plants. Furthermore, conventional power plants will need to adjust their output more dynamically and provide more operational flexibility,¹⁷ responding to the changes in variable energy production. The effects of renewable variability can also be captured from the perspective of a drop in the market value of renewables¹⁸. It then represents the opportunity costs of matching variable generation and load profiles through storage.

We are witnessing a paradigm shift from an energy system that puts a premium on baseload capacity to one that values flexibility.

This aspect of economic efficiency is just one lens through which to look at the reduced use of existing assets, however. It is also possible to assess the reduced utilization through the lens of greenhouse gas emissions: more renewables results in CO₂-emitting conventional power plants running fewer hours per year. Depending on whether one takes the point of view of the environmentally concerned citizen or the disadvantaged investor, the reduced utilization can be regarded either as positive or negative. The way

this effect is framed ultimately reflects a political choice.

From a technical point of view, most conventional power plants can be operated flexibly. Gas power plants are typically the most cost-effective flexible power plant technologies. But even nuclear and coal power plants, usually considered for baseload purposes only, can be operated flexibly – without costly redesign and significant losses in efficiency (see Annex 1 – Flexible operation of conventional power plants). In Japan, however, nuclear power is not allowed to modulate; in period of high renewables in-feed, it usually runs at full output, leading to higher RES curtailment.

From an economic point of view, however, existing capital-intensive power plants (designed for a world without renewables) are at a disadvantage once renewables are introduced into the system. Power plants run fewer hours, leading to higher specific costs of invested capital and higher average generation costs. Earnings are reduced, and investors may no longer recover their investment costs – a typical example of “sunk costs” for producers. On the other hand, the economics of existing mid-merit or peak-ing power plants may remain practically unaffected by increasing shares of renewables.

The increase in specific generation costs [¥/kWh] of residual generation (i.e. the non-renewable generation) of the system is sometimes used as a metric to calculate the cost of variability. But this approach is disputed by experts because it attributes some cost components specifically to renewables. In addition,

lowering remuneration from the market. When the renewables resources are scarce (night, low wind), however, prices spike on the market, but renewables cannot benefit from those high prices, as they usually do not produce during those hours. Overall, the remuneration of variable renewables is therefore lower than average market prices. This market-value approach reflects the marginal value of electricity at different moments in time. In a system at equilibrium the approach of costs (“cost of variability”) and of value can be proven to be equivalent.

17 Operational flexibility is defined by the overall bandwidth of operation from minimal to maximum load. The ramp rate indicates the speed by which net power feed-in can be adjusted; the start-up time is needed to attain stable operation from standstill.

18 The “market-value” approach is taken by IEA-NEA (2020). During windy and sunny hours, variable renewables power plants produce simultaneously at zero marginal costs, thereby reducing wholesale market prices and

integration costs vary significantly from one system to another depending on the existing power plant structure, storage capacities, the flexibility of the demand and renewable resources. They also depend on the way externalities (such as CO₂ costs) are internalized.

Within research and policymaking circles, there has been debate whether or not those integration costs can and should be attributed to new capacities (such as wind and solar power plants). While some argue that the costs for system adaptation are caused by the technologies that necessitate the adaptation, others argue that system adaptation inherently occurs in power systems and thus cannot be directly attributed to specific technologies. The basic question is whether the reduced profitability of existing power plants is the fault of new entrants or of a specific power plant's inflexibility.

The power system will not be transformed overnight. Renewables are integrated at a rate of a few percent each year; the rest of the power system has time to adapt. The integration will occur in the context of other developments such as power-plant closures (or reinvestment needs) and structural changes in the demand for more electrification (such as electric vehicles and heat pumps).

Situation in Japan

The economics of flexible power system operation is significantly influenced by market design and remuneration options. If Japan is to achieve a low carbon, competitive and secure power system, a refined market design that stresses increased system flexibility is essential.

With the rapid increase of solar power all over the country, and especially in areas such as Kyushu, as

well as with the potential growth of wind power, the rest of the power system requires demand response, flexible generation capacities, smart grids and storage technologies reflecting the need for enhanced flexibility. Electricity markets must be designed to support market actors that provide flexibility options by means of shorter-term electricity markets and products (such as intraday trading) and by adjusting balancing power arrangements. These changes facilitate the efficient integration of renewables into the power system and help avoid wasteful renewable energy curtailment.

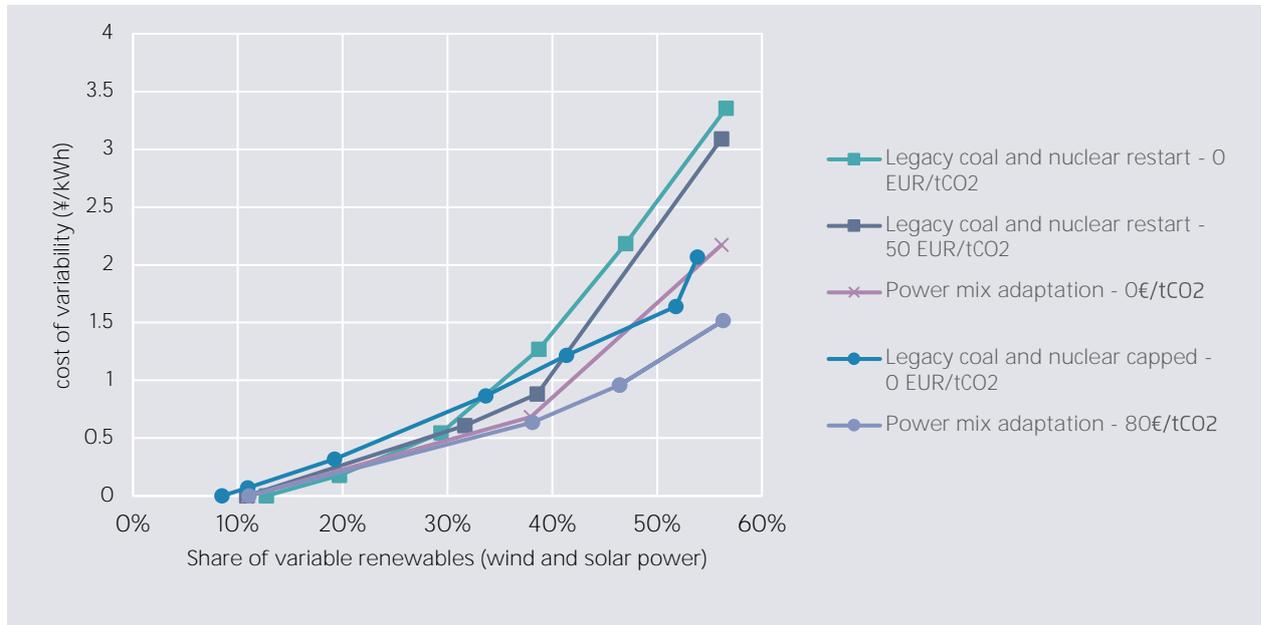
Japan has made some encouraging progress in this regard, with the introduction of day-ahead and intraday markets. Those market segments have gained relevance, in particular since the introduction of gross bidding in 2017. Today, about 35% of total electricity sales are traded on the day-ahead and intraday markets.¹⁹

In 2019 and 2020, new market segments were developed in Japan, in particular a "baseload market"²⁰, a capacity remuneration mechanism, and an electricity futures market. However, those market segments were not designed to provide more system flexibility; in fact, the name "baseload market" itself suggest that Japan is still far from the needed paradigm shift. Discussions are also ongoing for the introduction of a balancing market in 2021.

19 REI (2020c), p.26

20 The baseload market forces incumbents to sell part of their nuclear, coal and hydro production at fixed prices – reflecting historic costs – to the new entrants.

Figure 7: Cost of variability (¥/kWh) for different evolution of the Japanese power system



Agora Energiewende, 2020

Evaluation of the cost of variability in Japan

We calculated the cost of variability in Japan using the PyPSA open-source model, that we calibrated for Japan (dispatch and investment model up to hourly resolution for the 9 grid regions of Japan)²¹. Different scenarios were investigated:

- **Legacy coal and nuclear restart:** existing coal power plants that are profitable are kept in the system. The whole nuclear fleet restarts;
- **Legacy coal and nuclear capped:** existing coal power plants that are profitable are kept in the system. Only the nuclear power plants already running (or about to restart) are kept in the system;
- **Power mix adaptation:** coal and nuclear power are phased-out by 2030.

Several CO₂-price levels were also investigated: 80 €/tCO₂ (~10'000 ¥/tCO₂), 50 €/tCO₂ (~6'300 ¥/tCO₂) and 0 €/tCO₂.

²¹ The python scripts, as well as the input and output data can be obtained upon request.

As described above, the cost of variability²² is an attempt to measure how renewables affect the economics of the remaining part of power systems: with VRE, the utilisation of thermal generators declines, but they are still needed to guarantee adequacy.

The main findings are:

- The cost of variability depends strongly on how the power system adapts to renewables, as well as on how externalities (CO₂) are priced;
- A calculation based on the Japanese power system shows that the cost of variability of integrating 50% variable renewables²³ in Japan reaches about 1.25 ¥/kWh if the power system adapts to renewables (no more baseload power plants – coal and nuclear – shift to gas power plants) and if externalities are priced at 10'000 ¥/tCO₂ at least;
- If the power system does not adapt and baseload technologies remain in the system (high coal and nuclear restart), the cost of variability could be much higher, reaching up to 3.5 ¥/kWh for the same share of variable RES. This is also true for systems with no pricing of externalities (0¥/tCO₂);
- The difference between those scenarios shows that the cost of variability is not inherently caused by renewables, but rather is a consequence of how renewables interact with the rest of the power system. Rather than to speak about integration costs, we should speak about interaction costs;
- These calculations exclude flexibility in demand patterns and new electrification uses, which lower the cost of variability;

- Lower or even negative values (“integration benefits”) could result if there were more flexible system adaptation, lower capital costs or a high valuation of external costs imperfectly reflected in market prices.

Measures to minimize the cost of variability in Japan

The Japanese power markets must be refined to maximize the provision of flexibility and facilitate a shift towards less baseload and capital-intensive technologies and more mid-merit and peaking plants.

- The priority should be to refine market rules, structure and governance in order to provide flexibility at lower cost. Indeed, despite good progress in the liberalization process in Japan, oligopolistic structures prevail, and several barriers exist that still hamper proper competition and flexibility provision²⁴;
- A reformed energy-only market is a no-regret option. Making the energy-only market faster (shorter products, trading closer to real-time) and larger (cross-regional integration) is crucial to meeting flexibility challenges;
- Further integrating short-term markets across regions and vertically linking the different segments (day-ahead, intraday and balancing markets) can reduce flexibility requirements, allowing markets to better reflect the real-time value of energy and balancing resources.

22 The cost of variability is defined here as the increased specific generation cost of the non-renewables part of the system due to higher shares of renewables. The cost difference (with VRE and without VRE) is divided by the added VRE. Mathematically, it can be expressed as follow: (Cost of conventional power with high VRE shares – Cost of conventional power without VRE shares) / added VRE. For an in-depth discussion about this methodology, see Agora (2015), in particular section 2.4.

23 Corresponding to a share of about 60% renewables, including hydro, geothermal and bioenergy.

24 For an in-depth assessment of the current power markets structure in Japan and recommendations for its restructuring, see REI (2020c)

- Baseload and capacity markets should be reformed to reduce inflexibilities and ensure compliance with decarbonization objectives. While the baseload market was introduced to improve competition, its attractiveness is low.
- The capacity remuneration mechanism was introduced to guarantee resource adequacy (the results of the first pilot central auction were announced in September 2020). With increasing shares of variable renewables, security of supply will increasingly become a dynamic issue. Future capacity mechanisms – if any – will need to focus not only on the quantity of capacity, but also on operational capabilities. This change would minimize price spillover effects of capacity mechanisms to energy-only markets while also fostering greater reliability at lower costs. In addition, the mechanism should be compliant with decarbonization objectives: CO₂ emission performance standards (or similar mechanisms) should therefore be introduced into the auction design.
- In the upcoming evaluation and refinements of those market segments, legislators and regulators should perform flexibility and decarbonization compliance checks to abate inflexibilities wherever possible and promote instruments in line with decarbonization objectives.

3 Conclusion – towards a total system costs approach

Thanks to decreasing technology costs, wind and solar power are becoming the most affordable ways to generate electricity even in Japan and thus will inevitably play a major role in the decarbonization of the energy system. One question is, however, still raised frequently: what about the integration costs of wind and solar power? Germany has reached a share of about 25% wind and solar power in 2019, and the integration costs have so far been negligible. Integration costs can be kept low while the power plant fleet and the demand pattern are gradually adapted

through new market design practices and state-of-the-art grid planning.

This short analysis found that the additional cost of integrating 35 percent wind energy and solar PV into the Japanese power system (corresponding to more than 45% renewables in 2030) could reach about 1.5 ¥/kWh. Integrating 50% wind energy and solar PV, corresponding to a share of about 66% renewables in 2035, would come only at a slightly higher cost of 2 ¥/kWh.

Once again, the costs of integrating renewables into a power system depend on several issues, including not only the specifics of a given power system, but also, and perhaps more crucially, on the perspective considered, the applied methodology, the future development of the power system and the underlying market design.

Finally, the concept of integration costs poses methodological challenges, including a clear delineation between the elements that constitute it. A total system costs approach, assessing the total costs of the power system under different scenarios, would circumvent some, though not all, of the uncertainties associated with integration costs. In particular, this total system cost approach avoids the controversial attribution of system effects to specific technologies (cost causation). The approach could be better suited to support political decision-making, which needs to consider big-picture issues rather than cost allocations within a particular energy mix.

Beyond being a neat methodological solution to some of the problems described above, a total system costs approach acknowledges that society as a whole must bear the costs of the power system, regardless of the definition of elements or the form of redistribution. The total system approach is also open to ex-ante considerations, such as stipulations that the energy system's conformity with climate commitments be treated as a must-have. Further steps towards this goal can then be identified.

Annex

The flexible operation of conventional power plants is a major source of flexibility in all power systems.

From a technical point of view, most conventional power plants can be operated flexibly. Gas power plants are typically the most cost-effective flexible power plants. But even nuclear and coal power plants, usually considered for baseload purposes only, can be operated flexibly – without costly redesign and significant losses in efficiency.

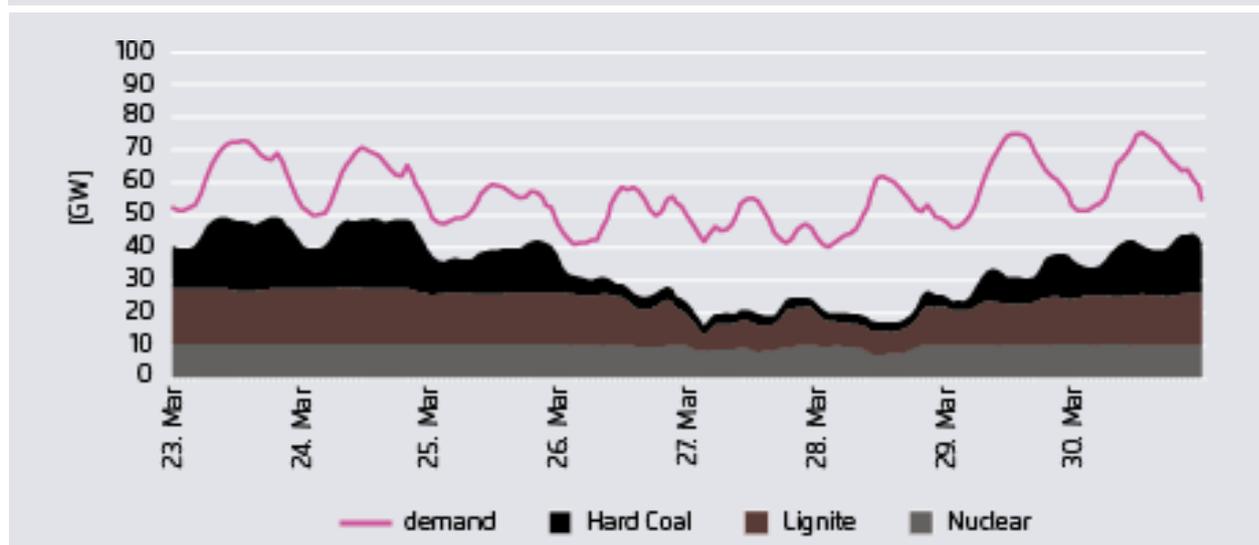
In the case of nuclear power, the French power system shows that modern reactors can follow loads, thereby provide significant operational flexibility for the system. For instance, the Civaux reactor, in operation since 1997, can decrease its output to 20 percent of its maximum load, up to twice a day. More flexibility can be created for new reactors through

suitable design, regular maintenance and sound operation skills. But safety concerns and technical issues prevent a high degree of flexibility in the last phase of each fuel cycle.

Experience in both Denmark and Germany shows that aging hard-coal fired power plants as well as some lignite-fired power plants can provide significant operational flexibility, as can be seen in Figure 6. They can adjust their output every 15 minutes, and even every 5 minutes, to compete on intraday and balancing markets.

A state-of-the-art hard coal power plant can operate at minimum load levels of 25–40 percent of nominal load. There are numerous technical ways to increase the flexibility of existing coal power plants

Figure 8: Power generation from nuclear, hard coal and lignite power plants and demand in Germany, 23 to 30 March 2016



Agora Energiewende (2017): Flexibility in thermal power plants, with a focus on existing coal-fired power plants.

even further²⁵; in Germany, for example, minimum load levels of 12 percent have been achieved. Targeted retrofit measures have been implemented in practice on existing power plants, leading to higher ramp rates, lower minimum loads, and shorter start-up times. Other important enabling factors include the adoption of alternate operation practices along with rigorous inspection and training programs.

But this operational flexibility puts greater strain on power plant components, resulting in shorter lifetimes and higher operation and maintenance costs. Because coal is and will remain the least climate-friendly energy source, the flexible operation of coal power plants can only be a temporary solution anyway – one that enables countries with high shares of coal to add more wind and solar power to the system. In these systems, however, carbon pricing will still be necessary to achieve a substantial net CO₂ reduction.

25 See Agora Energiewende (2017): Flexibility in thermal power plants, with a focus on existing coal-fired power plants.

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