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Distribution planning and pricing in view of increasing shares of intermittent, renewable energy in Germany and Japan

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Distribution planning and pricing in view of increasing shares of intermittent, renewable energy in Germany and Japan

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Abstract

In response to the global climate challenge many countries are faced with increasing shares of energy from renewable sources in their power supply. The integration of RES (renewable energy sources) generation however entails technical as well as institutional challenges for power grids. This study relies on recent experiences of German distribution network operators in network planning and network pricing and looks at their transferability to Japan.

Distributed generation may cause problems of voltage variation and asset overloading in conventional power grids. Technical solutions for these problems are available and well-known yet require considerable investments. The study presents regulatory incentives for network operators to take efficient means to maintain supply quality. With distributed generation self-supplying customers may contribute too little to network cost and new generators and flexible consumers may cause significant investment by uncoordinated siting and operation. An adequate pricing scheme can serve to sustainably finance the infrastructure while at the same time giving incentives to coordinate network users. This study points out options for network charging in grids with high shares of distributed generation from renewable sources.

1 Introduction

A rapid increase in intermittent generation based on renewable energy sources (RES) has been the cause of concern for electricity network planning and operation in the major developed countries including Germany and Japan. A generous feed-in-tariff scheme in both countries has attracted large amounts of RES generation facilities. Particularly, we have seen a surge of photovoltaic (PV) facilities in recent years. These PV plants are usually connected at distribution network level, and distribution system operators (DSOs) are required to incorporate such a large amount of PV while maintaining the reliability of the network.

This situation raises a number of technical challenges for the DSOs in their network planning. Unless they were allowed to curtail the outputs from PVs at their discretion, they would have to significantly upgrade the network, which takes a lot of investment. This in turn leads to several economic and regulatory problems. The DSOs are often incentivized to minimize the cost of operating and maintaining the network as they are usually subject to an overall revenue allowance. Ultimately they would have to consider the best allocation between operating expenditure (OPEX) and capital expenditure (CAPEX) to minimize the total cost while integrating RES generation in their network. To do so, traditional distribution planning and operation may need to be revised to take into account the technical problems caused by the massive amount of RES facilities to be developed. In addition, the role of regulation is important to induce the DSOs to take appropriate actions, and thus the regulators also need to understand the impact of the increasing amount of RES generation on reliability and the countermeasures to be taken. However, the technical problems actually faced by the DSOs are not yet well understood.

Another economic problem is the structure of the network tariffs (fixed charges versus usage-based charges, with or without time-of-use and locational elements, etc.). A related question would be: who is paying for what? With the existing tariff structures, DSOs may not be able to generate enough revenue to carry out the required investment, and also give wrong economic signals to the network users, which may eventually lead to inefficient network development. The issue has been recognized and discussed in the industry as well as academia in Europe[1]. The current practices of network pricing at European DSOs are not well known. Thus, it is hard to evaluate the difficulties associated with designing an optimal tariff structure and the potential for improvement.

The transfer of German experiences to Japan is particularly interesting, as Japan will be going through a series of market reforms. The purpose of this research is to investigate the potential for improvement of distribution network planning and structure of the network pricing, given the requirement to connect a large amount of PV generation facilities based on a case study of the current practice of German DSOs. The results of our research would be particularly useful for other countries including Japan, as they face the problem of a rapid increase in PV installations in many parts of the country.

The report is organized as follows: the next section provides some background on the increasing share of intermittent RES generation at distribution network level in Germany and Japan. Section 3 discusses the challenges and possible solutions in distribution planning given the large amount of

[1] The issue has been discussed also in the U.S. where the number of PV installations has rapidly increased in recent years [e.g. Kind 2013]. However, the discussion seems to be at an early stage, yet.

intermittent RES generation based on international practice with a special reference to Germany. Section 4 discusses the challenges and possible solutions in network pricing for German utilities, and derives some implications for other countries. Section 5 concludes our discussion and presents future research topics.

2 Background on increasing shares of intermittent RES generation and the electricity sector

2.1 Germany

Germany today has more than 800 local DSOs and 4 transmission system operators (TSOs). All of the TSOs and the larger DSOs are at least legally unbundled from other stages of the value chain, if not even in different ownership. However, the requirements for small DSOs with less than 100,000 customers are much weaker. Around 90% of the German DSOs remain integrated with retail and/or generation. The typical German “Stadtwerk” supplies electricity, gas and water while operating the respective networks. Network regulation in Germany is incentive-based and includes a revenue-cap and a quality element. The process of liberalization and unbundling in Germany dates back to 1998, when the implementation of the first European directive on common rules for the internal electricity market started.[2] In recent years a certain level of competition developed in electricity retail. An average customer can choose between 70 to 90 different suppliers, including suppliers of green electricity [BNetzA 2014].

Support for RES generation started as early as 1991. The support scheme has changed over the years. At first there was only a take-off obligation for the network operators and the requirement to connect renewable generators to the network. With the renewable energy act in 2000 a fixed feed-in tariff (FIT) was introduced. The guaranteed remuneration for a fixed period of time, for many technologies 20 years, boosted the development of RES generation over the years. The development since 1990 is depicted in Figure 1. With RES generation now supplying about one fourth of the total electricity consumption, the RES support is now transitioning to a market premium scheme. Existing plants that were built under the FIT will still continue to receive their fixed remuneration for the period set out in the respective laws. Yet new and larger plants under the new support scheme will only receive a premium on top of the market price for their electricity and will be in charge of selling their electricity.

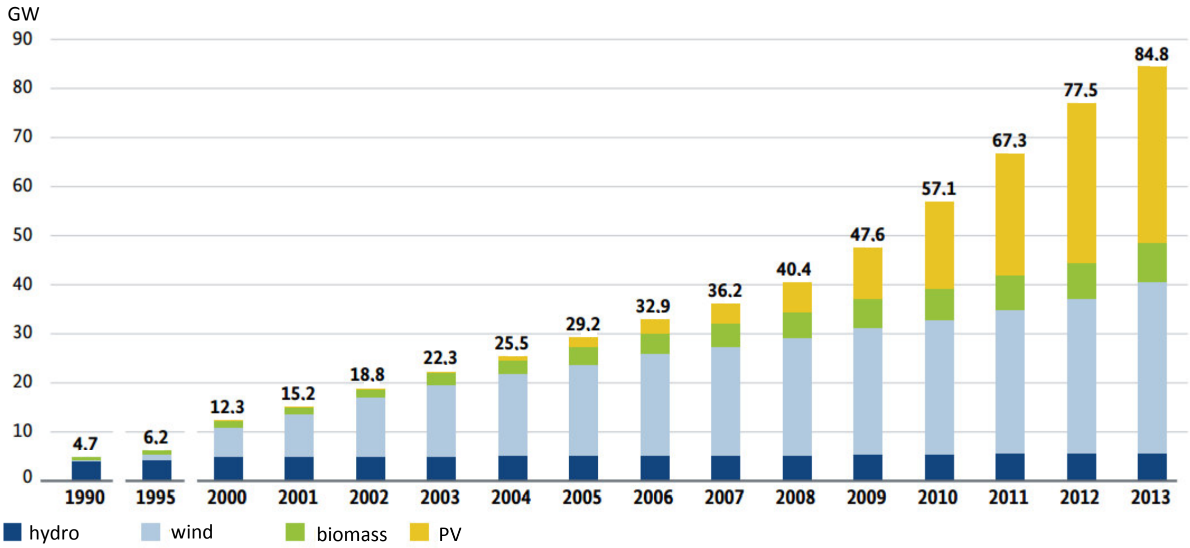

Figure 1: Development of installed RES capacity in Germany [BMWi 2014a]

[2] For a more detailed description of the process see Brunekreeft et al. [2014].

Today Germany has almost 85 GW of installed RES capacity. Even though the change of support scheme is meant to slow the development down, the installed capacity will continue to rise in the future. According to the renewable energy act the share should grow to over 120 GW within the next 15 years and the goals of the single states within Germany would add up to more than 200 GW. This development is predicted to entail a significant amount of network expansion. The additional investment needed for network expansion due to RES integration will amount to between 23 and 49 billion € in the upcoming 15 years. The yearly estimation is depicted in Figure 2.

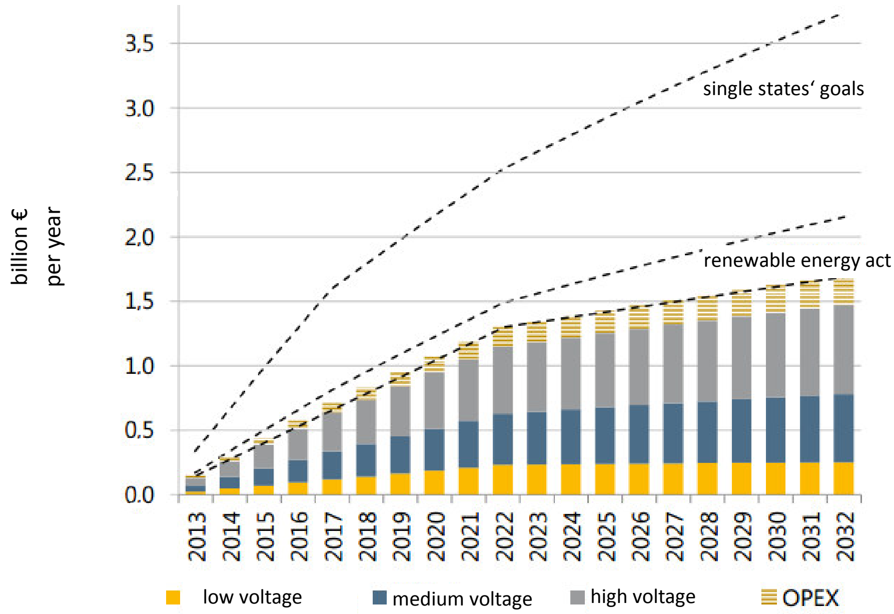

Figure 2: Yearly additional expenditures for integrating RES generation in distribution grids [BMWi 2014b]

The prediction of these large investment needs has led to a discussion of measures to reduce the investment need, including innovative network operation and innovative network pricing.

2.2 Japan

In Japan, regional electricity distribution networks are owned and operated by ten vertically integrated utilities with accounting separation between the network and other competitive segments. Except for Tokyo Electric Power Co. (TEPCO), they are privately owned companies[3]. The electricity retail markets for commercial and industrial customers have been opened up for competition since 2000, but the market for residential customers is regulated.

The Great East Japan Earthquake in March 2011 and the nuclear accident at Fukushima Daiichi plant compelled the government to initiate further reform of the industry. An experts subcommittee on electric power system reform was organized to discuss the institutional framework for the necessary reform. In February 2013 the committee submitted the final report that outlined the road map. The reform proceeds in three stages: the first stage is to facilitate wide area coordination of system operations by establishing the Organization of Cross-regional Coordination of Transmission Operation (OCCTO) in 2015. The second stage is to fully liberalize the retail market by allowing retail choice for residential customers in 2016. The third stage is, although the law was not enacted, to

[3] The majority (54.69%) of the share of TEPCO is owned by the government through Nuclear Damage Compensation and Decommissioning Facilitation Corporation.

secure the neutrality of the network by separating the transmission and distribution from vertically integrated utilities through legal unbundling.

Historically, the share of intermittent RES generation (not including hydro power generation) has been low in Japan, only accounting for less than 1% of total generation. A FIT for RES generation was introduced in 2012. The electric utilities are obliged to connect RES facilities to the network and purchase all their generated power. The purchase price is considered as generous. For example, when FIT was introduced in 2012, the purchase price of PV for residential was set to 42 yen per kWh[4], approximately twice the retail price for residential customers. The purchase price has been subsequently revised and is now somewhat lower. The current prices of PV and wind power are shown in Table 1.

	PV			Wind		
	10kW and over	Less than 10kW	Less than 10kW (with cogeneration)	20kW and over	Less than 20kW	Offshore
Purchase Price per kWh	32 yen plus tax	37 yen	30 yen	22 yen plus tax	55 yen plus tax	36 yen plus tax
Contract Period	20 years	10 years	10 years	20 years	20 years	20 years

Table 1: Purchase price and contract period for PV and wind under FIT[5] [ANRE 2014]

Such a generous FIT scheme has resulted in a rapid increase in RES generation projects certified by the government, especially non-residential photovoltaic. Table 2 shows the cumulative capacity in service as well as capacity certified under FIT by plant types.

(MW, as of September 30, 2104)

	PV (residential)	PV (non-residential)	Wind	Small & Medium Hydro	Geothermal	Biomass
Capacity in service	7320	10580	2660	240	0	1220
Capcity certified	3140	65840	1310	330	10	1350

Table 2: Status of RES facilities under FIT [ANRE 2014]

There are regional differences in the rate of increase in PVs, as shown in Figure 3. For example, in Kyushu area (southwest part of Japan) served by Kyushu Electric Power Company, if all the capacity were connected, then the installed amount of capacity would exceed regional peak demand.

In September 2014, Kyushu Electric Power Co. announced to temporarily suspend the review process for integrating RES generation facilities under FIT, due to the concern about the oversupply of power from PV. By October 2014, five utilities in total (Kyushu, Shikoku, Okinawa, Tohoku, and Hokkaido) were forced to temporarily suspend the process of integration (that is, putting the requests on hold) for similar technical reasons. Electric utilities had been allowed to curtail RES output from PV or wind with 500kW or more for up to 30 days per year without compensation[6]. They had to compensate such RES generators if they curtail after exceeding 30 days per year. These rules were revised in January 2015[7]. Now the utilities are allowed to curtail all certified facilities if necessary[8], for up to 360 hours for PV per year without compensation (up to 720 hours for wind). RES generators are also obliged to install remote control system for the curtailment. In the special case that the expected

[4] approximately 32 € cents per kWh, in January 2015, 1 yen converts to 0.0076€.

[5] Small gas engines are often offered together with small PV by Japanese gas utilities.

[6] A minimum of one hour of curtailment is regarded as „one day “.

[7] The changes do not apply to facilities whose application for connection was completed before the revision.

[8] Facilities with more than 10kW are prioritized.

amount of RES generation exceeds the capacity limit of the utilities' grid, then those utilities can become "designated utilities" who are allowed unlimited curtailment without compensation. Hokkaido Electric Power Company used to be the only such designated utility but now there are 6 others.

Although a discussion for revision of the FIT scheme is also likely to emerge, a fundamental reconsideration of network tariff regulation will be required in the future. As of this writing, the regulatory framework for transmission and distribution companies after legal unbundling is not yet clear.

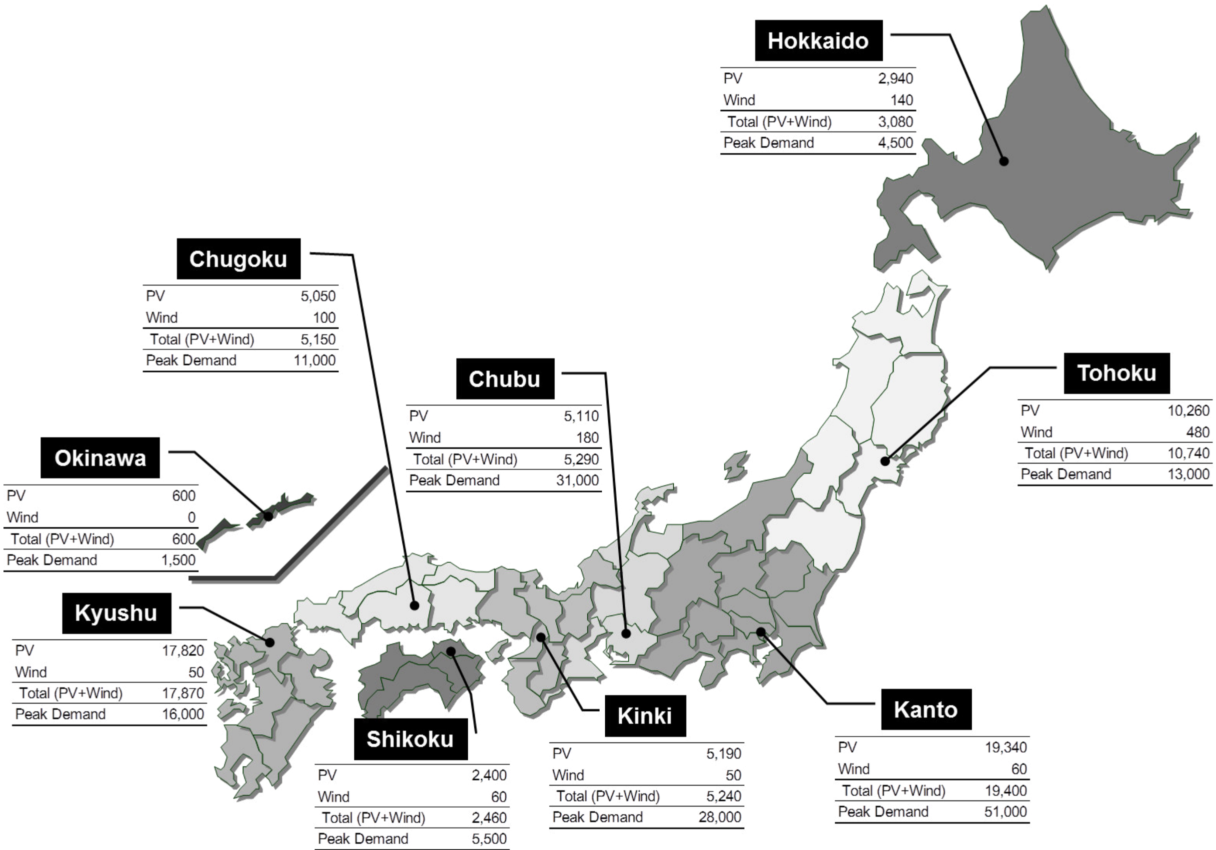

Figure 3: Status of certified RES facilities by areas of utility in MW[9] [ANRE 2014] and [FEPC 2014]

[9] Data is represented until May 2014, "Peak Demand" is the summer peak in 2013. Kanto is mainly served by TEPCO. Chubu is served by Chubu Electric Power Co. and Hokuriku Electric Power Co. Kinki is served by Kansai Electric Power Co.

3 Challenges and possible solutions in distribution planning

3.1 Current system of distribution planning

Currently, the distribution system operator (DSO) makes the network planning taking into consideration the uncertainties over the next 5-10 years. A typical flowchart of distribution network planning is shown in Figure 4 [Grond et al. 2013]. The objective function for distribution network investment planning is usually to minimize the total cost of investment, operation and maintenance, subject to the technical constraints, including the thermal limit of a line, the range of voltage deviations, and avoiding energy not supplied. Japanese DSOs (now as a part of the vertically integrated utilities) also employ these flowcharts [ESCJ 2014] [TEPCO 2012].

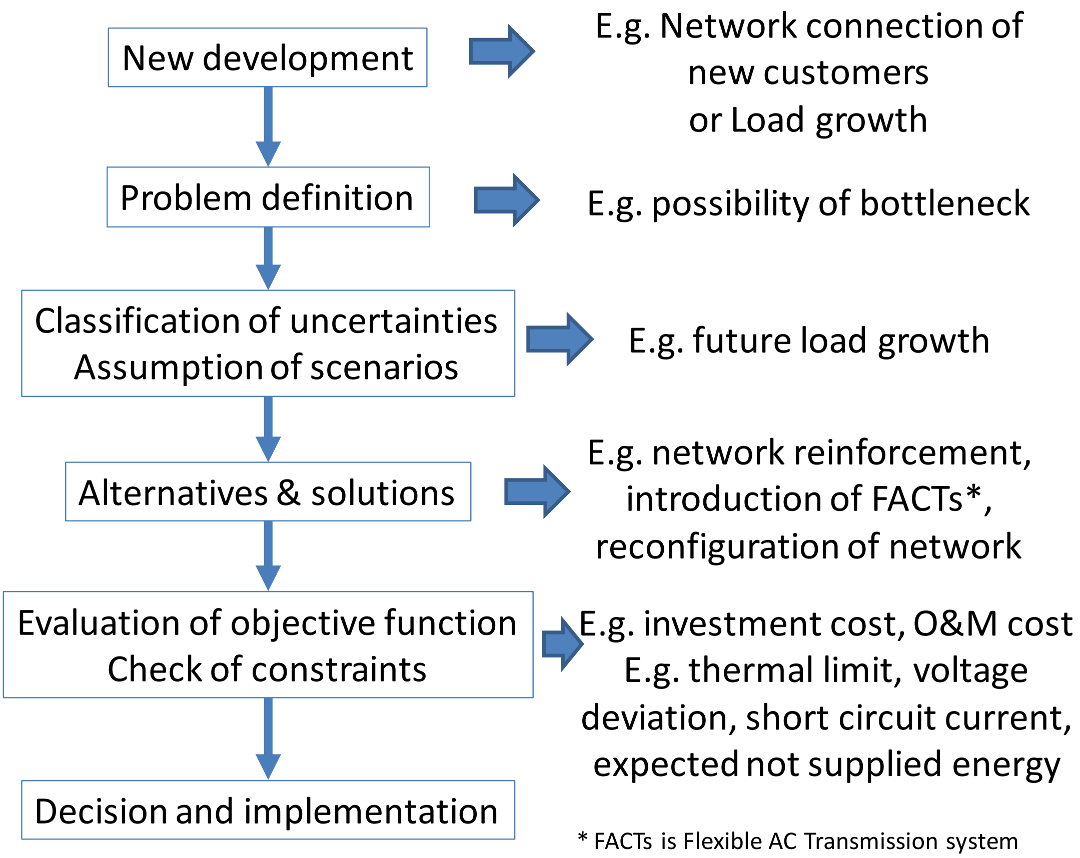

Figure 4: Flowchart of distribution network planning (own figure based on Gond et al. [2013])

Before the massive introduction of RES generation, the requests for network connection were rather rare. Therefore DSOs were able to process the requests along this flowchart and did not have much trouble with the queue for connection.

3.2 Experiences and anticipated problems

With a large amount of RES generation being promoted by the policy, the DSOs are faced with a large number of new connection requests from RES facilities. Large and unevenly distributed generation facilities require huge network investments. However new investment for the network may be stranded if there is a change or cancellation of the plan of those distributed generations. The current method of network planning evaluates only the worst case in a sense that the peak demand is realized, but this could be inappropriate because the technical constraints may be violated also in other times. In addition, it is difficult to process such a large number of the requests for connection. All of these factors make the network investment planning difficult for DSOs under the existing method.

DSOs would also have to deal with a technical problem that they have not experienced previously. Historically, the electricity used to flow from transmission to distribution network. When a lot of RES facilities are connected to the distribution network, the electricity may flow from distribution to transmission network [Eurelectric 2013a]. This reverse power flow may cause a voltage rise. In European countries, the reverse power flow is observed in more than 1% of 8,760 hours per year recently. The Italian case is shown in Figure 5. The total number of transformers is about 3,300 in the Italian distribution system. Reverse power flows from distribution to transmission network is now caused more frequently by high penetration of RES generation. One of the solutions is to upgrade the transformers with larger capacity. Although it incurs cost, it can be reduced by the cooperation between TSO and DSO.

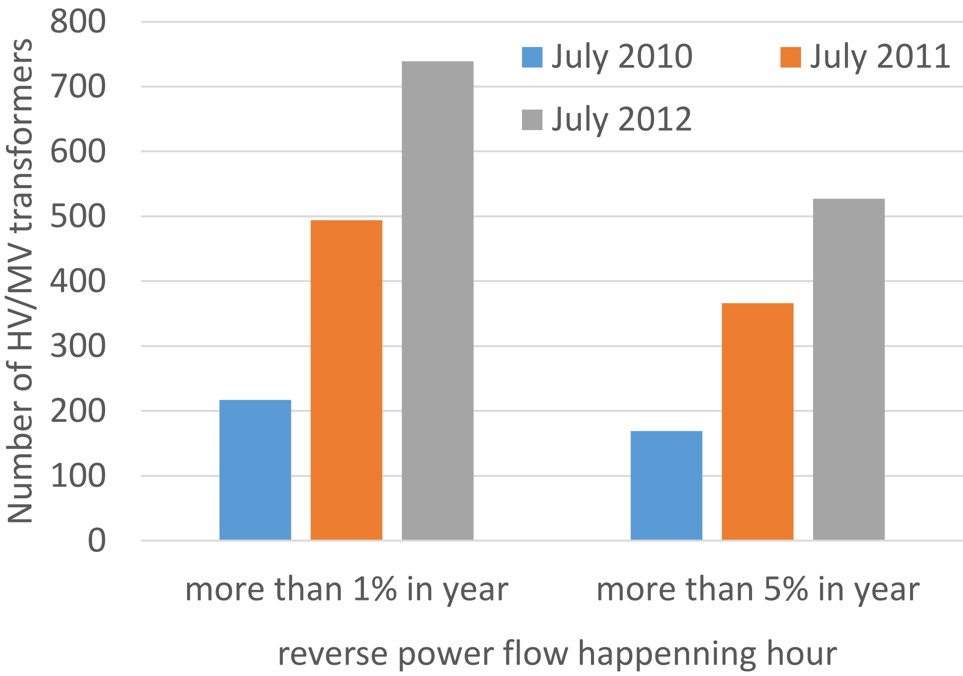

Figure 5: High/medium voltage transformers working in reverse power flow [Cazzateo et al. 2013]

A work group of the International Council on Large Electric Systems (CIGRE WGC6-19) gathered information on the methods and the processes of distribution network planning from several DSOs for a technical brochure [CIGRE C6 2014]. From the survey, the following main tasks of network planning have been identified as illustrated in Figure 6:

- analysis of market information and regulation
- forecast of demand and distributed generation
- network analysis
- identification of alternative countermeasures to technical problems
- prioritization of alternatives

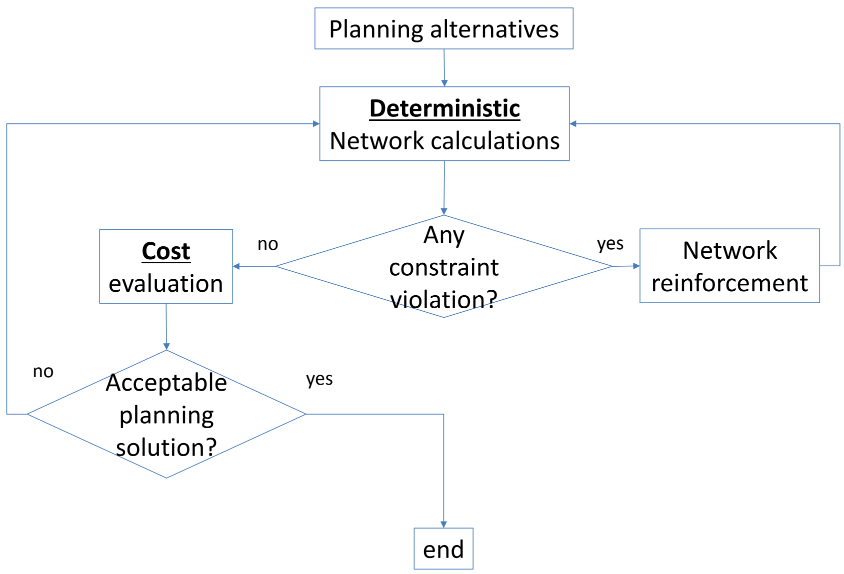

Figure 6: General planning framework for passive networks [CIGRE C6 2014]

However, DSOs are not yet fully prepared for demand response, connection of electric vehicles and advanced metering infrastructure. In a typical network planning process DSOs depend heavily on demand forecasts. For example, network analysis is extensively based on future demand scenarios from the forecast. Methodologies for demand forecasts include historical trending. It is difficult to forecast the future demand from emerging technologies like distributed generation or demand response based on historical data. Nonetheless DSOs have to manage the situation before historical data that reflects the changing environment is available. The solutions currently considered are shown in Table 3.

Challenge	Current solution
Voltage rise	Power factor 0.95 lagging
	Voltage/ Var control
Network capacity	Reinforcement of network equipment
Network power factor	Limits / bands for demand and generation
Sources of reactive power	Capacitor
Network asset loss of life	Strict connection design

Table 3: Present solutions for integration of distributed generation[10] [CIGRE C6 2014]

They are regarded as reactive rather than proactive, with which the traditional investment planning is called "fit and forget". Now DSOs seek to establish proactive distribution network planning by utilizing demand response and batteries to control voltage/Var in order to reduce cost.

High penetration of RES generation creates not only the problem of demand forecasting but also the problem of power quality and reliability of the network. Power quality is an important indicator for

[10] An increase of distributed generation could lead to an increase of short circuit current. This impact is not included in Table 3, perhaps because at the moment, the amount of distributed generation connected to the network is not large enough to make it a critical issue.

the electricity sector. There are several indices for power quality in distribution networks, for example[11]

- System Average Interruption Duration Index: SAIDI (respectively ASIDI, Average System …),
- System Average Interruption Frequency Index: SAIFI and
- voltage deviation.

In Germany the regulator publishes data on continuous unplanned interruptions of more than 3 minutes[12]. Low voltage in Germany refers to the voltage level between 400 V and 6 kV while medium voltage indicates the voltage between 6 kV and 36 kV. The SAIDI applied at low voltage available in Germany is a weighted average by the number of customers. The ASIDI applied at medium voltage is a weighted average by the rated apparent power of transformer.

Power quality in Germany is considered comparatively high, with an overall average of SAIDI of 15.32 minutes per year in 2013. At low voltage the indicator is as low as 2.47 minutes and at medium voltage 12.85 minutes as shown in Figure 7. The lower SAIDI at lower network levels may reflect the higher requirement of customers at this level or may stem from the fact that cables, which are more reliable than overhead lines, are often deployed at low voltage levels.

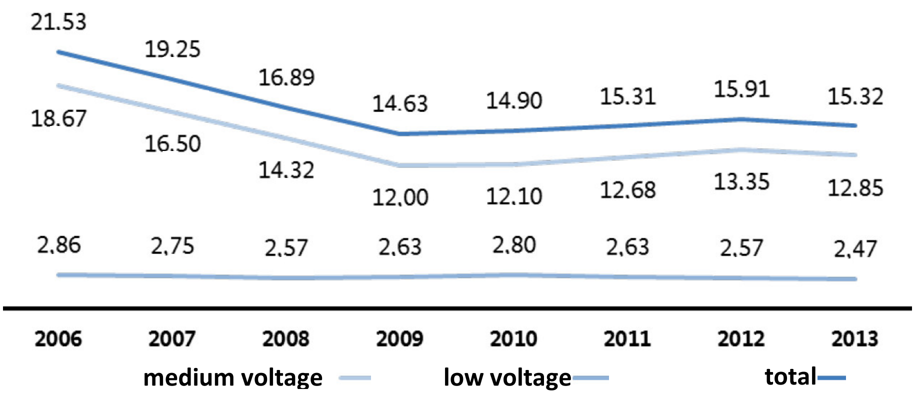

Figure 7: Development of SAIDI and ASIDI in minutes/year in Germany [BNetzA 2015]

These indices indicate that reliability is not necessarily deteriorated with integration RES generation. Historically DSOs maintain the adequacy of power systems with a certain buffer. TSOs and DSOs make investment planning and operate the system to maintain reliability indices within a certain range while considering cost-effectiveness. In their operation, TSOs and DSOs make good use of existing network equipment to decrease energy not supplied under technical constraints. When system security of the power system cannot be maintained even through the maximum utilization of the existing facilities, TSOs and DSOs consider power system enhancement to secure a stable supply of electricity. Investment planning and operation helps each other in order to improve SAIDI or ASIDI.

It seems that for German DSOs the SAIDI plays a significant role in distribution grid planning. The incentives for maintaining a high level of power quality for the DSOs stem from the concession contract with the cities as well as from federal regulation. In the concessions contract, the DSO is committed to maintain power quality. If power quality drops significantly the DSO faces the risk of losing the concession in the subsequent negotiations (and thus losing the foundation for the entire

[11] Frequency deviation is also used. However, frequency fluctuation is handled by the TSO.
[12] As defined in EN50160

business model). However, concessions are only negotiated every 10 years. Some DSOs think that the monetary incentive from the regulation cannot drive additional investments to increase power quality, as the quality aspect in the regulation is negligible, while other DSOs claim significant returns from the quality element in regulation.

The greatest technical challenge of integrating RES generation takes place at low voltage level. Most transformers in the grid today are not remotely adjustable and the scope to react to fluctuating generation is therefore limited. In the worst case, excess generation could cause damage to transformers or customers appliances. However, this problem is usually dealt with before it arises and the grid is upgraded as needed, maintaining better reliability with increasing shares of RES generation. DSOs also consider countermeasure against the technical issue, like forecasting demand, thermal limit and voltage problem.

The load profiles of smaller customers are approximated by standard profiles. In this case, the grid design does not need an exceedingly large buffer for deviations. With increasing shares of RES generation, it will need more excess capacity. However, large buffers are less affordable in view of the amount of investments required. In order to decrease the investment, it becomes more important to monitor the grid, the power flows and the asset usage in real time. The DSO prefers cables in urban areas and overhead lines in rural areas, where much more RES generation are expected to be installed. Maintenance is easier on overhead lines but the reliability of cables is higher. The decision is a matter of cost and the regulation prescribes under which conditions the additional cost[13] for cables is justified. For the DSOs this is often also a political issue as cables are more accepted than overhead lines.

Regarding the reverse power flow problems in transformers, expanding the transformer capacity is a typical counter-measure. For the voltage problems in rural areas, counter-measures are: Building parallel lines, next to the existing lines, installing smart transformers. Curtailment of RES generation would also be an effective countermeasure.

3.3 Recent modifications

With high penetration of RES facilities, European DSOs have to manage a more uncertain situation. DSOs consider several modifications concerning distribution network planning in view of the changed situation in the power system [CIRED C6 2012]. These are shown in Table 3. In addition, the objective function including reliability factors has been introduced recently in the evaluation [Paulinder 2013], otherwise DSO revenue is linked to the reliability index [Eurelectric 2013b].

[13] Cables can be 2.5 times more expensive than overhead lines.

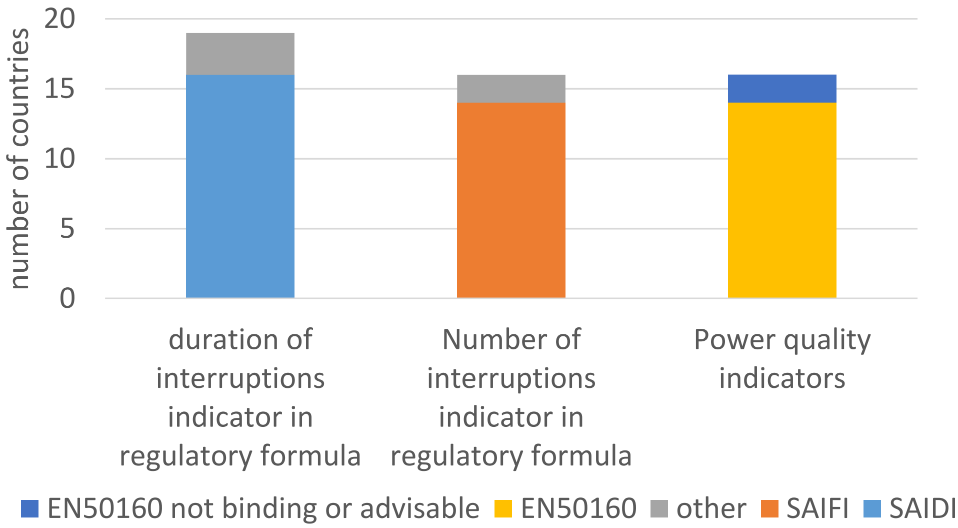

Figure 8: Performance on supply and power quality in regulation [Eurelectric 2013b]

There are more than 800 DSOs in Germany. In order to increase management efficiency, the revenue cap as incentive regulation has been introduced into network regulation in Germany. It is difficult to improve the reliability with only incentive regulation. Therefore a quality element has been introduced in 2012 [BNetzA 2014]. That is, allowed revenue of the distribution network increases as quality of supply improves [Pechan 2014]. However the impact of the quality element depends on the bonus or penalty. A high bonus may cause overinvestment and a high penalty may lead to underinvestment. The distribution of the actual bonus or penalty for German operators is shown in Figure 9.

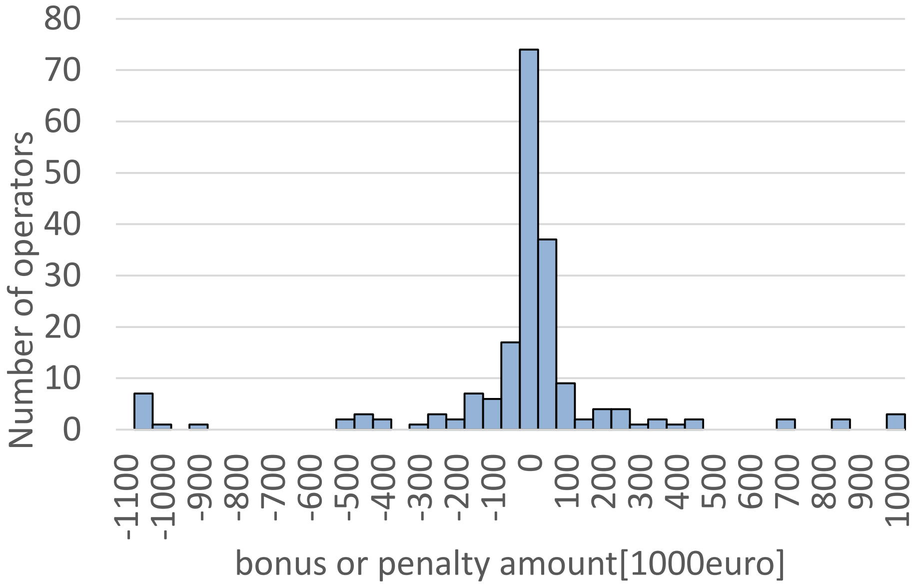

Figure 9: Bonus and penalty amounts for individual operators [data from BNetzA 2014]

In the coming years DSOs expect to consider new solutions in network investment planning as displayed in Table 4.

Challenge	Future solution
Voltage rise	Demand side management
	Voltage/ Var control
	Storage
Network capacity	Non-firm access
	Storage
	Demand side management
Network power factor	Constant voltage mode
Sources of reactive power	Storage
	SVC
	control of wind turbines
Network asset loss of life	Constant voltage mode
	Asset condition monitoring

Table 4: Future solutions for challenges with integrating distributed generation [CIGRE C6 2014]

Japanese DSOs also have to consider reliability in distribution network planning without a clear reliability goal. According to the rules, the DSO should invest in order to shorten the interruption period [TEPCO 2012]. Customer Average Interruption Duration Index (CAIDI) and Customer Average Interruption Frequency Index (CAIFI) of Japanese DSOs have been very low[14] except for the fiscal year (FY) 2010 (Figure 10). CAIFI and CAIDI in the fiscal year 2010 were high due to the damages caused by the earthquake on March 11th 2011 as well as the subsequent rolling blackout.

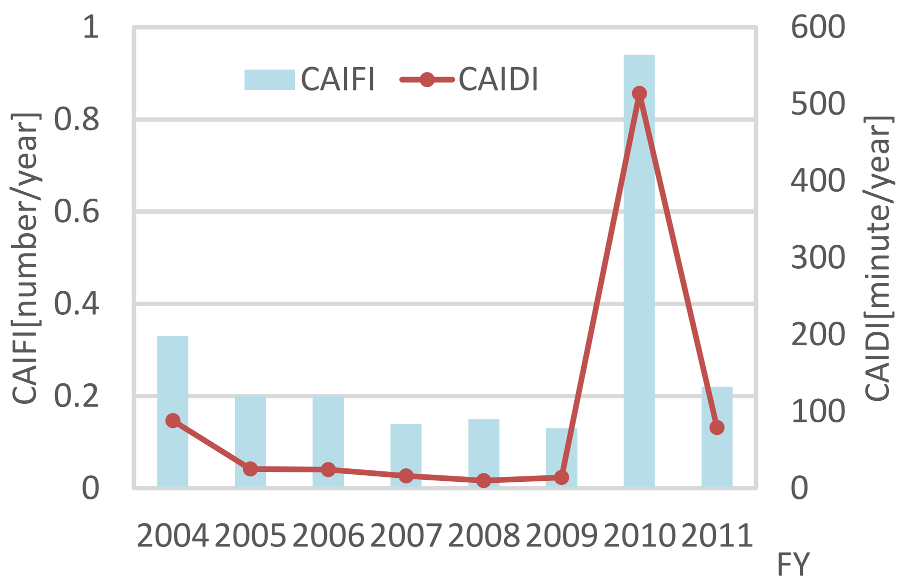

Figure 10: CAIDI and CAIFI in Japan [FEPC 2012]

Unlike in Germany, network tariffs in Japan are determined under a cost-of-service regulation. Therefore Japanese DSOs can make investment in order to maintain reliability as long as they are prudent. The cost of Japanese DSOs may increase with high penetration of RES generation in a couple of years while keeping CAIDI or CAIFI at a low level.

[14] Note that CAIDI and CAIFI used in Japan reflect planned and unplanned interruptions.

4 Challenges and possible solutions in network pricing

4.1 Current network pricing scheme in Germany

In Germany network operators charge for network connection as well as for network use. Regulation determines the total network cost for each network operator [§4-11 StromNEV] who then collects the approved cost through network charges. As metering is liberalized, operation of metering equipment, metering and billing is charged separately in addition to the network charge [§17(7) StromNEV].

Basically, network connection charges are shallow and cover only the immediate cost of connection from the nearest network connection point to the customers' facilities [§9 NAV]. The shallow charge applies to all consumers and to generators at medium and low voltage or of less than 100 MW [§9 NAV, §1+8 KraftNAV]. In addition to the shallow charges, network operators may collect a deep charge from connections larger than 30 kW[15] covering up to 50% of the cost incurred for upgrading the existing grid to accommodate the new connection's additional feed-in or withdrawal [§11 NAV]. Both parts of the connection charge are collected only once and determined according to a standard calculation and citing other comparable cases.

In Germany, only consumers pay for network use [§15(1) StromNEV]. Network use charges are fixed for one year [§15(2) StromNEV] and do not reflect the distance between consumption and generation [§17 StromNEV]. In 2013 the network use charges were on average 1.78 ct/kWh for industrial customers, 5.49 ct/kWh for businesses and 5.83 ct/kWh for private households. The differences stem from the structure of the charging scheme as described below.

Regulation prescribes cost-reflective charges for customers [§16 StromNEV] depending on network level, metering scheme and utilization hours [§17(1) StromNEV]. Customer charges consist of a load (€/kW_{peak}) and an energy component (ct/kWh) [§17(2) StromNEV]. At low voltage level the metering scheme for the majority of customers only registers consumed energy and not actual load. Load metering in intervals of 15 minutes is only required for customers with a consumption larger than 100,000 kWh per year [§ 12 StromNZV]. Smaller customers can apply for load metering, which is often beneficial for customers with consumption larger than 80,000 kWh. All other customers are accounted for based on type-specific standard load profiles (in Figure 11 at the bottom). Those standard customers pay only an energy charge (ct/kWh) [§17(6) S.1] and the network operator may decide to additionally collect a base charge (€/year) [§17(6) StromNEV S.2]. Regulation requires that the total charge for the standard customer is similar to the charge resulting from the regular scheme (of energy and load components, as described below) using the standard load profile [§17(6) StromNEV S.3]. Furthermore base and energy charge shall be in 'appropriate' relation [§17(6) StromNEV S.2]. Figure 11 depicts the distribution network charging scheme in Germany.

[15] The charge then only applies for the part of the connection which is above 30 kW.

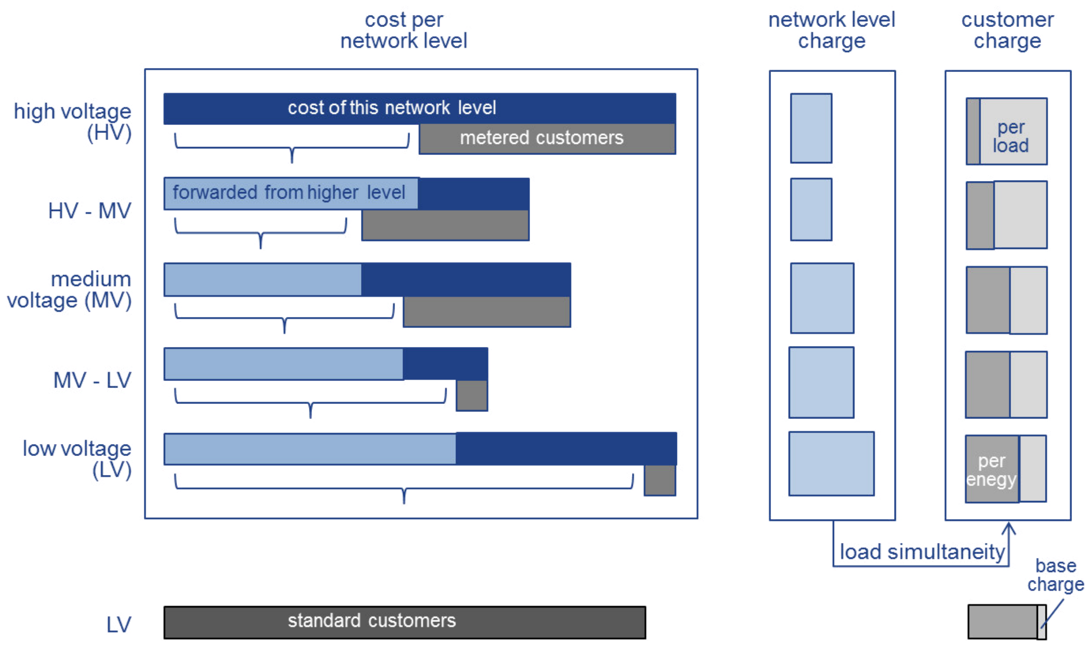

Figure 11: Network use charges in Germany (own figure based on Gottlob [2014])

Table 5 gives an example of the calculation for a simplified system of two subsequent network levels. On the first level there is one customer plus the withdrawal of the subsequent level; at level 2 there are two more customers.

		network level 1			network level 2		
		total	customer 1	next level	total	customer 2	customer 3
1	cost at network level	45,000 €			30,460 €		
2	forwarded cost	55,000 €			79,540 €		
3	total network level cost	100,000 €			110,000 €		
4	peak load	8.8 kW	4.0 kW	8.0 kW	8.0 kW	8.0 kW	8.0 kW
5	withdrawn energy	55,000 kWh	5,500 kWh	49,500 kWh	49,500 kWh	14,850 kWh	34,650 kWh
6	utilization		1375 h	6187 h		1856 h	4331 h
7	simultaneity		0.50	0.85		0.30	0.70
8	simultaneity factor		0.45	0.87		0.36	0.64
9	network level charge	11,364 €			13,750 €		
10	total customer charge		20,460 €	79,540 €		39,851 €	70,149 €
11	customer load charge		6,818 €	52,194 €		- €	31,176 €
12	customer energy charge		13,642 €	27,346 €		39,851 €	38,974 €

Table 5: Example calculation of network charges for two subsequent levels with three customers

For each network level the general charge (postage stamp) is total cost for this level divided by the level's yearly peak load [§16 StromNEV (1)] (in Table 5: row 3 / row 4 = row 9). Network level charges are forwarded from higher to lower network levels according to the energy forwarded to the lower level and the lower level's peak withdrawal [§14(1) StromNEV]. A customer-specific simultaneity factor translates the network level charges to consumer charges [§16 StromNEV (2)]. The total customer charge[16] (load and energy charge) is the product of network level charge, customer peak

[16] Load and energy charges follow from this equation, as the simultaneity factor sums (1) a fixed component (the starting point of the function) driving the load part of the charge and (2) component that varies with the utilization hours (the inclination of the function) driving the energy part of the charge.

load and customer simultaneity factor (in Table 5: row 9 * row 4 * row 8 = row 10). Withdrawn energy enters into the simultaneity factor via utilization hours (yearly consumption divided by yearly peak load, in Table 5: row 5 / row 4 = row 6). Hence the load and energy part of the total charge are determined by the function as depicted below in Figure 12.

The simultaneity factor is a value between 0 and 1 illustrating the probability that a consumer contributes significantly to the yearly peak load of the network level. A simultaneity factor of 0 corresponds to a probably low contribution and a value of 1 reflects a likely high contribution [StromNEV Appendix 4]. The network operator defines a simultaneity function for each network level which assigns every customer a factor based on his utilization hours[17]. The simultaneity function consists of two straight lines intersecting at 2,500 utilization hours. For 0 utilization hours the network operator can assign a simultaneity factor between 0 and 0.2 and for 8,760 utilization hours regulation prescribes a factor of 1. The function must further ensure that the sum of all charges matches the revenue-cap [§20(1) StromNEV]. Figure 12 depicts the simultaneity functions for the example above.

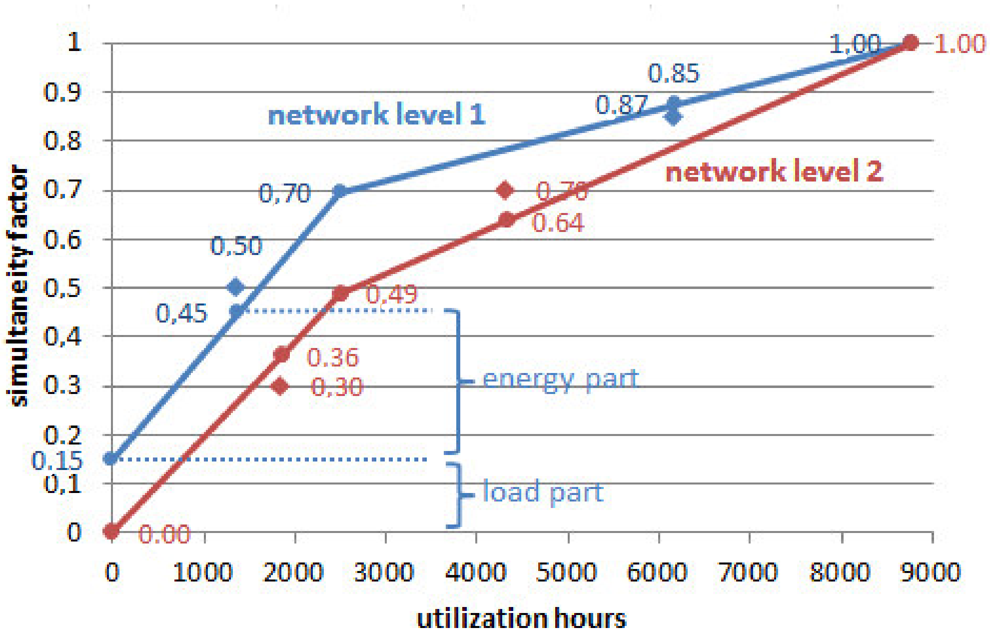

Figure 12: Example simultaneity functions for two subsequent levels with three customers

Consumers with special characteristics are eligible for reductions on the network charges as presented above. Consumers whose peak load does not coincide with the peak load of the network level can receive reductions of up to 80% [§19(2) StromNEV S.1][18]. Large customers who withdraw more than 10 GWh per year from the network and reach high utilization hours can also claim reductions [§19(2) StromNEV S.2] reflecting the avoided network cost [§19(2) StromNEV S.4]. Regulation determines that customers with utilization hours of more than 7,000h are eligible for reductions of up to 80%. To customers with more than 7,500h the network operator can grant reductions of up to 85% and to customers with more than 8,000h of up to 90% [§19(2) StromNEV S.3]. Importantly, these reductions do not follow the logic of high simultaneity for high utilization

[17] Consumers with few, high capacity peaks can demand monthly charges to better reflect their network use [§19(1) StromNEV].

[18] These reductions have been introduced in 2013; before those customers were completely exempted.

hours. Instead the reasoning is high predictability and facilities based competition for the network supply of these customers. The revenue foregone due to the reductions is cleared between network operators and socialized among all network users in a surcharge [§19(2) StromNEV S.15]. Furthermore network operators can offer reductions for controllable consumers who allow the network operator partial control over their devices [§14a EnWG]. The network operators presently use rather simple ripple control for night store heaters or heat pumps.

While generators do not pay network use charges, the network operator remunerates generation at distribution level for avoiding network charges at higher network levels [§18(1) StromNEV][19]. The idea is that electricity generated at lower levels (distributed generation), where the consumers are located, avoids transmission and distribution at higher network levels and thus defers the respective charges. Network operators feeding into higher network levels also receive this remuneration for avoided network charges [§18(1) StromNEV]. The remuneration corresponds to the higher level's energy charge for the avoided energy and to the higher level's load charge for the avoided peak withdrawal[20] [§18(2) StromNEV]. Hence it does not necessarily reflect actual avoided network cost.

4.2 Experiences and anticipated problems

The current network charging scheme as presented in the previous chapter is not fit for increasing shares of decentralized and fluctuating generation. With the ongoing change in the electricity system further conflicts are anticipated.

The main problem stems from the fact that the charging scheme primarily serves to finance the infrastructure but does not provide good signals to coordinate network users. New generators locate in remote areas with weak network infrastructure, consumers increase peak loads when simultaneously using new electric devices and so forth. As a consequence network operators face high network investments which could possibly be partially avoided in a more coordinated electricity system. Additionally, the charging scheme provides some perverse incentives to avoid network use by self-generation or prevent network users' flexibility. The following chapters discuss these two problems.

Smart metering brings another change factor into the German energy system. Today the majority of customers' energy consumption is only metered as a monthly or even yearly sum. Only customers with high consumption (of more than 80,000 to 100,000 kWh) are metered continuously[21]. European legislation requires a broader rollout of smart metering infrastructure. This means more precise and less aggregate metering on the one hand, and control equipment on the other hand. It is likely that Germany will follow this requirement for a large number but not all customers. While the exact rollout scheme is still under discussion, the development of smart metering will have a significant impact on network charging.

[19] This only applies if the generator does not simultaneously receive subsidies for RES generation or combined heat and power generation.

[20] Avoided energy is defined as the difference between energy drawn from the higher level and energy supplied at the lower level and avoided peak withdrawal defines as the difference between the lower level's peak withdrawal from the higher level and the peak withdrawal within the lower level.

[21] Continuous metering is required for customers above 100,000 kW. Smaller customers can request continuous metering at their own expense, which in practice is common from around 80,000 kW per year onwards.

Another aspect in the debate which is not discussed further in this paper are the regional differences between network charges within Germany. Generally the Eastern distribution networks have higher charges. This is partially of historical origin as networks required significant reinforcement after unification and hence depreciation is different than in the West. Furthermore, the Eastern regions are less densely populated and less industrialized. Thus, network cost distributes over fewer consumers. To a significant part, higher charges are also due to high shares of RES generation, especially onshore wind, in those areas. The difference in network charges is increasingly seen as a structural disadvantage. Discussions evolve around socializing the extra cost for the integration of RES generation in a nation-wide mechanism. Yet, this cost is difficult to determine. A uniform network tariff throughout Germany is one possible alternative which on the downside foregoes the opportunity to coordinate users through network charges.

4.2.1 Coordination between network and generation or demand

With the increasing shares of RES generation in the German electricity system, generation has evolved in remote areas with comparatively low load. In areas where the grid was historically not built to distribute local generation this means expansion and reinforcement. The fluctuating and somewhat uncertain nature of feed-in from wind and solar sources adds to the problem. Regulation guarantees feed-in for RES generators at any time. The network operator can only curtail as last resort if network stability is in danger. Network customers do not receive any incentives to voluntarily refrain from feeding in during contingency situations. Thus rare peaks of solar generation can cause significant investments. Network expansion may not always be the most efficient solution to these challenges. A PV panel may only reach its nominal peak load in very few hours in summer around noon, yet the network needs to be reinforced to distribute this peak. Wind peaks often do not coincide with local demand and require additional transformer capacity to the transmission level. As shown in Figure 13, studies find that curtailment of only a small percentage of this energy can cut the necessary network investments significantly.

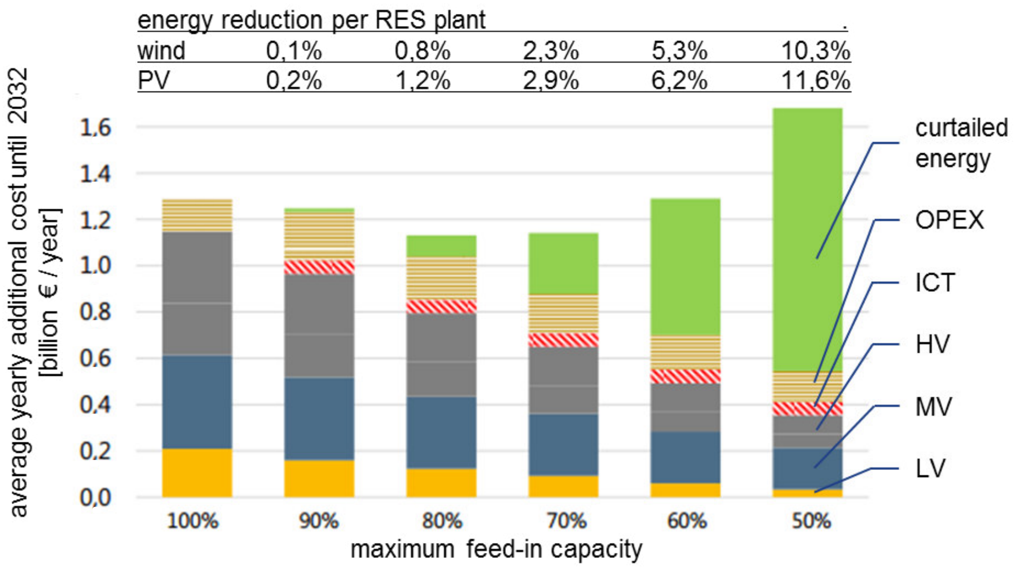

Figure 13: Network expansion needs with RES curtailment [translated from BMWi 2014]

Alternative siting may as well reduce the investment need and flexible demand can help to prevent regional electricity surpluses. The activation of the demand side, however, bears potential problems. Network operators anticipate additional electric devices. Network expansion is then needed to accommodate additional loads. This could be the case for electric vehicles, heat pumps and small scale storage in residential areas. Considering the flexibility of these and other consumers is a vital part of balancing the system in the future. Yet, their synchronization due to aggregation or market signals may increase peak loads beyond the simultaneity considered today. Again it seems that improved coordination of this network use could economize on network expansion. Furthermore, charging based on yearly peak load, as it is in place today, partially prevents consumers' flexibility. The incentive is to keep overall peak load as low as possible while increased consumption at times of local surplus would increase peak load.

4.2.2 Self-supply

Small decentralized generators are often directly linked to a consumer. This is the case for example for on-roof PV plants. Small-scale storage can increase their share of energy used on-site. Today in Germany, of the some 600 TWh total supply, 2.8 TWh are self-supplied from decentralized photovoltaics and another 44 TWh self-supplied in industry. From the network operator's perspective this generation is netted with the on-site consumption. As a consequence withdrawal from the network reduces significantly. The consumer may even rely on the network only for backup in case of maintenance or contingencies. Thus, the grid capacity to be kept available for these customers by the network operator remains the same[22]. In the German kWh-based charging system these customers contribute less to the overall network cost than regular customers. As a consequence, the overall network charges increase and in a vicious circle the incentive to economize network use grows further[23]. Besides the perverse incentive to refrain from using the network, self-consumers' highly unpredictable, non-standard load profiles cause additional problems for network operation.

4.3 Discussion on modifications in Germany

Network charges can set signals for location and operation of consumers as well as generators[24]. The shortcomings of the present German charging scheme have led to a discussion on modifications of network charges.

The network operators' discretion to modify network charges in response to the challenges presented above is small. The total amount to be charged at each network level and the rough charging scheme consisting of load and energy charge according to the simultaneity factor is fixed by regulation. Hence network operators cannot increase profits by modifying charges[25]. Although the calculation method for connection charges is highly standardized, network operators can influence the simultaneity factors of certain customer groups by setting the simultaneity function. This only concerns the starting point of the function (which can vary between 0 and 0.2) and the intersection point of the two straight lines that constitute the function. (The intersection has to be at 2500

[22] The network capacity needed by a self-consumer may even increase in case the energy produced is fed back into the grid in times when it is not consumed on-site.

[23] Self-consumers are also exempted from a number of surcharges usually collected together with network charges (i.e. renewable energy surcharge, concessions surcharge, etc.) making the incentive even stronger.

[24] Signals from network charges may get diluted on their way to the network user. They compete with possibly conflicting signals from the market or from taxes and surcharges. Additionally in Germany, retailers forward the network charges to consumers and may decide to average out some differentiation to avoid transaction cost.

[25] Network operators will use their influence to keep charges stable and to avoid customer complaints. The influence of local politics on network operators is often high despite the fact that they may be private companies. This is due to the need to renegotiate concessions contracts every 10 or 20 years and due to representation of government officials in the boards of network operators.

utilization hours, and is thus fixed at one axis but can be freely set on the other.). Furthermore, base charges for standard customers can be increased up to an 'appropriate' relation between base and energy charge. The level of reductions is negotiated between customer and network operators.

The modifications of the charging scheme, that the challenges presented above require, need to be implemented in the regulation and cannot be brought about only by network operators. The debate in Germany revolves around fixed and differentiated charges as well as contributions from the generation side. The arguments will be presented in the following subsections. The discussion also includes modifications of abolition of remunerations for distributed generation and reductions for industrial customers as well as leveling network charges throughout Germany. These last aspects, however, will not be dealt with in this paper.

4.3.1 Capacity charging

One possible modification in the current charging scheme is a shift to capacity-based charging[26]. Currently, a base charge, i.e. monthly fixed charge, exists for standard customers. These customers are not charged for occurred load but instead pay a fixed charge. Metered customers face a charge component based on load, i.e. used capacity. The further discussion in Germany includes a fixed charge component for connected capacity or even entirely flat charges. It can be observed that many network operators have introduced and increased base charges in the recent years. Many also advocate a further increase within the thresholds accepted by the regulator. This is seen as a trend towards capacity charges.

The introduction of a capacity-based charge or a sufficiently high base charge adjusts the contribution from self-supplying customers. It ensures a certain contribution to network cost from all customers connected for whom the network operator keeps network capacity available. As connected capacity is one of the major drivers for network capacity such a charging scheme can also set incentives for network users to economize on connected capacity and thus avoid network expansion. An entirely capacity-based, fixed charging scheme would also reduce complexity, and hence transaction cost, for networks users as well as network operators significantly. In addition, the increased connected capacity, from new devices, such as electric cars or decentralized storage, would be reflected in the network charges.

On the downside, a capacity charge or an increased base charge foregoes the incentives for energy efficiency which come with energy-based charging. Environmental groups even fear incentives for an increase in energy consumption. Also, capacity-based charges will have negative distributional effects for those customers who consume very little and benefit those with higher than average consumption. An entirely capacity-based charging scheme also conflicts with the remuneration for avoided network charges currently paid to decentralized generators. With entirely fixed charges there are no charges to be avoided by these generators. In addition, simultaneity of consumption is another important driver for network capacity and is not reflected in capacity-based charges. Therefore in Germany a compromise with a certain part of the charge as capacity-based fixed charge and another proportion as energy-based charge is likely. Furthermore, the incentives linked to connected capacity may be more efficiently reflected in connection rather than use charges. Smart

[26] Such a charging scheme based on available capacity - rather than occurred load is in place for German gas networks.

metering may enable load metering for large parts of today's standard customers and thus render the discussion about base charges obsolete[27].

4.3.2 Differentiated charging

Network use charges in Germany are fixed for a year and vary between networks and network levels. Part of the current debate revolves around a stronger differentiation according to time and location of network use. Ideally, charges set signals for efficient siting and operation of network users. Particularly flexible customers will shift consumption in response to these incentives. It is expected that the rollout of smart meters will enhance the options for differentiation significantly. Various degrees of time and locational differentiation are possible. Higher charges during predefined high consumption periods prevent regular peaks for example during noon or in the evenings when electric vehicles return home to charge. Real-time differentiation of charges may even coordinate simultaneous network uses. Higher charges in constrained parts of the network steer network use where it is most relevant, for example in residential areas with self-generation and flexible devices, while leaving other areas unconcerned. Individual charges are already in place in Germany for certain customer groups, such as industrial customers, heat pumps, storage heating or other storage. This concept can be interesting for other types of customers and can be decoupled from direct control by the network operator.

Opponents of differentiated charging assume that locational factors other than network charges dominate the siting decisions of network users. The potential for flexible operation, i.e. demand response, is thus higher than that of influencing location. However, smaller customers without flexible devices are expected not to respond to the signals from dynamic charges at all. The incentives should therefore be targeted mostly at businesses, industry or special device customers. In order to keep transaction cost low, network operators generally prefer direct control of customers over steering via price signals. The sector currently discusses authorizing network operators to curtail a small amount, e.g. 3 to 5 % of decentralized generators' yearly energy output to economize network expansion [c.f. BMWi 2014b]. It remains unclear, however, to what extent an unbundled network operator can interfere directly with consumption and generation[28]. Also in the vein of containing transaction cost network operators prefer to organize coordination with suppliers or aggregators rather than single customers. The effort and additional cost of implementing dynamic charges may only be justified for the larger and flexible customers.

4.3.3 Generation-component

Generators currently do not pay network use charges in Germany. The reasoning is that the incidence of cost is with consumers at any case since generators would forward their use. Also the rule was established to enable easy access for new generators and to enhance competition in generation. However, the problems described in 4.2 are strongly linked to decentralized generation,

[27] Despite the question of whether load-based charging is preferred over capacity-based charging, there is a debate about whether the current German regulation prevents base charges for any customer for whom metered load data is available.

[28] Another uncertain aspect is the responsibility for deviations from the expected load profiles. Currently, the network operator is in charge of balancing deviations from standard load customers.

which in the current charging system hardly receives any signals from the network[29]. Consequently, there is a discussion about introducing a generation component in network charges.

With large parts of the new generation locating in remote areas and additional generation needed in the South of Germany, a generation component reflects the cost of network expansion in generators' siting decisions. In cases when rare generation peaks congest local networks, a generation component sends signals to economize on network expansion by altering generators operation patterns. In view of the problems from self-suppliers feeding only their excess electricity into the grid when needed, a generation component (in combination with the adjustments mentioned in the previous sections) provides incentives to prevent the increase of the network level's peak load.

Common criticism of a generation component in network use charging involves the following arguments. Generators in Germany have suffered from low wholesale prices in the recent past and find themselves in strong international competition.[30] Additional charges which will be passed on to the wholesale market and eventually consumers will weaken their position. For German industrial customers, who bear only a small share of network cost, the resulting reduction in network charges may be modest while the increase in wholesale prices may have a substantial effect. Additionally, most of the generators which lack coordination are RES generators. In view of influencing siting decisions a generation component was needed only for newly built plants, which are mostly RES generators. They receive financial and political support and thus society may not accept additional charges for them. Lastly, the additional effort of charging a whole new customer group is seen critically by the network operators.

4.4 Evaluation and applicability to Japan

A large amount of intermittent renewable energy connected to the distribution network, especially solar PV, raised concern about financing the electricity distribution network in some major countries, including in the U.S. (especially in California). Reforming the structure of electricity distribution network charges has been discussed in the U.S. and it may well be discussed in other countries including Japan in the near future. Although the support scheme for renewable energy differs between countries, these countries would face similar problems as discussed in this report with reference to Germany.

In the U.S. there has been a discussion on capacity charging for electricity distribution companies to cut "the utility death spiral" of revenue shortfall due to the increasing amount of distributed solar PV, encouraged by "net metering" scheme. Historically, the electric utilities collect all of the revenue from small customers through volume-based charges. These utilities try to have or increase the fixed charges to offset declining sales caused by the solar PVs. Besides skepticism that the utility death spiral is exaggerated, there have been criticisms from various stakeholders to the reliance on fixed charges: Fixed charges to lower volumetric charges discourage energy efficiency, and adversely impact on small customers using very small amount of electricity. Therefore the discussion has been quite similar to that of Germany as described in 4.3.1. It is expected to be similar in other countries as well.

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[29] The remuneration for avoided network charges can be considered a network signal. However, this signal suffers from the standardized procedure of calculating the avoided charges as well as from the general shortcomings of the current charging system.

[30] The European regulator ACER is currently active to harmonize generation components within Europe.

To the extent that the cost structure of electricity distribution network is characterized as natural monopoly, two-part tariff structure may well be justified as second best. It is also necessary to compromise to some extent to avoid distributional impacts associated with fixed charges. These arguments are, however, based on the assumption that those who connected to the distribution network are users of electricity from the network. Consumers with solar PV and connected to the distribution network are able to sell their electricity generated by PV and also buy electricity from the network as needed. These consumers actually have the "right" to buy and sell electricity thanks to being connected to the network under uncertainty of their net demand. From the financial economics perspectives, these customers are holding such "options" and should be paying for premium of these options. This would perhaps give some background for generation-component issue. Perhaps exact pricing would be complex and less practical, but this would be another notion to think about when we discuss the fixed charges for distribution networks. [31]

Regarding a more differentiated charging, such as time-of-use tariff, there have been skepticisms about the effectiveness when implemented among the small (i.e. household) customers not only in Germany but also in the U.S. and Japan. Various field experiments suggest that even small customers react to price signals and change their behavior [32], although the cost-effectiveness of smart meters would still be ambiguous as economic impact of demand response alone may not be sufficient to cover the cost of smart metering. However, Japan, for example, has already decided to roll out smart meters to all the customers including households, in principle, by early in the 2020s and Germany envisages a partial rollout within a similar time frame. This would open up opportunities to more awareness of the time-varying nature of cost and new technology that enables the consumers to adjust the consumption profile without incurring much transaction cost.

Finally, we would like to point out that coordination between the network and RES generation may well be necessary to reduce the uneconomic burden on the network operators, as discussed in 4.2.1 with reference to Germany. The curtailment of generation from RES is the main countermeasure taken currently in Japan to solve the problem of excess energy supply from RES as described in 2.2. Some issues remain even with the revised curtailment. The first issue is how to ensure fairness in implementing the curtailment. Some arrangements may be necessary in case the curtailment is implemented too often for a particular RES generator. The second issue is how to mitigate risks associated with the curtailment. If the possibility of curtailment is perceived as economic risk for investors in RES projects, then it would discourage investment in RES generation. The experience of Japan for the next several years with the revised curtailment will demonstrate the effects of forced curtailment. Differentiated network charges for generators may send more efficient signals for generators to take the condition of the network into account in their siting decision and partially also in operation. As a consequence the need for forced curtailment by the network operator is reduced.

[31] For a more detailed discussion on this notion, see Pati et al. (2001).

[32] The results of various field experiments of demand responses in Japan can be found in the website "Japan Smart City Portal" (http://jscp.nepc.or.jp/en/).

5 Conclusions

In response to the global climate challenge many countries are experiencing or will be faced with increasing shares of RES in their power supply. While Germany has been a front runner for several decades, Japan is rapidly increasing its RES generation to comparable levels. The integration of RES generation however entails technical as well as institutional challenges for power grids. This study relies on recent experiences of German distribution network operators. The report distinguishes two main trends: network planning and network pricing of a distribution grid with large-scale RES.

First, large-scale integration of RES puts the distribution grids technically under severe stress. Conventional power grids are not designed for distributed generation and may struggle to accommodate reverse flows and uncertain generation patterns. Problems of voltage variation and asset overloading can be the consequence. Thus, changes in network planning and ultimately additional investments are required to keep supply quality constant. Furthermore the introduction of distributed and fluctuating generation changes the use of the network. Regarding network planning and asset management, the study draws two main conclusions:

- First, technical solutions to the experienced and anticipated problems from the integration of RES generation are available and well-known.)
- Second, incentives for network operators to take efficient means to maintain supply quality with RES generation can be implemented in regulation.

Second, large-scale integration of RES puts the structure of the distribution network charges under stress. Changes in tariff structures are discussed currently. Self-supplying customers only rely on the network for residual supply or feed-in of excess production. While requiring the same or even additional network capacity, their financial contribution is lower under the current charging schemes. Likewise new generators and flexible consumers may cause significant investment by locating in a remote area or operating during times when the network is already constrained. An adequate pricing scheme should sustainably finance the infrastructure while at the same time give incentives to coordinate the network users. Regarding network charging the study makes the following main conclusions:

- First, base or capacity charges (per kW), rather than withdrawn energy (per kWh), are a means to reflect the network capacity provided to self-supplying network users.
- Second, involving network users, i.e. generators and consumers, via differentiated network charges may be an alternative to forced curtailment. Additionally, differentiated network charges can also coordinate demand from new and flexible consumers.
- Third, exposing generators as well as consumers to network charges is the basis for them to take system cost into account with location and operation.

The network planning and network charging options discussed in this paper stem from the case studies of Germany and Japan. Yet, they are discussed or can be related to many other countries with increasing RES shares. Investments into network assets take time and increase network cost. Institutional changes are an additional and partially alternative measure. The effects of changes in grid infrastructure and institutional framework do not show immediately but over time. Hence, consideration of the issues discussed in this report is necessary already when developing RES generation rather than when the mentioned technical problems are already observed.

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